ANALYSIS OF IMPLICATIONS OF A DECARBONISED POWER SECTOR IN SCOTLAND BY 2030

Technical Report

WWF Scotland

Report No.: 03, Rev. E
Document No.: 112965-UKGL-R-03-E
Date: 2014-11-24

IMPORTANT NOTICE AND DISCLAIMER

1. This document is intended for the sole use of the Client as detailed on the front page of this document to whom the document is addressed and who has entered into a written agreement with the DNV GL entity issuing this document ("DNV GL"). To the extent permitted by law, neither DNV GL nor any group company (the "Group") assumes any responsibility whether in contract, tort including without limitation negligence, or otherwise howsoever, to third parties (being persons other than the Client), and no company in the Group other than DNV GL shall be liable for any loss or damage whatsoever suffered by virtue of any act, omission or default (whether arising by negligence or otherwise) by DNV GL, the Group or any of its or their servants, subcontractors or agents. This document must be read in its entirety and is subject to any assumptions and qualifications expressed therein as well as in any other relevant communications in connection with it. This document may contain detailed technical data which is intended for use only by persons possessing requisite expertise in its subject matter.

2. This document is protected by copyright and may only be reproduced and circulated in accordance with the Document Classification and associated conditions stipulated or referred to in this document and/or in DNV GL's written agreement with the Client. No part of this document may be disclosed in any public offering memorandum, prospectus or stock exchange listing, circular or announcement without the express and prior written consent of DNV GL. A Document Classification permitting the Client to redistribute this document shall not thereby imply that DNV GL has any liability to any recipient other than the Client.

3. This document has been produced from information relating to dates and periods referred to in this document. This document does not imply that any information is not subject to change. Except and to the extent that checking or verification of information or data is expressly agreed within the written scope of its services, DNV GL shall not be responsible in any way in connection with erroneous information or data provided to it by the Client or any third party, or for the effects of any such erroneous information or data whether or not contained or referred to in this document.

4. Any wind or energy forecasts estimates or predictions are subject to factors not all of which are within the scope of the probability and uncertainties contained or referred to in this document and nothing in this document guarantees any particular wind speed or energy output.

KEY TO DOCUMENT CLASSIFICATION

Strictly Confidential	:	For disclosure only to named individuals within the Client's organisation.
Private and Confidential	:	For disclosure only to individuals directly concerned with the subject matter of the document within the Client's organisation.
Commercial in Confidence	:	Not to be disclosed outside the Client's organisation.
DNV GL only	:	Not to be disclosed to non-DNV GL staff
Client's Discretion	:	Distribution for information only at the discretion of the Client (subject to the above Important Notice and Disclaimer and the terms of DNV GL's written agreement with the Client).
Published	:	Available for information only to the general public (subject to the above Important Notice and Disclaimer).

Project name:	Analysis of implications of a decarbonised power sector in Scotland by 2030	
Report title:	Technical Report	
Customer:	WWF Scotland, The Tun, 4 Jackson's Entry, Holyrood Road, Edinburgh EH8 8PJ, UK	
Contact person:	Gina Hanrahan	
Date of issue:	2014-11-24	
Project No.:	112965	
Report No.:	03, Rev. E	
Document No.:	112965-UKGL-R-03-E	

DNV GL Energy
Renewables Advisory
7 West Nile St
Glasgow
G1 2PR
United Kingdom
Tel: +44 (0)141 242 6045
GB 810 7215 67

Task and objective: To investigate the options for a decarbonised electricity system in Scotland by 2030.

Prepared by:	Verified by:	Approved by:
Paul Gardner Senior Principal Engineer	Ioannis Papadopoulos Consultant	Oscar Fitch-Roy Senior Consultant
Anastasios Koumparos Consultant		

☐ Strictly Confidential
☐ Private and Confidential
☐ Commercial in Confidence
☐ DNV GL only
☒ Client's Discretion
☐ Published

Keywords:
Renewable, integration, carbon intensity, 2030

Reference to part of this report which may lead to misinterpretation is not permissible.

Rev. No.	Date	Reason for Issue	Prepared by	Verified by	Approved by
A	2014-05-30	Draft for client comment	P Gardner		
B	2014-07-07	Draft after client comment	P Gardner		
C	2014-07-11	Final draft	P Gardner	I Papadopoulos	
D	2014-08-01	Final	P Gardner, A Koumparos	I Papadopoulos	O Fitch-Roy
E	2014-11-24	Section 4.3.4, numerical correction	P Gardner	-	-

Table of contents

Appendices

1 EXECUTIVE SUMMARY

Scotland is on track to meet its 2020 target for electricity production from renewable sources. At UK and European level there is considerable debate about targets for energy or emissions for 2030, and the Scottish Government is committed to achieving an emissions target for electricity generation of 50 gCO_2e/kWh[1]. Large-scale use of variable renewables such as wind and PV raises concerns for security of electricity supply and the operation of the electricity supply system.

This report seeks to address these issues against a background of a decarbonised power sector in Scotland by 2030, assuming no new nuclear development, and catering for the possibility that Carbon Capture and Storage (CCS) technology fails to become widely commercialised by 2030.

A range of scenarios are developed. The primary axes on which the scenarios vary are:

- ***long-term energy demand in Scotland***: three alternative options, exploring credible alternative assumptions about progress of energy efficiency, and electrification of heat and transport.
- ***short-term system flexibility***: two alternatives, 'low' and 'high' flexibility, differing in assumptions about levels of demand response and energy storage.

These axes are chosen because they represent some of the greatest uncertainties.

Two alternative levels of CCS capacity are also defined.

From these 12 combinations of options (three options for demand, two for flexibility, and two for CCS), the study selects four scenarios, which are considered to bracket most of the possible outcomes for 2030, and chosen to illustrate the possibilities and the issues raised. These are shown in the table below. One of the demand options is dropped completely, as its impacts are covered by the selected scenarios.

The scenarios chosen can be seen as representing alternative levels of political ambition and public acceptance:

- Scenarios 1 and 2 are consistent with futures where energy and climate issues, particularly energy efficiency, have relatively low political priority. This low priority also means that regulatory, energy market and public acceptance barriers remain for new pumped-storage plant in Scotland.
- Scenarios 3 and 4 on the other hand are consistent with high political priorities for energy and climate issues, and high public acceptance. There are major efforts to reduce energy demand, high uptake of electric vehicles, and low barriers to construction of new pumped-storage plant.

<table>
<tr><th>Variable</th><th>Scenario 1
Weak policy drive, high CCS</th><th>Scenario 2
Weak policy drive, low CCS</th><th>Scenario 3
Strong policy drive, high CCS</th><th>Scenario 4
Strong policy drive, low CCS</th></tr>
<tr><td>Electricity demand</td><td colspan="2">Increased energy efficiency outweighed by increased underlying demand, and some electrification of heat and transport</td><td colspan="2">Substantial efforts in energy efficiency outweigh increased electric heating and electrification of transport. Transport demand is stabilised</td></tr>
<tr><td>Flexibility</td><td colspan="2">Some increase in pumped-storage capacity, limited demand response</td><td colspan="2">Substantial additional pumped-storage and demand response</td></tr>
<tr><td>Fossil generation fitted with CCS</td><td>High (2500 MW)</td><td>Low (340 MW)</td><td>High (2500 MW)</td><td>Low (340 MW)</td></tr>
</table>

[1] Defined as the total carbon emissions from electricity generation in Scotland, divided by total electricity generation. The units are in grams of CO_2 'equivalent' per kWh, where emissions of other compounds are weighted by their 'greenhouse gas' effect.

For each scenario, a mix of generation capacity is selected, and assessed for performance against the objectives.

The outputs of the study are grouped as answers to a series of Research Questions, which are summarised here:

1. How can the 2030 decarbonisation target be delivered in a low CCS, no new nuclear scenario?

With only renewables and a small amount of gas generation with CCS in Scotland, decarbonisation targets are met and exceeded. During periods of high electricity demand and low renewables production, electricity may need to be imported from the rest of the GB system**.** Other solutions are available which may also contribute to managing this situation.

2. How can system security be achieved under the 2030 decarbonisation target?

Electricity supply in Scotland will be secure if the combined GB system is secure. National Grid studies for high-renewables cases show that this is achievable.

With the transmission capacity to the rest of the GB currently existing or planned, there is little or no need for conventional generating capacity in Scotland to maintain security of supply, even in periods of low renewables production.

3. What does the analysis indicate about likely capacity margins in 2030 and how do they compare to other European countries?

Capacity margin for Scotland can become negative in the scenarios studied, but this is not important, if the entire GB system is secure.

4. What will the electricity transmission flows between Scotland and the rest of the UK from 2020 to 2030? What will the import/export balance look like to 2030 under the various pathways?

Scotland would continue to be a net exporter of electricity. Net volumes of exports, and the peak flows, will depend on the economic case for renewable capacity in Scotland, and the economic case for transmission capacity to allow exports.

5. What is the security of supply implications for the rest of the UK of the Scottish 2030 decarbonisation target?

The security of supply implications for the rest of the GB system are small. The current Scottish conventional generation fleet is a small fraction of the GB total: its contribution to GB system security may be replaced by several alternatives, including ‘peaking’ plant, located wherever is most economic.

6. What role should energy efficiency, demand management, storage and interconnection play in system security in 2030 and is it feasible to achieve this role in a no CCS scenario?

All can play a part, but the main contributor to secure decarbonised electricity supply for Scotland is transmission capacity to the rest of the GB system.

7. What transmission, distribution, storage and generation infrastructure is required to maintain security of supply in 2030 and at what cost?

No additional infrastructure is needed for the scenarios investigated in this study beyond that already planned, except (in some cases) some further transmission reinforcement.

8. Is the current policy regime adequate to deliver the 2030 power sector decarbonisation target with respect to a) transmission b) the energy market c) planning and d) generation?

Yes, provided that political will and public acceptance is maintained. Political will post-2020 is by no means clear.

There are specific difficulties with connections to the main island groups, which require political intervention.

9. What policy recommendations flow from this analysis?

There are three main areas for policy action, at both Holyrood and Westminster level:

Maintaining industry confidence in the short and medium term:

- Rapid resolution of the uncertainties around Electricity Market Reform is crucial.
- Wave and tidal technologies and projects are at risk of being ignored in the short term. Governments need to 'check in' frequently with the wave and tidal industries to ensure that connection issues, transmission charging, and electricity market reform do not impede progress.

Post 2020:

Continuation of a market for new renewables projects after 2020 needs to be established, including adoption of the Fourth and Fifth Carbon Budgets, and a firm decarbonisation target for 2030.

Further, with strong efforts on energy efficiency and demand reduction in Scotland, the volume of renewable generation already existing or under construction will get Scotland close to the target of 50g/kWh well in advance of 2030. Therefore, demand reduction within Scotland makes it easier to achieve this ambition despite possible uncertainty or even unhelpful policies in Westminster and Brussels.

Scottish island groups:

A solution to the problems of renewable generation on the three main island groups, in obtaining a grid connection at acceptable cost and in time, would produce several hundreds of MW of onshore wind generation at costs significantly cheaper than offshore wind. This would also provide major economic and social benefits to disadvantaged areas, and could provide sites for demonstration of wave and tidal arrays at reasonable connection cost.

2 INTRODUCTION

WWF Scotland (WWF) has appointed Garrad Hassan & Partners Ltd, trading as DNV GL, to provide analysis of the implications of a decarbonised power sector in Scotland by 2030, assuming no new nuclear development, and assuming the failure of Carbon Capture and Storage (CCS) technology to become commercialised.

The Scope of Work is structured into a three-stage approach as follows:

- Phase 1 Scenario Development
- Phase 2 Scenarios Analysis
- Phase 3 Reporting

This report covers the work of all Phases.

The work reported here assumes that, in the event of a Yes vote in the forthcoming independence referendum, the GB electricity system would continue to be operated as one system and one wholesale energy market. There are currently no explicit commitments to renewables at the UK level beyond 2020, though the Climate Change Act (2008) is expected to drive deployment of renewables. It is assumed that the current UK obligations for greenhouse gas reduction and renewable electricity would be allocated equitably between Scotland and the remaining UK, so that the economic conditions for renewable generation located in Scotland would be substantially unaffected.

3 SCENARIO DEVELOPMENT

3.1 Introduction

This section covers development of the scenarios, which will then be used for analysis in later sections.

The aim is to develop a range of scenarios, to explore the implications for the Scottish electricity system of achieving a 'carbon intensity'[2] of 50 gCO_2e/kWh without any new nuclear capacity, and assuming the failure of CCS technology to become commercialised.

The primary axes on which the scenarios vary are:

- ***long-term energy demand in Scotland***: three alternative options, exploring credible alternative assumptions about progress of energy efficiency, and electrification of heat and transport.
- ***short-term system flexibility***: two alternatives, 'low' and 'high' flexibility, differing in assumptions about levels of demand response and energy storage.

These axes are chosen because the future development of these factors represents some of the greatest uncertainties.

The implications to be assessed will include consideration of:

- Associated power sector generation mixes;
- The in-day and annual Scottish electricity net demand situation;
- The 'capacity margin';
- Scotland's net energy balance;
- The need for the rest of the GB system; and
- Transmission build requirements.

3.2 Establishing the background: targets and aspirations for 2030

In the European Union (EU), national and sub-national energy policy is influenced by the overall aims set at the European community level by each government. These overarching energy targets or aspirations then filter down to the individual national energy policies which in turn affect developments in each country. As such it makes sense to begin any investigation of energy targets at the highest relevant level i.e. the European Union (EU) level.

European, UK and Scottish targets and aspirations for 2030 are summarised in Table 3-1. More detail is provided in Appendix A.

For the purposes of this study, the most important in 2030 are:

- At least 40% reduction in emissions (European target). This is driving other European aims, and also sets the 'big picture' for European governments for 2030.
- Decarbonisation of the electricity sector to below 50gCO_2/kWh (UK, Scottish Government). This level of decarbonisation is well established and accepted as necessary to meet aspirations for 2050. It also has the advantage of being readily defined and measured. Further, achieving this target requires action by a relatively small number of actors, in an industry which is already heavily regulated.
- 'Significant progress' made towards total decarbonisation of heat and transport sectors by 2050 (Scottish Government). These aims are less well defined than the electricity decarbonisation target, and also may be harder to measure in practice. They are important here in clearly establishing policy priorities and setting direction of travel.

---

[2] Defined as the total carbon emissions from electricity generation in Scotland, divided by total electricity generation. The units are in grams of CO_2 'equivalent' per kWh, where emissions of other compounds are weighted by their 'greenhouse gas' effect.

Table 3-1 Summary of targets, recommendations and estimates for 2030

Item	European Union	United Kingdom	Scotland
Emissions (weighted to CO_2 equivalent)	At least 40% reduction (EC target)	60% reduction, to 310 $MtCO_2e$ (CCC recommendation)	60% reduction (Scottish Government estimate, to meet legal obligation for 2050)
Renewable energy	27% of energy consumption (EC target)	40-60% of electricity generation /1/ or30-45% /2/ (CCC analysis)	No figure
Renewable electricity	45% of electricity production (EC estimate to meet other targets)	Electricity sector to reach $50gCO_2/kWh$ (CCC recommendation)	Electricity sector to reach $50gCO_2/kWh$ (Scottish Government target) Discussion of possible renewable share to be 125% of gross domestic consumption
Demand reduction, energy efficiency	25% reduction (EC estimate to meet other targets)	No figure	No figure
Heat	>50% of heat demand (external modelling)	No figure	'Significant progress' made towards total decarbonisation of heat sector by 2050
Transport	20% GHG reduction compared to 1990 levels (EC estimate to meet other targets)	No figure	'Significant progress' made towards total decarbonisation of transport sector by 2050

3.3 Scenario assumptions

The fundamental assumptions behind the development of the scenarios are:

- All scenarios must achieve emissions from the combined electricity generation capacity located in Scotland of 50g CO_2e/kWh or lower in 2030.
- All scenarios must be credible in technical and economic terms, including in terms of build rate and feasible rates of renewable energy penetration onto the grid.
- Existing unabated coal and nuclear generation is assumed to retire as defined in earlier work for the Scottish Government /3/, shown in Table 3-2.[3] Since these assumptions were published (2011), Cockenzie coal-fired plant closed in 2013, as anticipated. The closure dates for the remaining coal and nuclear plant are not certain, but currently there is no indication that any will be running in 2030.
- Deployment of Carbon Capture and Storage is considered as two separate cases:
    - CCS reaches the Scottish Government's 2.5 GW target by 2030, which may include installing on existing thermal plant;

[3] The Scottish Electricity Dispatch Model (SEDM), which may have results useful to this study, is understood to be close to completion but results are not expected to be published for some time.

