GL Garrad Hassan

OPTIONS FOR COPING WITH HIGH RENEWABLES PENETRATION IN SCOTLAND

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CONTENTS

0 EXECUTIVE SUMMARY

This study considers plausible developments in electricity generation from renewable sources in Scotland, to 2030. In conjunction with the client, two scenarios for renewable generation were developed which are believed to bracket the range of likely outcomes. The scenarios are based on known volumes of projects under development, estimates of available resource and constraints, stated targets, and achievable construction rates. Assumptions are also made about changes to the fossil and nuclear generation in Scotland.

Two scenarios for development of electricity demand in Scotland were also developed, again believed to bracket the range of likely outcomes.

The combination of scenarios gives four cases, and it is shown that in the most conservative case (low renewables, demand growth), renewable electricity production in Scotland in 2030 equates to 89% of gross electricity consumption. In all other cases, the figure is well over 100%. The target for Scotland is now 80% by 2020, with aspirations for 100% by 2025, and 'largely decarbonised' electricity *supply* (as distinct from consumption) by 2030. Therefore these targets are well within reach.

These figures are calculated on an annual basis. Therefore there will be periods within each year when Scotland is exporting large amounts of electricity, mostly from renewable generation. When renewables production is low, Scotland will import significant amounts of electricity. Over the year, exports will dominate, and will be significantly higher than at present. It is possible that one effect will be reduced use of the large conventional (fossil and nuclear) generating stations in Scotland, which could in principle result in some being closed.

The large volumes of exports calculated in this study depend on there being sufficient purchasers. The export from Scotland will not swamp the likely future demand for renewable electricity in the UK (determined by UK targets), but the study has not looked at the relative competitiveness of Scottish renewable electricity exports against other renewable generators in the UK.

It is shown that 'security of supply' will be satisfactory, provided the British electricity system itself is secure, and provided there is sufficient interconnection capacity to Scotland. It is not meaningful to talk of the security of the Scottish electricity system alone.

It is shown that it is not necessary for security of supply for there to be any coal, gas or nuclear generating stations in Scotland.

It is shown that the interconnection capacity required for a secure electricity system is less (probably substantially less) than the interconnection capacity which may be economically justified by the value of electricity exports.

The effects of possible future electrification of heat and of transport are quantified, and it is shown that these, though important, will not significantly change the broad conclusions.

1 SCOPE

This report has been prepared by Garrad Hassan (GH) for Friends of the Earth Scotland (FOES), to consider credible options for generating electricity from renewable sources in Scotland equivalent to 100% of Scotland's annual electricity consumption, in 2030, and in particular to examine alternative approaches to ensuring security of supply with very high levels of renewables penetration.

In this respect 'credible' means:

- Economically credible: the net costs to the country will not be prohibitively greater than achieving the established target for renewable electricity.

- Technically credible: reliability of electricity supply will not be reduced below current levels.

This report updates the methodology and results established in previous GH work in this area, and which was used as the technical basis of a report by FOES and partner organisations [1].

This report makes use of many recent publications which cover similar areas. In particular, National Grid has consulted on its views on coping with high renewables penetration in the GB electricity system in 2020 [2], [3], and others have considered very high renewables penetrations at the European level, and also including North Africa [4]. In particular, reference is made to the recent detailed Roadmap to 2050 produced by the European Climate Foundation [5].

Section 2 provides the background to the work.

Section 3 summarises the renewable resources in Scotland.

Section 4 describes current electricity generation and demand in Scotland, and how these might evolve to 2030. 'High' and 'Low' scenarios are developed for both electricity demand and renewables generating capacity. The scenarios are intended to bracket the range of likely outcomes.

Section 5 discusses security of electricity supply with high renewables penetration.

Section 6 shows the electricity production that can be expected to 2030 given the scenarios defined in Section 4, and discusses their feasibility.

Section 7 provides general conclusions and recommendations.

2 BACKGROUND

2.1 Targets for reductions in emissions and energy consumption

Current commitments, targets and aspirations are summarised in this section [6] [7].

2.1.1 European Union

Targets for 2020 are:

- Greenhouse gas (GHG) emissions: 20% cut (from 1990 levels), or 30% if others do the same. A change to 30% is currently under discussion by some parties.
- Energy supply: 20% of all energy supply to be renewable
- Demand: 20% reduction in total energy demand

2.1.2 United Kingdom

Targets for 2020 are:

- GHG emissions: 34% cut, or 42% if the EU target is raised as noted above.
- Energy supply: 15% of all energy supply to come from renewables. Likely to be achieved by:
    - Electricity: 30% renewable
    - Heat: 12% renewable
    - Transport: 10% renewable
- Demand reduction: under Article 4 of the Energy End-Use Efficiency and Energy Services Directive the United Kingdom has adopted and aims to achieve an overall indicative national energy savings target of 9% over the period 2008 to the end of 2016.

2.1.3 Scotland

Targets for 2020 are:

- GHG emissions: 42% cut
- Energy: 20% of total Scottish energy use coming from renewables [19].
    - Electricity: 80% of 'gross electricity consumption' (defined below) from renewable sources, with an interim target of 31% by 2011. 22% was achieved in 2008.

   - Heat: A target of 11% of heat energy to be supplied from renewable sources.

   - Transport: A 10% target for renewable transport.

- Demand reduction: the Scottish Government consulted late in 2009 on targets in the range of 12-22% reduction by 2020 on 2010 levels.

Longer term aims for Scotland are set out in the Climate Change Delivery Plan [8], for 2030 and 2050:

- Emissions: 80% cut by 2050

- Electricity: largely decarbonised by 2030. More recently, the First Minister announced an aspiration for 100% or more of gross consumption from renewables by 2025.

- Heat: largely decarbonised by 2050, with significant progress by 2030, through a combination of reduced demand, energy efficiency, and a major increase in renewable or low carbon heating.

- Transport: almost complete decarbonisation of road transport by 2050, with significant progress by 2030.

2.2 ECF Roadmap to 2050

The European Climate Foundation funded a detailed technical and economic study of means to achieve 80% Greenhouse Gas (GHG) emissions reduction in Europe by 2050 [5]. The study covers all main sources of emissions, but has most detail on electricity supply. The main conclusions of this study which are relevant for this work are as follows:

- The aim can be achieved at reasonable cost. In some circumstances the total cost to the European economy can be less than the 'baseline' (i.e. with no particular measures to reduce emissions beyond those already in train). Even under pessimistic assumptions the cost to the economy is not great. Security of electricity supply is effectively unchanged.

- It is essential to achieve virtually complete decarbonisation of the electricity supply industry (>95% reduction).

- Three options for decarbonisation of electricity supply were evaluated, all of which achieved the aims, differing in the relative proportions of nuclear, carbon capture and storage (CCS) and renewables technologies used for electricity generation. The mixes studied varied from 40% renewables, 30% CCS and 30 % nuclear to 80% renewables, 10% CCS and 10% nuclear. A fourth option of 100% renewables was also found to be technically achievable.

- All options depend critically on major efforts to reduce energy demand, which is the lowest-cost and lowest-risk step towards achieving the aim.

- All options are broadly comparable in costs and risks, although the nature of the risks differs between options.

- Electricity demand in 2050 is roughly the same as in 2010, as the effects of energy efficiency are approximately balanced by the effects of electrification of heat and transport.

- The lowest-cost way to deal with the variable renewables (wind and PV) is by interconnection, i.e. transmission system reinforcement. This was found to be cheaper than options using more energy storage, more back-up generation, or more curtailment of renewables output.

- Public acceptance of substantial transmission reinforcement, CCS plants and nuclear plants was seen as a major risk.

- Capital expenditure in the period 2010 – 2020 has to be high, most of which is for new generating plants. This is balanced by subsequent rapid reduction in operating costs (principally fuel costs, because of the higher production from renewable generation), so that over the period to 2050 the total cost of energy supply is broadly similar to the baseline.

- No technical breakthroughs are required. Cost reduction for each technology comes from assumed 'learning rates'.

- A rapid start is required. Costs of delay are high. In particular, the analysis assumed that existing generating plant would be retired at the end of its normal life. A later start would require more rapid changes, which would mean that some generating plant would be retired before the end of its normal life. This is costly.

- Although unit *electricity* costs are likely to rise, total household *energy* bills are unlikely to increase significantly, and may even fall as a result of efficient electrification in the heating and transport sectors.

For Scotland, some relevant conclusions can be drawn.

- The study does not contain sufficient regional detail to provide quantitative results for Scotland.

- The conclusions are in broad agreement with current UK and Scottish Government policy.

- Scotland's very large renewables resource and potential carbon storage capability will be valuable.

- There is likely to be very substantial development of international transmission systems. The study included a UK-Norway link. A link to Iceland was not found necessary to meet the aims.

3 RENEWABLE ENERGY POTENTIAL IN SCOTLAND

Scotland has very large resources of renewable energy. In many cases, for practical purposes the resource will ultimately be limited by public acceptability and by cost, and at present we do not have a good idea of where those limits will lie. However in the short and perhaps medium term, renewable energy production is limited by the rate at which projects can be consented, financed and constructed.

Scotland could become a major exporter of electricity relying only on its hydro, onshore wind and offshore wind resource, so all other renewable technologies can be seen as having eventually to compete against those three. This competition will be on cost, including costs of using the electricity transmission network.

The main resources can be characterised as follows:

Hydro

A significant resource is still available, largely as smaller 'run of river' schemes, i.e. without reservoirs.

Onshore wind

There is a huge resource, limited principally by public acceptance of the visual effects, noise limits, and land areas designated for biodiversity or landscape interest. Variability results in higher costs for using the transmission system than most other renewables, but this is only important at high penetrations. A recent study for DECC [20] concluded that onshore wind was the cheapest of all generating technologies except new nuclear, assuming that nuclear could realise the potential savings expected from substantial series production. If that assumption is not fulfilled, then onshore wind is the cheapest source of electricity from around 2015 onwards.

Offshore wind

This also is a huge resource. There are no significant limits due to public acceptance, although biodiversity issues will create some constraints. Costs are currently higher than for onshore wind, nuclear, coal and gas generation, but there are prospects of substantial cost reductions. It is not at all clear whether sites in Scottish waters will have a net advantage over sites further south: the benefits of higher wind speeds and (in some cases) shorter distances to shore may be outweighed by the more severe wave climates and seabed conditions, and higher transmission costs to major centres of electricity demand.

Wave

This also is a huge resource. Wave is similar to offshore wind in most respects, but with greater uncertainty on costs.

Tidal

The resource is also large, and is dominated by tidal stream sites rather than impoundment. Again, costs are less certain than for offshore wind. The predictability should result in some cost savings compared to wind.

Biomass

There is potentially a large resource, but no particular advantage for Scotland compared to other locations, due to poor soils, and low solar input. Current plans for biomass generation include significant import of biomass. There are opportunities for providing district heating. Although biomass capacity is dispatchable, relative fuel and capital costs mean it is likely to be designed to be operated at relatively high capacity factors.

Energy from waste

This is a relatively small resource, but with low risk. There are opportunities for providing district heating. There is no particular Scottish advantage.

There are many other proposed technologies, such as concentrated solar, photovoltaics (PV), osmotic pressure, geothermal and geopressure. Although this may change within the period to 2030, none of these have yet demonstrated low costs, or have a very large resource available in Scotland, or have some other particular advantage in Scotland. For example, PV is becoming a mature industry, but the vast majority of interest in PV in the UK which has been generated by the FIT incentive is concentrated in south-west England.

