UNIVERSITY OF SOUTHAMPTON

FACULTY OF ENGINEERING AND THE ENVIRONMENT

Sustainable Energy Research Group

Integrating renewable energy sources with the UK electricity grid through interconnection or energy storage systems

by

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Thesis for the degree of Engineering Doctorate

June 2016

UNIVERSITY OF SOUTHAMPTON

ABSTRACT

FACULTY OF ENGINEERING AND THE ENVIRONMENT

Thesis for the degree of Engineering Doctorate

INTEGRATING RENEWABLE ENERGY RESOURCES WITH THE UK ELECTRICITY GRID THROUGH INTERCONNECTION OR ENERGY STORAGE SYSTEMS

Marcus Joseph Alexander

This thesis considers the generation and demand challenges of a 100% renewable UK electricity grid and how this can be addressed with interconnection or energy storage. Hourly demand and electricity generation profiles for a year have been constructed: Business as Usual with a yearly demand of 540TWh and Green Plus (rapid uptake of energy efficiency and green measures) with a demand of 390TWh. In addition, two extra scenarios based on the above have been considered with electrification of heating (air source heat pumps) and transportation. The resultant hourly imbalances have been used to calculate the interconnection and energy storage requirements. The calculated interconnector capacity required was found to be 60GW at a cost of GBP 58 billion for the BAU scenario. Energy storage capacity requirements vary depending on the selected technology. Rated capacity was estimated to be 14GW with storage capacity of 3TWh for pumped storage, 11GW and 2.3TWh for liquid air, and 65GW and 13.6TWh for hydrogen storage, at a cost of GBP 65, GBP 76 and GBP 45 billion respectively. This thesis indicates that storing hydrogen in underground caverns would offer the cheapest solution. However, whilst these technological solutions can address generation and demand imbalance in a fully renewable electricity grid, there remain barriers to each technology.

A further technological solution is to exploit the use of electric heat pumps for domestic heating and hot water, as well as the moderate uptake of electric vehicles. It is proposed that these technologies are used on a local scale to help integrate the additional renewable electricity generated within a pre-determined zone of the electricity network. Analysis has been carried out to determine the constraints in the UK network where renewable electricity generation is greater than local electricity demand. From this, consideration has been made to understand the real impact distributed energy storage in the form of heat pumps and electric vehicles could have. Results show that depending on the demand scenario and location on the network, there is the potential to accommodate up to 50% of the excess electricity generated.

Lastly, analysis was conducted on a hybrid technological solution which combines interconnector and energy storage capacity in order to ensure that demand is met year round. This analysis indicates that an optimal combination of a 37GW interconnector plus 11GW of hydrogen (cavern) storage at a cost of GBP 42 billion for the BAU scenario is possible. Likewise, for the GP scenario a 24GW interconnector plus 8.5GW of hydrogen (cavern) storage at a cost of GBP 28 billion was found to be optimal. This analysis shows that a hybrid solution provides a lower cost option than installing either one of the solutions separately.

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DECLARATION OF AUTHORSHIP

I, ...

declare that this thesis and the work presented in it are my own and has been generated by me as the result of my own original research.

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I confirm that:

1. This work was done wholly or mainly while in candidature for a research degree at this University;

2. Where any part of this thesis has previously been submitted for a degree or any other qualification at this University or any other institution, this has been clearly stated;

3. Where I have consulted the published work of others, this is always clearly attributed;

4. Where I have quoted from the work of others, the source is always given. With the exception of such quotations, this thesis is entirely my own work;

5. I have acknowledged all main sources of help;

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7. Parts of this work have been published as:
    - Alexander, M., James, P. & Richardson, N. 2014. Energy storage against interconnection as a balancing mechanism for a 100% renewable UK electricity grid. IET Renewable Power Generation, Volume 9, Issue 2, March 2015, pages 131-141. DOI: 10.1049/iet-rpg.2014.0042. ISSN: 1752-1416
    - Alexander, M. & James, P. 2015. Role of distributed storage in a 100% renewable UK network. Proceedings of the ICE – Energy, Volume 168, Issue 2, April 2015, pages 87-95. DOI: 10.1680/ener.14.00030. ISSN: 1751-4223

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Acknowledgements

Firstly I would like to identify the instrumental support, time and focus that have been given to me in framing this Thesis from my academic supervisors Dr Patrick James and Dr Neil Richardson, without whom I would not have completed this research. Also I would like to give my thanks to my industrial mentor, Ed Bower from Ricardo UK, who provided insightful feedback on my various reports and who guided me through my invaluable industrial experience at Ricardo. I would also like to extend my gratitude to the Engineering and Physical Sciences Research Council for providing the funding that enabled this Programme.

Lastly, but not least, I would like to give my deepest thanks to Rachel Murray for her much needed love, patience and support throughout this process.

Academic institution:

Industrial sponsor:

Funding body:

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Definitions and Abbreviations

All units in this report are part of the International System of Units (SI) and, as such, are not defined herein.

Abbreviation	Definition
ASHP	Air Source Heat Pump
BAU	Business as Usual scenario
BAU+EV&ASHP	Business as Usual scenario plus Air Source Heat Pumps and Electric Vehicles
CAES	Compressed air energy storage
CCGT	Combined cycle gas turbine
CCS	Carbon Capture and Storage
CoE	Cost of Energy
COP	Coefficient of performance
CSP	Concentrated Solar Power
DER	Distributed energy resources
DG	Distributed generation
DSM	Demand-side management
DSO	Distribution system operator
EV	Electric vehicles that plug-in to the grid (PHEV, RE-EV and BEV)
FACTS	Flexible AC transmission systems
FITs	Feed-in tariffs
GDP	Gross Domestic Product
GHG	Greenhouse gases
GP	Green Plus scenario
GP+EV&ASHP	Green Plus scenario plus Air Source Heat Pumps and Electric Vehicles
GW	Gigawatt
H2	Hydrogen energy storage
HVDC	High Voltage Direct Current
ICT	Information and communication technology
kWh	Kilowatt-hour
LAES	Liquid air energy storage
$MtCO_2e$	Million tonnes of CO_2 equivalent
MW	Megawatt
O&M	Operation and Maintenance
OCGT	Open cycle gas turbines
PS	Pumped hydro energy storage
PV	Photovoltaics
RES	Renewable energy sources
SCADA	Supervisory control and data acquisition
SMC	Surface-mediated cells
STOR	Short-term operating reserve
T&D	Transmission and Distribution
ToU	Time-of-Use tariffs
TSO	Transmission system operator
TWh	Terawatt-hour
VPP	Virtual power plant
WAN	Wide area networks

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Chapter 1: Introduction

1.1 Background and Motivation

This Chapter introduces the concept of energy and how the human species has become dependent on it. It also provides an insight into the three key areas that have been defined for sustainable development: economy, society and the environment. The issues surrounding the science of climate change and targets required to enable future sustainable development will be discussed. Finally, an investigation in to the UK greenhouse gas (GHG) emissions will be conducted in this Chapter, focusing on the emissions specific to the UK energy sector.