- Alternatively, CCS fails to reach commercialisation beyond a single demonstration plant of around 500MW in 2020.

The most recent information on the progress of the CCS project at Peterhead indicates that the demonstration unit will have a generation capacity of 340 MW, running at 85% capacity factor, in operation by 2020 /4/. Therefore 340 MW is used instead of 500 MW.

Table 3-2 Assumed development of unabated coal and nuclear generating capacity [MW]

Year	2010	2015	2020	2030
Coal (unabated)	3,386	2,284	1,713	0
Nuclear	2,289	2,289	2,289	0

Source /3/ 2011. Figures are for Scenario 2, i.e. Hunterston B nuclear station lifetime extended to 2021[4].

3.4 Scenario parameters: electricity demand in Scotland

3.4.1 Definitions

Throughout this report, electricity demand is defined as Gross Consumption. This is defined as total electricity generated within Scotland, less net exports. It therefore includes energy consumed in transmission and distribution losses before it reaches consumers, and by generators ('own use'). Total Consumption is an alternative definition, which is defined as total electricity generated, less net exports, losses and 'own use'. These definitions are taken from /5/.

Gross Consumption is more appropriate in this study, as it includes an estimate of transmission and distribution losses.[5] Total Consumption within Scotland in 2012 was 30.8 TWh, whereas Gross Consumption was 36.6 TWh /5/.

3.4.2 Demand Option 1 (Scottish Government 2012)

The definition agreed with WWF is:

> *Scottish domestic electricity demand develops in line with the forecast from SKM's 2012 report to the Scottish Government /5/.*

In /3/, Total Consumption in 2030 is estimated as 36.7 TWh, and Gross Consumption is implied to be 43.1 TWh.

This scenario includes an assumption of increased energy efficiency, counterbalanced from 2020 onwards by some allowance for electrification of transport and heat. Figures are not given for each component of the annual demand: for the purposes of this study, electric heating is assumed to contribute around 6 TWh in this scenario (currently 6.4 TWh).

It should be noted that this figure of 43.1 TWh is an increase of 18% on the 2012 figure of 36.6 TWh /5/. This is an annual increase of around 0.9%, which is well within rates experienced for the UK in recent history[6].

---

[4] Since extended to 2023.

[5] 'There is an argument that using gross consumption in this case overestimates future demand, as generator 'own use' will reduce as the contribution from thermal generation reduces. This is because most thermal generators have substantially more 'own use' than most renewables, for example to drive boiler feed pumps and fans. However this effect is expected to be small, and is not included here.

In comparison, National Grid's Future Energy Scenarios /6/ predicts a *reduction* in UK electricity demand over the same period, in the Slow Progression scenario (appropriate in this case). In particular:

- Domestic demand is reduced by improvements in heating and lighting efficiency, but then increases due to population growth and GDP growth. The net effect is a slight increase over current domestic demand.
- Industrial demand is driven by assumptions about economic trends. This results in lower industrial demand than at present.
- 'Commercial and other' demand decreases significantly, driven by economic assumptions about energy efficiency and economic growth.

Electricity demand in Scotland has been decreasing in recent years (2008-2012), by about 3% per year; however this is a relatively short period from which to extrapolate to 2030, and is of course heavily affected by the major economic upsets during the period.

3.4.3 Demand Option 2 (Electrification focus)

The definition agreed with WWF is:

> *Electrification of transport and heat proceeds at pace while energy efficiency policies fail to achieve traction.*

Energy efficiency and demand growth

The effect of energy efficiency in this case is based on the assumptions underlying the Demand Growth scenario (i.e. slow progress on energy efficiency) in previous DNV GL work /7/, providing the technical basis of the Friends of the Earth (FOE) Scotland document 'The Power of Scotland Secured' (PoSS) /8/.

This assumes 0.9% demand growth per annum to 2015, then 0.5% onwards. Applying this to the latest data for 2012 results in an estimate of 40.5 TWh in 2030.

Transport

The dominant element in transport suitable for electrification is the passenger car and light van fleet, and only this element was considered here. Although electrification of rail, ferries, other light road freight and bus transport is likely, the impact on electricity consumption is small in comparison: currently 93% of all road vehicles in Scotland are cars and light vans, around 2.5 million in total /9/.

Transport Scotland's Electric Vehicle Roadmap /10/ envisages that by 2030 half of all new car sales will be battery-electric or plug-in hybrid. In /9/, this results in EVs forming over 30% of the car and van fleet in 2030, or 750,000 vehicles[7]. However, this level of ambition for 2030 appears low for this Demand Option. Therefore, for this option it is assumed that 60% of the fleet are EVs (1.5 million vehicles). This is ambitious but not infeasible: recent work for the Committee on Climate Change shows how a 'high EV uptake' target for the UK could be achieved, resulting in a UK fleet of 13.6 million electric cars and vans in 2030 /11/.

National Grid's Future Energy Scenarios 2013 /6/ predicts about 2.6 TWh of additional electricity demand per million EVs, for the UK in 2030[8]. 1.5 million vehicles therefore will require approximately 3.8 TWh of additional electricity demand[9].

---

[6] 2.4% per year for 1970 to 2005 /15/

[7] Assuming the size of the car and van fleet is similar to the present.

[8] 'Gone Green' scenario, which is the appropriate scenario for comparison in this case.

[9] This additional demand is approximately the same as estimated in PoSS for the Traffic Growth scenario, which corresponds to Demand Option 1.

Space and water heating

The effect of electrification of space and water heating assumes that the Scottish government's objective of 'significant progress' by 2030 towards a largely decarbonised heat sector is achieved through a large but credible increase in the use of electric forms of heat delivery such as heat pumps. The impact is difficult to estimate, as there are many competing options for heat provision, and considerable uncertainty about costs, technical developments, and adoption rates /12/.

Recent WWF work on domestic heat /13/developed a 'high abatement' scenario[10], based on Scottish Government's ambition to decarbonise the heat sector in Scotland by 2050. The study interprets this as corresponding to a target of 50% penetration of renewable heat in the **domestic** sector by 2030. The results show 10.7 TWh of renewable heat delivered from heat pumps, almost all Air Source Heat Pumps (ASHP), with a net electricity demand of 3.2 TWh per year. This excludes electric heating in industry and commercial buildings.

The draft Heat Generation Policy Statement /14/ contains estimates of heat supply for 2050 in several scenarios, for both domestic and non-domestic (industrial and commercial) uses. The most relevant in the context of Demand Option 2 is the High Government Intervention and Low Uptake scenario. 'Low Uptake' matches the assumption in Demand Option 2 that energy efficiency policies 'fail to achieve traction'.

Heat demand from electric heating in this case is estimated as shown in the table below. DNV GL has then converted this to electricity demand, assuming an average Coefficient of Performance for heat pumps of 3.0[11]. Although heat from electricity approximately doubles between 2010 and 2030, the net result is a ***reduction*** in total electricity demand for heat, due to the existing resistive heating load[12] being replaced by heat pumps, and also reduced by improved building insulation.

The data in the Heat Generation Policy Statement is the most recent detailed analysis, so these figures are adopted, i.e. electricity demand for heating reduces from 6.4 TWh currently to 5.8 TWh in 2030.

---

[10] The 'Medium Abatement' scenario aims to supply around 30% of domestic heat demand from renewable sources in 2030, and shows 7.2 TWh of renewable heat delivered in 2030 from heat pumps, resulting in an additional electricity demand of 2.3 TWh.

[11] Currently the Coefficient of Performance for air-source heat pumps is around 2.5, but this is expected to improve by 2030.

[12] Substantial resistive electric heating load exists in Scotland, likely to be particularly prevalent in areas off the gas grid.

Table 3-3 Electrification of heat for 2030 estimated in Heat Generation Policy Statement (Low Uptake assumption)

Source	2010 heat supplied	2010 electricity demand	2030 heat supplied	2030 electricity demand
Domestic resistive heating	5.4 TWh	5.4 TWh	2.4 TWh	2.4 TWh
Domestic air-source heat pump	-	-	6.8 TWh	2.3 TWh
Domestic ground-source heat pump	-	-	1.5 TWh	0.5 TWh
Non-domestic resistive heating	1.0 TWh	1.0 TWh	0.2 TWh	0.2 TWh
Non-domestic air-source heat pump	-	-	1.0 TWh	0.3 TWh
Non-domestic ground-source heat pump	-	-	0.2 TWh	0.1 TWh
Totals (rounded)	**6.4 TWh**	**6.4 TWh**	**12.1 TWh**	**5.8TWh**

3.4.4 Demand Option 3 (Energy efficiency and electrification drive)

The definition agreed with WWF is:

> *Energy efficiency improves rapidly with substantial electrification of heat and transport, and 'stabilisation' of transport demand.*

Energy efficiency and demand growth

The effect of energy efficiency is based on the assumptions underlying the Demand Reduction scenario in PoSS. This assumed approximately 1% demand reduction per annum to 2030[13]. Applying this to the latest data for Gross Consumption for 2012 results in an estimate of 30.5 TWh in 2030.

As noted earlier, gross consumption in Scotland has reduced by around 3% per annum in recent years, though this is not a good basis for extrapolation to 2030.

Transport

In contrast to Demand Option 2, this option assumes 'stabilisation' of transport demand, in particular reduced passenger car travel distances caused by changes in travel patterns and greater use of alternative transport options. In this option, the EV fleet is assumed to be 750,000 vehicles as in

[13] National Grid's Future Energy Scenarios work also shows approximately the same rate of demand reduction in the Slow Progression case, to 2020.

Transport Scotland's Electric Vehicle Roadmap, rather than doubled as for Demand Option 2[14]. This results in an electricity demand of 1.9 TWh[15].

Space and water heating

The effect of electrification of space and water heating follows Demand Option 2, except that the High Uptake assumption in the Heat Generation Policy Statement is more appropriate. The result is shown in Table 3-4. Electricity demand for heat is reduced further, due to greater uptake of energy efficiency and low-carbon options.

Table 3-4 Electrification of heat for 2030 estimated in Heat Generation Policy Statement (High Uptake assumption)

Source	2010 heat supplied	2010 electricity demand	2030 heat supplied	2030 electricity demand
Domestic resistive heating	5.4 TWh	5.4 TWh	1.4 TWh	1.4 TWh
Domestic air-source heat pump	-	-	7.5 TWh	2.5 TWh
Domestic ground-source heat pump	-	-	1.7 TWh	0.6 TWh
Non-domestic resistive heating	1.0 TWh	1.0 TWh	0.1 TWh	0.1 TWh
Non-domestic air-source heat pump	-	-	1.0 TWh	0.3 TWh
Non-domestic ground-source heat pump	-	-	0.2 TWh	0.1 TWh
Totals (rounded)	**6.4 TWh**	**6.4 TWh**	**11.7 TWh**	**4.9TWh**

3.4.5 Discussion

The three options were chosen in order to explore the important factors. Summating the effects of energy efficiency/demand growth, electrification of transport, and electrification of heat results in a wide range of estimates for annual electricity demand in 2030, as shown in Table 3-5.

For comparison, the figures from National Grid's Future Energy Scenarios (FES) 2013 report for the UK /6/ are included[16], scaled for Scotland by the ratio of electricity consumption in 2012. The assumptions behind the FES scenarios are:

[14] Because fewer EVs are needed to meet expectations for reduction in transport emissions.

[15] This figure is close to the figure of 1.7 TWh derived in PoSS for the Traffic Stabilisation scenario, which assumed passenger car travel distances would be reduced to 2001 levels.

[16] 'Gone Green' results in higher electricity demand than 'Slow Progression' for a variety of reasons, partly because of greater assumed uptake of heat pumps and EVs in domestic consumption, but principally driven by an assumption of a more favourable economic environment increasing industrial demand.

- Domestic demand is reduced by improvements in heating and lighting efficiency, but then increases due to population growth and GDP growth, and (in the Gone Green scenario) due to uptake of heat pumps and electric vehicles. The net effect in both cases is a slight increase over current domestic demand.
- Industrial demand is driven by assumptions about economic trends. This results in higher industrial demand than current in the Gone Green scenario, and lower than current in the Slow Progression scenario.
- 'Commercial and other' demand decreases significantly in both Gone Green and Slow Progression scenarios, driven by combinations of energy efficiency and economic growth.

Table 3-5 Comparison of Demand Options

All figures are Gross Consumption, per year in 2030

Demand Option	Effect of energy efficiency and demand growth	Effect of electrification of transport	Effect of electrification of heat	Total
1. SG 2012	43.1 TWh, inc. 6 TWh of electric heat	-	-	43.1 TWh
2. Electrification focus	40.5 TWh	+3.8 TWh	-0.6 TWh	43.7 TWh
3. Energy efficiency & electrification drive	30.5 TWh	+1.9 TWh	-1.5 TWh	30.9 TWh
FES 'Gone Green'	-	-	-	35.9 TWh
FES 'Slow Progression'	-	-	-	28.2 TWh

The results show that the dominant effect is the assumption about future underlying demand growth and/or efficiency measures. Electrification of heat and transport have relatively small effects, though they are important for considerations of demand flexibility later in this work. This dominant effect can be seen as a contrast between historic rates of electricity demand growth (2.4% per year for 1970-2005 /15/) and recent negative growth in demand.

3.5 Scenario parameters: Short-term system flexibility

3.5.1 Purpose

The ability of the power system to react to in-day (and longer) changes in net demand is a factor in determining the volume of variable renewable power generation that can be accommodated. Several options exist to 'smooth' net demand profile, maintain system stability and uninterrupted supply, and avoid the need to turn-down or curtail excess variable generation. The topics considered in this study are:

- demand response, also termed deferrable demand or demand-side management;
- energy storage;
- interconnection to other electrical systems.

Other options for reducing the variability of wind and PV generation exist[17], but they are not studied here as the impacts on Cost of Energy (COE) are not well understood. They are also likely to be more expensive than the options listed above, until very high renewable energy penetrations are achieved.

The future requirement for interconnection to the rest of the GB power system and the rest of Europe is considered to be a key output from the analysis. Therefore two options are developed, reflecting different levels of short-term flexibility driven by energy storage and demand response in the Scottish electricity system.

3.5.2 Low flexibility option

The definition agreed with WWF is:

> *Deployment of (new non-hydro) energy storage and demand response measures are thwarted by barriers (technical, regulatory and otherwise) and are unable to contribute meaningfully to 'load shifting' before 2030.*

Under these assumptions, only new pumped-storage hydro energy storage can be assumed. Existing stations and published proposals are:

- Foyers, 300 MW, 6 GWh. Existing
- Cruachan, 440 MW, 10 GWh. Existing
- Coire Glas, 600 MW, 30 GWh. Proposed, planning consent received.
- Balmacaan, 300-600 MW, 30 GWh. Proposal.
- Sloy, 152 MW. Proposal for conversion of existing conventional hydro to pumped storage, by adding 60 MW pump capacity.
- Cruachan expansion. Proposal for expansion by a further 600 MW capacity and larger reservoir.