The list above has concentrated on electricity generation, as this is seen as a relatively ‘easy win’ to achieve significant emissions savings, compared to energy for heating and transport. Polices at EU and UK level depend on achieving high decarbonisation of electricity supply.

For electricity generation, R&D in new renewables technologies remains justified, but the major benefits in cost and risk reduction at this stage will be gained by full-scale demonstration installations, and by volume production.

4 ELECTRICITY GENERATION AND DEMAND IN SCOTLAND

This section describes the current state of electricity supply in Scotland, and plausible developments.

4.1 Electricity demand

Electricity demand and total generation in Scotland has remained relatively flat in recent years. Figure 1 shows the most recently available annual figures [9] [10] for:

- **Consumption**. This is electricity used by consumers located within Scotland, and includes consumption for those customers who have their own generation on-site ('autogenerators')
- **Losses.** This is the total of electricity lost in the transmission and distribution systems (largely as resistive losses to heat), and includes electricity consumption within power stations. It also includes electricity consumption used by pumped-storage stations when pumping.
- **Net export**. This is the net total of exchanges with England and Northern Ireland. Scotland currently has significant electricity exports, mainly to England.

The sum of these elements is the total electricity generated within Scotland.

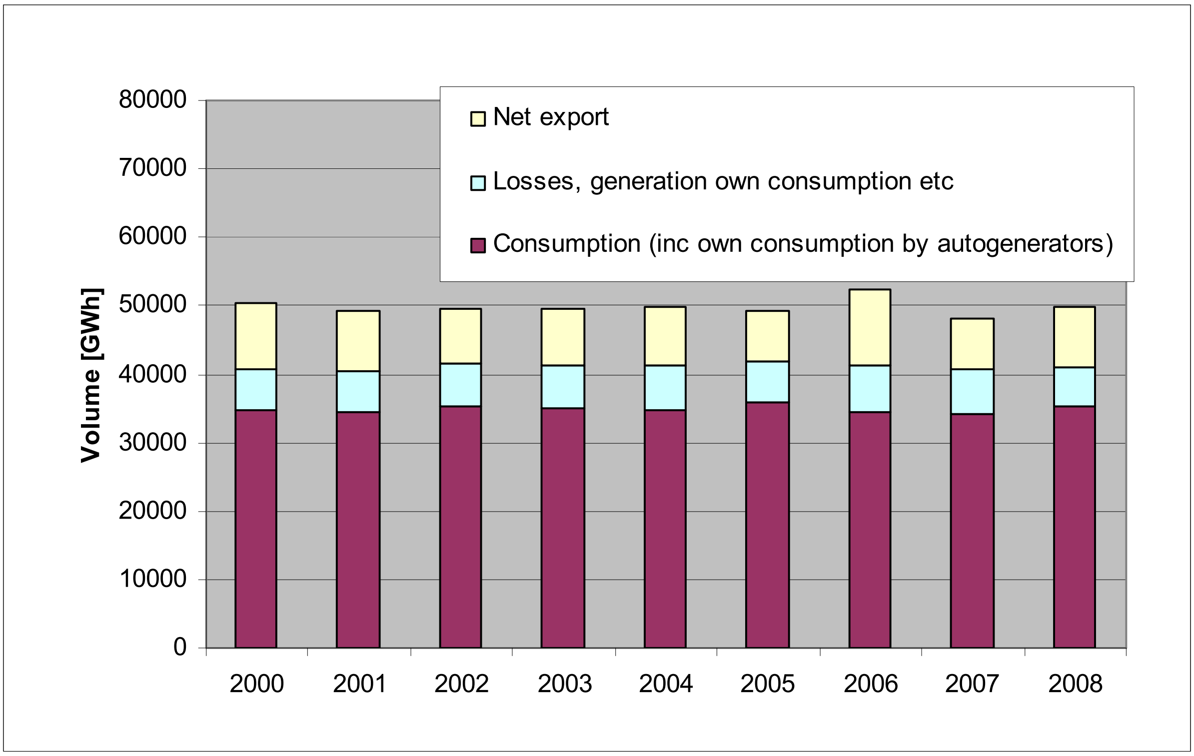

Figure 1: Annual electricity generation, demand and export for Scotland, 2000-2008

The higher total for 2006 is seen to be caused by higher exports. This is understood to be principally due to failures of other major generators in England and Wales, which caused more exports from coal and nuclear plants in Scotland in that year.

Note that the Scotland target for renewable electricity production in 2020 is defined as a percentage of 'gross electricity consumption'. Gross consumption is defined as consumption plus losses. This is equivalent to total electricity generation less net export.

A corollary of this definition is that all renewable electricity production in Scotland counts towards the target, even if some of it is generated at times when Scotland is exporting electricity.

The averages of these figures for 2000-2008 can be tabulated as follows:

Total electricity generation in Scotland	49,779 GWh	100%
Made up of:		
Net export	8,632 GWh	17.3%
Losses (including generator own consumption)	6,243 GWh	12.5%
Consumption (including autogenerators)	34,904 GWh	70.1%

Table 1: Annual electricity generation, demand and export for Scotland, average 2000-2008

For this work, it is necessary to forecast electricity demand (i.e. gross consumption) to 2030. This is difficult because the economic recession has affected historical trends. Also Government policy is to reduce demand considerably, and it is not clear how successful the initiatives that have been introduced or are expected will be in the period to 2030. Therefore in this work we have defined two electricity demand scenarios that are expected to bracket the range of possible outcomes:

Demand growth (DG)

The latest published information is for gross consumption in 2008 (40,900 GWh) [10]. No growth is assumed in 2009 and 2010, with 0.5% growth in 2011 as the recession is assumed to end, 0.9% growth in 2012-15 (close to projections made before the recession), then 0.5% growth for 2016-20 as energy saving measures start to have an effect. From 2020 – 2030, credible forward projection is harder. The ECF study [5] estimates 26% demand growth between 2010 and 2030 for all Europe in the baseline case, which if applied here would give an annual growth rate far in excess of historical trends for Scotland. Therefore a continuation of the 0.5% annual growth from 2020 onwards is assumed here. This results in gross electricity consumption in Scotland reaching 43,680 GWh in 2020 and 45,900 GWh in 2030, a net increase of 12.2% from 2008.

Demand reduction (DR)

Zero growth is assumed in 2009 - 2011, followed by 0.5% annual reduction in 2012 and 2013, and 1.0% reduction thereafter to 2020. The overall reduction by 2020 is 7.7%, which is in line with the long-term trend shown in the ECF study for all Europe: 29% by 2050. Therefore it is assumed here that the trend for Scotland extends linearly to 35180 GWh by 2030, a net reduction from 2008 of 14%.

Note that the UK Committee on Climate Change (CCC) anticipates significantly more rapid reduction for the UK: 20% by 2020 [12], and Scottish Government consultations on an energy efficiency action plan included targets in the range of 12-22% reductions over 2010 levels by 2020.

Therefore greater demand reduction rates than assumed here may be feasible and would certainly be desirable. However, a relatively conservative Demand Reduction scenario has been chosen here, in order to avoid the results for renewables penetration being seen as entirely due to dramatic demand reduction assumptions.

Neither scenario takes account of any transfer of energy consumption from heat and transport to electricity. This is discussed further in Section 6.6.

The figures above are for annual electricity generation and consumption. It is important also to consider peak electricity demand, as this is a measure of how much electricity generating capacity and interconnection capacity must be available in order to avoid ‘the lights going out’. Peak demand each year occurs in weekday late afternoons in winter, and for Scotland is of the order of 6100 MW [11].

It is assumed here that peak demand remains effectively unchanged to 2030. This is in line with National Grid forecasts [16]. It is assumed that increasing volatility of electricity prices (especially at peak demand periods), increasing visibility of prices to customers (through smart metering), and increasing availability of controllable loads will cause customers to limit consumption in the traditional peak periods. It is likely that under the Demand Reduction scenario, peak demand may decrease considerably (before allowing for the effects of electrification of heat and transport), but this is not assumed here. Similarly, the effect of expected milder winters has not been taken into account.

4.2 Current generating capacity

Current electricity generating capacity in Scotland is shown in Table 2. This is based on latest data, primarily from [10] for 2008, with updated figures for renewable generators. There is some difficulty in reconciling data from different sources: this is thought to be largely due to differing definitions of capacity, and should not significantly affect the analysis.

Note that capacity here is defined as design capacity or ‘nameplate’ capacity: for the large generators, it is feasible also to use Transmission Entry Capacity (TEC). The level of TEC assigned to a generator is partly a commercial decision by the operator, and can change from year to year. For example, the current TEC for Hunterston B nuclear station is 860 MW [10].

Generating technology	Capacity [MW]
Conventional thermal and combined-cycle gas turbine (CCGT)	5,223
Longannet coal	*2,400*
Cockenzie coal	*1,200*
Peterhead gas	*1,500*
Fife CCGT	*123*
Nuclear	2,410
Hunterston B	*1,210*
Torness	*1,200*
Gas turbines and oil	264
Pumped storage	740
Renewables	3,665
Hydro (excluding pumped storage)	*1,387*
Wind onshore	*1,918*
Wind offshore[1]	*180*
Biomass	*79*
Energy from waste	*100*
Wave	*0.8*

Table 2: Grid-connected electricity generating capacity in Scotland

4.3 Conventional and nuclear generation: low renewables growth (LR) case

The LR case is intended to represent a situation where renewables continue to expand, though at a relatively conservative rate (see section 4.5). A scenario for the development of the fossil and nuclear generation in this case has been developed in conjunction with FOES, as follows.

[1] Robin Rigg offshore wind farm is included, although it is connected to the electricity system in Cumbria.

Longannet, Peterhead and Fife CCGT are assumed to continue in operation, possibly with the addition of Carbon Capture and Storage plant (CCS) without reduction in net station capacity (this would require an increase in gross station generating capacity), or to be replaced by plant of similar size and characteristics.

Cockenzie is assumed to close at the end of 2015.

Hunterston B closes at the end of 2016, and Torness at the end of 2023.

In this scenario, the proposed new 1600 MW coal plant at Hunterston (Ayrshire Power) is assumed to commence operation in 2018.

The proposed new 1000 MW gas-fired power station at Cockenzie is not specifically included here: it is considered that this is likely to be an alternative to the Hunterston coal plant, i.e. it is assumed that even in a low renewables scenario, only one of these proceeds. Hunterston is selected here as it is the larger.

The 'gas turbines and oil' category, which is understood to contain mainly standby generators, is assumed to continue unchanged, except that in 2019 unidentified projects totalling 500 MW are added. This follows National Grid's Transmission Network Quarterly Connections Update [13] for April 2010, which is based on connection applications received from proposed generating projects.

4.4 Conventional and nuclear generation: high renewables growth (HR) case

In contrast to the low-renewables growth case set out in Section 4.3, an alternative was developed in conjuction with FOES, where renewable generation takes a larger share. In this HR case, the new Hunterston coal plant, the Cockenzie gas plant and the unidentified 500 MW thermal projects do not proceed. The likely capacity factors of the remaining thermal plant are considered later.

4.5 Renewables: low renewables growth (LR) case

Two cases for growth in renewables generation are set out in this section and the next section. Both are based on published figures for known projects under development, estimates of resource, targets, and growth rates experienced to date. It is important to note that these estimates are not based on identification of particular projects, except where specifically noted.

There is considerable uncertainty on many issues, especially the success rate in achieving consents, and the costs and rate of technical development of some of the newer sources such as wave and tidal. Therefore the Low and High Renewables cases have been chosen as credible lower and upper bounds on what may be achieved: the truth will probably lie in between.[2]

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[2] The assumptions presented here for the LR case in 2030 differ from those in Garrad Hassan's concurrent work for Scottish Renewables for 2020, only in small details. Hydro is anticipated to grow slightly more rapidly in the early years, and wave and tidal capacities in 2020 are each 100 MW higher than assumed in the Scottish Renewables study.