1.1.1 Evolution of energy consumption

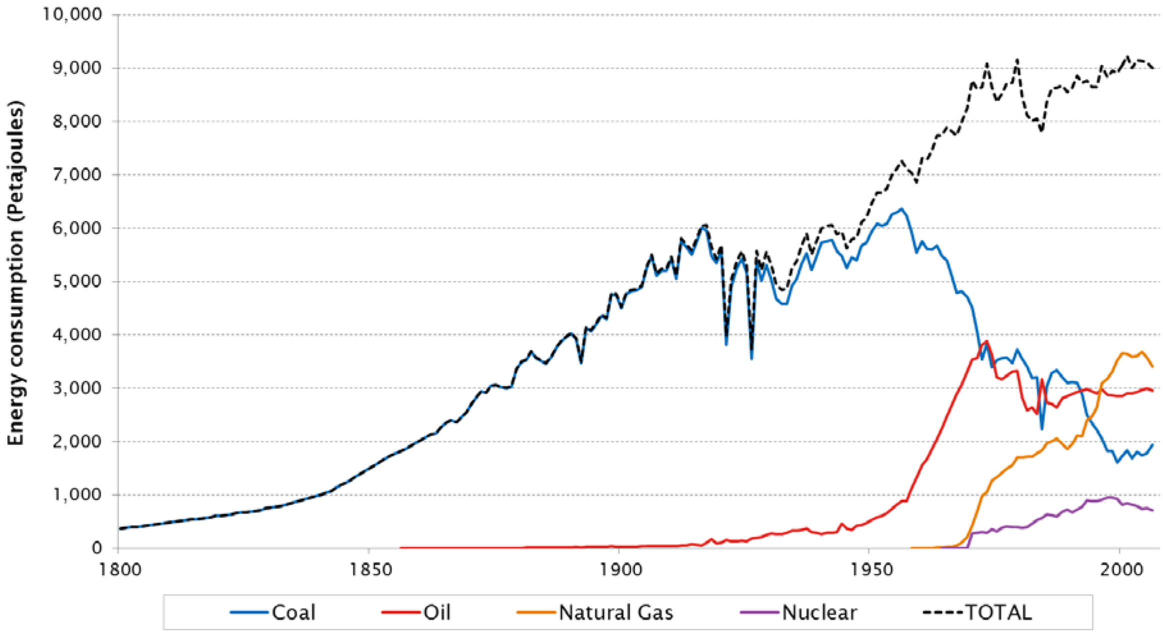
Energy is the basis of all life. In one form or another, energy is extracted from the environment and converted into a usable form. From the first vestiges of the human race, energy has been used to sustain life. In the first instances, this energy was obtained from the food that was available. As humans evolved, tools were invented and fire was discovered, energy consumption increased. With every step in the evolution of the human species, new ways of harvesting energy have been developed; this increase in energy consumption can be followed through the various ages, with minimal impacts on the Earth, up until the advent of the Industrial Revolution. The discovery of the steam engine and the benefits that this gave sparked the inexhaustible demand for energy which has led to present day lifestyles.

To put this into context, Figure 1-1 illustrates the evolution of energy consumption in the UK in the period from 1800 to 2006. The rapid increase in energy consumption during this period has been enabled first by the use of coal (blue line) and then by oil (red line) and natural gas (orange line) (Warde, 2007). These sources of energy are products of the decomposition of carbon life forms over millennia, and as such are finite in nature. This leads to two issues:

1. These resources will eventually run out from over-exploitation; and
2. The conversion of these sources into usable forms release carbon dioxide (CO_2), a greenhouse gas (GHG), to the atmosphere.

Whilst the focus of this Thesis is the implications of a 100% renewable UK electricity grid, it is important to consider both of these issues as they are major drivers for de-carbonising the electricity grid.

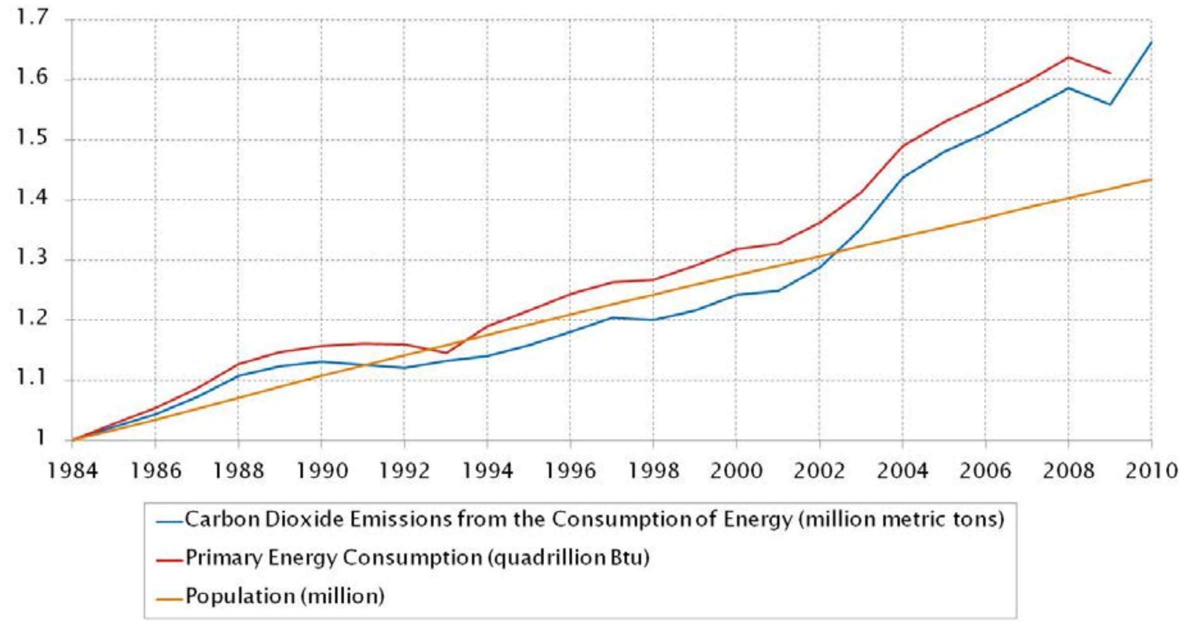
Figure 1-1: Energy consumption in the UK 1800-2006 (Warde, 2007)



Historically it was thought that growth in energy consumption was linked with growth in population: higher energy availability improved living conditions (Perez-Lombard et al., 2008). However, this is only the case in developed and developing countries. The improved lifestyle also brought with it an increase in energy demand. Accordingly, when the period from 1984 to 2009 is considered (Figure 1-2), the global primary energy consumption can be seen to grow by 61% whereas population growth was 42% (EIA, 2012). It is also possible to appreciate the scale of the release of CO_2 related to energy consumption; during this period, there was a growth of 56% (compared to the growth in primary energy consumption of 61%), which suggests a close relation between energy consumption and CO_2 emissions.

It is important to note that growth in population follows an exponential growth profile. However, due to the small timeframe considered in Figure 1-2, 26 years, the growth appears to be linear. From the start of the industrial revolution, when the world's population reached 1 billion, population has increased exponentially to 7 billion in 2011 (United Nations, 2013). It is projected that by 2024, the world population will have grown to a total of 8 billion, though the rate of growth is projected to drop to be less than 1% growth per year from a peak of above 2% per year in the late 1960s (Worldometers, 2014).