Development work on Coire Glas is currently suspended, awaiting greater clarity on electricity market reform and transmission charging reform.

For the Low Flexibility option, it is assumed that only one of the possible future 600 MW proposals proceeds, resulting in a total pumped-storage capacity of 1340 MW and 46 GWh.

The electric heating loads and electric vehicle charging loads estimated in Section 3.4 are assumed to provide some within-day demand response. A conservative assessment of the fraction of these loads which are available for this purpose is defined in Section 3.8.

3.5.3 High flexibility option

The definition agreed with WWF is:

> *Technical, regulatory and other barriers are overcome to allow significant growth in both energy storage and demand response (whenever economic) capability in Scotland between now and 2030.*

For this option, it is assumed that the equivalent of three new 600 MW/30 GWh pumped-storage schemes are built by 2030: these could be Coire Glas, Balmacaan and Cruachan expansion, but location is not important in this context. This results in total pumped-storage capacity of 2540 MW and 106 GWh.

Earlier work on options for large-scale energy storage in Scotland /16/ identified the two main technology options as pumped-storage hydro and Compressed Air Energy Storage (CAES), but concluded that pumped-storage is the most suitable for Scotland. Therefore no other large-scale energy storage options are assumed here. However it is worth noting that if other options such as CAES or seawater lagoons became more attractive than pumped-storage, this would not have a great effect on the results

[17] Examples: using large rotors on wind turbines relative to generator size, so that the turbines spend more of the time operating at full power; orientation of PV panels to east and west rather than due south; seeking to optimise the mix of wind and PV to minimise net variations.

of this study, as the important characteristics (principally capital cost, efficiency, and storage timescales) are unlikely to be radically different.

Electric heating loads and electric vehicle charging loads are estimated in Section 3.8, with less conservative assumptions than for the Low flexibility option.

3.6 Selection of scenarios

The three Demand Options, two Flexibility Options and two assumptions about CCS result in a total of 12 possible combinations. To achieve the most useful results within acceptable cost, four scenarios were selected for the analysis of Phase 2.

Table 3-6 Scenarios selected

Scenario	Description	Demand Option	Flexibility Option	CCS Option
1	Weak policy drive, high CCS	No. 1: Scottish Government 2012 (43.1 TWh)	Low flexibility	High CCS
2	Weak policy drive, low CCS	No. 1: Scottish Government 2012 (43.1 TWh)	Low flexibility	Low CCS
3	Strong policy drive, high CCS	No. 3: Energy efficiency and electrification drive (30.9 TWh)	High flexibility	High CCS
4	Strong policy drive, low CCS	No. 3: Energy efficiency and electrification drive (30.9 TWh)	High flexibility	Low CCS

Demand Option 2 was dropped, as the others approximately cover the range of annual Gross Consumption estimates in Table 3-5, including the Future Energy Scenarios estimates by National Grid. There is an argument for inclusion of Demand Option 2 because it has the greatest absolute volume of controllable EV and electric heating demand (3.8 + 5.8 TWh). However, Demand Option 3 is satisfactory as it has the same *relative* volume of controllable demand: approximately 22% of Gross Consumption.

On a more fundamental level, the scenarios chosen can be seen as representing alternative levels of political ambition and public acceptance:

- Scenarios 1 and 2 are consistent with futures ***where energy and climate issues, particularly energy efficiency, have relatively low political priority***. This low priority also means that regulatory, energy market and public acceptance barriers remain for new pumped-storage plant in Scotland.
- Scenarios 3 and 4 on the other hand are consistent with ***high political priorities for energy and climate issues, and high public acceptance***. There are major efforts to reduce energy demand, high uptake of electric vehicles, and low barriers to construction of new pumped-storage plant.

3.7 Peak demand

Estimates of peak demand are necessary to assess the required generation capacity. Peak demand in 2030 depends significantly on assumptions about consumer behaviour, response to price signals, and willingness to manage demand.

Therefore estimates are based on the results of the detailed analysis in the Future Energy Scenarios for the UK /6/, which are stated as 'derived from annual demands…' with additional analysis applied for new emerging technologies such as heat pumps and electric vehicles'.

For Scenarios 1 and 2 the ratio of peak demand to annual demand in the FES Slow Progression case is used (0.191 GW/TWh), which results in an estimate for Scotland of 8.2 GW.

For Scenarios 3 and 4 the ratio in FES Gone Green is used, which is very similar (0.194 GW/TWh), and results in an estimate of 6.0 GW.

Note that these estimates are for 'average' peak demand. In any year, the actual peak demand could be slightly higher or lower, affected principally by weather.

3.8 Potential for demand response

3.8.1 Purpose

Estimates of the potential for demand response are necessary, as this may be important for dealing with infrequent events such as combinations of low renewables output, high electricity demand and forced outages of other generation.

The main sources of demand response in 2030 are likely to be electric heating, EV charging and some commercial and industrial loads that can be shifted (e.g. cooling loads, heating water loads). These and other sources are discussed in this section.

3.8.2 Electric heating

For Scenarios 1 and 2, electric heating contributes 6 TWh to annual electricity demand, and is assumed to be mainly resistive heating. The majority of this will be in domestic properties.

These scenarios assume 'low flexibility', and so it is assumed here conservatively that there is effectively no scope for demand response at peak periods.

For Scenarios 3 and 4, electric heating contributes 4.9 TWh to annual electricity demand. This is made up of domestic and non-domestic resistive and heat pump loads (see Table 3-4). These scenarios assume 'high flexibility', and so a figure of 200 MW of demand response (out of 6000 MW peak demand) is assumed.

In Table 3-4, the domestic heat pump component is the largest (3.1 TWh per year). This translates to around[18] 500,000 domestic heat pump installations, i.e. roughly 20% of households. Using analysis by Imperial College /17/ and Baringa /18/ for the UK, it is estimated that the heat pump load which could be deferred at peak demand periods in Scotland is around 130 MW[19]. The assumption of around 200 MW of demand response from all heating loads is therefore reasonable, or possibly conservative.

3.8.3 Electric vehicle charging

Scenarios 1 and 2 assume Low Flexibility, and therefore it is conservatively assumed here that the electric vehicle (EV) charging demand provides effectively no contribution to demand response.

---

[18] Each domestic heat pump is expected to consume 5,850 kWh per year /21/

[19] The Imperial College work estimates that without attempting to manage the heat pump load, the load at peak demand periods will be around 50% of heat pump capacity. Domestic heat pumps have nominal capacity around 3.5 kW. Baringa made a conservative assumption that around 15% of this could be shifted from peak demand periods. 500,000 x 3.5 kW x 50% x 15% = 130 MW. Baringa also proposed 33% as an optimistic estimate, but for conservatism this is not assumed here.

Scenarios 3 and 4 assume High Flexibility. From Section 3.4.4, the EV fleet is assumed to be 750,000 vehicles, contributing 1.9 TWh to annual electricity demand. From this, a further 100 MW of demand response capability is assumed, based on analysis by Imperial College and Electricity Networks Association /17/[20].

It is assumed that deferral of EV charging loads is only feasible within-day. Deferral over several days or into weekends might prove possible, given the right incentives to vehicle owners, but there is no experience of this and it would be unwise to assume substantial demand can be deferred on this timescale.

Similarly, it is assumed that the use of EV batteries to supply energy to the grid (‘Vehicle to Grid’) is not significant. Several recent studies do not take account of vehicle-to-grid functionality /17//18//19//20/. This technology is still a controversial issue as it can lead to battery deterioration.

3.8.4 Other domestic loads

The potential for domestic demand response during peaks is estimated to be between 5%-20% /21/. Whilst 5% is a realistic assumption, 20% is considered to be a ‘stretch’.

A typical UK household without electric heating has a demand of 600W during peak hours /22/. There are 2.4 million households in Scotland, and so domestic demand response potential is estimated to be 5% to 20% of 1440 MW, i.e. 70 MW to 290 MW.

3.8.5 Other commercial and industrial loads

There is insufficient data available for the other commercial and industrial loads in Scotland in 2030 to be able to make a good assessment of the contribution to demand management at peak periods. For conservatism, this is assumed to be zero.

3.8.6 Summary

Taken together, it is estimated that for the ‘low flexibility’ options (Scenarios 1 and 2), the capability for demand response at peak periods is conservatively assessed to be around 100 MW, and 500 MW for the ‘high flexibility’ options (Scenarios 3 and 4). There is very considerable uncertainty on these estimates.

[20] The expected contribution of EVs to the peak demand without demand response is approximately 16% of the theoretical worst case scenario where all EVs are charged during peak time. Assuming charging power for each EV of 3 kW, this translates to 750,000 x 3kW x 16%=0.36GW. According to the same analysis, approximately 24% of that peak demand could be shifted, allowing approximately 0.36GWx24%=0.09GW of peak EV load shift.

4 DEVELOPMENT OF GENERATION MIX FOR SCENARIOS

4.1 Objectives

For each of Scenarios 1 to 4 defined in Section 3.6, an appropriate generation mix is developed, to meet the annual electricity demand and the carbon intensity target. Basic output statistics are developed.

4.2 Generation options

4.2.1 Fossil and nuclear

In Section 3.3, it is assumed that there will be no unabated coal-fired generation or nuclear plant in Scotland by 2030.

There will be coal or gas-fired plant fitted with Carbon Capture and Storage, with total capacity 2.5 GW (High CCS assumption) or 340 MW (Low CCS). For the purposes of this study it is assumed that this will be gas-fired.

It is also assumed that there are no restrictions (e.g. location, fuel availability) on the total capacity of new gas-fired plant that may be constructed if necessary. Depending on economics, these may be a mixture of open-cycle gas turbines (OCGT) and closed-cycle gas turbines (CCGT). CCGT are more efficient than OCGT, i.e. lower operating costs (£/MWh) but with substantially higher capital cost (£/MW). Therefore OCGT plants are economic[21] when required to run infrequently, i.e. for 'peaking' duty.

Carbon emissions intensity is assumed to be 460 gCO_2/kWh for OCGT, 380 gCO_2/kWh for CCGT, and 60 gCO_2/kWh for CCGT with CCS /23//24//25/.

4.2.2 Hydro

Currently there is around 1.5 GW of hydro capacity in Scotland, excluding pumped-storage. Section 3.5 covers pumped-storage capacity. Approximately 1.3 GW of the hydro capacity is large-scale reservoir hydro /26/, and the rest is smaller. For the purposes of this study, it is assumed that this smaller hydro generation is predominantly run-of-river, i.e. without reservoirs. The annual capacity factor for hydro in Scotland varies from year to year, but on average is around 34%.

There is estimated to be a further 1.2 GW of hydro capacity available and financially viable within Scotland, depending on financial assumptions /27/. For the purposes of this study, it is assumed that around 1000 MW of this is developed by 2030: as hydro is a low-risk technology and well understood, it seems likely that further hydro of this order will be built by 2030, irrespective of costs of other renewable generation projects. In other words, this additional hydro capacity is treated as a 'given'. It is assumed all to be run-of-river, i.e. no further reservoir capacity is added.

The existing hydro capacity is assumed to still be in operation in 2030, resulting in a total of 2.5 GW.

4.2.3 Onshore wind

Onshore is currently the cheapest large-scale form of renewable generation. Capacity in Scotland is currently 4.5 GW, with a further 3.7 GW in construction or awaiting construction, and 4 GW in the planning consent system.

[21] Providing a suitable payment mechanism is in place. The UK is currently setting up a capacity market, as otherwise there is a risk the payments to peaking plant and other contributors to managing peak demands will be too uncertain to allow such plant to be financed. An alternative is to allow the TSO to invest in energy storage or other solutions that are driven by capital costs rather than operating or fuel costs.

The capacity factor of the operational wind farms varies from year to year, but on average in Scotland is around 29%[22].

The maximum achievable onshore wind capacity in practice is determined by public acceptance, and by economics: as wind capacity increases, less productive sites will be used, increasing the costs. Also, at very high wind penetration levels, there will be times of high wind production and low electricity demand, when some wind production will not be able to find a buyer, or only at very low prices. These factors are poorly understood, and so it is not possible to define an upper economic or physical limit on onshore wind capacity in 2030.

4.2.4 Offshore wind

Currently offshore wind capacity in Scottish waters is 190 MW. Consents were recently granted for two large projects on the east coast, with a total capacity of 1,866 MW, though it is likely that smaller phases would be built initially. A further 2.5 GW is in the planning consent process, and other projects or phases of projects are under development.

As for onshore wind, the practical limit for offshore wind capacity is determined by economics and public acceptance, rather than any fundamental physical limit. The economic factors are particularly important for offshore wind, as the costs are currently high compared to alternatives. The industry is aiming to get costs down to around £100 per MWh for projects consented in 2020 /28/: achieving this figure is by no means guaranteed, and assumes that there is sufficient volume of projects to justify the required innovation, and investment in vessels and capabilities. For the period to 2020, the costs for offshore wind projects are particularly critical, as total spend on supporting low-carbon generation and other climate-change policies is capped by the Levy Control Framework /29/. Higher costs for offshore wind projects will result in fewer being funded by 2020. However the impact on new projects after 2020 is not yet clear.

Capacity factor for future wind projects in Scottish waters are not accurately known, but DNV GL experience indicates that a range of 45-50% is expected for projects currently under development. To avoid optimism bias, 45% is assumed here.

4.2.5 Wave and tidal

Both wave and tidal energy generation are at the development and demonstration stage, and heading towards demonstration of small arrays. The UK, and Scotland in particular, has a leading position in this field. The resource is very large, especially the wave resource. However costs are not yet clear and so it is not feasible to estimate how much of either technology might be in place by 2030.

However, in the context of this study, this is not a major disadvantage. The important characteristics of both technologies are similar to those of offshore wind. Wave and offshore wind production is slightly less predictable on timescales of a few hours than tidal, while tidal is more variable (four generation cycles from zero to full output per day), but all require multiple low-speed high-torque devices of a few MW in scale, installed in arrays. For all technologies, major cost reduction is anticipated, and indeed is essential, and the available resource is not clear.

Therefore, this study includes wave and tidal with offshore wind, as 'marine' energy sources. This implies that if wave or tidal achieve wide commercial application in Scottish waters by 2030, it is expected that they will be in direct competition with offshore wind.

[22] DECC quarterly data /26/ from 2011 to 2013 for all onshore wind projects in Scotland (12 quarters) shows an average capacity factor of 28.8%.

Capacity factors for optimised wave and tidal array are not yet established, so in this study 45% is assumed, as for offshore wind. This is based on internal DNV GL assessment.

4.2.6 Solar

Recent very rapid reductions in the price of solar photo-voltaic (PV) system prices, coupled with the Feed-in Tariff support mechanism, have resulted in high installation rates on UK domestic and commercial properties, and also as ground-mounted solar farms. The installed capacity in Scotland visible to DECC is only 116 MW /26/, though growing rapidly. A recent estimate suggests a total of around 7 GW of rooftop PV is technically feasible in Scotland /30/.

Future Energy Scenarios assumes a capacity factor of 8%, which is considered realistic.

4.2.7 Biomass, waste and landfill gas

Biomass can include biogas, sewage gas, anaerobic digestion (AD) and solid biomass. The input fuel can be wastes, energy crops grown in Scotland, and energy crops imported for the purpose.