4.5.1 Hydro and pumped storage

Hydro capacity in Table 2 excludes Glendoe (100 MW), which is assumed to return to operation at the start of 2012.

Information from National Grid [13] on projects known to them indicates a further 8 MW added in 2010, increasing to 14 MW in 2019. Further development of hydro in Scotland is estimated in [14], which shows a total resource of around 1200 MW at 8% discount rate and 1000 MW at 10% discount rate.[3] This remaining hydro resource is made up of relatively small projects. Based on [14], and making some allowance for other limiting factors, GH has assumed that a further 700 MW of hydro capacity is developed by 2030, at a rate of 50 MW per year starting in 2017, giving a total of 2200 MW hydro capacity by 2030.

Pumped storage is included in the capacity figures in Table 2, despite not contributing much in annual energy production, because it contributes significant capacity at peak periods. The existing stations at Cruachan and Foyers are assumed to continue in operation. SSE's proposals for new pumped storage schemes at Balmacaan and Coire Glas are assumed to result in a further 300 MW in 2018, increasing to 900 MW in 2019. The current application by SSE to convert Sloy hydro station to pumped storage is not taken into account here, as it would not increase the peak output of the existing station.

4.5.2 Onshore wind

Onshore wind projections in the LR case are developed as follows:

- Figures from Scottish Renewables (SR) [15] for projects 'under construction' are assumed to be built in 2010 (620 MW).
- SR figures for 'resolution to consent' (i.e. approved) (2847 MW) are assumed to be built over the period 2011- 14, at a rate of 700 MW per year.
- SR figures for 'in planning', 'in appeal', and 'scoping' (total 7025 MW) are assumed to have a 20% success rate (1400 MW), and to be built over the period 2015-2020 (a rate of 233 MW per year). The historic success rate for wind projects submitted for planning consent in Scotland is around 2/3rds, so this rate could be considered conservative. However, success rates are expected to drop as cumulative impact and biodiversity issues become more significant.

It should be noted that the projections have not been based on a geographical analysis of available land areas, or conflicts with other land uses or designated areas. These issues are assumed to be covered by the relatively low consenting success rates assumed.

[3] This is based on assumptions of Feed In Tariff (FIT) rates for new small hydro generation which are not identical to current rates, but GH believes this will not affect the figures significantly.

The total onshore wind capacity in 2020 is 6738 MW. The resulting profile for onshore wind capacity is in line with or below figures published by National Grid [13], based on generator connection applications in the Scottish Hydro and Scottish Power areas.

No new onshore wind is assumed after 2020. It is likely that at the minimum some re-powering of sites would occur, i.e. replacement of older wind turbines with fewer larger machines, but this has not been assumed here.

4.5.3 Offshore wind

The total Scottish offshore wind resource as identified in the Crown Estates leasing process for Scottish Territorial Waters (STW) and Round 3 is 11,000 MW. Using GH internal estimates of success rates and build rates for all European offshore wind projects, we have assumed that offshore wind capacity in Scottish waters ramps up from 2015 to 2020, reaching 3000 MW. This is a relatively pessimistic estimate.

Growth rates after 2020 are very uncertain. In this LR case it is assumed that no new offshore wind is constructed in Scottish waters after 2020. This represents a case where the easier sites have been developed, and the more difficult potential offshore sites (with greater water depths, more onerous wave climates, and further from shore) cannot compete for financing against sites in the southern North Sea or Baltic.

4.5.4 Biomass

New biomass is assumed to be installed as follows:

- Figures from Scottish Renewables [15] for projects ‘under construction’ are assumed to be completed in 2010 (14 MW).
- SR figures for ‘resolution to consent’ (87 MW) are assumed to be built in 2011 – 2013, at a rate of 29 MW per year.
- SR figures for ‘in planning’, ‘in appeal’, and ‘scoping’ (total 445 MW) are assumed to have a 40% success rate and to be built over the period 2014-2018 (a rate of 35 MW per year).

The biomass total in 2018 is 355 MW.

It is assumed that no new biomass for electricity generation is built after 2018. This represents a case where the biomass resource reaches a limit, or where there is competition for biomass fuel for heating or for transport fuels.

4.5.5 Energy from waste

There is little new Energy from Waste capacity in the pipeline, according to Scottish Renewables figures. The SR total for ‘under construction’, ‘resolution to consent’ and ‘in planning’ is 25 MW.

GH has assumed this is built at a rate of 5 MW per year, reaching a total of 125 MW in 2015. This is close to the total resource estimated in [17] (112 MW).

It is assumed that there are no new Energy from Waste plants after 2015.

Note that there could be significant developments of anaerobic digestion (AD) plants, to produce biogas from waste. This gas could be injected into the gas grid, used locally, or used to produce electricity (most logically as part of CHP[4] schemes). AD has been omitted in this study, as it is not certain how much will be used for electricity generation. This is a conservative assumption: if significant AD-fuelled electricity generation capacity emerges, it will make achievement of renewable electricity targets easier, while biogas injection into the grid would increase the contribution of renewables to heat energy, reducing the level required from renewable electricity to meet overall renewable energy targets.

Even if the majority of future Energy from Waste development is for biogas to the gas grid, this will not have significant impacts on either the total level of renewable electricity generation, or its relative security.

4.5.6 Wave and tidal

Figures for future wave energy capacity are uncertain. SR figures for projects under development total 607 MW, virtually all still at the scoping stage, and National Grid figures show connection applications for a total of 723 MW. GH has assumed that 300 MW is built in 2020, and a further 300 MW in 2023.

Similarly for tidal, SR figures show 662 MW at the scoping stage. GH has assumed that 330 MW is built in 2020, and a further 330 MW in 2023.

4.5.7 Effect of capacity assumptions

Note that, in the context of this work, there is little difference between offshore wind, wave and tidal. For the purposes of modelling renewables generation capacity, all have similar characteristics: similar unit sizes, locations (at least for the onshore network connections), capacity factors and variability, though tidal is of course significantly more predictable than wind or wave. Therefore the exact split of capacity between these three technologies is less important than the total capacity.

Biomass and Energy from Waste also have similar characteristics, so the exact split is not critical.

The take-up of microgeneration (such as PV and domestic-scale wind generation) is currently very hard to estimate, until the effect of the new FIT scheme is clear. As a conservative estimate, no microgeneration capacity has been included in this analysis.

[4] CHP: Combined Heat and Power. Use of the waste heat produced by fossil-fuelled electricity generators in industry or to heat buildings. Depending on design, the ratio of heat output to electricity output can be varied at will.

4.6 Renewables: high renewables growth (HR) case

As an alternative to the generation LR case, a more optimistic High-Renewables case was developed[5].

New hydro is assumed to reach 1000 MW in 2030, at a rate of 50 MW per year from 2011. The total hydro capacity in 2030 is 2500 MW.

New onshore wind is assumed to grow at 360 MW per year over the period 2015-2019. This is equivalent to assuming a 26% consenting success rate. This is still well below the historic success rate, to reflect increasing cumulative impacts and the effect of environmental constraints. This gives a total of 7500 MW in 2020. As for the LR case, no new onshore wind is assumed after 2020.

Offshore wind is assumed to reach 5000 MW in 2020, at a rate of 1000 MW per year, and then to expand more slowly to 7000 MW by 2024. This allows for some attrition from the 11,000 MW of sites already identified by Crown Estates, due for example to conflicts with other users, environmental constraints, or poor project economics.

Biomass is assumed to be installed at 50 MW per year from 2014 to 2030, reaching 1030 MW in 2030. This total assumes there is no significant world-wide constraint on biomass resource.

New Energy from Waste capacity is assumed to continue its growth at 5 MW per year to 2020, giving a total of 150 MW. As this is thought to be close to the total waste resource for electricity generation, no new capacity after 2020 is assumed.

For wave, it is assumed that 300 MW is built in 2016, with further 300 MW capacity additions in 2020, 2022 and 2024. These dates are indicative only, and are not based on analysis of specific projects.

Similarly for tidal, 330 MW is assumed to be built in 2016, with further 330 MW capacity additions in 2020, 2022, and 2024.

The projections for 2030 for offshore wind, tidal and wave are extremely uncertain. As noted above, in practice the exact split of capacity between these three technologies is relatively unimportant.

4.7 Generation capacity factors

To convert the generation capacities defined above into annual energy production, capacity factors have been used, as shown in Table 3. The capacity factor is the ratio of the actual output of the plant over a long period, to the theoretical output assuming it could run at full output continuously.

5 As in the LR case, the assumptions behind the HR case for 2030 differ only slightly from the assumptions in the parallel study by Garrad Hassan for Scottish Renewables for 2020. Hydro capacity is assumed to grow more rapidly to 2020, wave capacity is assumed to be 600 MW in 2020 rather than 300 MW, and tidal capacity is assumed to be 660 MW in 2020 rather than 300 MW.

For thermal, nuclear, pumped storage and hydro, the figures are the average capacity factors for UK stations for 2000-2008, calculated from figures in [10], and using 'nameplate' capacity as the definition of capacity, as in Table 2. In this analysis, a single average capacity factor of 0.55 is used for all coal and gas stations.

Technology	**Capacity factor**
Coal	0.47
Gas	0.76
Coal and gas together	0.55
Nuclear	0.78
Hydro pumped storage	0.12
Hydro natural flow	0.36
Wind onshore	0.35 decreasing to 0.27
Wind offshore	0.39
Biomass	0.70
Energy from Waste	0.90
Wave	0.30
Tidal	0.35

Table 3: Assumed capacity factors (based on nameplate capacity)

It is appreciated that these capacity factors are a function of the electricity market, and need not necessarily apply in future. As more generation capacity, especially renewable, is added to the mix, existing stations can be expected to produce less in any year, especially if demand reduction measures are successful. On the other hand, some conventional stations may close as they become uneconomic, thereby increasing the capacity factor of the remaining stations. This is discussed further in Section 6.

The capacity factor for onshore wind is taken as 0.35, which is realistic for current Scottish sites, reducing gradually to 0.27 by 2020 as development is forced onto less windy sites. Note that this is the average of all operating sites: under these assumptions, the capacity factor for a new project starting operation in 2020 will be significantly lower than 0.27.

Offshore wind is given a capacity factor of 0.39, which is realistic for the sites most likely to be developed first. Sites further offshore can be expected to have higher winds, but this may be offset by poorer availability given the wave climate and distance from shore.

The figure for Energy from Waste projects is taken from [17].

The figures for wave and tidal are GH internal estimates, based on previous experience. They are believed to be representative of devices and sites likely to be developed in foreseeable timescales. Note that other recent work [18] assumed a lower factor (0.25) for wave, and a higher factor (0.40) for tidal, so these estimates are subject to some uncertainty.

5 SECURITY OF THE ELECTRICITY SYSTEM

5.1 Introduction

'Security of supply' is a term used loosely to provide some measure of the reliability of an electricity system. There are several other terms with strict definitions used by power system planners. Estimation of the reliability of a power system is a complex matter, requiring probabilistic assessment of many variables which may be correlated, including demand, weather, failure rates of transmission system elements, failure rates of conventional generation, and 'failure' rates (including unavailability of resource) of renewables. No new analysis of the situation for Scotland can be covered within the scope of this work, but some general conclusions can be drawn.

It should be noted that conventional analysis tools are not able to cope fully with variable distributed renewables, especially wind, and modification of the tools is currently under way within the transmission system operators and academia.