Figure 1-2: Global primary energy consumption, CO_2 emissions and population evolution from 1984-2010 (EIA, 2012)



The rise in energy consumption was mainly driven by industry and agriculture. However, there has been a steady increase in energy consumption from the domestic sector. This can be attributed to a rise in energy for space heating as well as an increase in consumer electronics in the household. For example, the number of domestic appliances has doubled from 1971 to 2002 in the UK, with a forecasted rise of 12% by the end of 2010 (EST, 2006). Energy consumption from domestic appliances in 2011 was 38,842 thousand tonnes of oil equivalent (toe) (DECC, 2012g). This constitutes a 5% increase on 1970 consumption levels, but 5% lower than 1990. It is also predicted that the growth of in-house entertainment appliances will be responsible for 45% of the total domestic energy consumption by 2020 (EST, 2007).

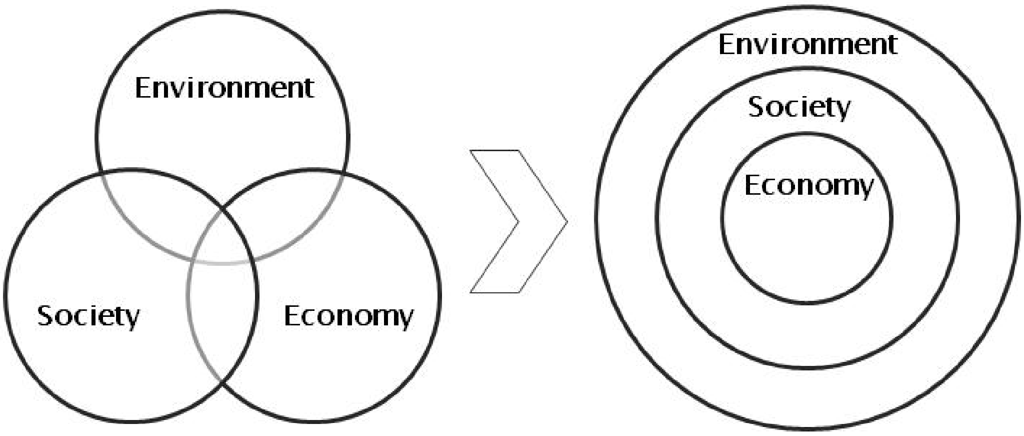
This accelerated growth in energy consumption will continue as long as there are plentiful resources. The main factor that could slow down this rising trend is economic recession. Nevertheless, the current trend of energy use will exhaust the available fossil fuel resources, such as oil, gas and coal, and produce serious environmental effects if it is left unchecked (Perez-Lombard et al., 2008). It has been estimated that by the end of 2013, there was 1,687,900 million barrels of oil left to be exploited (BP, 2014). If the rate of consumption of oil is maintained at the 2013 rate of 90.48 million barrels per day (BP, 2014), there is only 52 years left of oil. The situation for natural gas and coal on the other hand is not quite so alarming. Reserves of natural gas have been estimated at 187.7 trillion m^3 and reserves of coal have been estimated at 891.5 billion tonnes as of 2013 (BP, 2014). At the rate of consumption in 2013 of 3,347.6 billion m^3 and 5.5 billion tonnes per year for natural gas and coal respectively, this gives an estimate of 55 years and 163 years for these resources respectively. However, some estimates suggest that reserves of natural gas may increase up to 220 years when considering the abstraction of recoverable and unproven resources (IEA, 2014). The challenge for the future is to promote energy efficiency in the household, the public sector and private sector as well as raising awareness of the effects of not looking after our individual and collective energy consumption on the environment. To reduce the CO_2 emissions from the production of energy, new technologies that exploit carbon-free sources of energy need to be promoted. Only in this way will it be possible to move forward towards a sustainable energy future.

1.1.2 Sustainable development

Sustainable development as a concept has been around since the emergence of a post-WWII environmental movement. It was born from the recognition that human growth and development has a negative impact on the environment and communities. The most commonly used definition 'development that meets the needs of the present without compromising the ability of future generations to meet their own needs' was derived by the United Nations report of the World Commission on Environment and Development in 1987, also known as the Brundtland Report (UN, 1987). Until recently, there has been a separation of the environment from socio-economic issues. The traditional view was that the environment was there to be exploited and used for humanity's needs. However, sustainable development has at its core the balance of different needs against the three 'pillars' - the economy, society and the environment (DEFRA, 2011). This approach ensures that the wider and future impacts are considered to minimise the consequences of unsustainable development, the most detrimental of which is climate change. Ultimately, 'humanity should strive to live within its environmental limits' (SDC, 2011). However, the needs of the people must be included to make sure that quality of life is not affected and that future communities have social cohesion, personal wellbeing and equal opportunities.

The three 'pillars' or sectors of humanity are frequently shown as three interconnected rings, each equally sized (Price, 1997). This simple illustration encourages the study of all categories individually in a balanced way. Sustainable development is presented as the solution and reconciliation of any conflicts that may arise. However, this can also lead to a targeted solution, a technical fix approach that only focuses on certain aspects. In order to tackle the deeper issues and to see the connections between society, economy and the environment a nested view has been developed (Giddings et al., 2002). This more accurate representation of the relationships can be seen in Figure 1-3. In this way, it is possible to understand the inherent relationships between the economy, which is nested within society, which itself is nested within the environment.

Figure 1-3: Traditional and nested three sector view of sustainable development (Giddings et al., 2002)



Having the economy at the centre of the diagram does not mean that this is the main focus around which the other sectors revolve. It illustrates that the economy is a subset of the other two and as such is dependent on them. In this way, society depends upon the environment, however the environment would continue without society (Lovelock, 1995). Likewise, the economy depends on society and the environment, yet society did exist without economy.

The key issue is to integrate the different sectors so that a holistic view can be obtained. The nested model encourages this mentality in order to overcome barriers between disciplines, providing a suitable solution that addresses future sustainable development.

1.1.3 Climate change and historic targets

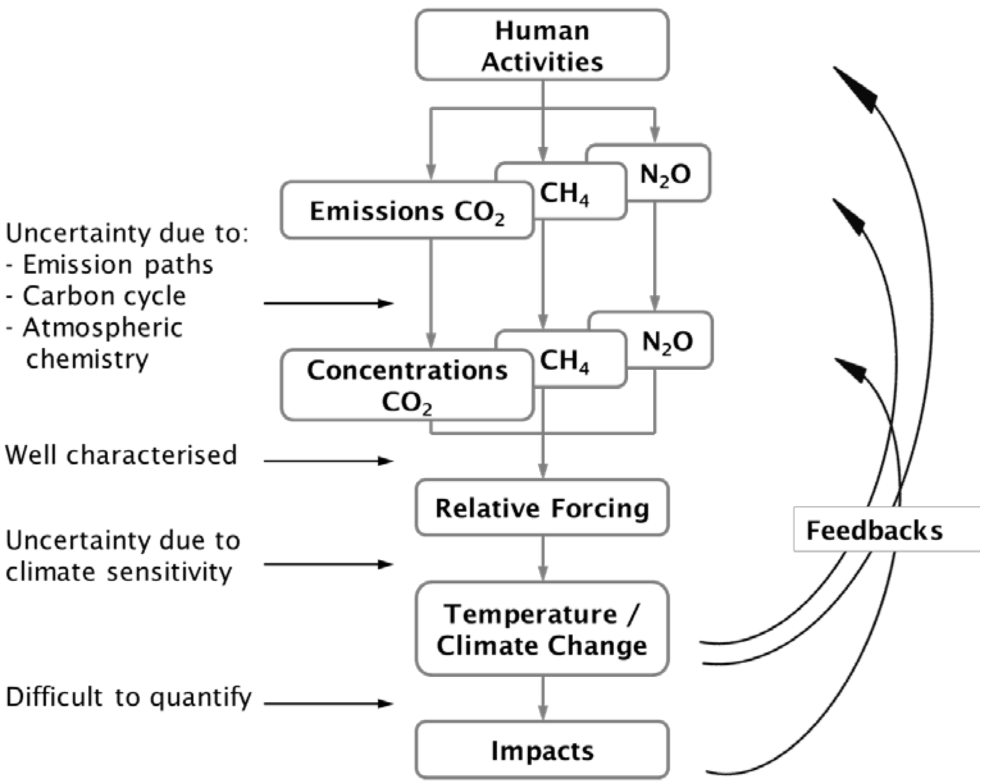
One of the most debated topics of today is climate change and its effects on humanity. However there is a rift between what this means to different communities.