WWF regards energy derived from organic based materials including farming or forestry ‘wastes’, manures and forestry brash (off cuts), as sustainable or renewable, but does not hold the same position on energy from municipal solid waste (MSW). MSW is therefore not included in this analysis. Landfill gas is also excluded from this analysis, as it is anticipated that existing landfill sites will be close to exhausted by 2030, and new landfill will be severely restricted.

Scotland currently has 140 MW of other biomass in operation, principally plant biomass, 316 MW in construction or awaiting construction, and around 250 MW in the planning system /26/.

The Scottish Government has stated a strong preference for biomass to be used in heat-only projects, or in good-quality Combined Heat and Power (CHP), preferably located in rural areas off the gas grid. Large-scale biomass schemes in Scottish cities, with some CHP and perhaps using foreign biomass imported direct to a harbour within the city, have been proposed and are clearly feasible. However at present they are facing considerable difficulties in consenting.

The available biomass resource within Scotland, and future international trade in biomass, are both uncertain.

For these reasons, this study assumes a conservative level of 500 MW of electricity generating capacity fired by biomass in 2030. This is roughly the capacity already in operation, in construction or awaiting construction. Note however that substantially higher capacity could be achieved if felt necessary, by establishing extensive energy crop production in Scotland, such as short-rotation coppicing, or by accepting the use of large volumes of imported biomass.

Current biomass stations would expect to operate at high capacity factors, of the order of 70 to 80%.

4.2.8 Geothermal

There are indications that geothermal energy may be an option for Scotland. However the costs and the resource are insufficiently understood at present, and there are arguments that the resource may best be used directly for heating. Therefore as a conservative assumption no geothermal electricity generation capacity is assumed for 2030.

4.3 Generation mix

For each scenario, the generation mix is first chosen in order to meet annual electricity demand, and then reviewed against the need to meet peak demand and provide adequate security of supply.

Further renewable generation to reach 100% of annual electricity demand is also considered, as this is the target for 2020. A 'stretch' target for 125% of annual electricity demand is also considered.[23]

4.3.1 Scenario 1: Weak policy drive, high CCS

Scenario 1 combines high annual electricity demand (43.1 TWh) with low flexibility (1340 MW of pumped storage) and high CCS capacity (2500 MW).

Meeting annual gross consumption

Annual electricity production is summarised in the table below.

Table 4-1 Meeting annual electricity demand, Scenario 1

Source	Capacity factor assumed	Generating capacity assumed	Production
CCS	0.8	2500 MW defined by scenario	17.5 TWh
Hydro	0.34	2500 MW assumed for 2030 (of which 1300 MW is reservoir hydro)	7.4 TWh
Onshore wind	0.29	4500 MW existing capacity (2013). Substantial further capacity in construction or consented (3700 MW), of which 1000 MW is assumed to be constructed.	11.4 TWh from existing capacity. 2.5 TWh from assumed additional capacity
Marine (offshore wind, wave and tidal)	0.45	190 MW existing offshore wind capacity. Substantial further capacity is consented or in the consenting process.	0.7 TWh from existing capacity.
Solar PV	0.08	116 MW existing. Substantial resource available.	0.1 TWh from existing capacity.
Biomass	0.8	500 MW assumed for 2030	3.5 TWh
Total			43.1 TWh
Fraction of gross consumption from renewables			25.6 TWh, 59%

[23] This 'stretch' target is included in order to show how challenging a 'high RE export' policy might be. 125% is chosen as it matches a possible target previously discussed by the Scottish Government: see Appendix A.

The table shows that, without any new renewable generation capacity other than the assumed increases in hydro and biomass, total production is almost enough to meet demand on a simple comparison of annual figures. An additional 1000 MW of onshore wind capacity (less than that currently under construction) is sufficient to increase total production to match gross consumption.

Carbon intensity

Carbon production from the CCS plant is 1050 thousand tonnes (kt) of carbon dioxide, and carbon intensity is therefore comfortably within the 2030 target, at 24 gCO_2/kWh.

Higher RE targets

However, renewables only meet 59% of annual gross consumption. To reach 100% requires a further 17.5 TWh of renewable production. This could be met by:

- A further 7 GW of onshore wind. The total for onshore wind would then be around 12.5 GW, roughly equivalent to the total currently in operation, in construction, consented, and in the consenting process.
- Or 4.4 GW of marine renewables. This is roughly equivalent to the total of offshore wind currently consented or in the consenting process.
- Or a mixture of both, possibly with some contribution from PV. The combined total of onshore and offshore wind which has achieved consent would produce around 14.3 TWh, so not much more would need to achieve consent by 2030 to meet this.

To reach 125% of gross consumption in 2030 would require substantial further renewable production, such as a further 4 GW of onshore wind or 2.5 GW of offshore wind or other marine renewables. This would therefore be very challenging, but within the total capacity of onshore and offshore wind projects which are currently known. It would result in total renewable generation capacity in Scotland of well over 15 GW, well in excess of existing transmission capacity. Substantial interconnection to other electricity markets would be needed for exports at times of high renewables production.

Meeting peak demand

The generating capacity in Table 4-1 will not be sufficient to meet peak demand of 8.2 GW with any certainty (see Section 3.7). Capacity available to meet peak demand in these circumstances is shown in Table 4-2.

Table 4-2 Meeting peak demand, Scenario 1

Source	Generating capacity assumed	Capacity available at peak
CCS	2500 MW	2500 MW assumed
Hydro	2500 MW	1300 MW reservoir hydro assumed available. All run-of-river hydro (1200 MW) conservatively assumed to be unavailable at peak demand due to frozen conditions.
Onshore wind	5500 MW	385 MW (7% of capacity, as assumed in Future Energy Scenarios, based on evidence that peak demand can coincide with cold calm conditions in winter[24])
Marine (offshore wind, wave and tidal)	190 MW existing offshore wind	13 MW (7% as for onshore wind[25])
Solar PV	116 MW existing.	Zero, as peak demand is assumed to occur on winter evenings
Biomass	500 MW	500 MW
Pumped storage	1340 MW	1340 MW
Total		6000 MW

Therefore generation within Scotland could be around 2,200 MW less than peak demand. This can be met by:

- Imports from the rest of the GB system;
- Interconnection to Scandinavia or other countries bordering the North Sea[26];
- Demand response;
- Substantial additional biomass generation;
- Gas-fired generation, either OCGT or CCGT;
- Temporary increased output from the CCS plant[27].

Note that generation capacity in Scotland to meet unexpected plant *failures* in Scotland at the time of peak demand is not required, as this is an issue for robustness of the combined GB electricity system. The biggest single unscheduled loss is likely to be the CCS plant. A plant of this size is likely to be designed and operated as two or more independent generators, so a loss of around 1,250 MW is credible.

See Section 4.4 on transmission capacity to deal with contingencies.

[24] Strictly speaking, 7% is used in FES as a measure of diversity of wind production across all GB during calm periods. Less diversity could be expected across a smaller geographical area, such as Scotland. However, in the context of security of the GB system, this figure is appropriate.

[25] If there was a large component of tidal generation, well dispersed around the coast, this figure of 7% could be increased substantially.

[26] The electricity system of the island of Ireland is expected to have substantial wind generation capacity, and very similar weather conditions to Scotland, so interconnection with Ireland is not expected to contribute substantially at times of peak demand. Of course, substantial interconnection may well be justified for electricity trading.

[27] It may be technically feasible to design CCS plant to operate without the CCS function when necessary. As the CCS equipment requires substantial energy to operate, switching it off or reducing its throughput at times of peak demand could increase electrical output, perhaps by around 20%. The emissions would of course increase considerably, but if only used for rare events this could be an attractive option.

4.3.2 Scenario 2: Weak policy drive, low CCS

Scenario 2 has the same high annual electricity demand (43.1 TWh) and low flexibility (1340 MW of pumped storage) as Scenario 1, but with low CCS capacity (340 MW).

Meeting annual gross consumption

Annual electricity production is summarised in Table 4-3.

Table 4-3 Meeting annual electricity demand, Scenario 2

Source	Capacity factor assumed	Generating capacity assumed	Production
CCS	0.8	340 MW defined by scenario	2.4 TWh (compared to 17.5 TWh in Scenario 1)
Hydro	0.34	2500 MW assumed for 2030 (of which 1300 MW is reservoir hydro)	7.4 TWh
Onshore wind	0.29	4500 MW existing capacity (2013). Substantial further capacity in construction or consented (3700 MW) or in planning (4000 MW), of which 6900 MW is assumed to be constructed.	11.4 TWh from existing capacity. 17.6 TWh from assumed additional capacity
Marine (offshore wind, wave and tidal)	0.45	190 MW existing offshore wind capacity. Substantial further capacity is consented or in the consenting process.	0.7 TWh from existing capacity.
Solar PV	0.08	116 MW existing. Substantial resource available.	0.1 TWh from existing capacity.
Biomass	0.8	500 MW assumed for 2030	3.5 TWh
Total			43.1 TWh
Fraction of gross consumption from renewables			40.7 TWh, 94%

The table shows that, to meet annual gross electricity consumption, the existing and assumed renewable generation must increase to provide a further 17.6 TWh. In the table it is shown that this can be achieved with 6900 MW of additional onshore wind generation, but it could also be achieved by a mix of renewables. For example, the onshore wind generation currently under construction or awaiting construction (i.e. with planning consent), plus the consented offshore wind capacity, would be very close to meeting this requirement (16.4 TWh).

Carbon intensity

Carbon production from the CCS plant is 144 thousand tonnes (kt) of carbon dioxide, and carbon intensity is therefore very low indeed, at 3 gCO_2/kWh.

Higher RE targets

In this scenario, renewables production is close to 100% of gross annual consumption. To meet 100% requires a further 2.4 TWh, which could be met by a further 900 MW of onshore wind or 600 MW of marine renewables. This appears feasible.

To reach 125% of gross consumption, very substantial further renewable production is needed (13.2 TWh). Though demanding, this could be met in several ways, and would result in the same volumes of renewables production as for Scenario 1. However the volume of exports would be less than in Scenario 1, as there is less production from the CCS plant.

Substantial interconnection to other electricity markets would still be needed for exports.

Meeting peak demand

The generating capacity in Table 4-3 will not be sufficient to meet peak demand of 8.2 GW with any certainty. Capacity available to meet peak demand is shown in Table 4-4.

Table 4-4 Meeting peak demand, Scenario 2

Source	Generating capacity assumed	Capacity available at peak
CCS	340 MW	340 MW assumed
Hydro	2500 MW	1300 MW reservoir hydro assumed available. All run-of-river hydro (1200 MW) conservatively assumed to be unavailable at peak demand due to frozen conditions.
Onshore wind	11,400 MW	800 MW (7% of capacity, as assumed in Future Energy Scenarios, based on evidence that peak demand can coincide with cold calm conditions in winter)
Marine (offshore wind, wave and tidal)	190 MW existing offshore wind	13 MW (7% as for onshore wind)
Solar PV	116 MW existing.	Zero, as peak demand is assumed to occur on winter evenings
Biomass	500 MW	500 MW
Pumped storage	1340 MW	1340 MW
Total		4300 MW

Therefore generation within Scotland could be around 3900 MW less than peak demand. This can be met by:

- Imports from the rest of the GB system;
- Interconnection to Scandinavia or other countries bordering the North Sea;
- Demand response;
- Substantial additional biomass generation;
- Gas-fired generation, either OCGT or CCGT;
- Temporary increased output from the CCS plant, small in this scenario.

The biggest single unscheduled loss in this scenario is likely to be a large pumped-storage station, around 600 MW.

4.3.3 Scenario 3: Strong policy drive, high CCS

Scenario 3 has substantially lower electricity demand than Scenarios 1 and 2 (30.9 TWh), high flexibility (2540 MW of pumped storage), and high CCS capacity (2500 MW).

Meeting annual gross consumption

Annual electricity production is summarised in the table below.

Table 4-5 Meeting annual electricity demand, Scenario 3

Source	Capacity factor assumed	Generating capacity assumed	Production
CCS	0.8	2500 MW defined by scenario	17.5 TWh
Hydro	0.34	2500 MW assumed for 2030 (of which 1300 MW is reservoir hydro)	7.4 TWh
Onshore wind	0.29	4500 MW existing capacity (2013). Substantial further capacity in construction or consented (3700 MW) or in planning (4000 MW)	11.4 TWh from existing capacity.
Marine (offshore wind, wave and tidal)	0.45	190 MW existing offshore wind capacity. Substantial further capacity is consented or in the consenting process.	0.7 TWh from existing capacity.
Solar PV	0.08	116 MW existing. Substantial resource available.	0.1 TWh from existing capacity.
Biomass	0.8	500 MW assumed for 2030	3.5 TWh
Total			40.6 TWh
Fraction of gross consumption from renewables			23.1 TWh, 75%

The table shows that in this scenario, electricity generation (40.6 TWh) is substantially greater than electricity demand (30.9 TWh). Apart from the assumed increases in hydro and biomass production, no new renewables capacity beyond that operating at present is necessary. Compared to Scenarios 1 and 2, this highlights the enormous benefits of demand reduction.

The figures in the table therefore assume substantial exports, without any further renewable generation being constructed. In reality, less biomass, hydro and CCS capacity may be constructed than assumed in the table, and the biomass and CCS plant may operate at lower capacity factors.

Carbon intensity

Carbon production from the CCS plant is 1050 thousand tonnes (kt) of carbon dioxide, and carbon intensity is 26 gCO_2/kWh.

Higher RE targets

To reach renewables production equivalent to 100% of gross consumption would require a further 7.8 TWh, and to reach 125% would require 15.5 TWh. The onshore and offshore wind capacity already in construction or consented would be sufficient to achieve this.

Substantial interconnection to other electricity markets would still be needed for exports.

Meeting peak demand

Capacity available to meet peak demand of 6.0 GW is shown in Table 4-6.

Table 4-6 Meeting peak demand, Scenario 3

Source	**Generating capacity assumed**	**Capacity available at peak**
CCS	2500 MW	2500 MW assumed
Hydro	2500 MW	1300 MW reservoir hydro assumed available. All run-of-river hydro (1200 MW) conservatively assumed to be unavailable at peak demand due to frozen conditions.
Onshore wind	4,500 MW	315 MW (7% of capacity, as assumed in Future Energy Scenarios, based on evidence that peak demand can coincide with cold calm conditions in winter)
Marine (offshore wind, wave and tidal)	190 MW existing offshore wind	13 MW (7% as for onshore wind)
Solar PV	116 MW existing.	Zero, as peak demand is assumed to occur on winter evenings
Biomass	500 MW	500 MW
Pumped storage	2540 MW	2540 MW
Total		7170 MW

Therefore generation within Scotland, even under these onerous assumptions, would be around 1200 MW greater than peak demand. In fact the pumped-storage, reservoir hydro and CCS capacity alone is greater than predicted peak demand.

As for Scenario 1, the biggest unscheduled loss is likely to be a CCS unit, around 1250 MW.

This does not rule out further expansion of transmission capacity to the rest of the GB electricity system, or interconnection to other countries: some expansion may be justified by the economic value of exports.

4.3.4 Scenario 4: Strong policy drive, low CCS

Scenario 4 has low electricity demand (30.9 TWh) and high flexibility (2540 MW of pumped storage), as for Scenario 3, but low CCS capacity (340 MW).

Meeting annual gross consumption

Annual electricity production is summarised in Table 4-7.