Considering Scotland in particular, it is important to note that generation and transmission in Scotland is effectively part of the GB system. All formal assessments of system security have to be done on this basis. Providing a secure electricity system in Scotland without considering the connections to the rest of the GB system would result in a significantly more expensive system. A major justification for the development of 'national grids' in the first half of the 20th century was that spare generation capacity only had to be provided to cover the failure of the largest generator on the interconnected system, rather than providing spare capacity in each city.

Trends in Europe are now for greater interconnections between national systems, and for analyses to be done on an international scale rather than a national or regional scale. This is partly driven by political pressure from Brussels to achieve a single electricity market and reduce the commercial power of large vertically-integrated utilities, and partly by the need to respond to greater variability due to higher renewables penetration. However, it is also likely that even without these pressures, there are strong economic arguments, that up to now have not been visible in national-level studies. There are now organisations for energy regulators and for transmission system operators at European level, with responsibilities for these issues.

5.2 Options

There are four main ways to provide or contribute to 'security of supply':

- backup conventional generation
- deferrable demand
- energy storage
- interconnection.

Backup

'Backup' is a term which is often misused, and power systems planners and operators use instead several different concepts of 'reserve', differentiated mainly by timescale. Backup generation is generation available to start (or to increase its output) at will, on various timescales.

It is relatively expensive. True 'backup' generation will be designed on the basis that it will run very infrequently, i.e. in the event of a rare combination of circumstances, for example high electricity demand, low renewables production, and perhaps also failure of some conventional generation. For such 'low capacity factor' generation, economics will dictate that it is plant with low capital cost but high fuel cost. Examples are standby diesel generators, or open-cycle gas turbines.

One problem with provision of this form of generation is that in many electricity markets there is no firm payment to generators for providing generating capacity: the generator's income is through selling electricity. Low-capacity-factor generation depends on there being sufficient hours in the year when the electricity price is high enough. It is therefore a relatively risky investment.

One new source of reserve may become available in future. Conventional thermal generators fitted with CCS effectively have their output reduced substantially (of the order of 20 to 30%) by the energy demand of the CCS plant. When generating capacity is needed in exceptional circumstances, it would be feasible to reduce the energy consumption of the CCS plant, thereby substantially increasing electricity production. With some additional materials capacity in the CCS plant, it can continue to function for some time. Alternatively the carbon dioxide would be released into the atmosphere, incurring costs for emissions, but provided this happened very infrequently, it could be environmentally and financially acceptable.

Deferrable demand

Power system operators already make extensive use of interruptible demand. These are usually large industrial customers who are contracted to be able to reduce their demand substantially at short notice, and for short periods only.

Deferrable demand allows the demand to be shifted in time by a few hours. Heating and cooling are the main opportunities. New developments open up the possibility of controlling commercial and domestic fridges and freezers in this way. 'Smart meters' will be installed in domestic and commercial premises across the UK by 2020. These will have the capability to communicate electricity price signals to electricity-consuming devices.

It is not yet clear how great the effect will be on overall electricity demand, though it is likely that the effect on peaks will be very significant. This will be useful for dealing with short-term variability and unpredictability of renewables such as wind, tidal and wave, on timescales of a few hours. However it is unlikely to provide much assistance in dealing with the typical longer-term weather-related variations in output of wind and wave plant, which in northern Europe generally have an underlying cycle of around three or four days. This is because few consumers will have loads that can be deferred by a day or two. There are possible exceptions to this: for very well-insulated buildings or very well-insulated hot water systems, it is possible that cooling times will be so long that they match the 'wind cycle'. However, it is by no means clear that this would be economically attractive: it should in principle be more attractive first to deal with the daily demand cycle, i.e. shift all such heating to overnight, where it can be supplied by cheap baseload generation. However, the benefits of having deferrable demand capable of contributing on these timescales are potentially great, and this is an area that would be worthy of detailed study in a Scottish context.

The recent DECC study [29] assumed that domestic space heating could be time-shifted by up to 12 hours in well-insulated houses, and water heating by up to 24 hours. This study shows around 300 TWh/yr of domestic heat demand in the UK, so with reasonable assumptions about Scotland's share, and the share that can be taken by electric heating, it is clear that in winter there would be at least several hundred megawatts of deferrable electric heating in Scottish homes.

Such electric heating of buildings and hot water could either be direct, or use heat pumps. The decision in any particular case would depend on capital cost and anticipated usage, and is not a major issue for this discussion.

Heat storage has been identified as an important measure to allow high integration of wind energy in Denmark [30]. Denmark has a very high level of CHP district heating systems: adding central heat storage to these systems allows the CHP stations to prioritise electricity production over heat production when there is low wind, and could also allow surplus electricity production from wind generation to be used to charge the heat stores, probably using heat pumps. This depends on there being extensive district heating networks, which is not yet the case in the UK. However, 'package' CHP systems for individual buildings, with heat storage, can also be used in this way without the need for heating networks. A large number of small installations can be remotely controlled by a single operator to provide a controllable electrical output of the same magnitude as large conventional generators [31].

Electric vehicles can also contribute to deferrable demand: this is quantified in Section 6.6.

Energy storage

In this context, energy storage means storage of energy that can then be turned into electricity. Heat storage is covered in the previous section.

Energy storage would allow output of variable renewables to be matched to electricity demand. Currently, the only option for substantial storage that is economic is pumped storage hydro. Other options may well emerge, including compressed-air storage (one plant already exists in northern Germany, where there is no opportunity for pumped storage), chemical flow batteries, and the use of electric vehicle batteries to export energy on demand.

In the Scottish context, the main immediately foreseeable opportunities are pumped storage and electric vehicles. SSE are already developing schemes for new pumped storage plant, and for conversion of an existing hydro station to provide some pumped storage capability.

Interconnection

Traditionally, interconnection between systems has been justified on the basis of:

- Sharing reserve: failures of major generators on two interconnected systems are unlikely to occur simultaneously, so the interconnection can be treated as providing backup for both systems.

- Energy trading: systems can buy energy over the interconnection when it is cheaper to do so.

- Smoothing demand: demand peaks in northern Europe in winter occur in late afternoons, for example, so the peak in Germany occurs before the peaks in the Netherlands and France.

With variable renewables, interconnection also allows the variability to be ‘smoothed’ over a larger geographical area.

A single interconnector cannot provide all these functions at the same time.

Currently Scotland has an interconnection to Northern Ireland (500 MW). There are two interconnection routes to England, total 2800 MW. Due to the high volume of renewables connection applications received in Scotland, this will increase to 4000 MW for winter 2014/15 and approximately 5800 MW by winter 2015/16 [16]. The latter reinforcement is intended to be an HVDC[6] subsea cable between Hunterston and Deeside, and is currently at the stage of preconstruction engineering work in order that ‘construction can commence when there is sufficient confidence that the reinforcement will be required’ [16].

The Electricity Networks Strategy Group [27] demonstrated a business case for further substantial subsea HVDC interconnection on the east coast, nominally 1,800 MW. This could be in place before 2020.

Beyond that, further interconnection to England and Ireland is feasible, but greater benefits may be achieved by interconnections to Norway, Iceland, the Netherlands or Germany. Norway and Iceland would effectively provide ‘storage’ or backup via existing or new hydro or geothermal generation. The Netherlands or Germany would primarily be customers for renewable generation from Scotland.

Cost comparison

Costs of each of the options above will depend greatly on the circumstances. However some indicative estimates can be made, as shown in Table 4. These figures are indicative only, and do not provide a basis for direct comparisons.

[6] High Voltage Direct Current. This is a relatively new technology at the voltages, power ratings and distances now being proposed, but is now seen as attractive by transmission system owners and operators, especially for subsea connections.

Item	Indicative cost	Source, details
'Backup'	£588k/MW (Combined-cycle Gas Turbine), and £2,035k/MW (coal with CCS)	DECC [29], 2020 capital costs for new-build, central estimates (excludes operating costs, finance costs, fuel costs and carbon costs). Capital costs for open-cycle gas turbine would be lower than CCGT. Costs of providing reserve on various timescales from existing generators are significantly less than these figures [22].
Deferrable demand	Wide range.	Costs are likely to be very low or zero for initial 'easy wins' (domestic appliances, electric vehicle charging), becoming very high for long deferment times.
Energy storage	Reservoir hydro £1,600k/MW. Should be low, for use of electric vehicle batteries.	Cost is for Glendoe hydro station (excludes operating costs), which gives an indication of possible future pumped-storage station costs in Scotland. Conversion of existing hydro stations to pumped storage should be cheaper.
Interconnection	£400k/MW	Based on budget costs of 1,800 MW HVDC subsea interconnectors on West and East coasts [27]. Excludes operating costs.

Table 4: Indicative costs of options for contributing to security of supply

5.3 ECF study results

The ECF study [5] looked at these options in detail for Europe as a whole. The major conclusions are:

- interconnection provides the greatest benefits at the lowest cost;
- with interconnection, very high penetration of renewables (including the variable renewables wind and photovoltaics (PV)) is possible, with satisfactory security of supply.

The study in particular demonstrated a need for major transmission system reinforcements to bring energy from PV installations in Spain into France and onwards into Germany.

The ECF scenarios did show the need for some backup generation, but in relatively small quantities, increasing as renewables capacity increased.

The cost of interconnection and other means of dealing with high volumes of variable renewables was large in absolute terms, but was shown to have a very small impact on overall costs, i.e. on consumer electricity prices. Under some assumptions of high fuel and carbon costs, the additional cost of decarbonisation of Europe's electricity supply could be negative.

The study did not include sufficient detail to allow conclusions specifically for Scotland to be reached, except to note that it included a UK-Norway interconnector and did not include a connection to Iceland.

5.4 Discussion

From Table 2, the total thermal (fossil and nuclear) generation in Scotland at present is 7900 MW (nameplate capacity), and with pumped storage and hydro the total is around 10,000 MW. The current interconnection capacity with the rest of the GB system is 2800 MW via two routes, and approximately 500 MW to Northern Ireland. This currently gives an adequate level of security. As noted above, full analysis of security of supply needs to be dealt with on a probabilistic basis. However to illustrate the issue, it can be seen that Scotland's current peak demand of around 6000 MW can be met with the thermal generation and the interconnection to England, even if one major generating unit or one part of the interconnection is unavailable.

The interconnection with Northern Ireland is ignored in this discussion, as there is a strong possibility that if Scotland is short of generation due to low output from renewables, the island of Ireland will be in the same position.

As noted above, by 2016 there will be an increase in interconnector capacity of 3000 MW, through multiple routes. This has approximately the same effect on security of supply as 3000 MW of conventional generating capacity. On this basis Cockenzie and Hunterston B (total 2400 MW) do not require replacement for system security reasons, even without taking into account the proposed increase in pumped storage capacity, or any contribution from new renewables capacity.

Further interconnection capacity increases, to a figure of the order of 8 - 10,000 MW, would allow all coal, gas and nuclear generation in Scotland to be closed without threatening security of supply. This may not be the economic optimum solution, given proximity to gas fields and potential carbon storage, but it is technically entirely feasible. This is discussed further in Section 6.7.

This assumes that there is sufficient generation in England and Wales, to make up for plant failures and low renewables output in Scotland. This emphasises that security of supply is an issue that needs to be analysed on the basis of the entire GB system, and increasingly the entire European system.

This also implies that, at times of low renewables production and perhaps failures of thermal generation, Scotland will import electricity from England and Wales. Depending on whether this energy is assumed to come from the marginal generating plant in operation at the time, or from some form of average mix of generating technologies, it may include production from coal and nuclear plant.