1.1.3.1 Consensus on climate change

A draft statement written for the G8 summit in 2005 formulated that there is 'increasingly compelling evidence of climate change, including rising ocean and atmospheric temperatures, retreating ice sheets and glaciers, rising sea levels, and changes to ecosystems' (Walther et al., 2005). This proceeded to spark a debate between member countries, and as a result, the final published statement was 'climate change is a serious and long term challenge that has potential to affect every part of the globe'. This goes to show the extent to which there are differences in consensus. The first statement reflects what has been discovered by scientific research, whereas the second statement reflects the views of the political community. The final statement does not relay the importance of acting fast to stop the cause of climate change, deferring the issues in favour of more research. However, the consensus from the scientific community is that action must be taken immediately in order to minimise the effects of climate change caused by the build-up of greenhouse gases (GHG) in the atmosphere. A consequence of not acting now is that addressing these issues in the future will only be more difficult and costly, with potential irreversible effects to the globe (NSA, 2005).

The Intergovernmental Panel on Climate Change (IPCC), formed of over 2,500 climate scientists, constitutes the main force advising governments and politicians on the effects of climate change. As with any science, there is a certain level of disagreement between scientists. However, the overwhelming majority of IPCC scientists agreed that the most likely cause of climate change is of anthropogenic origin, i.e. from humans (Bray, 2010). The main differences in scientific consensus arise from the complexity of climate change. This can be appreciated in the cause-effect chain from human activities releasing atmospheric emissions to the impacts these have on the environment (Corfee-Morlot and Hohne, 2003) (Figure 1-4). There are many uncertainties in the interrelationships between the different steps, as well as feedback loops that continuously affect the model.

Figure 1-4: Cause-effect chain from emissions to impacts (Corfee-Morlot and Hohne, 2003)



Although there are many uncertainties, the effects of climate change are already being appreciated and are having noticeable effects on our ecosystem. A greater understanding of these uncertainties will only serve to make more accurate predictions of the outcomes of climate change.

One of the effects of there being a difference in opinion on climate change and its causes and effects is that the general public does not have a clear idea of the issue. This leads to scepticism and uncertainty on the issue which in turn can be a barrier to the development of a sustainable society; society at large is not prepared to make certain sacrifices for a cause that they are unsure about (Poortinga et al., 2011). The majority of the public accept that climate change is an issue; however scepticism arises as to what the cause is and what the effects are, with some that do not believe that climate change is happening at all (Whitmarsh, 2011). The challenge is to engage the public in order to transmit the urgency of the effects of climate change. This will help push the issue in to the political agenda and to bring about the implementation of measures to reduce greenhouse gas (GHG) emissions into the atmosphere and therefore minimise the impacts of climate change.

1.1.3.2 UNFCCC and greenhouse gas reduction targets

The UN General Assembly began negotiations on what was to become the UN Framework Convention on Climate Change (UNFCCC) in December 1990. The objective of this Convention is ‘to stabilise greenhouse gas concentrations in the atmosphere at a level that will prevent dangerous anthropogenic interference with the climate system. Such a level should be achieved within a time frame sufficient to allow ecosystems to adapt naturally to climate change; to ensure that food production is not threatened and to enable economic development to proceed in a sustainable manner' (UN, 1992). The provisional emissions reduction provided in the Convention were deemed to be inadequate. As a result in 1997, the Kyoto Protocol was adopted. This was intended to legally bind developed countries to more stringent emission reduction targets - a 5.2% reduction of GHG emissions on 1990 levels (McGinness, 2001). The Kyoto Protocol targets cover six global warming gases: carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs) and sulphur hexafluoride (SF_6) (UNFCCC, 2012). These gases are weighted by their global warming potential (GWP) for consistency; this is defined as the warming influence relative to CO_2 and therefore GHG emissions are measured in units of carbon dioxide equivalent (CO_2e). The GWP of these gases, relative to CO_2 are listed in Table 1-1.

Table 1-1: Direct Global Warming Potentials (IPCC, 2007)

Industrial designation or common name	GWP for 100-year time horizon (from 4th assessment report)
Carbon Dioxide (CO_2)	1
Methane (CH_4)	25
Nitrous Oxide (NO_2)	298
Hydrofluorocarbons (HFCs)	12 – 14,800
Perfluorocarbons (PFCs)	7,390 – 12,200
Sulphur hexafluoride (SF_6)	22,800

The commitment period of the Protocol was 2008-2012 and most industrialised nations and some central European countries ratified this agreement. However, there were some notable exceptions with countries such as the USA and China not agreeing to the commitment.

Subsequent climate negotiations have been carried out since the Protocol. However, the most notable agreements were achieved in the UNFCCC Conference of the Parties (COP15) in 2009 that endorsed a two degrees warming limit as the benchmark for global progress on climate change (DECC, 2012a). This also marked a milestone in the number of associated countries, accounting for over 80% of global emissions. The UNFCCC COP17 in Durban 2011 is also notable for including for the first time developing countries such as China and India, as well as the United States of America (UNFCCC, 2012). Additionally, in the UNFCCC COP21, scheduled for the 30th November to 11th December 2015 in Paris, France, it is anticipated that a legally binding and universal agreement on climate from all nations will be achieved (UNEP, 2014). The end goal is to reduce GHG emissions in order to limit the chances of a global temperature increase of 2°C above pre-industrial levels.

These targets have been formulated in order to reduce the risk of major irreversible changes to the environment. A concerted effort is required by all in order to achieve this. It is important to note that there is a time lag between emissions and the subsequent rise in temperature. It has been estimated that even if emissions are stabilised now, there would still be a rise of at least 1.4°C by 2100 relative to pre-industrial temperatures (HM Government, 2009). Therefore, nations must act now to curb this rise and the related effects.

1.1.4 UK commitments

The UK Government has decided to implement more stringent targets in order to bring about the transition to low carbon – an 80% reduction in all GHG emissions by 2050. These targets have been set in the 2008 Climate Change Act and are legally binding (DECC, 2008). The Act also set out a carbon budgeting system over five-year periods to ensure that this target is met. The first four budgets have been set to:

- 2008-12: annual average reductions of 23%;
- 2013-17: annual average reductions of 29%;
- 2018-22: annual average reductions of 35%, and
- 2023-27: annual average reductions of 50%.