Table 4-7 Meeting annual electricity demand, Scenario 4

Source	Capacity factor assumed	Generating capacity assumed	Production
CCS	0.8	340 MW defined by scenario	2.4 TWh (compared to 17.5 TWh in Scenario 3)
Hydro	0.34	2500 MW assumed for 2030 (of which 1300 MW is reservoir hydro)	7.4 TWh
Onshore wind	0.29	4500 MW existing capacity (2013). Substantial further capacity in construction or consented (3700 MW), of which 2100 MW is assumed to be constructed.	11.4 TWh from existing capacity. 5.4 TWh from assumed additional capacity
Marine (offshore wind, wave and tidal)	0.45	190 MW existing offshore wind capacity. Substantial further capacity consented or in the consenting process.	0.7 TWh from existing capacity.
Solar PV	0.08	116 MW existing. Substantial resource available.	0.1 TWh from existing capacity.
Biomass	0.8	500 MW assumed for 2030	3.5 TWh
Total			30.9 TWh
Fraction of gross consumption from renewables			28.5 TWh, 92%

The table shows that, to meet annual gross electricity consumption, the existing and assumed renewable generation must increase to provide a further 5.4 TWh per year. In the table it is shown that this can be achieved with 2100 MW of additional onshore wind generation (which is within the amount already consented but not yet built), but it could also be achieved by a mix of other renewables. For example, the offshore wind capacity already consented would be more than enough, as would 7,700 MW of PV capacity. As noted in Section 4.2, 7 GW of rooftop PV may be technically feasible in Scotland.

Carbon intensity

Carbon production from the CCS plant is 144 thousand tonnes (kt) of carbon dioxide, and carbon intensity is therefore very low, below 5 gCO_2/kWh.

Higher RE targets

The renewable generation assumed in the table above is close to reaching 100% of gross consumption. To reach 100% would require around 900 MW of onshore wind or 600 MW of marine renewables. To meet 125% would instead require around 4 GW of onshore wind or 2.6 GW of marine renewables. The additional onshore and offshore wind capacity already consented would together be sufficient.

Substantial interconnection to other electricity markets may be justified for exports.

Meeting peak demand

Capacity available to meet peak demand of 6.0 GW is shown in the table below.

Table 4-8 Meeting peak demand, Scenario 4

Source	**Generating capacity assumed**	**Capacity available at peak**
CCS	340 MW	340 MW assumed
Hydro	2500 MW	1300 MW reservoir hydro assumed available. All run-of-river hydro (1200 MW) conservatively assumed to be unavailable at peak demand due to frozen conditions.
Onshore wind	6600 MW	460 MW (7% of capacity, as assumed in Future Energy Scenarios, based on evidence that peak demand can coincide with cold calm conditions in winter)
Marine (offshore wind, wave and tidal)	190 MW existing offshore wind	13 MW (7% as for onshore wind)
Solar PV	116 MW existing.	Zero, as peak demand is assumed to occur on winter evenings
Biomass	500 MW	500 MW
Pumped storage	2540 MW	2540 MW
Total		5150 MW

Therefore generation within Scotland could be around 900 MW less than peak demand. This can be met by:

- Imports from the rest of the GB system;
- Interconnection to Scandinavia or other countries bordering the North Sea;
- Demand response;
- Substantial additional biomass generation;
- Gas-fired generation, either OCGT or CCGT;
- Temporary increased output from the CCS plant, small in this scenario.

The biggest single unscheduled loss in this scenario is likely to be a large pumped-storage station, around 600 MW.

4.3.5 Summary

For reference, the scenarios are compared in the table below.

Table 4-9 Comparison of scenarios

Characteristic	Scenario 1: Weak policy drive, High CCS	Scenario 2: Weak policy drive, Low CCS	Scenario 3: Strong policy drive, High CCS	Scenario 4: Strong policy drive, Low CCS
Gross annual electricity consumption	43.1 TWh	43.1 TWh	30.9 TWh	30.9 TWh
Total electricity production	43.1 TWh	43.1 TWh	40.6 TWh	30.9 TWh
Renewables production	25.6 TWh, 59%	40.7 TWh, 94%	23.1 TWh, 75%	28.5 TWh, 92%
Carbon intensity	24 gCO2/kWh	3 gCO2/kWh	26 gCO2/kWh	5 gCO2/kWh
Achieving RE equivalent to 100% gross annual consumption	Feasible, e.g. with onshore and offshore wind capacity only slightly greater than already in construction or consented.	Identical to Scenario 1.	Achievable with onshore and offshore wind already in construction or consented.	Identical to Scenario 2.
Peak demand	8,200 MW	8,200 MW	6,000 MW	6,000 MW
Generation in Scotland at peak demand	6,000 MW	4,300 MW	7,170 MW (Note that PS, reservoir hydro and CCS alone are greater than peak demand)	5,150 MW

As the results for all scenarios show carbon intensity values well below the target, it is interesting, as an aside, to consider how much non-CCS gas generation could be feasible within the target. If the CCS plant in the scenarios is instead replaced with a 1000 MW CCGT station[28], and assuming the volumes of renewable generation shown above are unchanged, the result is that in all bar Scenario 2, the capacity factor of the CCGT plant would be below 50% [29]. This is substantially less than is currently assumed in the economic case for CCGT plants. In Scenario 2, the capacity factor would be 70%, which is still lower than current assumptions.

[28] For example, the Cockenzie site has consent for a 1000 MW CCGT plant.

[29] For each scenario, the CCGT production without CCS which is feasible within the carbon intensity target is calculated, and from this the capacity factor of a 1000 MW plant is calculated. Scenario 1: 3.88 TWh per year, 44%. Scenario 2: 6.17 TWh per year, 70%. Scenario 3: 3.50 TWh per year, 40%. Scenario 4: 4.32 TWh per year, 49%.

4.4 Other technical issues

The previous sections have evaluated Scenarios 1 to 4 on the basis of their ability:

- to meet gross electricity consumption in Scotland on an annual basis;
- to meet the carbon intensity target;
- to meet higher fractions of renewable generation - 100% and 125% of gross consumption;
- to meet peak demand.

Other issues are reviewed in this section. The Royal Academy of Engineering has taken evidence on these and related technical issues, and concluded that "*for levels of penetration of wind energy up to around 20% of electricity consumption (…) the system will remain secure using the balancing mechanisms already in place. Technical issues will arise, such as those relating to system inertia and frequency control, but these will be manageable if given sufficient consideration.*"/31/

4.4.1 Security of supply

Scotland forms part of the Great Britain (GB) electricity system. The GB system is developed and operated as one system and is subject to a single Regulator, though owned by three separate organisations[30]. The reliability of the system ('security of supply') is a function of this whole system: for any geographical area of this system to achieve the same level of reliability independently would be significantly more expensive.

Section 4.3 has shown that during periods of high electricity demand and low renewables production (expected to be infrequent, but frequent enough to require designing for), Scotland may require generating capacity additional to that assumed in each scenario, or imports from the rest of the GB system or from Europe.

The important figures from Section 4.3 are summarised in the table below. Unavailability of the largest generating unit in these circumstances is also considered credible, and is added to the potential shortfall.

Table 4-10 Potential generation shortfall

Scenario	Potential shortfall at peak demand	Plus: Loss of largest unit in Scotland	Less: Demand response available at peak demand	Net shortfall
1: Weak policy drive, high CCS	2200 MW	1250 MW (CCS unit)	100 MW	3350 MW
2: Weak policy drive, low CCS	3900 MW	600 MW (pumped-storage unit)	100 MW	4400 MW
3: Strong policy drive, high CCS	(1200 MW surplus)	1250 MW (CCS unit)	500 MW	No shortfall
4: Strong policy drive, low CCS	900 MW	600 MW (pumped-storage unit)	500 MW	1000 MW

[30] Currently, both sides in the Scottish independence referendum envisage a common GB energy market and common electricity system operation in the event of a Yes vote, with separate regulators. A similar system already functions for the island of Ireland.

The 'net shortfall' identified in the table can be met by additional generating capacity in Scotland, or imports from the rest of the GB system or elsewhere in Europe.

The capacity of the Scotland-England connections at present is 3300 MW. Reinforcements already in hand, including a subsea connection on the west coast, will raise this to 6500 MW by 2016 /32/. Further reinforcements are under consideration, driven by the anticipated increase in renewable generation in Scotland, and can raise the capacity to 8.5 GW in 2020, and around 13 GW by 2025.

Note that this is 'firm' connection capacity, i.e. it includes an allowance for non-availability of some elements of the transmission system.

Therefore, even for Scenario 2, transmission capacity to the rest of the GB system will be more than adequate well before 2030. In fact, it is feasible (subject to transmission capacity within Scotland[31]) that peak demand in Scotland could be satisfactorily met entirely by imports, i.e. with no generation of any kind in Scotland.

The upshot of this is that 'security of supply' is an issue only at GB level. National Grid studies /6//32/ indicate that a secure GB system is feasible with levels of renewable generation in Scotland similar to those of Scenarios 1 to 4. These studies also include consideration of transmission reinforcement required elsewhere in Scotland and the rest of GB.

4.4.2 Transmission capacity for exports

As noted above, reinforcement of transmission capacity to the rest of the GB system is already under way, with more planned, driven by the requirements to export energy from Scotland. This is largely from renewable generation.

Under current arrangements in GB, the costs of reinforcing and operating the transmission system are reflected back on generators (and demand customers) through costs determined by location. For generators, the costs are strongly driven by the distance to the major centres of demand. The costs can be considerable, and have been a major impediment to the development of otherwise excellent onshore wind sites on the main Scottish island groups.

The amount of transmission capacity that gets built, over and above that required for a secure system, is therefore an economic decision which, under current arrangements, is made by generators.

The transmission capacity required to avoid any constraint of renewable generation in Scotland is quantified in Table 4-11, using the results of Section 4.3, both for the requirement to match annual production with demand, and the more onerous case of meeting a 'stretch' target for renewables production to equal 125% of annual gross consumption. For the second case, the additional renewables production is assumed to come from a mix of onshore wind and marine, though other mixtures are of course feasible.

In this table it is assumed that:

- the CCS plant would not run in these circumstances, but biomass would;
- reservoir hydro would not run;
- all demand response actions have been exhausted (e.g. all electric vehicles fully charged);
- all pumped-storage reservoirs are full;
- electricity demand in Scotland is at its minimum (assumed to be half of the peak demand).

[31] Likely to include reactive power control functions as well as conventional transmission lines.

Table 4-11 Exports from Scotland under maximum renewable generation and minimum demand

Scenario	Total output, all generation	Minimum demand	Export capacity required
Renewable capacity sufficient for annual production (all sources) to match gross annual consumption:			
1: Weak policy drive, high CCS	7500 MW	4100 MW	3400 MW
2: Weak policy drive, low CCS	13400 MW	4100 MW	9300 MW
3: Strong policy drive, high CCS	6500 MW	3000 MW	3500 MW
4: Strong policy drive, low CCS	8600 MW	3000 MW	5600 MW
'Stretch' case: renewables production equivalent to 125% of gross annual consumption: (additional capacity assumed to be a mix of onshore and offshore wind)			
1: Weak policy drive, high CCS	7500 MW + 9500 MW	4100 MW	12900 MW
2: Weak policy drive, low CCS	13400 MW + 4400 MW	4100 MW	13700 MW
3: Strong policy drive, high CCS	6500 MW + 5500 MW	3000 MW	9000 MW
4: Strong policy drive, low CCS	8600 MW +3400 MW	3000 MW	9000 MW

In the base case, in all except Scenario 2 the transmission capacity to the rest of the GB system currently existing or under construction will be adequate.

For Scenario 2, and for the 'stretch' case, further transmission capacity will be needed. As noted in the previous section, transmission reinforcement to 13 GW is under discussion for implementation around 2025.

Beyond the 125% 'stretch' case, there is very substantial further RE capacity in Scotland should it prove economic to export it, particularly wave, tidal and PV.

It is worth re-emphasising the point made above, that the amount of transmission reinforcement which gets built for exports of renewable electricity is fundamentally decided by the generators. Transmission costs are almost entirely determined by capacity (MW), whereas the revenue earned by generators is per unit of energy (MWh). In a situation with, for example, very high wind capacity in Scotland, peak exports over a relatively small fraction of the year would need to pay for peak transmission capacity. It is therefore very likely that the export capacity figures shown in the table will not be economically justified: it will be economically advantageous for wind generation (for example) to install less export capacity, and accept that occasionally they will not be able to export all production.

For wind, and possibly other variable renewables, this argument becomes even stronger if the region to which the electricity is being exported also has substantial wind generation: it is likely that electricity prices will on average be lower at times of peak wind production.

4.4.3 Frequency control and response

Traditionally, conventional thermal and nuclear generation uses synchronous generators. These have the ability to continually adjust their output to respond to changes in the system frequency. Mismatches between generation and demand at any instant will cause all spinning masses (dominated by the synchronous generators) to accelerate or decelerate, changing the system frequency. Therefore it is necessary for at least some of the generators in operation at any time to control their output in order to control frequency to the nominal value of 50 Hz.

As well as slowly-varying steady-state control, very rapid response is also needed, to respond to sudden large disturbances, such as the sudden loss of a large generator or interconnector to another electricity system.

Biomass generation also uses synchronous generators, and can provide the same function, as can large hydro generators. Small hydro plant may use a different type of generator, and also may not provide rapid automatic control of the energy extracted from the flowing water.

Older wind turbines cannot provide this function, but most modern types can, onshore and offshore. Further work is required to fully establish the detailed technical requirements, and how these are best tested and demonstrated, but DNV GL does not anticipate insurmountable difficulties. The same applies in principle to wave and tidal devices, and PV. The main issue is that when providing this function, the wind turbines will produce less energy than is available from the wind: this becomes an economic penalty which eventually is paid for by electricity consumers. The same is true for conventional thermal generation, but the economic penalty is less, as there are savings in fuel costs.

4.4.4 Inertia

This issue is closely related to the frequency control issue. The effect of a mismatch between demand and generation output at any instant is to accelerate and decelerate the spinning masses. Their inertia helps to slow down the rate at which frequency can change. The function is provided by conventional thermal generation, biomass, and hydro.

Modern wind turbines do not provide synchronously-connected inertia, and therefore electricity systems where wind has displaced conventional generation will see greater deviations in frequency. This is already observable on the electricity system of the island of Ireland, where the system operator currently limits wind production at any instant to a fraction of the electricity demand[32].

Modern wind turbine technology can in principle provide a 'synthetic' inertia effect, and this has already been demonstrated. More work is needed to agree the required characteristics, how the capability is specified, and how it can be tested and demonstrated. It will also be necessary to agree how wind farm owners are incentivised to provide this function, as it is likely to be provided at the expense of some loss of production. Options range from a mandatory requirement to short-term competitive markets.

---

[32] Previously 50%, but recent statistics indicate the limit is being increased in certain circumstances.

It is harder to provide this function with PV technology, and it has not yet been demonstrated. Some wave and tidal devices may also have difficulty.

However it is concluded here that, for the scenarios studied here, inertia is not a 'show-stopper'.

4.4.5 Black Start

A 'black start' refers to the actions necessary to re-start an electricity system after a major disturbance which has resulted in all generators shutting down. Such events are extremely rare.

Major power stations require a strong electricity supply in order to start up, to drive auxiliary systems such as pumps and fans. System operators have black-start plans which rely on being able to start a few generators without any external supplies, and then gradually start larger generators and re-connect the system together again. These black-start plants would typically have diesel generators on site to drive their auxiliaries while starting.

Wind, wave, and PV plants are clearly poor at providing black-start capabilities: although they do not need external power to drive large auxiliary systems, they may not be available when required. Reservoir hydro, pumped-storage and biomass plants would be suitable. Tidal plant may also be suitable, if geographically dispersed.

For the scenarios considered here, generation in Scotland would in principle be able to provide an adequate contribution to a black start of the GB system.