The main conclusion for Scotland is that coal, gas and nuclear stations located in Scotland are not essential. Interconnection to the rest of the GB system can provide sufficient security, if the combined system itself is secure. Connections from Scotland to other systems (such as Norway, Netherlands, or

Germany) may be justified at high renewables penetrations for energy trading, but are not essential to provide a secure system.

The optimum solution will contain some elements of deferrable demand and energy storage, but from the results of the ECF study, it appears that interconnection provides the greatest contribution to secure electricity supply with high renewables penetration, especially variable renewables.

Note that interconnection capacity of 8 - 10,000 MW is likely to be significantly less than the interconnection capacity which is economically justified by the potential renewable energy exports from Scotland.

6 ELECTRICITY GENERATION CASES FOR 2030

This section quantifies the effects of the generation and demand scenarios set out in Section 4.

6.1 LR and HR cases

Figure 2 shows the development of generation capacity (MW) in the low-renewables case. The effect of the closures of Cockenzie, and Hunterston and Torness nuclear stations in 2015, 2016 and 2023 can be seen, as can the startup of the Hunterston coal plant in 2018. The picture is dominated by the expansion of onshore wind, and later offshore wind.

Figure 3 shows the energy production (GWh per year) from this generation mix, applying the capacity factors defined in Section 4.7. The effect of the lower capacity factors of renewable generation compared to coal, gas and nuclear can be seen.

Figure 4 shows the generation mix in the High Renewables case. It is directly comparable to Figure 2.

Figure 5 shows energy production in the HR case, and is equivalent to Figure 3.

Note that the dips in energy production in 2016 and 2017, as shown in Figures 3 and 5, do not represent a technical problem. A large part of this electricity production will be exported, so the 'dips' must be seen in the context of electricity supply for the entire GB system. In this context they are not significant.

6.2 Results for 2030

The results of the analyses are shown in Table 5. The two generation scenarios (Low Renewables and High Renewables) and the two demand scenarios (Demand Growth and Demand Reduction) give a total of four cases.

The CO_2 reductions attributable to the LR and HR cases can be estimated. Figures produced by DEFRA [28] support the figure generally used of 0.43 tonnes of CO_2 saved for every MWh of electricity production saved, or in this case displaced by renewable electricity. However this figure will reduce over time as electricity supply is decarbonised, decreasing to 0.19 tonnes in 2030. The net effect is:

- Low Renewables case: a saving of 7.8 million tonnes of CO_2 in 2030; the average annual saving over the period 2010-2030 is 9.8 million tonnes of CO_2 per year.

- High Renewables case: a saving of 12.4 million tonnes of CO_2 in 2030; the average annual saving over the period 2010-2030 is 13.2 million tonnes of CO_2 per year.