These targets have been put in place to ensure that climate change is tackled in a timely fashion and that the effects of it do not pose serious threats to the community. As a result of these targets, the UK had succeeded in lowering GHG emissions by 21% below 1990 levels by 2009 (HM Government, 2009) thereby meeting their Kyoto Protocol agreements.

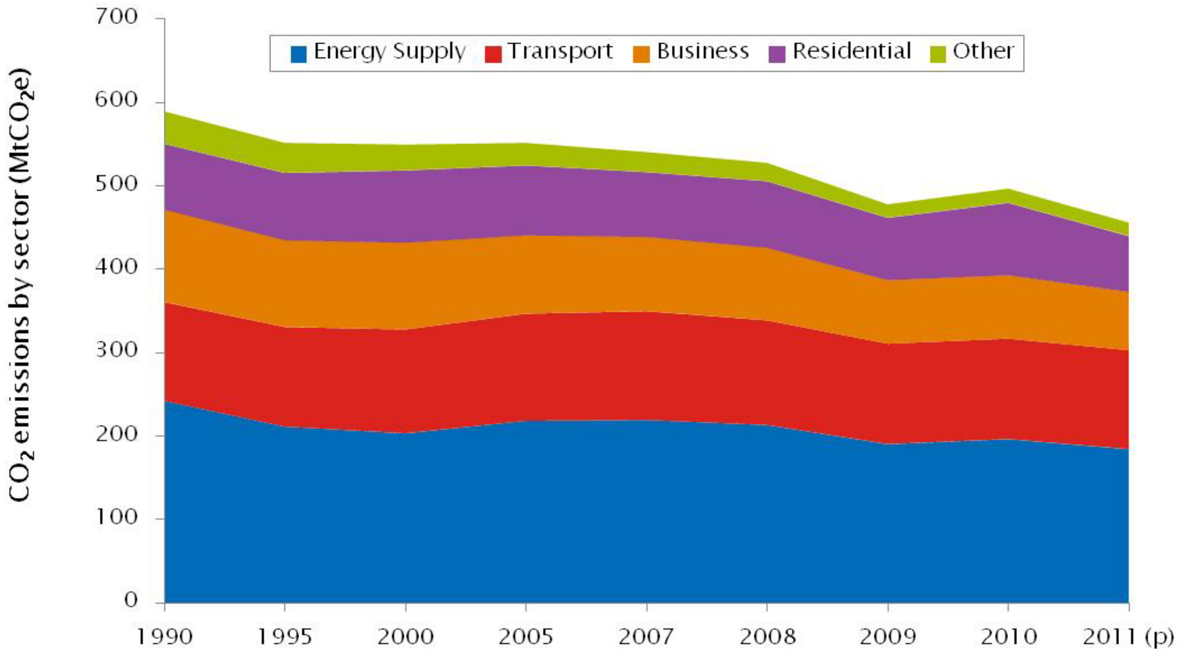
Although change is being brought about to UK energy usage and emissions, climate change is already in effect. As a consequence, climate risk has been introduced into Government planning. The UK is also committed to increasing public awareness of climate change and how it can be acted on, as well as promoting energy efficiency and the use of clean energy technology such as renewable energy sources (RES), nuclear and carbon capture and storage.

1.1.5 UK greenhouse gas emissions by sector

By the end of 2011, carbon dioxide emissions have reduced by 23% from 1990 levels, which satisfy the first budget set out in the 2008 Climate Change Act. In this period, CO_2 accounted for 84% of the UK's greenhouse gas emissions in 2010 (DECC, 2012l) Total GHG emissions in the UK were 549.3 million tonnes of carbon dioxide equivalent ($MtCO_2e$), 7% lower than in 2010. A number of factors have contributed to the reductions that have been seen. The main reasons result primarily from the decrease in energy demand for domestic heating, due to warmer average temperatures, and also a decrease in the use of coal for the less carbon intensive natural gas for electricity generation. Energy consumption during this period also saw a decline of 5%. Throughout 2011 there was also a greater availability of nuclear power which lowered the dependency on carbon intensive fuels.

Figure 1-5 illustrates the evolution of UK CO_2 emissions from 1990 to 2011. These emissions are attributed to five main sectors: energy supply, transport, business, residential and other. In 2011, the energy sector accounted for 40% of the CO_2 emissions, transport made up 26%, the business and residential sectors both emitted 15% of the CO_2 emissions and 4% was emitted by other sectors (DECC, 2012l).

Figure 1-5: UK carbon dioxide emissions by sector 1990-2011 (DECC, 2012l)



The energy sector saw a decrease in emissions of 6% between 2010 and 2011. This decrease in emissions can almost entirely be attributed to electricity generation: technical problems with some nuclear power stations, which affected the slight rise in emissions in 2010, were resolved. This reduced gas dependency by 17% over the period and electricity demand was also 3% lower in 2011 than in 2010.These combined effects resulted in a decrease of emissions from electricity generation of 7%.

Transport sector emissions remain largely unchanged from 1990 levels; however, they are at their lowest annual point since 1992.

The marked decrease in emissions from the residential sector is attributed to external temperatures. The average temperature for 2011 was 9.62°C, 1.03°C warmer than the average temperature between 1971-2000 (MetOffice, 2011). However more importantly, it was significantly warmer than 2010 which had an average temperature of 7.97°C. This significantly contributed to the 23% reduction in use of natural gas for space heating and the consequent reduction in CO_2 emissions.

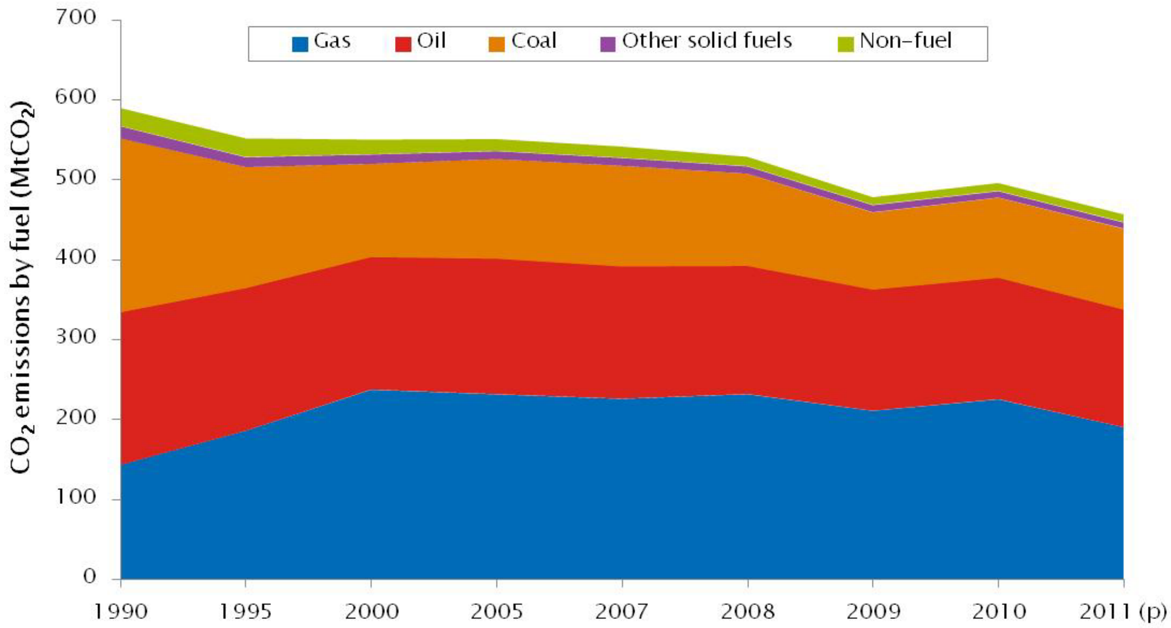
The UK uses a mix of different fuels and technologies in order to supply the energy demand of the five sectors illustrated above. The main fuels are natural gas, coal and oil (Figure 1-6). The amount of CO_2 released by the consumption of one unit of energy depends on the type of fuel consumed, and this is related to the carbon intensity of the fuel. For instance, emissions from electricity generated from coal in the UK were 887tCO_2 in 2011, based on coal power plant emitting