4.4.6 Increased short-term variability

Variable renewables introduce a new problem to power systems: short-term variability of output ('ramps'). Wind and PV are the most extreme examples. The important timescales are of the order of tens of minutes to a few hours: there is very little variability in shorter timescales, because of the strong spatial averaging over geographically-dispersed wind and PV installations. For variability on timescales of a few hours and longer, operators of power systems can compensate by scheduling other generation, demand response and pumped storage.

For wind, there is evidence from operating data on national electricity systems that in northern Europe, the most extreme changes in output are of the order of 20% of rated capacity in 30 minutes. This could occur at the same time as, and in the opposite direction to, a change in electricity demand of the same order, for example during the morning 'pickup' (6-8am).

This additional rate-of-change is predictable and can be dealt with by:

- scheduling thermal generation and pumped storage plant, to reduce or increase its output or pumping demand;
- adjusting imports and exports (in effect, spreading the variability over the entire GB system and interconnected systems);
- demand response;
- limiting the rate of change of wind output.

The latter option is technically very simple: the technology already exists to send a ramp rate limitation signal from the system operator[33] to all wind generation, to limit its increase in production to a set rate

[33] In practice, it could be implemented by a market mechanism.

per minute or per ten minutes. For downward ramps, the same would apply, though the system operator would need to initiate the controlled downward ramp in advance of the forecast reduction.

The disadvantage is a severe economic penalty, due to the lost production. Therefore this capability is best used for rare extreme events.

4.4.7 Extended periods of low renewables production

In Section 4.3, the ability to meet peak demand during a period of low renewables production was examined. This assumed that reservoir hydro, pumped-storage capacity and demand response could be used to their full capacity at times of peak demand. This is true when dealing with peak demand within one day, because:

- Reservoir hydro has storage capacity of weeks or months;
- Pumped-storage plant has storage capacity of around 20 hours at full output (for existing plant: the proposed Coire Glas has a storage capacity of around 50 hours at full output), and can therefore be recharged on a daily basis after the peak demand period has passed;
- Demand response typically allows demand to be shifted for periods of hours.

However it is known that periods of low wind output in northern Europe in winter can persist for extended periods. Calm anticyclonic conditions are likely to coincide with low temperatures and high heat demand. The same applies to wave generation, and PV also provides substantially less output in winter. DECC's pathways analysis tool /33/ includes a five-day 'stress test' where very low wind production is assumed. DNV GL believes that in reality, more onerous conditions of several weeks' duration are credible.

Given the good transmission capacity with the rest of the GB system, the problem is best solved at the GB level. National Grid's Future Energy Scenarios /6/ achieves adequate security for the GB system in the Gone Green scenario, through 40 GW of gas-fired generation and a further 20 GW of CCS plant, interconnector capacity and nuclear. Other solutions are of course possible: the FES Gone Green example is given here as it has been addressed in detail by National Grid.

It is feasible that some of this gas generation capacity could be located in Scotland, but it is not necessary. In fact, it is likely to be more economical to locate it closer to the major demand centres in the south of GB, unless there is some other locational factor such as fuel source (gas import terminal location, or onshore gas wells).

5 EVALUATION OF OUTCOMES FOR SCENARIOS

WWF set several Research Questions, which are addressed in this section.

5.1 Credible generation mixes

1. *How can the 2030 decarbonisation target be delivered in a low CCS, no new nuclear scenario?*

With only renewables and a small amount of gas generation with CCS in Scotland, decarbonisation targets are met and exceeded. During periods of high electricity demand and low renewables production, electricity may need to be imported from the rest of the GB system (other options are described below).

Scenarios 2 and 4 show the 'Low CCS' options. Scenario 2, which assumes high annual electricity demand, requires around 14 GW of renewable generation located in Scotland. Scenario 4, with substantially lower electricity demand, requires around 10 GW of renewables.

For both scenarios:

- Renewables production exceeds 90% of Scottish gross annual electricity consumption.
- Only relatively small further renewables capacity is needed to achieve 100% of gross annual consumption, i.e. to maintain the target currently set for 2020.
- Carbon intensity is very low, below 5 g/kWh, because all Scottish generation is renewables or CCS.
- With low CCS generation capacity in Scotland, total generating capacity in Scotland will not meet peak demand in the most onerous circumstances (Table 4-10). The most straightforward solution is to rely on the rest of the GB system, as transmission capacity reinforcements already in hand will be more than adequate. Other options are interconnection to other European systems, further demand response, additional biomass generation, design of the CCS plant to provide additional output in extreme circumstances, or gas-fired generation (most likely OCGT) located in Scotland[34].

For both scenarios, there will be substantial export flows at periods of high renewables production and low demand, and substantial import flows when the reverse applies. Most of these flows are likely to be to and from the rest of the GB system[35], but there is no reason to exclude interconnection to other northern European countries if energy markets can justify the cost of the subsea cable. Substantial additional interconnection capacity between GB and other European countries is already planned or under discussion /32/.

Assuming these export and import flows are entirely within the GB system, transmission capacity up to around 13.7 GW may be required in the most onerous condition considered (Scenario 2, renewables production equivalent to 125% of annual consumption: see Section 4.4.2). Transmission reinforcement to around this figure is already under discussion, for implementation around 2025. Export of very large quantities of renewable electricity from Scotland is therefore entirely credible by 2030, assuming that the generation capacity and the transmission export capacity are economically justified.

This last point is worth emphasising: for variable generation such as wind, it is very likely that full export capacity is not economically justified, i.e. that it will be more economical to pay for less transmission capacity, and accept that occasionally it will not be possible to export all production.

---

[34] This latter option is effectively the same as locating in Scotland some of the gas-fired generation which makes the GB system secure. It is therefore an economic decision on best location.

[35] The island of Ireland and GB are subject to similar weather, and electricity demand patterns are also similar, so flows to and from Ireland will be limited, except in unusual circumstances.

5.2 Security

2. How can system security be achieved under the 2030 decarbonisation target?

Electricity supply in Scotland will be secure if the combined GB system is secure. National Grid studies for high-renewables cases show that this is achievable.

Section 4.4 covers technical issues, and demonstrates that adequate security of supply is achievable if:

- the GB system itself is secure; and
- there is adequate transmission capacity with the rest of the GB system.

National Grid studies for 2030 and beyond /6/ discuss the important issues and demonstrate how the GB system can be secure with high renewables capacity.

Although transmission capacity with the GB system is the principal option considered here, as it is well understood and is likely to be among the cheaper options, there are alternatives such as interconnections to other European countries, or locating gas-fired generation in Scotland rather than elsewhere in GB.

It is worth repeating that transmission capacity from Scotland to England or to Wales is only part of the issue: it needs to be matched with transmission capacity from generators to border, and from border to loads.

5.3 Capacity margin

3. What does the analysis indicate about likely capacity margins in 2030 and how do they compare to other European countries?

'Capacity margin' for Scotland can become negative in the scenarios studied, but this is not important if the entire GB system is secure.

There are several different definitions of 'capacity margin' and related concepts. Indeed, National Grid's Future Energy Scenarios 2013 /6/ has an appendix comparing alternative methods used in its publications.

Rather than evaluate the scenarios of this study against a specific definition, Table 4-10 shows that, using 'derated' capacity values for renewables in accordance with National Grid's assumptions (and specifically an assumption of 7% of wind capacity), capacity margin for Scotland alone is negative, or at best around zero for Scenario 3. However, from the FES Gone Green scenario, satisfactory capacity margin for the GB system is achieved[36]. The important point is that because of the strong transmission connections, the GB system including Scotland has adequate capacity margin, and considering capacity margin for Scotland alone has little meaning.

However, achieving adequate capacity margin for Scotland alone, if desired, is technically entirely feasible through several options. The most straightforward is to build a limited number of unabated CCGT and OCGT peaking plant, which would operate infrequently but would be available to contribute to a secure electricity system at all times. Further demand response, reservoir hydro and pumped-storage plant could also contribute.

5.4 Net energy balance to 2030

4. What will the electricity transmission flows be between Scotland and the rest of the UK from 2020 to 2030? What will the import/export balance look like to 2030 under the various pathways?

[36] Estimates for capacity margin beyond 2020 are not calculated in FES, but the capacity of thermal generation and the peak demand do not change markedly to 2030.

Scotland would continue to be a net exporter of electricity. Net volumes of exports, and the peak flows, will depend on the economic case for renewable capacity in Scotland, and the economic case for transmission capacity to allow exports.

Peak export and import flows are estimated for 2030 in Table 4-10 and Table 4-11. These represent credible but extreme flows resulting from coincidence of renewables production and electricity demand within Scotland. The transmission capacity required is similar to the results of other studies with similar scenarios /3//32/. The rate at which these flows increase from present-day levels, and the rate at which transmission capacity is built to meet them, depends on the rate at which renewables capacity is developed in Scotland. It is worth noting that, unlike most transmission development, this new transmission capacity is not justified by agreed rules for achieving adequate reliability of electricity supply: instead it must be justified by the economic value of the energy it transports.

5.5 Interaction with the rest of the GB system

5. What are the "security of supply" implications for the rest of the UK of the Scottish 2030 decarbonisation target?

The "security of supply" implications for the rest of the GB system are small. The current Scottish conventional generation fleet is a small fraction of the GB total: its contribution to GB system security may be replaced by several alternatives, including 'peaking' plant, located wherever is most economic.

National Grid's Future Energy Scenarios studies show how the GB electricity system must develop to 2030 and beyond, to meet levels of renewables production in GB which are consistent with the scenarios in this study. Although further interconnection capacity to other European countries is assumed to increase, the major contributors to maintaining a secure GB system are continued transmission system development to meet the new power flows, and total thermal generation capacity approximately the same as today. A relatively small fraction of the gas generation is assumed to be replaced by CCS around 2030. The gas generation fleet may well trend towards a greater fraction of peaking plant (OCGT), and can be located wherever it is most economic, relative to the electricity demand and fuel supply.

If demand response capability develops as anticipated, this could provide a contribution to system security, as an alternative to some peaking plant.

5.6 Contributing factors

6. What role should energy efficiency, demand management, storage and interconnection play in system security in 2030 and is it feasible to achieve this role in a no CCS scenario?

All can play a part, but the main contributor to secure decarbonised electricity supply for Scotland is transmission capacity to the rest of the GB system.

Comparing Scenario 1 with 3, and Scenario 2 with 4, shows that reduction in electricity demand greatly reduces the renewables capacity required to meet the targets and aspirations.

It also reduces the need for measures to provide adequate security of supply, whether that is additional transmission capacity, demand response or thermal generation.

Pumped-storage capacity is effective in contributing to security by meeting peak demand. Alternative forms of energy storage could provide the same benefits, but at present in Scotland it is difficult to see a strong competitor to pumped-storage.

In the context of Scotland, demand management appears likely to be more important for its economic value (i.e. ability to shift demand from periods of high electricity prices to low prices) than its contribution to security of supply. Table 4-10 shows that transmission capacity to the rest of the GB system is more significant than the capacity for demand response at the time of peak demand.

Interconnection capacity does not of itself solve the problems of high penetration of variable renewables, but in the case of Scotland it is highly beneficial, because of the existence of a significantly larger neighbouring system with similar decarbonisation targets and (it is assumed) less competitive renewable resources.

5.7 Cost implications

7. What transmission, distribution, storage and generation infrastructure is required to maintain security of supply in 2030 and at what cost?

No additional infrastructure is needed for the scenarios investigated in this study beyond that already planned, except (in some cases) some further transmission reinforcement.

Transmission infrastructure

Table 4-11 shows that no additional transmission infrastructure between Scotland and the rest of the GB system is needed beyond that already existing or under construction. The exception is the case of Scenario 2, where a further 3 GW would be required to allow unconstrained exports, if economically justified.

The costs of additional transmission infrastructure elsewhere in the GB system cannot be estimated accurately without detailed study of the entire GB system. However the costs are not anticipated to be infeasible in comparison with costs of generation (see below): work for the Committee on Climate Change /34/[37] estimated that a further 22 GW of transmission reinforcement would be needed for the GB system between 2020 and 2030, at a capital cost of £2 billion.

Distribution infrastructure

Electricity distribution systems are the lower-voltage equivalents of the transmission system, where the vast majority of customers are connected. Distribution-system costs attributable to widespread use of renewables as considered in this study are close to zero. This is because, under current charging arrangements, distribution-connected generation pays all the capital and operating costs attributable to their connection. The exception to this is small-scale generation connected at the domestic level: if this becomes dominant in a specific area (for example, widespread domestic PV installations in a housing development which is largely unoccupied during the day), there could be substantial costs in reinforcing the local distribution network to cope. These costs are under investigation but are currently not well understood /17/.

Generation and storage capacity

Section 4 has shown that additional conventional generation capacity and storage capacity are not essential in Scotland to achieve the scenarios used here.

However, generation costs can be compared on cost of energy and emissions, against a 'gas only' case. The scenarios as set out in Section 4.3 in their basic form differ only in the amount of CCS generation and the onshore wind which is assumed (though it is clearly possible to choose other mixes of renewable generation). This allows a simple comparison of the generation costs for the CCS and the new[38] onshore wind elements, against the alternative of generating the same volume of electricity from gas, as set out in the table below. Generation costs are taken from the latest available DECC figures /35/.

[37] Summarised on p131 of /34/.
[38] I.e. not including the onshore wind capacity already in place.

Table 5-1 Comparison of scenarios against 'gas-only' alternative

Scenario	Alternatives	Production [TWh/y]	Unit cost [£/MWh]	Cost of production [£M/y]	Emissions [kT CO_2 per year]
1	CCS plant	17.5	94	1,645	1,050
	New onshore wind	2.5	81	203	0
	Total	20		**1,848**	**1,050**
	Alternative, CCGT	20	81	**1,620**	**7,600**
2	CCS plant	2.4	94	226	144
	New onshore wind	17.6	81	1,426	0
	Total	20		**1,651**	**144**
	Alternative, CCGT	20	81	**1,620**	**7,600**
3	CCS plant	17.5	94	1,645	1,050
	New onshore wind	0	81	0	0
	Total	17.5		**1,645**	**1,050**
	Alternative, CCGT	17.5	81	**1,418**	**6,650**
4	CCS plant	2.4	94	226	144
	New onshore wind	5.4	81	437	0
	Total	7.8		**663**	**144**
	Alternative, CCGT	7.8	81	**632**	**2,964**

When comparing estimates of future generation costs, it is critical to understand the assumptions. The DECC estimates used in this comparison are based on the following.

- Costs for wind and CCGT are for projects assumed to be commissioned in 2020. Clearly this does not represent what will happen by 2030, but this assumption allows a clear comparison of alternatives without having to make assumptions about the timings of new generation projects.
- Costs for CCS are for a 'First of a Kind' project in 2025, post-combustion carbon capture retrofitted to CCGT plant. CCS is not expected to be available in 2020.
- Costs use technology-specific hurdle rates[39]. This allows lower borrowing costs to be used for technologies perceived to have lower risks.
- DECC Central estimates are used. High and Low estimates are provided, and in some cases are significantly different.
- The cost of carbon included in these projections may change: the Committee on Climate Change uses +/-50% for sensitivity studies for 2020/36/. A lower assumption for carbon would improve the position of gas compared to onshore wind.

[39] DECC Table 7 /35/

The cost estimates used are for projects commissioning in 2020, for which DECC projections show that onshore wind in Scotland has very similar costs to gas-fired generation (CCGT). The table shows that the 'gas-only' option is cheaper than the scenarios developed in this work (though with significantly higher carbon dioxide emissions), but this is largely due to the costs of the assumed CCS component.

DECC central projections show onshore wind is cheaper than gas from 2025 onwards.

Other costs for managing the variability of renewable generation, especially wind and PV, need to be calculated on a GB-system basis. The Committee on Climate Change has funded work on this issue /34/ which produced an estimate of £10 per MWh of additional wind in 2030[40].