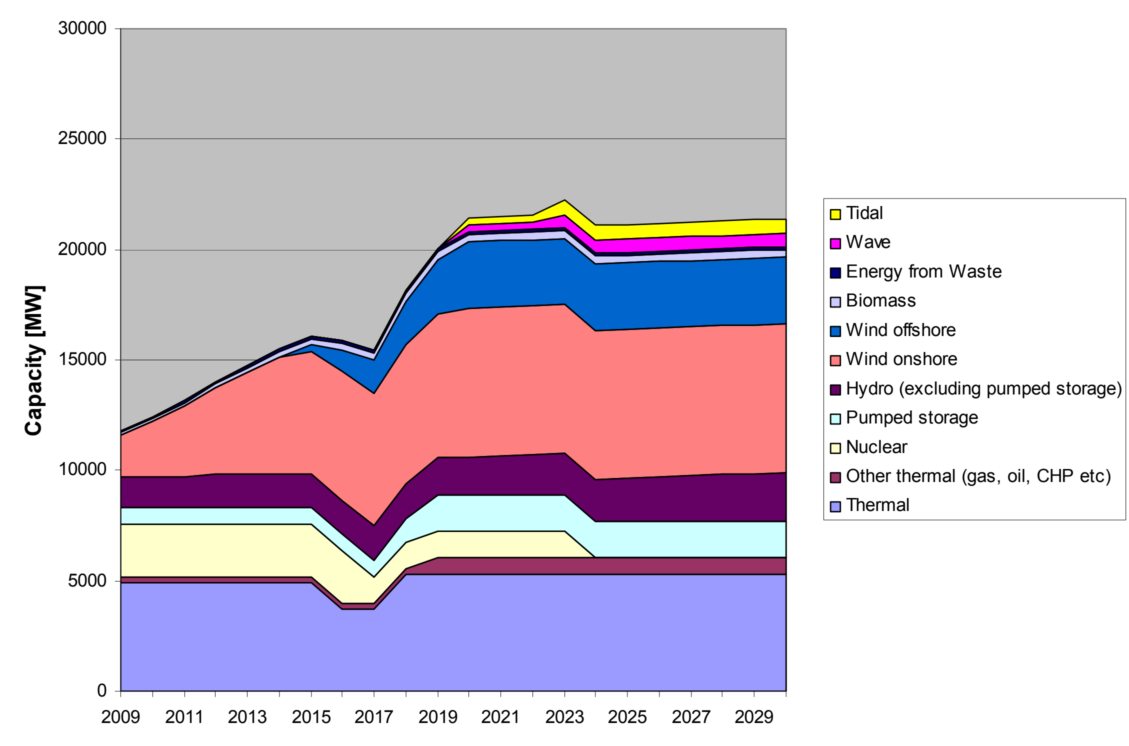

Figure 2: Generation capacity, LR case

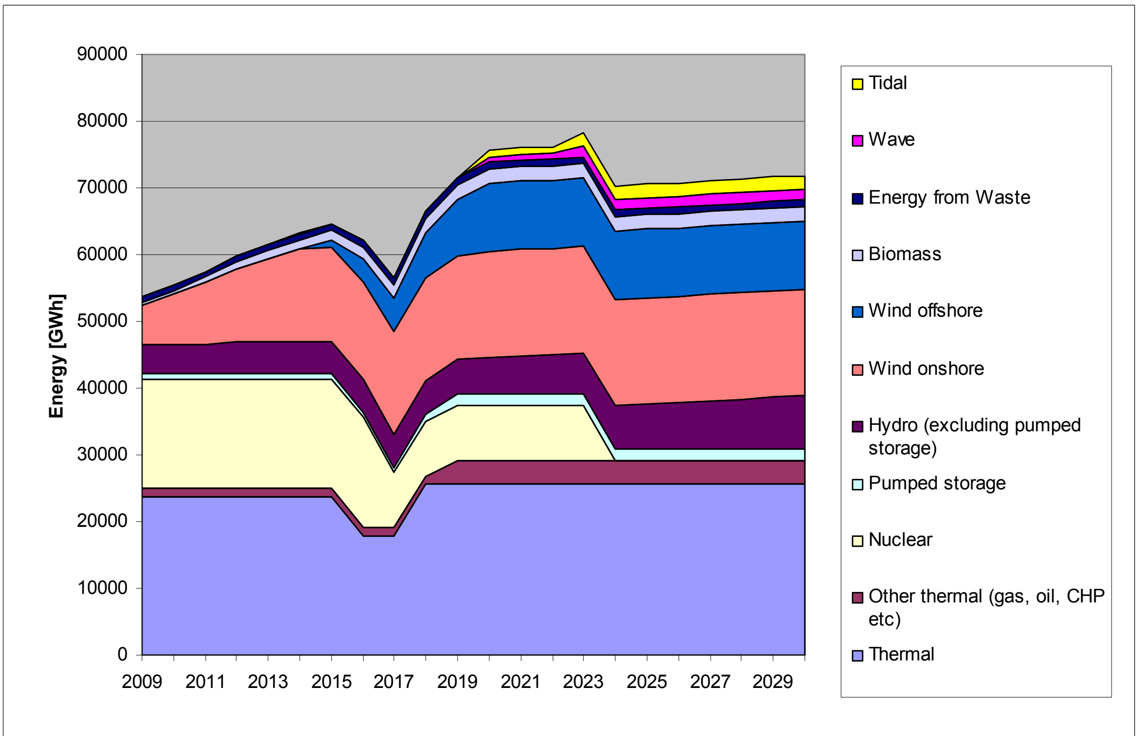

Figure 3: Annual electricity production, LR case

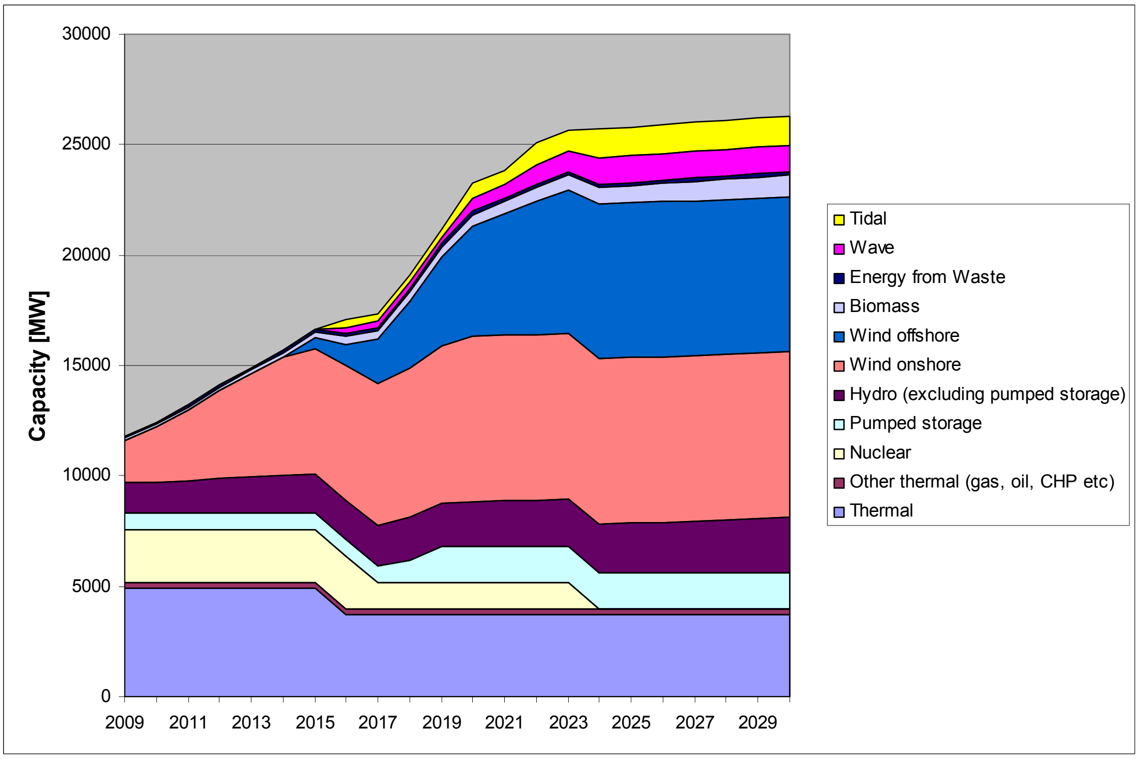

Figure 4: Generation capacity, HR case

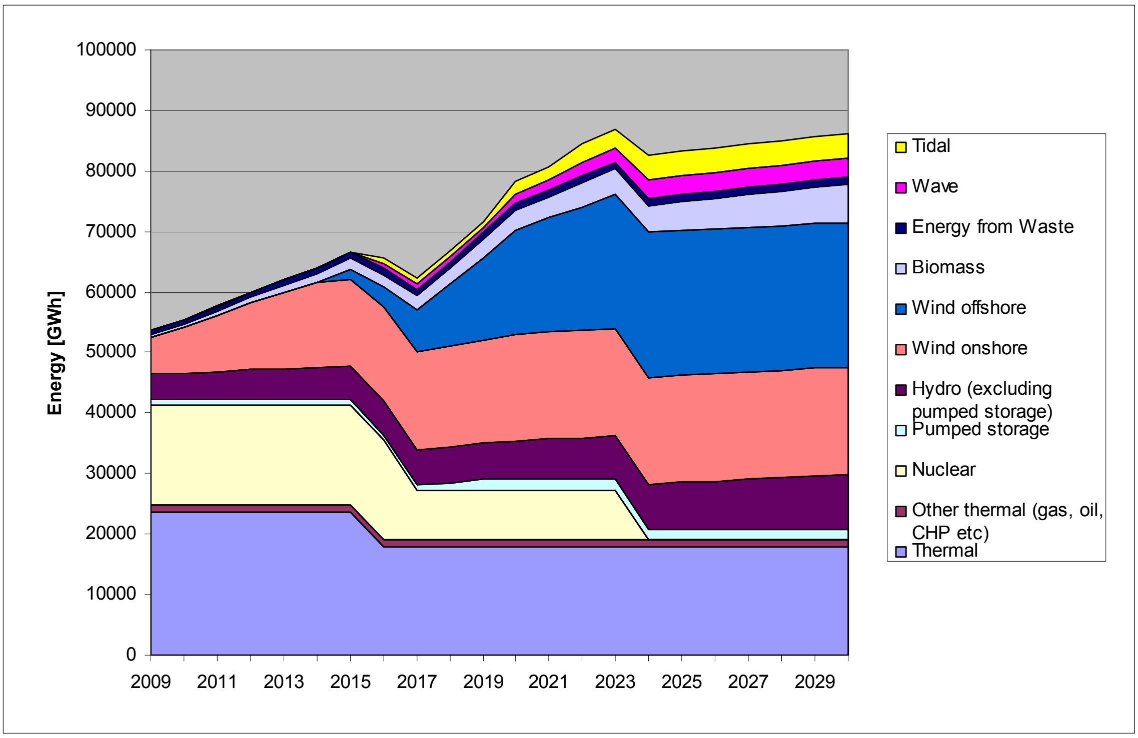

Figure 5: Annual electricity production, HR case

Case	**Low Renewables Demand Growth**	**High Renewables Demand Growth**	**Low Renewables Demand Reduction**	**High Renewables Demand Reduction**
Total generation capacity	21,388 MW	26,308 MW	21,388 MW	26,308 MW
Fossil, nuclear and pumped storage capacity	*7,707 MW (36%)*	*5,607 MW (21%)*	*7,707 MW (36%)*	*5,607 MW (21%)*
Renewables generation capacity	*13,681 MW (64%)*	*20,701 MW (79%)*	*13,681 MW (64%)*	*20,701 MW (79%)*
Total electricity production	71,815 GWh	86,174 GWh	71,815 GWh	86,174 GWh
Fossil, nuclear and pumped storage production	*30,955 GWh (43%)*	*20,837 GWh (24%)*	*30,955 GWh (43%)*	*20,837 GWh (24%)*
Renewables production	*40,860 GWh (57 %)*	*65,337 GWh (76%)*	*40,860 GWh (57 %)*	*65,337 GWh (76%)*
Gross consumption[7]	46,049 GWh	46,049 GWh	35,316 GWh	35,316 GWh
Net export	25,766 GWh	40,125 GWh	36,499 GWh	50,858 GWh
Net export (% of total production)	36%	47%	51%	59%
Renewables production as % of gross consumption	**89%**	**142%**	**116%**	**185%**

Table 5: Results for 2030

In all cases, total generating capacity is around double current Scottish generating capacity (12,000 MW).

Total electricity production increases by 40 - 60% compared to current levels, which causes exports to increase by a factor of 3 to 5.5.

It is seen that even in the most conservative case (LR generation, Demand Growth), renewables production is 89% of gross consumption, thereby exceeding the current 2020 target of 80%, and very

[7] A small correction has been added to the Gross Consumption figure in order to allow for the increased energy consumption for pumping caused by the increased Pumped Storage capacity.

close to a practical definition of 'virtual decarbonisation' of electricity consumption. In all other cases, renewables production exceeds 100% of gross consumption, which (depending on definitions) can be taken as providing complete decarbonisation of electricity consumption in Scotland, and a major contribution to meeting the UK targets.

'Virtual decarbonisation' of electricity *supply* could be achieved if any remaining large scale fossil fuelled generation were closed down by 2030, or were fully fitted with carbon capture and storage technology.

In reality, with these high volumes of output from renewables generators, it is highly likely that (if they continue to generate) the coal, gas and nuclear generators will produce less than is estimated here, which is based on an assumption that historic capacity factors for these generators are maintained. Therefore exports will be less than shown in Table 5.

To show the plausible development to 2030, the figures for renewables production in each case in Table 5 are also shown for 2010, 2015, 2020 and 2025, in Table 6.

Case	**Low Renewables** **Demand Growth**	**High Renewables** **Demand Growth**	**Low Renewables** **Demand Reduction**	**High Renewables** **Demand Reduction**
Renewables production as % of gross consumption, 2010	33%	33%	33%	33%
Renewables production as % of gross consumption, 2015	53%	57%	57%	62%
Renewables production as % of gross consumption, 2020	83%	112%	96%	130%
Renewables production as % of gross consumption, 2025	88%	139%	108%	171%
Renewables production as % of gross consumption, 2030	89%	142%	116%	185%

Table 6: Renewables production for 2010, 2015, 2020, 2025 and 2030

6.3 Technical feasibility

As discussed previously, the Scottish electricity system could feasibly operate with no fossil or nuclear generation, exporting renewables when available and importing electricity from the rest of the GB system and possibly elsewhere when necessary. Security of supply would be maintained by interconnection capacity, with contributions from biomass, energy from waste, reservoir hydro, pumped storage and deferrable demand. The variable renewables would also provide some contribution on a probabilistic basis.

It would be necessary to conduct studies to show how the GB system could operate stably in this situation. The ECF study which examines similarly high renewables penetration at a European scale indicates that this would be the case. It may be necessary to add additional equipment, such as voltage control equipment, or to require the renewables generation (especially wind) to have control capabilities similar to those of conventional generators. These issues are unlikely to present any fundamental technical problems.

6.4 Economic feasibility

Generation costs

It should be noted that a recent study by Mott MacDonald for DECC [20] [29] indicates that onshore wind is now or will shortly be cheaper than all other forms of new-build generation, except perhaps nuclear[8]. Depending on future fuel and carbon prices, and especially the retiral rates of existing fossil generation, it is feasible that at some point onshore wind will not require the same level of support from the ROC[9] mechanism.

From Figures 3 and 5, it is clear that the total generation costs under these scenarios by 2030 depend critically on the costs of offshore wind, and to a lesser extent wave and tidal, compared to coal with CCS, gas with CCS, and nuclear. The DECC study estimated that offshore wind close to shore would be slightly more expensive than combined-cycle gas turbines (CCGT) with CCS, and sites further offshore would be more expensive again[10]. It also acknowledges that there are very significant uncertainties for the costs of all these technologies, and indeed did not contain costs for wave or tidal projects. Therefore in the context of this study it is not possible to identify the relative costs of alternative options for 2030. However it is possible to state that at present there is no evidence to support ruling out any of these options on cost grounds.

System costs

The term 'system costs' here means the costs of building and operating the electricity system. The critical issues for systems with high renewables penetration are the costs of transmission reinforcement (as the new generation is often located far from major demand centres, and far from conventional generation locations), and the costs of dealing with variability. Many previous studies have shown that these costs do not have a very significant impact on final customer bills [26], though at significantly lower levels of renewables penetration than is considered here.

[8] Assuming new nuclear designs can achieve substantial cost savings due to economies of scale and learning.

[9] ROC: Renewables Obligation Certificate system of financial support for renewable electricity generation.

[10] Costs included the cost of providing connection to shore, but not the costs of transmission reinforcement onshore.

National Grid's views on further investigation of these issues were set out in a recent consultation document [2] [22], in which the costs of short-term reserve attributable to wind generation were estimated as £229M in 2020/21, with total GB installed wind capacity of 26,000 MW. Assuming a capacity factor of 0.27 as in Table 3, this equates to £4/MWh of wind production, which is roughly 4% of the estimated cost of onshore wind generation [20]. Other possible increases in operating costs are discussed but are not quantified.

As the cost of transmission reinforcement is dominated by the capital cost, it will not be economically justifiable to build interconnection capacity between Scotland and the rest of GB to cope with the most extreme levels of export, as these will only occur very rarely: i.e. very high output from all renewables coupled with very low electricity demand in Scotland. The optimum level of interconnection capacity will depend on the capital costs, constraint costs[11], and which parties are liable for the costs and risks. The transmission capacity which is economically justified will be well in excess of what is needed for system security: perhaps a total in the order of 15 - 20,000 MW in the LR case, and 20 - 25,000 MW in the HR case.

It is not possible to quantify this issue further within the scope of this work, but it is notable that the ECF study [5] found that:

- substantial transmission system reinforcement was economically justified to allow long-distance transmission of the production from low-capacity-factor generation;
- transmission costs in these cases formed a relatively small part of the total cost to consumers;
- transmission system reinforcement is typically cheaper than other ways of dealing with variable renewables: more energy storage, more 'backup' generating plant, or more curtailment of renewables output (see Table 4 above);
- there is a significant risk of public opposition to transmission reinforcement proposals.

A logical next step for Scotland is to understand the economics of interconnections for export of renewables production, especially to Norway, the Netherlands and Germany.

Finding a market

The substantial volumes of exports shown in Table 5 will only occur if generators in Scotland are able to find markets for their energy and for the ROCs they generate, at adequate prices, in competition with generators south of the border. There is no guarantee of this. The excellent renewables resources in Scotland will be a benefit (i.e. wind and wave projects in particular are likely to be more productive on average than projects further south), but against this is the cost of transmission capacity to reach the markets. This additional transmission capacity has to be justified on economic grounds, i.e. the value of the energy exports it permits, not as is usually the case, on grounds of security of supply.

[11] The cost of paying a generator on the 'wrong' side of a transmission bottleneck not to generate, i.e. the generator's lost profits, and paying the next most economic generator on the other side of the bottleneck to generate instead.

A recent report by DECC shows possible illustrative ‘pathways’ for the UK to meet targets in 2050 [29]. The ‘Alpha’ pathway has a rough balance of contributions from nuclear, CCS and renewables, and shows total UK renewable electricity generation of around 200,000 GWh in 2030[12]. The renewables generation in Scotland shown in Table 5 represents around 20 to 30% of this total. Therefore renewable generation in Scotland of this magnitude is not likely to swamp the UK market.

Conclusions

The conclusions are:

- There is no evidence at present to rule out any of the renewables components of the scenarios for 2030 on cost grounds. There are substantial uncertainties for the costs of most generation technology options, including gas with CCS, coal with CCS, and nuclear generation[13].

- With high renewables production in Scotland and high export, the costs of transmission interconnections, and other costs of using the electricity system, are unlikely to be prohibitive.

- However, renewables generation exporting from Scotland will have to compete on price against renewables generation south of the border, and perhaps eventually also abroad, and costs of using the transmission system will be higher for projects in Scotland. It is by no means clear that purchasers can be found for the levels of export envisaged in Table 5, at a satisfactory price.