0.955kgCO_2/kWh. On the other hand, 363tCO_2 was emitted for electricity supplied by gas in 2011, based on gas power plant emitting 0.599kgCO_2/kWh (Glasnovic and Margeta, 2011).

However, electricity is the product of many fuels or sources that also include non-carbon based sources such as nuclear and renewables. Therefore, the average UK supplied electricity emitted 436tCO_2/GWh in 2011, a 1% decrease on the 2010 electricity emissions of 444tCO_2/GWh (Hart-Davis, 2013). The average electricity intensity for 2012 has been estimated at 496tCO_2/GWh. This increase is mainly due to the larger contribution from coal generation in this period compared with 2011. The increase in coal use is dues to 3.9GW of nuclear power plant capacity being offline due to maintenance, refuelling or unforeseen repairs (Reuters, 2011).

Over the period 1990 to 2011, CO_2 emissions from fossil fuels decreased by 21%. Over the same period, overall primary consumption of fossil fuels was broadly unchanged. The relatively higher decrease in emissions has been due to an increase in the use of gas accompanied by a decrease in the use of coal and other solid fuels.

Figure 1-6: UK carbon dioxide emissions by fuel 1990-2011 (DECC, 2012l)



The electricity supply sector will be the main focus for this Thesis. Meeting the target of 80% reduction in GHG by 2050 will require immediate action across all five sectors. However, being the main contributor to UK GHG emissions, 40% in 2011, the energy sector will need to play a large role in moving the UK towards a sustainable future. The de-carbonisation of the electricity grid and energy efficiency are key topics that need to be discussed.

1.2 Aims and Research Objectives

As has been introduced throughout this chapter, the UK is committed to reducing its greenhouse gas (GHG) emissions across all sectors by 80% from 1990 levels by 2050. This requires an extensive de-carbonisation of the energy supply sector as is highlighted by the targets set by the European Commission Roadmap 2050 (EC, 2011). The percentages given have been based on a large number of different decarbonisation scenarios which results in the ranges in Table 1-2.

Table 1-2: Division of share of GHG reductions across different economic sectors (EC, 2011)

GHG reductions compared to 1990	2005	2030	2050
TOTAL	-7%	-40 to -68%	-79 to -82%
Power (CO_2)	-7%	-54 to -68%	**-93 to -99%**
Industry (CO_2)	-20%	-34 to -40%	-83 to -87%
Transport (incl. CO_2 aviation, excl. maritime)	30%	20 to -9%	-54 to -67%
Residential and Services (CO_2)	-12%	-37 to -53%	-88 to -91%
Agriculture (non-CO_2)	-20%	-36 to -37%	-42 to -49%
Other Non-CO_2 emissions	-30%	-72 to -73%	-70 to -78%

This will be achieved through the increase in generation from renewable sources of energy. The UK Low Carbon Transition Plan (DECC, 2009) includes sources such as wave, tidal, geothermal and solar, but mainly onshore and offshore wind. These sources are, by nature, variable and in some cases unpredictable. This variability will increasingly become an issue for electricity grid operators. In order to ensure the end user has electricity on demand, grid operators balance available electricity generation capacity with demand. At present, the real-time balancing of the supply and demand of electricity on the electricity grid is carried out by flexible thermal power plant which are capable of increasing or decreasing output rapidly as required by the grid operator. These plant are run on gas and coal, which as a result have high penalties in terms of fuel cost and GHG emissions.

However, if the targets are to be met and to decrease the reliance on fossil fuels, these conventional balancing systems will have to be substituted by other solutions which will ensure that renewable energy is available on demand.

To add to the variability of the future supply, renewable energy is also geographically dispersed. This means that invariably electricity will be generated far from where it is in demand in places of high natural resource. In order to get this electricity from source to end user there will be a heavy reliance on the grid infrastructure, putting pressure on existing constraints in the network.

1.2.1 Thesis research question

This thesis will address the question of how the reductions in greenhouse gas emissions from the power sector can be met and what this would look like in terms of generation mix and network balancing systems. A series of potential future scenarios, taking into account future electricity demand and electricity generation technologies, will be supplied to inform this discussion.

As the result of the uptake of variable renewable energy sources, the substantial issue of grid imbalance will be investigated and potential technological solutions to address this will be examined. These will be compared on their technological suitability as well as an economical assessment of the solutions based on capital costs estimates.

The main research question of this thesis is: *"What mix of energy technologies, with realistic CAPEX, will achieve a feasible 100% renewable electricity supply under different future scenarios for the power generation sector?".*

This question will be answered in this thesis through exploring the imbalance between generation and demand resulting from a fully renewable capacity mix. This will be realised through the creation of four future electricity hourly demand scenarios to understand the increase in installed capacity. The electricity will be generated solely from renewable energy sources (RES) and an hourly generation mix has been determined for each of the demand scenarios proposed. Analysis of the hourly supply and demand imbalance resultant from the scenarios provides the characteristics for the balancing mechanism required to ensure that end users are not affected. The thesis will discuss two major technological solutions capable of meeting the required characteristics: interconnectors and large scale energy storage.

The thesis contributes to the discussion on the feasibility of powering the UK solely through RES. The major concern is the variability of supply from renewable generation due to the effect of weather patterns on output. This leads to a measure of uncertainty which at present levels of RES on the electricity grid is balanced by thermal plant. However when the levels are increased, alternative solutions will be required.

The main contribution to this field is provided by the introduction of a hybrid solution between an increase in the interconnector capacity to Europe and the installation of large scale energy storage in the UK. This provides a technological solution that ensures supply and demand balance in a future where the electricity grid is supplied by 100% renewable energy sources.