5.8 Current policy regime

8. Is the current policy regime adequate to deliver the 2030 power sector decarbonisation target with respect to a) transmission b) the energy market c) planning and d) generation?

Yes, provided that political will and public acceptance is maintained. Political will post-2020 is by no means clear.

There are specific difficulties with connections to the main island groups, which require political intervention.

Electricity transmission construction rates and consenting process

Transmission construction timelines are a potential limiting factor: the Committee on Climate Change concluded that 'a significant expansion is likely to be required' /34/. The very large expansion of capacity between Scotland and the rest of the GB system currently in progress avoids the risk and delay of major planning enquiries for overhead transmission lines, by implementing instead additional control equipment at single locations (substations), and by using a subsea cable on the west coast. Further subsea cables can in principle be implemented almost without limit: the Electricity Ten Year Statement /32/ mentions three possible new subsea cables on the east coast, providing more than enough transmission capacity before 2030. The costs are higher than overhead lines, but with substantially faster and more certain construction times, less subject to consenting risk.

However transmission capacity between Scotland and the rest of the GB system is only part of the issue; substantial reinforcement works may be needed on land. The experience of the Beauly-Denny line shows how long this can take: application for consent was submitted in 2005 and granted in 2010, and completion is expected in 2015. This difficulty may be addressed, if it arises, by going underground either with AC or DC. Costs are significantly higher, but as with subsea cables, consenting risk and delays should be significantly reduced. The Regulator will have to be convinced of the need for the higher cost, but this has already been achieved for the West Coast subsea cable.

Renewables construction rates and consenting process

Scenario 2 requires the greatest volume of renewable capacity (14,700 MW). The main components of new renewable generation assumed are as follows, though of course other renewables could also meet the requirement:

---

[40] See summary on p119 of /34/. This cost is the marginal cost of additional renewables in 2030, i.e. at high renewables penetration: the cost of managing lower penetrations of renewables before 2030 is likely to be lower, per MWh of renewables production.

- 1,000 MW of new hydro;
- 6,900 MW of new onshore wind, or 4,500 MW of new offshore wind (or a mixture).

Over the period to 2030, the required build rates are 67 MW/y for hydro, and 460 MW/y for wind.

DECC statistics[41] show that onshore wind generation in Scotland increased by an average of 680 MW/y over the period 2011-2013, with a peak of 930 MW/y in 2012. It is therefore concluded that there are no organisational or capacity constraints on building onshore wind generation at the rates envisaged in the scenarios. There may of course be constraints on achieving planning consents and grid connection, but given the pipeline of projects already in development, these constraints are not expected to prevent construction of this volume of wind generation by 2030, provided the current level of political will in Scotland is maintained.

However hydro (large and small-scale) increased by only 16 MW/y over the same period. There are signs that hydro development may be expanding: a total of 77 MW is awaiting construction or is in construction. If however hydro capacity cannot expand by 1000 MW by 2030, other renewables technologies should be able to fill the gap.

Energy market

The market for renewables in the UK is currently relatively clear only until 2020[42]. There is clear intention throughout Westminster and Holyrood to meet 2020 targets, with heavy reliance on renewables. In the period to 2020 in Scotland, the risks are:

Electricity market reform - renewables

Renewables projects funded through the Renewables Obligation mechanism are certain of their income, but this mechanism will not be available to new projects from 2017. Under Electricity Market Reform, uncertainties are gradually being resolved, but the 'allocation risk' (the risk of new projects not winning a Contract for Differences[43]) is still not clear. There is a fixed pot of money to 2020 (the Levy Control Framework) for renewables and other low-carbon policies, and there will be competition on price for it[44]. There is also competition on timing and size. It is feasible that a small project may be successful in one of the rounds in preference to a larger project with lower unit costs, if it fits within the budget available for that round.

Offshore wind is particularly affected, especially Scottish projects, as these face less certainty on costs for a number of reasons, including deeper waters and more onerous conditions.

Electricity market reform – conventional generation

As shown in Section 4.3.5, conventional generating plant without CCS can expect to operate at substantially lower capacity factors than at present. Electricity Market Reform includes a Capacity Market, to provide income to such generators in addition to the income from electricity sales.

Grid connection delays and costs

The Connect and Manage regime has made a big difference for projects in Scotland /34//37/. This process allows projects to connect in advance of all necessary transmission reinforcement being completed, and has allowed some projects to be built several years early. This principle will continue,

---

[41] DECC Energy Trends, Table 6.1c. Latest figures at https://www.gov.uk/government/collections/energy-trends

[42] See e.g. Committee on Climate Change 2014 progress report /34/.

[43] Contract for Difference: a mechanism by which projects are paid the difference between a measure of wholesale electricity prices, and an agreed 'strike price'. In principle this gives projects a guaranteed electricity price, which leads to lower financing costs, and also avoids the risk of projects being over-rewarded, which can occur with premium-price systems for support of renewables.

[44] DECC recently announced the draft budget notice for CFD allocation, Round 1 https://www.gov.uk/government/publications/indicative-cfd-budget-notice-for-the-autumn-2014-cfd-allocation-round. Analysis of this indicates that there will be significantly more renewable capacity chasing CFDs than can be funded in the period to 2020.

and with National Grid actively managing the connection queue (i.e. detecting projects which are delayed for other reasons, such as planning consent, where other projects could use the connection capacity earlier), it is difficult to see how the situation on the transmission system could be improved further without major regulatory change.

However projects on the main Scottish island groups are in a very difficult position that does not appear to allow them to connect before around 2020. Delays can affect the chances of getting a Contract for Difference. Projects cannot bid for a Contract for Difference without knowing the cost and timing of their grid connection, but equally cannot sign a binding connection agreement without knowing if they will get a Contract for Difference. Further, the Regulator wants to see a demonstrated need in order to authorise the major capital investment of a connection to an island group, demonstrated by signed connection agreements. This difficulty is fundamentally unresolvable under current arrangements, and so requires political intervention.

Transmission charging principles have been under review for several years, with particular concern about the conflict between locational charging (to accurately reflect the costs incurred by connecting a generator far from the major demand centres), the exploitation of the most favourable locations for onshore and offshore wind, wave and tidal, and the major social and economic advantages that employment could bring to disadvantaged areas. New charging principles have now been agreed /38/, which reduce costs for renewable generators located in Scotland; however, costs in the north and especially the islands remain very substantially higher than further south.

Additional support for projects on the islands, to allow for higher transmission costs and other costs, are proposed as part of Electricity Market Reform, /39/ though currently the proposals appear to limit capacity to well below that which the islands could support.

After 2020

After 2020, the situation is much less clear, principally because there are no firm targets for renewables in the UK, only aspirations for emissions reduction and decarbonisation of electricity. The negative effects of this are set out by the Committee on Climate Change /34/.

Unlike some other countries (e.g. Spain), it is expected that Government support for renewables projects will not be reduced arbitrarily after the commitment to invest is made. However, support for new projects is not at all certain post 2020. Most renewables are capital-intensive, with effectively fixed operating costs. They are therefore very sensitive to uncertainties about future income. Post-2020 uncertainty is therefore now starting to influence initiation and development of post-2020 projects.

5.9 Future policy actions

9. What policy recommendations flow from this analysis?

There are three main areas for policy action, at both Holyrood and Westminster level:

5.9.1 Maintaining industry confidence in the short and medium term

Rapid resolution of the ***uncertainties around Electricity Market Reform*** is crucial. This is already affecting development and construction programmes for offshore wind, and is also causing a rush of onshore wind projects attempting to construct in time to qualify under the Renewables Obligation before it is terminated. This requires DECC to avoid further delays, and giving weight to renewable developers' concerns about details of the allocation mechanisms.

Wave and tidal technologies and projects are at risk of being ignored in the short term. These technologies are now at the critical stage of deployment at array scale, where costs are much higher than prototype and development stages, and yet investors cannot fund arrays unsupported.

Governments need to 'check in' frequently with the wave and tidal industries to ensure that connection issues, transmission charging, and electricity market reform do not impede progress.

5.9.2 Post 2020

The ***continuation of a market for new renewables projects after 2020*** needs to be stated clearly by Government. Adoption of the Fourth and Fifth Carbon Budgets /40/ would provide a suitable signal. A firm decarbonisation target for 2030 for the electricity supply industry is a sensible step and provides a clear message. Without these signals, large renewables developers and investors may find other countries present more attractive opportunities. Also there is a danger, particularly for offshore wind, that lack of clarity on future needs will prevent the major capital investments and innovation required to bring down costs. This may also make it harder to justify inward investment to establish manufacturing and jobs in the UK.

It is worth noting that with strong efforts on ***energy efficiency and demand reduction*** in Scotland (e.g. Scenarios 3 and 4), the volume of renewable generation already existing or under construction, and therefore likely to be in operation before 2020, will get Scotland close to the target of 50g/kWh for 2030. Therefore, demand reduction within Scotland makes it easier to achieve this ambition despite possible uncertainty or even unhelpful policies in Westminster and Brussels.

Demand reduction is an area where the Scottish Government has considerable freedom of action. Current policy priorities cover all the important areas – however, experience is being gained rapidly, particularly on heat and on electric vehicles, and policy actions will need to be revisited frequently.

Electric vehicles and electrification of heat also provide opportunities for managing demand to accommodate variable renewables. Governments should therefore aim to ensure (by market mechanisms or otherwise) that ***the true value of demand response services*** is available to those able to provide it.

5.9.3 Scottish island groups

A solution to the ***problems of renewable generation on the three main island groups***, in obtaining a grid connection at acceptable cost and in time, would produce several hundreds of MW of onshore wind generation at costs significantly cheaper than offshore wind.

This would also provide major economic and social benefits to disadvantaged areas, and could provide sites for demonstration of wave and tidal arrays at reasonable connection cost.

This will not happen under current regulatory and commercial frameworks, and therefore it requires political intervention. Current proposals under electricity market reform, for island renewables, wave and tidal may not be sufficient, and therefore DECC and Scottish Government should resolve these concerns at the earliest opportunity.

6 REFERENCES

/1/ Committee for Climate Change, "The Fourth Carbon Budget – reducing emissions through the 2020s," 07 December 2010. [Online]. Available: http://www.theccc.org.uk/publication/the-fourth-carbon-budget-reducing-emissions-through-the-2020s-2/. [Accessed 25 March 2014].

/2/ Department of Energy and Climate Change, "UK Renewable Energy Roadmap," July 2011. [Online]. Available: https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/48128/2167-uk-renewable-energy-roadmap.pdf. [Accessed 26 March 2014].

/3/ SKM (for Scottish Government), "Scottish generation scenarios and power flows: an analysis," 1 November 2011. [Online]. Available: http://www.scotland.gov.uk/Resource/0039/00394230.pdf. [Accessed 25 March 2014].

/4/ Shell press release, "Shell signs agreement to advance major clean energy project at Peterhead," 24 February 2014. [Online]. Available: http://www.shell.co.uk/gbr/aboutshell/media-centre/news-and-media-releases/2014/shell-signs-agreement-clean-energy-project-peterhead.html. [Accessed 25 March 2014].

/5/ Scottish Government, "Energy in Scotland 2014", February 2014. [Online]. Available: http://www.scotland.gov.uk/Resource/0044/00444530.pdf [Accessed 8 April 2014].

/6/ National Grid, "Future Energy Scenarios," July 2013, [Online]. Available: https://www.nationalgrid.com/NR/rdonlyres/2450AADD-FBA3-49C1-8D63-7160A081C1F2/61591/UKFES2013FINAL3.pdf. [Accessed 25 March 2014].

/7/ GL Garrad Hassan for FOE Scotland, "Options for coping with high renewables penetration in Scotland," September 2010, document 107688/GR/01 issue E. [Online]. Available: http://www.foe-scotland.org.uk/power-secured. [Accessed 25 March 2014].

/8/ Friends of the Earth Scotland, "Power of Scotland secured, summary for policymakers," No date. [Online]. Available: http://www.foe-scotland.org.uk/power-secured. [Accessed 25 March 2014].

/9/ The Scottish Government, "Low Carbon Scotland Meeting the emissions reductions targets 2013-2027: The second report on proposals and policies," Scottish Government, Edinburgh, 2013.

/10/ Transport Scotland, "Switched on Scotland: a roadmap to widespread adoption of plug-in vehicles," September 2013. [Online]. Available: http://www.transportscotland.gov.uk/road/sustainability/low-carbon-vehicles. [Accessed 25 March 2014].

/11/ Element Energy, Ecolane and University of Aberdeen (for Committee on Climate Change), "Pathways to high penetration of electric vehicles", December 2013 [Online] Available: http://www.theccc.org.uk/wp-content/uploads/2013/12/CCC-EV-pathways_FINAL-REPORT_17-12-13-Final.pdf [Accessed 15 May 2014].

/12/ Ove Arup and Partners Ltd, "Scenarios for Scottish Heat: Heat Pathway Scenarios Model Factual Report", May 2014. [Online] Available: http://www.scotland.gov.uk/Topics/Business-Industry/Energy/Energy-sources/19185/Heat/HeatScenariosReport

/13/ WWF, "The burning question: what is Scotland's renewable heat future?" February 2014. [Online]. Available: http://assets.wwf.org.uk/downloads/rh_web.pdf. [Accessed 25 March 2014].

/14/ Scottish Government, "Towards decarbonising heat: Maximising the opportunities for Scotland. Draft heat generation policy statement for consultation", March 2014 [Online]. Available: http://www.scotland.gov.uk/Publications/2014/03/2778/downloads [Accessed 23 March 2014].

/15/ Platchov LM, Pollit MG, "The economics of energy (and electricity) demand", April 2011. Electricity Policy Research Group, University of Cambridge. EPRG Working Paper 1116 [Online]. Available: http://www.eprg.group.cam.ac.uk/wp-content/uploads/2014/01/EPRG-WP-1116_complete1.pdf

/16/ AEA Technology (for Scottish Government), "Energy storage and management study", Oct 2010.