6.5 Capacity factor issues

As noted earlier, it is assumed in this analysis that the capacity factors of the fossil and nuclear generators are effectively fixed at historic levels. This is a major approximation. A detailed analysis would required an economic study of the evolution of competing generating plant developments to 2030, throughout the UK, and almost certainly requiring some treatment of generation costs in other countries. This is beyond the scope of this study, but it is very likely that capacity factors of fossil and nuclear generating plant in GB will fall in future as more variable renewables are added. The effect is likely to be more extreme in Scotland, as so much of the output is likely to be exported south, and as noted above interconnection capacity is likely to cause constraints for economic reasons. It is much more likely that thermal generation will be constrained (because at least the fuel costs are saved) than wind, wave, tidal or run-of-river hydro (where in contrast the ‘fuel’ is effectively wasted).

[12] Note that this volume of renewables production implies either that the ROC mechanism or other support mechanism is extended significantly beyond current assumptions; or that some renewables no longer require financial support, possibly because wholesale electricity prices have increased sufficiently.

[13] In fact, because future fuel prices and carbon prices are very uncertain, and the capital and operating costs of CCS, new nuclear plant, offshore wind, wave and tidal in volume production are also uncertain, onshore wind has the greatest certainty in future costs.

Therefore the volumes of fossil and nuclear production shown in Table 5, and the volumes of exports, are likely to be overestimates.

If the capacity factor of a fossil or nuclear plant declines sufficiently, it will eventually be closed on economic grounds, unless it can remain economic as a 'peaking' plant (i.e. running only at the times of highest electricity prices), or if it receives payment for providing other services. In Scotland, the most likely candidate for closure is Longannet, especially if the Hunterston coal plant or the Cockenzie gas plant proceeds.

Capacity factors for pumped storage stations are likely to increase significantly, which will increase the economic case for such installations. As the additional energy production is balanced by additional consumption for pumping, there will be very little effect on the results in Table 5.

As such a large part of the renewables production in Figures 3 and 5 is from onshore and offshore wind, it is worth considering the effect of the assumptions about wind capacity factors. There are many factors which could influence these:

- Choice and availability of sites: for onshore wind, a substantial reduction in capacity factor over time has been assumed, on the basis that the best sites will be developed first. For offshore wind, there is much less experience. Sites further from shore, which will be developed later, are expected to have better wind conditions, but are likely to suffer greater downtime due to accessibility for maintenance.

- Long-term climatic effects: there is currently no scientific consensus on the likely effect of climate change on wind speed distributions in the UK.

- Wind turbine design: if energy prices increase relative to material costs, as seems likely in future, then economics will tend to drive wind turbine designers towards higher capacity factors. This has not been taken into account in this analysis.

Quantification of these uncertainties in 2030 is not possible. However, it can be noted that a reduction in capacity factor over all wind generation of 3 percentage points would reduce production as shown in Figures 3 and 5 by around 10%. In the most conservative case (low renewables, demand growth), renewables production as a fraction of gross consumption would then decrease from 89% to 83%.

Short-term reductions in wind production, as occurred in the early part of 2010, are naturally-occurring events which would be dealt with as for other generation failures or interruptions of supply. There is no indication that the low wind production experienced in early 2010 is anything other than a rare extreme meteorological event.

6.6 Effect of electrification of transport and heat

The ECF study included the effect of electrification of transport and heat within its predictions of electricity demand. The effect of energy efficiency savings on electricity demand in Europe to 2050 was found to be cancelled out almost exactly by the effects of electrification of transport and heat.

The results presented so far in this report have been based on estimates of electricity demand within Scotland which did not include electrification of transport and heat. These are considered here.

6.6.1 Transport

Four scenarios for electrification of transport in 2020 and 2030 in Scotland are set out in [23]. The two 'Stretch' scenarios are relevant for this study, as they are based on the changes necessary to meet the Climate Change Delivery Plan, i.e. 27% saving in transport emissions by 2020. It is assumed that the entire transport target must be met from road transport, as this dominates transport emissions.

The 'Traffic Growth' scenario (TG) assumes traffic grows in line with official projections to 2020: see Table 7. The 'Traffic Stabilisation' scenario (TS) assumes car-km travelled in 2020 are stabilised at 2001 levels. This is in line with one scenario developed by the Committee on Climate Change.

In both cases the electric vehicle population is assumed to grow sufficiently to contribute to a 70% reduction in emissions in the passenger car sector by 2030. It should be noted that in both cases the major impact on emissions reductions by 2020 is achieved by improvements in internal-combustion engine vehicle (ICEV) efficiency and usage, rather than use of electric vehicles. The passenger car sector accounts for around 60% of all surface transport emissions [32], so the net effect is roughly 40% reduction in total surface transport emissions.

Relevant figures from the study are shown in Table 7.

Scenario	Traffic Growth	Traffic Stabilisation
Assumed vehicle distance driven (all cars, figure for 2020)	42,500 m car-km/y	31,900 m car-km/y
Vehicle population:		
Battery Electric (BEV)	29.4%	17.9%
Plug-in Hybrid (PHEV)	70.6%	42.9%
Internal Combustion Engine (ICEV)	0%	39.3%
Theoretical electricity storage capacity of EVs	32.1 GWh	19.5 GWh
Annual electricity consumption of EVs	3,798 GWh	1,706 GWh
As a fraction of gross electricity consumption, Demand Reduction case	*11%*	*5%*

Table 7: Assumptions and results for electric vehicles in Scotland, 2030, from [23]

The TG scenario requires enormous rates of growth for electric vehicles, especially to 2020. The TS scenario, on the other hand, achieves the same objective with more credible growth rates. This illustrates the obvious point that reducing car-km travelled and improving ICEV efficiency are the 'low cost first steps' to reducing transport emissions, not electrification.

Effect on energy consumption

Table 7 shows that the total electricity consumption of electric vehicles is expected to form a relatively small fraction of Scottish gross electricity consumption in 2030, as estimated in Table 5, reaching only 11% even under the most extreme assumptions of the Traffic Growth case coupled with the low gross electricity consumption assumed in the Demand Reduction case.

The ECF study estimated that EV energy consumption would reach 24% of electricity demand across Europe, in 2050. The total is 800 TWh. Considering the ratio of population, the equivalent figure for Scotland would be around 8,000 GWh in 2050. This provides reasonable support for the figures above for 2030.

Effect on peak electricity demand

In [23] it is suggested that a large fraction of the electric vehicle fleet is likely to be charged at home. It is assumed here that, as much of this load is deferrable on timescales of hours in the evening and overnight, electricity suppliers will create tariffs which will result in no significant impact on electricity demand peaks.

Storage

It is technically possible to use electric vehicles as energy storage, when connected up to their charging supplies, particularly overnight. The charging process can be deferred by several hours, and energy can be taken out of the batteries in order to cope with temporary shortages of generation. The theoretical storage capacity of EVs in Scotland is shown in Table 7, though it must be noted that at any one time a large fraction of this capacity can be expected to be unavailable, either because it is not plugged in to a charging system, or because it is in the wrong state of charge (too full to be charged, or too empty to be discharged). Commercial arrangements to encourage vehicle users to provide this service at acceptable cost will also need to be developed.

In [23], the theoretical storage capacity of EVs is compared to the storage capacity of the Cruachan pumped storage scheme (9 GWh). This is a useful comparison, as electric vehicles have similar charging and discharging timescales as pumped storage. In 2030, it is expected that total pumped storage capacity in Scotland will be approximately four times the size of Cruachan, unless further developments take place. This gives a rough estimate of 36 GWh pumped storage capacity.

Comparing this with Table 7, it can be seen that the storage capacity of EVs in 2020 could be a very useful adjunct to pumped storage, but is not a 'game-changing' development in Scotland, even if means could be put in place to ensure most of the EV storage capacity is available when needed. Other countries, without pumped storage resource, may gain greater benefit.

6.6.2 Electrification of heat

It is possible in future, if electricity generation becomes much less dependent on fossil fuels, if gas and oil prices rise, and if domestic and public buildings become much better insulated, that electricity (however generated) could be used extensively for heating, purely on economic grounds. However, in this study the electrification of heating is assumed to occur as a result of the target for 2020 (for 11% of heat demand to be met by renewable sources[14]), and for 2030 ('significant progress' towards large-scale decarbonisation).

The 2020 target of 11% equates to 6,420 GWh of heat per year. A figure of 40% is assumed here as a reasonable interpretation of the 2030 target.

The Renewable Heat Action Plan for Scotland [24] and other studies [12] unfortunately do not give projections of the role of each renewable heat technology in meeting the 2020 target. In order to quantify electricity requirements to meet this target, it is necessary to estimate the role of renewable heating technologies which use electricity.

In [12] and [25], Marginal Abatement Cost Curves for renewable heat technologies are developed for the UK, which indicate the lowest-cost options to meet any desired level of carbon abatement. Unfortunately these only extend to 2022. As the methodology includes the effects of limitations on installation rates, the results cannot be used as an estimate of the capacity of heating systems likely to be installed by 2030.

Therefore in this study, the results of the ECF study [5] for all Europe are used to provide some guidance. This shows a 'fuel shift' to electricity of 500 TWh for buildings in 2050, largely for heating and cooling from heat pumps. By ratio of population, the equivalent figure for Scotland would be around 5,000 GWh of additional electricity demand in 2050, and assuming a target of 40% of this in 2030 results in 2,000 GWh. However, this should be adjusted for the higher heating demand likely for Scotland compared to the average for Europe. Also, the ECF study assumed a Coefficient of Performance for heat pumps of 4.0, whereas in [25] a seasonally-adjusted figure of 3.0 is considered more appropriate for the UK. An adjusted figure of 5,000 GWh additional electricity demand is therefore assumed here for Scotland in 2030. It should be recognised from the assumptions made in deriving this figure that this is an order-of-magnitude estimate only.

Effect on energy consumption

Using heat pumps to contribute to the renewable heat target in this way would increase Scottish gross electricity consumption in 2030 by about 14%.

Effect on peak electricity demand

A large part of the heat pump capacity is estimated to be in commercial and public buildings, though by 2030 there may be a substantial amount in homes. Therefore there is likely to be a peak in electricity demand for heat pumps in the early mornings, and continued use throughout the day, but the peak in the early evenings may not be as great.

It is likely that the morning peak can be managed to some extent, for example by activating the heating an hour or two in advance and making use of the inherent thermal storage in buildings. Electricity prices are likely to encourage commercial building operators to do this.

[14] 'Renewable' here is taken to mean 'low carbon', a term which includes heat pumps.

Without greater understanding of the penetration of domestic heat pumps and their likely usage in 2030, it is not possible to estimate the effect on peak demand, and the opportunities for limiting this if necessary. This issue deserves further study.

6.6.3 Summary

Taken together, the likely additional electricity demand required for electrification of heat and transport in 2030 is around 20 to 25% of gross electricity consumption. This contributes to delivering roughly 40% decarbonisation of each of the heat and transport sectors.

The spread between the Demand Growth and Demand Reduction scenarios is also around 25%. Therefore it is clear that for 2030, heat and transport electrification need to be taken into account, but do not radically affect the picture for electricity.

Similarly, the ECF study also found that the estimated increase in electricity demand in Europe due to electrification of heat and transport was almost completely balanced by the estimated reduction in electricity demand due to energy efficiency measures.

6.7 Interconnection capacity required with no large thermal stations

The work reported above shows that in principle it is possible (though not necessarily optimal) to achieve a secure electricity supply in Scotland with no large coal, gas or nuclear generating stations. As this would depend crucially on interconnection to the rest of the GB system, this section considers alternative interconnection capacities[15].