These points are presented in the following publications:

- Alexander, M., James, P. & Richardson, N. 2014. Energy storage against interconnection as a balancing mechanism for a 100% renewable UK electricity grid. IET Renewable Power Generation, Volume 9, Issue 2, March 2015, pages 131-141. DOI: 10.1049/iet-rpg.2014.0042. ISSN: 1752-1416
- Alexander, M. & James, P. 2015. Role of distributed storage in a 100% renewable UK network. Proceedings of the ICE – Energy, Volume 168, Issue 2, April 2015, pages 87-95. DOI: 10.1680/ener.14.00030. ISSN: 1751-4223

1.2.2 Thesis scope and assumptions

Some of the key assumptions,drivers and boundaries of the thesis are outlined below:

- The main objective of the thesis is to show the feasibility of powering the UK solely from RES, whilst ensuring electricity security of supply.
- The renewable technologies that are considered are: onshore and offshore wind, solar photovoltaic, hydro, tidal and geothermal.
- Whilst it can only be considered as carbon-neutral, carbon generated from the combustion of biomass does not contribute to greenhouse gas emissions in accordance with international guidelines from the Intergovernmental Panel on Climate Change (IPCC) and the United Nations Framework Convention on Climate Change (UNFCCC) (Blundell et al., 2004). For this reason, bioenergy has also been considered as an electricity source in this thesis. However, this technology would have to be installed with the capacity to reduce emissions of volatile organic compounds (VOCs), carbon monoxide (CO) and nitrogen oxides (NOx) in order to minimise the impact on the environment.
- The thesis is based on a snapshot view of the future and therefore does not consider the transition from the current, carbon intensive, thermal generation plant to a fully renewable electricity generation plant.
- It is proposed that in the future scenarios there is no use of carbon intensive fossil fuels to enable a full decarbonisation of the electricity network. This also includes the use of carbon capture and storage (CCS) as this relies on fossil fuels in the first instance and the technological and economic viability of this solution is uncertain (Nykvist, 2013, Pires et al., 2011).
- It is further assumed that there will be no electricity generation from nuclear power. This stance is taken to reduce the dependence on imported fuel sources – historically, uranium and thorium for use in nuclear power generation was imported from Canada, Australia and South Africa (Berkemeier et al., 2014), though today it is mainly from Australia (BGS, 2010). Additionally, whilst nuclear power is cost competitive with current electricity

generation, the capital costs are far greater and, as a other large infrastructure projects, the costs tend to be underestimated (World Nuclear Association, 2016a) – the current cost estimate for the proposed Hinkley Point C nuclear power plant is GBP 24.5 billion if you include financing and inflation (World Nuclear Association, 2016b). Added to this, there are also long lead times to build and commission nuclear power plant, averaging 6 to 8 years in Europe (Nuclear Energy Agency, 2014) without including design and licencing. However, it is noted that nuclear will play an important role in the transition to the fully renewable electricity grid due to its carbon-free emissions.

- All costs are based on 2012 values unless otherwise stated.
- It will only consider the HV electricity network (400kV–132kV), though there is a discussion on the impact of distributed energy storage which is on the LV network.
- For the purpose of this thesis, it is assumed that the existing National Grid electricity infrastructure layout is not altered. There are, however, proposed changes and upgrades to the network which have been included in the discussion where information is available.

Further technology specific assumptions that are made will be highlighted throughout the thesis chapters as required for ease of reference.

1.2.3 Philosphical approach of the Thesis

It is important to note the philosophical assumptions as well as the interpretive frameworks when conducting research which uses either part or all qualitative methods. Philosophy is concerned with three basic issues, as defined by Denzin and Lincoln (2000): ontology or being; epistemology or knowing; and axiology or acting. When considering this in relation to conducting research, the ontological issue relates to the nature of reality and its characteristics – how the world is seen; the epistemological issue concerns how the knowledge is known based on the subjective evidence assembled by the individual; and the axiological is the value that the researcher brings to the study (Creswell, 2013).

The ontological and epistemological stand points in this research are exemplified as follows:

- The overall assumptions for the thesis have been outlined above, where the author speficies the reasoning for excluding nuclear and carbon capture and storage and the focus of the thesis on a fully renewable UK electricity grid. This starting point is chosen out of a requirement to de-carbonise the UK electricity sector in order to achieve climate change commitments.

- The literature collated in Chapter 2 sets out the scientific and technological background for renewable energy sources, balancing technologies (transmission and energy storage) as well as the feasibility of a fully renewable electricity grid.
- Necessarily, views and confirmations have been sought that confirm and verify the authors' assumptions, as substantiated by the references.
- A number of scenarios have been produced based on previous research to test and qualify the authors' research question.

Axiology is useful in setting out the research methodology as it combines the ontological and epistemological assumptions that the researcher has taken (Ruona and Lynham, 2004). The methodological approach to the thesis is to carry out a qualitative and quantitative assessment of the technical feasibility of producing the UK's electricity demand solely via renewable energy sources. This stand point has been taken to understand and investigate the practical issues to achieving a full decarbonisation of the UK electricity sector and the effect on the balance of electricity supply and demand that arises from inherently variable energy sources. To achieve this reality a radical change in the views of society would be necessary, either at the government and policy maker level or by the individual taking on responsibility for their electricity consumption.

Chapter 2: Literature Review

2.1 Introduction

The world is currently facing one of its greatest challenges, climate change, which has overarching effects affecting all aspects of our lives. The scientific consensus is that the increase in atmospheric levels of carbon dioxide (CO_2) released from the mass use of carbon based fossil fuels has brought about this change (Poortinga et al., 2011). There are six atmospheric gases that make up the basket of greenhouse gases (GHG) as defined in Chapter 1: carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs) and sulphur hexafluoride (SF_6). However, the standard measure for GHG emissions in our environment is million tonnes of carbon dioxide equivalent ($MtCO_2e$). In 1997, the Kyoto Protocol set a legally binding UK target to reduce the levels of GHG concentrations in the atmosphere by 5% from the 1990 levels in the period of 2008-2012 (McGinness, 2001). In addition to these targets, the UK Government has implemented a target to reduce 80% of all GHG emissions by 2050 (DECC, 2008). In order to meet this target, major reforms will need to be made to all UK sectors: energy supply, transport, business, residential and other. The energy supply sector, the main contributor to UK GHG emissions contributing 40% in 2011 (DECC, 2012l), is the main focus in this Thesis. More specifically, the supply of electricity for consumption will be the key focus discussed.

Traditionally, the electricity system has dispatchable generation in the form of conventional thermal plant running on coal, natural gas or oil. This plant is regulated by the network operator and is run to meet the electricity demand requirements. However, these fuel sources, as mentioned above, emit CO_2 amongst other gases in their combustion to generate electricity. In order to meet future GHG emissions targets, these sources of electricity generation will need to be minimised or cease to be used. These fuel sources, known as fossil fuels, are only found in finite supplies in specific locations around the globe. This adds a further constraint to the continuation of generating electricity from these sources as the costs of discovering, extracting and refining these fuels will increase as the resources are depleted.

The use of renewable energy sources (RES) such as the sun, wind, hydro and geothermal, will effectively cease the carbon emissions from electricity generation. These resources are essentially infinite, with the exception of geothermal, and emit no GHG emissions when generating electricity. However, most RES technologies are not dispatchable like conventional thermal power stations, and in most cases they are found in remote areas (e.g. off-shore wind farms). When considering maximising the use of RES generation to meet demand in an electricity grid, it is imperative to control the variability of supply and the disperse nature of resource in order to ensure that demand is met at all times.

Other sources of electricity generation that can be considered 'carbon-free' at point of generation include nuclear generation and thermal plant with carbon capture and storage (CCS). However, these rely, in the main part, on imports of finite fuel in order to generate electricity and as such can potentially pose security of supply risks in the long term future.