/17/ Imperial College, Energy Networks Association, "Benefits of advanced smart metering for demand response based control of distribution networks", April 2010. [Online] Available: http://www.energynetworks.org/modx/assets/files/electricity/futures/smart_meters/Smart_Metering_Benerfits_Summary_ENASEDGImperial_100409.pdf

/18/ Baringa and Element Energy for DECC, "Electricity System Analysis – future system benefits from selected DSR scenarios" August 2012 [Online]. Available: https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/48551/5759-electricity-system-analysis--future-system-benefit.pdf

/19/ Pöyry, "Assessment of DSR price signals", December 2011. [Online] Available: http://www.poyry.co.uk/news/publication-assessment-dsr-price-signals-report-commissioned-national-grid-and-electricity-north-west

/20/ Imperial College and NERA Economic Consulting (for DECC), "Understanding the balancing challenge", August 2012. [Online] Available: http://www.nera.com/nera-files/PUB_DECC_0812.pdf

/21/ Frontier Economics and Sustainability First, for DECC, "Demand side response in the domestic sector – a literature review of major trials", Final report, August 2012. [Online] Available: https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/48552/5756-demand-side-response-in-the-domestic-sector-a-lit.pdf

/22/ Energy Saving Trust, "Powering the Nation – Household electricity-using habits revealed", June 2012. [Online] Available: http://www.energysavingtrust.org.uk/Publications2/Corporate/Research-and-insights/Powering-the-nation-household-electricity-using-habits-revealed

/23/ Dept of Energy & Climate Change, "2013 UK Greenhouse Gas Emissions, Provisional Figures and 2012 UK Greenhouse Gas Emissions, Final Figures by Fuel Type and End-User", 27 March 2014. [Online] Available: https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/295968/20140327_2013_UK_Greenhouse_Gas_Emissions_Provisional_Figures.pdf [Accessed 23 May 2014]

/24/ House of Commons Energy and Climate Change Committee, "Emissions Performance Standards, First Report of Session 2010-11", 2010. [Online] Available: http://www.publications.parliament.uk/pa/cm201011/cmselect/cmenergy/523/523.pdf [Accessed 22 May 2014]

/25/ Department of Energy and Climate Change, "Electricity Market Reform: Update on the Emissions Performance Standard", 2012. [Online] Available: https://www.gov.uk/government/publications/electricity-market-reform-policy-overview [Accessed 22 May 2014]

/26/ Scottish Government, "Scottish Energy Statistics Database" [Online]. Available: http://www.scotland.gov.uk/Topics/Statistics/Browse/Business/Energy/Database [Accessed 20 May 2014]

/27/ N Forrest and J Wallace, "The Employment Potential of Scotland's Hydro Resource", 2009. http://www.scotland.gov.uk/Resource/Doc/299322/0093327.pdf

/28/ "Offshore Wind Cost Reduction Task Force Report", June 2012. [Online] Available: https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/66776/5584-offshore-wind-cost-reduction-task-force-report.pdf

/29/ Levy Control Framework: see http://www.publications.parliament.uk/pa/cm201314/cmselect/cmenergy/872/87203.htm

/30/ Scottish Institute for Solar Energy Research and others, "Solar Energy – a viable contributor to renewables in Scotland", May 2014 http://siser.eps.hw.ac.uk/docs/a__solar_vision_for_scotland.pdf

/31/ Royal Academy of Engineering, "Wind energy - implications of large-scale deployment on the GB electricity system", April 2014. [Online] Available: http://www.raeng.org.uk/news/publications/list/reports/wind_report.pdf

/32/ National Grid, "Electricity Ten Year Statement", Nov 2012. [Online] Available: http://www.nationalgrid.com/NR/rdonlyres/DF56DC3B-13D7-4B19-9DFB-6E1B971C43F6/57770/10761_NG_ElectricityTenYearStatement_LR.pdf [Accessed 23 May 2014]

/33/ Department of Energy & Climate Change, "2050 Calculator" [Online] Available: https://www.gov.uk/2050-pathways-analysis [Accessed 27 May 2014]

/34/ Committee on Climate Change, "Meeting carbon budgets – 2014 Progress Report to Parliament", July 2014. [Online] Available: http://www.theccc.org.uk/wp-content/uploads/2014/07/CCC-Progress-Report-2014_web_2.pdf

/35/ Department of Energy and Climate Change, "Electricity and generation costs 2013", Dec 2013. [Online] Available: https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/269888/131217_Electricity_Generation_costs_report_December_2013_Final.pdf

/36/ Committee on Climate Change, "Fourth Carbon Budget Review – part 2," 01 December 2013. [Online]. Available: http://www.theccc.org.uk/publication/fourth-carbon-budget-review/. [Accessed 25 March 2014].

/37/ National Grid, "Connect and Manage Quarterly Reports". [Online] Available: http://www2.nationalgrid.com/UK/Services/Electricity-connections/Industry-products/connect-and-manage/

/38/ Ofgem, "Ofgem gives green light to new £1.2 million Scottish subsea link and transmission charging reform", July 2014. [Online] https://www.ofgem.gov.uk/press-releases/ofgem-gives-green-light-new-%C2%A31.2-billion-scottish-subsea-link-and-transmission-charging-reform

/39/ Department of Energy and Climate Change, "Scottish Islands Renewables – Update Report", Dec 2013. [Online] Available: https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/267481/SIR_update_report_final_template.pdf

/40/ UK Government, "Reducing the UK's greenhouse gas emissions by 80% by2050", March 2014. [Online] Available: https://www.gov.uk/government/policies/reducing-the-uk-s-greenhouse-gas-emissions-by-80-by-2050/supporting-pages/carbon-budgets

/41/ European Commission, "Energy 2020 A strategy for competitive, sustainable and secure energy," 10 November 2010. [Online]. Available: http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=COM:2010:0639:FIN:En:PDF. [Accessed 24 March 2014].

/42/ European Council, "Cover Note European Council 20/21 March 2014 Conclusions," 21 March 2014. [Online]. Available: http://www.consilium.europa.eu/uedocs/cms_data/docs/pressdata/en/ec/141749.pdf. [Accessed 24 March 2014].

/43/ European Commission, "A policy framework for climate and energy in the period from 2020 to 2030 COM (2014) 15 final COMMUNICATION FROM THE COMMISSION TO THE EUROPEAN PARLIAMENT, THE COUNCIL, THE EUROPEAN ECONOMIC AND SOCIAL COMMITTEE AND THE COMMITTEE OF THE REGIONS," European Commission, Brussels, 2014.

/44/ European Commission, "WHITE PAPER Roadmap to a Single European Transport Area – Towards a competitive and resource efficient transport system COM/2011/0144 final", European Commission, Luxembourg, 2011.

/45/ European Commission, "GREEN PAPER A 2030 framework for climate and energy policies COM(2013) 169 final", European Commission, Luxembourg, 2013

/46/ European Commission, "Energy roadmap 2050 (COM(2011) 885 final", European Commission, Luxembourg, 2011

/47/ EREC, "Renewable Heating & Cooling".[Online]. Available: http://www.erec.org/policy/sectoral-policy/heating-cooling.html [Accessed 01 April 2014].

/48/ Department for Energy and Climate Change, "UK Renewable Energy Roadmap Update 2013," November 2013. [Online]. Available: https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/255182/UK_Renewable_Energy_Roadmap_-_5_November_-_FINAL_DOCUMENT_FOR_PUBLICATIO___.pdf. [Accessed 25 March 2014].

/49/ Department of Energy and Climate Change, "Updated Energy and Emissions Projections 2013," September 2013. [Online]. Available: https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/239937/uep_2013.pdf. [Accessed 25 March 2014].

/50/ UK Government, “National Renewable Energy Action Plan for the United Kingdom, Article 4 of the Renewable Energy Directive 2009/28/EC”, June 2010. [Online]. Available: https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/47871/25-nat-ren-energy-action-plan.pdf [Accessed 01 April 2014].

/51/ The Scottish Government, “Electricity Generation Policy Statement - 2013,” Scottish Government, Edinburgh, 2013.

/52/ The Scottish Government, “Action on energy in Scotland”, Dec 2013. [Online]. Available: http://www.scotland.gov.uk/Topics/Business-Industry/Energy/Action/ [Accessed 01 April 2014].

/53/ The Scottish Government, “Climate Change Delivery Plan: Meeting Scotland’s Statutory Climate Change Targets,” June 2009. [Online]. Available: http://www.scotland.gov.uk/Resource/Doc/276273/0082934.pdf. [Accessed 2 April 2014]

/54/ The Scottish Government, “Energy efficiency policy in Scotland”, July 2013. [Online]. Available: http://www.scotland.gov.uk/Topics/Business-Industry/Energy/Action/energy-efficiency-policy [Accessed 01 April 2014].

APPENDIX A: ESTABLISHING THE BACKGROUND

European Union Energy Policy

The main aims of European energy policy are to set and meet its climate and environmental targets, while ensuring affordable energy prices, industrial competitiveness and security of supply. The key metrics that the EU is aiming for are set out in its targets for greenhouse gases (GHG), renewable energy (RE) and energy efficiency (EE). These are set for 2020, in the Energy 2020 Strategy, which was adopted in 2007 /41/The three targets, known as the "20-20-20" targets, for this period are:

- 20% reduction in the EU's GHG emission levels, relative to 1990 levels
- 20% share of renewable energy in the EU's total energy consumption, with specific targets for certain Member States, based on projected energy demand;
- 20% saving in energy consumption compared to the EU's projected energy use.

There are also targets set for other sectors of the economy, including the use of RE in the transport sector and the decarbonisation of transport fuels.

The contributions to the 2020 targets are expected to be finalised by the European Commission and national members by the end of 2015. The 2020 targets are implemented at EU level through policy instruments.

The EU's targets for 2030 are to be considered following an UN Climate Summit planned for the end of 2014. It has been highlighted by recent EC publications that the 2030 targets will also have to be in line with the longer term goals of the EU's 2050 targets /42/. The EU's 2050 targets have been described by the European Commission as ambitious, aiming to reduce GHG emissions by between 80% and 95% by 2050 compared to the baseline 1990 levels.

Based on these longer term targets, the EC has suggested that the 2030 targets for GHG emissions will need to be set at a level of at least 40% reduction in order to be on track to meet the 2050 targets. It has been estimated that in order to achieve the overall 40% target, the sectors covered by the EU emissions trading scheme (EU ETS) would have to reduce their emissions by 43% compared to 2005. All other sectors not covered by the ETS would be expected to cut their emissions by 30% below the 2005 level. The plan would attempt to ensure that the required effort would be shared equitably between the Member States, importantly by binding national emissions targets.

The emissions targets above have resulted in an expected RE share of at least 27% of total energy consumption by 2030. This has been translated in certain European Commission publications as an expected 45% share of renewables in the EU electricity production mix /43/.

With respect to the 2030 energy efficiency targets (EE), the European Union will consider the role of EE in an upcoming Energy Efficiency Directive. The European Commission has indicated that in their estimations, energy savings of 25% by 2030 would be required to achieve the aforementioned GHG target of 40% in the same period /43/.

For the transport sector, the EU has proposed in its Transport White Paper GHG reductions of 60% for 2050 compared to 1990 and by around 20% by 2030 compared to 2008 levels (or 8% above 1990 levels) /44/. Use of renewable energy sources in transport by 2020 on the other hand has been targeted at 10% for 2020 /45/. It has been noted in the Energy 2050 Roadmap that "electricity could provide around 65 % of energy demand by passenger cars and light duty vehicles" /46/.

No clear mention appears to have been made with regards to the renewable heat aspirations for 2030, but research undertaken by the European Renewable Energy Council and supported by the EC, has indicated that renewable heating (and cooling) could cover more than half of the EU´s heat demand by 2030 /47/.

Decisions on the actual framework to implement the 2030 targets were originally to be concluded by March 2014 but have now been deferred until October 2014 at the latest. Proposals suggest that the renewable energy target apply to the EU as a whole rather than being legally binding on individual nations, as were the 2020 targets.

UK energy policy

No target for emissions or for electricity demand yet exists for 2030. In fact, in recent EU level meetings with regards to the European 2030 targets, the UK has been one of the most prominent opponents of translating EU targets into legally binding national targets for renewable energy or energy efficiency, preferring instead to allow the energy markets to decide the optimum penetrations of renewables on their grids, subject to the national emissions reduction target. Given this current approach it is not expected that the current Government will provide anything more than "aspirational" targets for 2030.

At the same time however, the UK is legally bound (through the 2008 Climate Change Act) to reduce its greenhouse gas emissions in 2050 by at least 80%, compared to the 1990 baseline level of 773 $MtCO_2e$. Prior to this, the UK is also committed to delivering 15% of its energy demand from renewable sources by 2020 /48/. It has been generally agreed that to meet this wider energy and GHG target, the electricity generation sector will be at the forefront of the RE drive.

Based on these obligations, the Committee on Climate Change (CCC) published its Fourth Carbon Budget report in December 2010 /1/. This provides advice to Government on emissions targets which should be adopted for the period 2023-2027, and suggests policies to reach those targets (with other budgets having dealt with other periods e.g. up to 2020). As part of the work for this report, the CCC has produced estimates of emissions reductions that should be achieved in 2030. The Fourth Carbon Budget was reviewed in December 2013, and the CCC recommended that there was no reason to modify the original existing carbon budget /36/. Looking specifically at the power sector, the December 2013 update provided different scenarios for decarbonisation that estimated the share of renewables in electricity production to range between approximately 40%-60% by the 2030 mark, based on modelling undertaken by the CCC to coincide with the UK Government's release of the Electricity Market Reform plan. In summary, the CCC stated that the main conclusions from the original document are still valid and for 2030, greenhouse gas emissions should be reduced by 60%, to 310 MtCO2e.

According to the CCC's analysis in the Fourth Carbon Budget, the electricity sector would need to be almost completely decarbonised by 2030, with emissions intensity figures forecast to be of the order of 50 gCO_2e/kWh (under their Medium Investment scenario; the "High-" and "Low Investment" scenarios arrived at values of 40 to 130 gCO2e/kWh respectively /1/) compared to some 500g today. The Energy Act 2013 specifies that a 2030 decarbonisation target can be set no earlier than mid 2016 and must first be laid before and agreed by Parliament.

Another government publication, the Energy and Emission Projections provides estimates of the emission levels and energy mixes going forward. Additional modelling requested by the Government and undertaken by the CCC in 2011 indicated that there was scope for the penetration of renewables to reach 30%-45% of all final energy consumption by 2030 /2/. The 2013 Update of the Government's Energy and Emission Projections provides projections out to 2030, based on the current policies, which estimate that the UK territorial emissions for 2030 will be at a level of around 396 $MtCO_2e$ /49/. This is significantly higher than the CCC recommendation of 310 $MtCO_2e$.

With respect to renewable heat targets, the UK is committed to producing 12% of heat from renewable sources by 2020, as stated in the Government's National Renewable Energy Action Plan submitted to the European Commission /50/. The same document also includes a target of achieving 10% of transport demand from renewables by 2020.

The December 2013 update of the CCC's Fourth Carbon Budget provides some indications of the levels of renewable energy required for both renewable heat and transport, in order to meet the Carbon Budgets. Specifically, the December update indicates that a "60% penetration of electric vehicles in new car sales by 2030" will be required, whilst heat pumps will be required at a "penetration rate of 25% of heat demand in the residential sector, and around 60% in the non-residential sector by 2030." /36/

Scottish energy policy

In 2009, the Scottish Government passed its own climate change legislation, including a 42% reduction in emissions by 2020. The 2009 Climate Change (Scotland) Act also mandated annual targets, and a 80% reduction target for 2050. On the pathways to the 2050 targets for the whole Scottish economy, a target of a 60% reduction in GHG emissions by 2030 can be expected.

In further Government reports, aspirations to further decarbonise the Scottish power sector by 2030 were also presented, which would mean a 2030 target of approximately 50 gCO_2/kWh for power generated in Scotland /9/.

There is also a target for renewables to provide 100% of Scotland's gross electricity consumption[45] by 2020. The potential for 125% of gross consumption by 2030 has been raised /51/.

In the case of renewable heat, similar aspirations have been set with a nominal target of decarbonising the Scottish heat sector by 2050, and with significant progress having been made by 2030. The equivalent 2020 target is for 11% heat demand from renewables /52/.

The same approach is mentioned with regards to road transport; specifically the Scottish Climate Change Delivery Plan states that the target is for "complete decarbonisation of road transport by 2050 with significant progress by 2030 through wholesale adoption of electric cars and vans, and significant decarbonisation of rail by 2050" /53/. In both cases however, no explicit targets are set.

Finally with respect to energy efficiency measures, a target of 12% reduction in final energy use by 2020 is in place, from a baseline set for 2005-2007 /54/

[45] 'Gross Consumption' in this case is defined as total electricity used by consumers, plus transmission and distribution losses, plus 'own use' by generating stations.

About DNV GL

Driven by our purpose of safeguarding life, property and the environment, DNV GL enables organizations to advance the safety and sustainability of their business. We provide classification and technical assurance along with software and independent expert advisory services to the maritime, oil and gas, and energy industries. We also provide certification services to customers across a wide range of industries. Operating in more than 100 countries, our 16,000 professionals are dedicated to helping our customers make the world safer, smarter and greener.