Table 8 shows various cases, based on the total 4000 MW interconnection capacity planned for 2014/15, plus a number of additional 1800 MW HVDC connections, as intended for the planned west and east coast subsea connections.

In the table, electricity supply for Scotland is considered ‘secure’ if peak demand can still be met, assuming concurrent failure of the two largest elements of interconnection capacity. For each case, the last column shows the generation that would be required in Scotland in order to ensure peak demand is still met. This generation is assumed to be made up of pumped storage, reservoir hydro, biomass and Energy from Waste plants.

Several caveats must be noted:

- As stated earlier, true analysis of security of supply is complex, and this section serves only to give an indication of important factors.

[15] ‘Interconnection’ as used here is technically incorrect, because the entire GB transmission system is designed and operated as one system. The term is more correctly applied to connections between transmission systems. The connections discussed here are technically just reinforcements to the GB transmission system. However ‘interconnection’ is in common usage, and in this case also serves to cover possible true interconnections to e.g. Norway, which would serve the same purposes.

- It is assumed that a prolonged cold spell, due to an anticyclone, results in zero output from onshore wind, offshore wind and wave generation. The output of run-of-river hydro is also assumed to be zero, due to frozen ground. The output of tidal generation is assumed to be zero, because of random coincidence of slack water with peak electricity demand (though if tidal generation is distributed around the coast, this would be a conservative assumption).

- Effects of major failures of the transmission system within Scotland are not considered. This is unlikely to have a significant effect, as these elements are mostly smaller than the elements of the transmission system which are considered as 'interconnections' here, and the probability of concurrent failures is small.

- It is assumed that there are no failures in the reservoir hydro, pumped storage, biomass and Energy from Waste plants. This is a realistic assumption, because failure concurrent with two major transmission failures and peak demand is highly unlikely.

- In practice, total interconnection capacity is affected by other transmission system factors, and the sizes of the steps shown in Table 8 are a simplification. Capacity limitations on the transmission system within Scotland are not considered.

- The interconnection with Northern Ireland (500 MW) is ignored, though in reality it is likely that in extreme circumstances such as those shown in Table 8, this interconnection would be used to import power.

- The effect of interruptible or deferrable demand in reducing peak demand is ignored. It is also assumed that no electric vehicle batteries are available to provide energy at the time of peak demand (late afternoons in winter), as this is likely to coincide closely with peak vehicle usage.

Case	Total interconnection capacity [MW]	Interconnection capacity assuming failures of two largest elements [MW]	Peak demand [MW]	Required output of generation in Scotland [MW]
1	9400 (4000 + 3 x 1800)	5800 (4000 + 1800)	6000	200
2	7600 (4000 + 2 x 1800)	4000	6000	2000
3	5800 (4000 + 1800)	~3000	6000	3000

Table 8: Effect of reduction of interconnection capacity on generation required within Scotland

Case 1 can be considered secure, if the combined GB system itself is secure. This case assumes that the planned west and east coast subsea interconnectors are built, and a further unspecified interconnector of the same size.

Even with the loss of the two largest interconnections, it is only necessary to be able to generate around 200 MW within Scotland at the time of peak demand. This could be met entirely by existing pumped storage plant, recharged overnight.

Case 2 assumes only the east and west coast interconnectors are added. In this case, at the time of peak demand, it is necessary to be able to generate around 2000 MW within Scotland. Current pumped storage capacity is 740 MW, but there are proposals for a further 2 x 600 MW. With reservoir hydro, biomass and Energy from Waste, this option can also be considered secure.

Case 3 assumes only the planned west coast interconnector is added. In this case, at the time of peak demand, it is necessary to be able to generate around 3000 MW within Scotland. If pumped storage capacity is increased by 1200 MW as proposed, i.e. to 1940 MW, this option may also be secure, but detailed study of possible causes of concurrent 'failure' of some of the pumped storage, reservoir hydro, biomass and Energy from Waste plants would probably be necessary. A substantial amount of deferrable demand would also be of assistance.

Further cases with even lower interconnection capacity could also be considered. However it is likely that in such circumstances there would be insufficient time and interconnection capacity to recharge the pumped storage stations overnight, ready for the next day's peaks.

All cases shown in Table 8 would, even without any transmission failures, result in substantial constraint[16] of exports from Scotland at times of high renewables production. This is a restating of the fundamental point that with high renewables capacity in Scotland, the economically-justified level of interconnection capacity will be substantially greater than the interconnection capacity required solely for security of supply.

[16] Within the scope of this study, the volume of these constraints cannot be quantified.

7 CONCLUSIONS AND RECOMMENDATIONS

7.1 General

Demand reduction

All objectives become substantially easier to achieve, with less risk and cost, if electricity demand reduction measures are achieved. These measures are generally understood to be lower cost than all other means of reducing emissions.

The same applies to transport emissions: reducing car-km travelled and improving internal combustion engine vehicle efficiency provide more substantial benefits, earlier, than electric vehicles.

Renewables production and exports

Even relatively cautious estimates of generation from renewables in Scotland, based on known projects and current rates of development, show very high levels of renewables production by 2020, and potentially higher levels thereafter, sufficient to effectively decarbonise electricity consumption in Scotland before 2030.

This is calculated on an annual basis, i.e. annual renewables production equal to or greater than annual gross electricity consumption, and does not preclude the consumption of electricity from coal, gas or nuclear generation for some fraction of the year.

This will result in high levels of export to the rest of the GB system, and potentially also abroad.

The interconnection capacity required to permit this substantial export from Scotland (and also for transfers within Scotland) is greater than the interconnection capacity required for system security.

As transmission costs are dominated by capital costs, it will not be economic to build sufficient transmission capacity to cope with infrequent events, such as maximum renewables output and minimum demand in Scotland. Therefore there will be some constraint of electricity exports, and possibly also of transfers within Scotland. It is likely that thermal generation will be constrained before renewables.

It is by no means certain that the large volumes of exports envisaged in this study will all be able to compete for purchasers against renewables generation south of the border, or possibly abroad.

From other studies [4] [5] [20] [26], the additional costs to consumers of a high proportion of electricity from renewable sources are not great, compared to the likely costs of future fossil-fired generation, and under some assumptions of future fuel and carbon prices the total costs to the consumer would be reduced. In addition, with a high proportion of renewable generation, consumers are better insulated from fuel price variations or future fuel scarcity.

System security

A secure electricity supply for Scotland is technically feasible with high renewables production, to at least 100% of gross consumption on an annual basis, provided the GB system as a whole is secure.

Transmission interconnections will have the major role in achieving this. From other studies, the impact of interconnections and other system costs on electricity costs to consumers is not prohibitive.

Thermal generation

Depending on assumptions about future fuel prices and carbon price, new coal and gas-fired generation is expected at some point before 2020 to be more expensive than onshore wind.

Given sufficient interconnection capacity to the rest of the GB system, it is not essential for there to be any coal, gas or nuclear generation in Scotland. Generation location is therefore substantially an economic decision. Transmission system costs and risks will tend to favour generation located near the main load centres in the southern half of the UK. The proximity to gas fields and potential carbon storage capacity will tend to favour location in Scotland.

With low thermal generation capacity in Scotland, at some times Scotland will import electricity which can be considered to be provided by some mixture of coal, gas and nuclear generators.

7.2 Policy options for Scottish Government

Current policies at Scottish and UK levels are generally heading in the right direction to achieve emissions reduction targets in the electricity generation sector. However there are big questions, in two principal areas:

- Can the forecast or desired pathways be achieved?
- What is the lowest-cost and lowest-risk set of options?

Some policy issues are listed below, grouped under these two questions.

Achieving the desired effects

Car usage reduction, electricity and heat demand reduction are within the Scottish Government’s powers, by influencing consumer behaviour, by its own purchasing decisions, and by regulation or legislation (particularly building regulations). Achieving substantial reductions in these areas makes achieving all other objectives easier. As a result, the announcement of firm and ambitious demand reduction targets for 2020 and 2030 should be an early priority.

It would also be useful to start developing firm targets for renewable electricity generation, heat, transport and energy efficiency for 2030 and 2040. The renewable electricity target should include allowances for electrification of heat and transport.

Some of the elements of the ROC market are within control of the Scottish Government, and can be used to ensure that renewable technologies particularly appropriate to Scotland are supported.

The Scottish Government also has powers over transmission reinforcement, including links to the rest of GB and other countries. As interconnection is a significant benefit in managing systems with high renewables penetration, it is likely that further large-scale transmission reinforcement and interconnections to other countries will be proposed, and it will be necessary to develop policy to balance local and national concerns. This may be particularly difficult if a transmission line is justified purely on economic grounds, i.e. benefit to the generator owner, with no benefit in reduced electricity costs or increased system security to those affected by the route. The low visual impact of underground or undersea cables will have to be balanced against the low cost and low environmental impact of overhead lines.

The key steps to achieving the high renewables penetration envisaged in the scenarios presented in this study are:

- demand reduction, for electricity, heat and transport;
- allowing adequate transmission reinforcement to be built in time;
- ensuring that system security issues are considered (within National Grid and within Government) on the basis of the interconnected GB system, and possibly including connections to countries beyond the GB system;
- ensuring that there is an adequate market for renewable electricity, beyond the anticipated ROC market if necessary, recognising that substantial exports are expected and therefore transmission system charges are important.

Achieving lowest cost and risk

The UK, and in particular Scotland, is fortunate in having a number of options for achieving the demanding emissions reductions targets. The ‘low-hanging fruit’, or quick gains, are now becoming apparent, but after that it is not at all clear which mix of these options will be lowest cost and/or lowest risk.

In this context, the risk of a major part of a policy framework failing to deliver can be more important than minimising total cost.

Although as noted above, interconnection is likely to be the major contributor to security with high renewables, it would be wise to spread the associated risks by also encouraging investments in energy storage and deferrable demand. This is especially true for those which offer complementary benefits: for example smart metering can also help reduce household energy use, and enable more effective delivery of social tariffs to help address fuel poverty.

The Scottish Government has powers to permit or refuse generating station applications above 50MW, and to set guidance for the determination of such applications. Such guidance could usefully reflect the analysis set out in this report, and clarity over both the goals and how system security is to be achieved would reduce uncertainty and risk for generation project developers.

A number of recommendations are made below for further investigations into issues which are particularly relevant in a Scottish context.

Other issues are being taken forward at UK or European level, and policymakers in Scotland should continually review policies and forecasts for Scotland against published results of these studies.

7.3 Recommendations

To guide policymakers, the estimated costs of offshore wind, wave and tidal generation in Scottish waters should be regularly reviewed in the light of the latest data, and compared to other generation options, including renewables located elsewhere in GB, using a similar methodology to that used in [20].

The economics of transmission connections between Scotland and Norway, the Netherlands and Germany for export of renewables production (especially onshore and offshore wind, wave and tidal) should be investigated.

National Grid should be encouraged to extend their current studies to consider whether the GB system can operate stably with no large power stations in Scotland, and what changes to the transmission system may be required to achieve this, or what improved technical performance would be required from renewable generators.

A study should be undertaken to quantify the electric vehicle battery storage capacity that may be available in Scotland to the system operator, as a function of time of day, assuming that commercial arrangements are attractive to vehicle users.

The analysis of renewable heat options reported in [25] should be repeated specifically for Scottish conditions, and should include an analysis of the effect of heat pumps, especially domestic, on peak demands.

The economics of using building heat loads (space heating and hot water) to be used as deferrable demand to match the three or four day ‘wind cycle’ should be studied, assuming very high levels of insulation, and specifically in a Scottish context.

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