Many analyses have been carried out to determine the whole life GHG emissions of generating electricity from conventional sources as well as renewable sources and future technologies. These studies consider not only the emissions from generation, but also the amount of energy required to build and operate the plant required, therefore acknowledging the fact that although renewable sources do not emit GHG when generating electricity, there is still an amount emitted in the construction and maintenance of the plant. Table 2-1 (Moomaw et al., 2011) summarises the main findings from these studies, presenting the median emissions by resource as well as the minimum and maximum values found (in parenthesis). It can be observed that although electricity generation from renewable sources still emit GHG emissions, they are at least an order of magnitude lower than fossil fuel sources as expected. Even when considering CCS technology, renewable sources still outperform fossil fuel resources.

Table 2-1: Aggregated results of LCAs of GHG emissions from electricity generation technologies (Moomaw et al., 2011)

Electricity generation resource	Whole life GHG emission factors (gCO_2e/kWh)
Coal	1,001 (675 – 1,689)
Coal + CCS	98 – 396
Oil	840 (510 – 1,170)
Gas	469 (290 – 930)
Gas + CCS	65 – 245
Nuclear	16 (1 – 220)
Hydropower	4 (0 – 43)
Wind	12 (2 – 81)
Bioenergy	18 (-633 – 75)
Solar PV	46 (5 – 217)
Solar CSP	22 (7 – 89)
Geothermal	45 (6 – 79)
Marine	8 (2 – 23)

It is also expected that once there is a base of renewable generation on the electricity grid, the emissions from the production of new renewable technologies would further be reduced, whereas for fossil fuels there is still a considerable amount of GHG emissions due to the fuel used.

This further compounds the reasons why these sources of electricity generation will not be considered further in this study.

For these reasons, studies have been conducted to investigate the applicability of using 100% renewable energy in various systems. The main aspects investigated relate to energy savings from electrification, efficient conversion technologies and replacement of fossil fuels. However, it is important that any such investigation include aspects of the effect on the economy and the benefits for climate mitigation. In some cases, the targets for reduction of GHG emissions have been criticised as being detrimental to economic growth, especially in developing countries. However, as Mathiesen et al. (2011) point out, if a top-down government led energy policy is implemented on a country scale, as is the case of Denmark over the last three decades, reductions in carbon emissions can be obtained whilst maintaining economic growth.

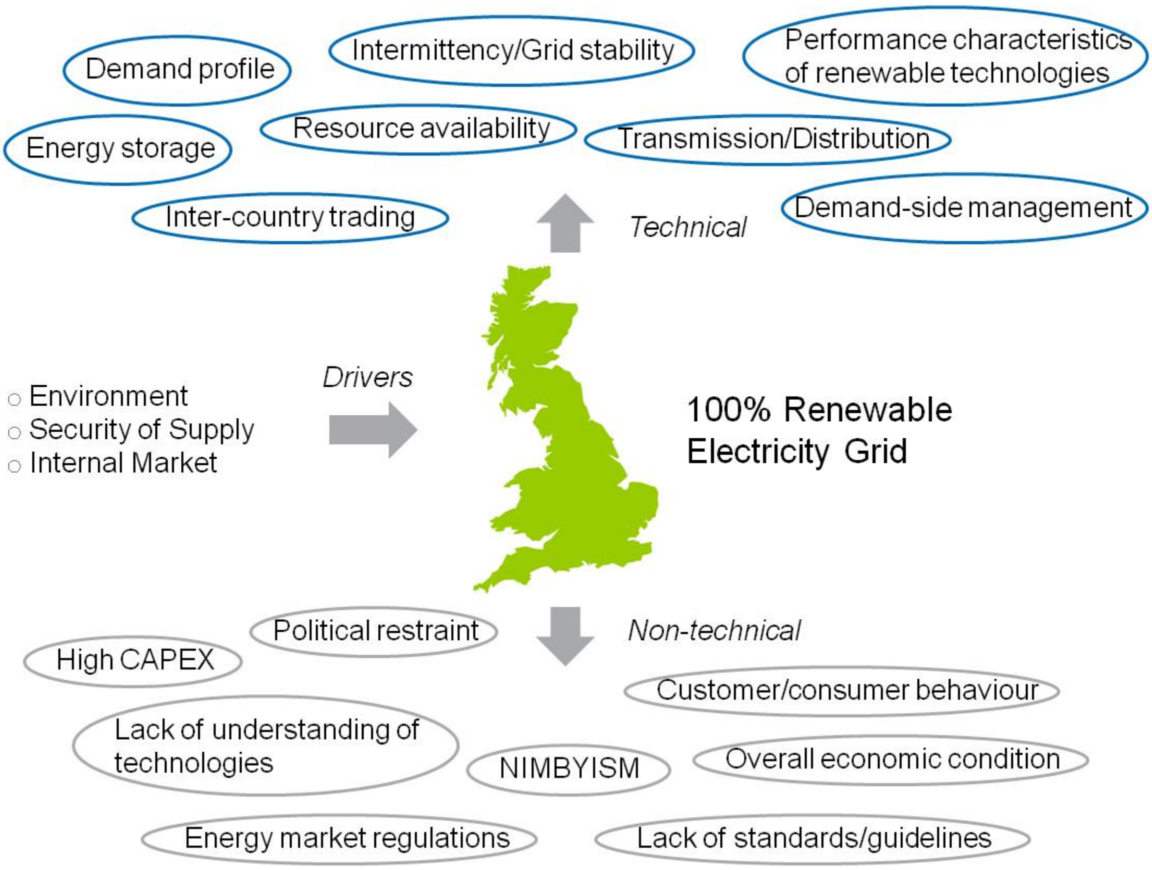
The current penetration of renewable generation in Europe varies widely between countries. This is mainly due to the amount of available resource and the political drive of the particular country. For example, Norway sources nearly all of its electricity from hydro power as they have a large resource, whereas Poland historically sourced most of their electricity requirements from locally available coal resources. Table 2-2 gives an overview of the contribution that renewable generation has in a selection of countries in the EU, as well as the average of the EU-27. Increasing the level of penetration of renewable sources in the UK from circa 10% to 100% poses some significant challenges for the future.

Table 2-2: Electricity generated from renewables as a percentage of electricity consumption (Eurostat, 2013)

Country	Electricity generated from RES 2011 (%)
EU (27 countries)	21.7%
United Kingdom	8.7%
Denmark	35.9%
France	16.5%
Germany	21.3%
Spain	31.5%
Norway	100%
Poland	8.2%

The main drivers for the fully renewable grid can be attributed to the reduction of GHG emissions in order to sustain our environment for the future, striving for a secure supply of energy to sustain our lifestyle and increasing the competitiveness and innovation in the internal market through new generation technologies and market structures to create a more secure economic setting. Figure 2-1 presents a schematic of the technical and non-technical barriers to the realisation of the fully renewable electricity grid. Whilst it is known that there are a number of non-technical barriers that need to be addressed, the main focus lies on the technical barriers and how these can be overcome.

Figure 2-1: Schematic of barriers and drivers to the 100% renewable electricity grid



It is now important to consider the context within which this study is conducted. This Chapter considers the existing UK electricity grid, the supply and demand of electricity, renewable energy technologies and their supply potential in the UK, alternative energy solutions, electricity transmission, energy storage technologies and a review of 100% renewable electricity grid studies.

2.2 Review of the Existing UK Electricity Transmission Grid

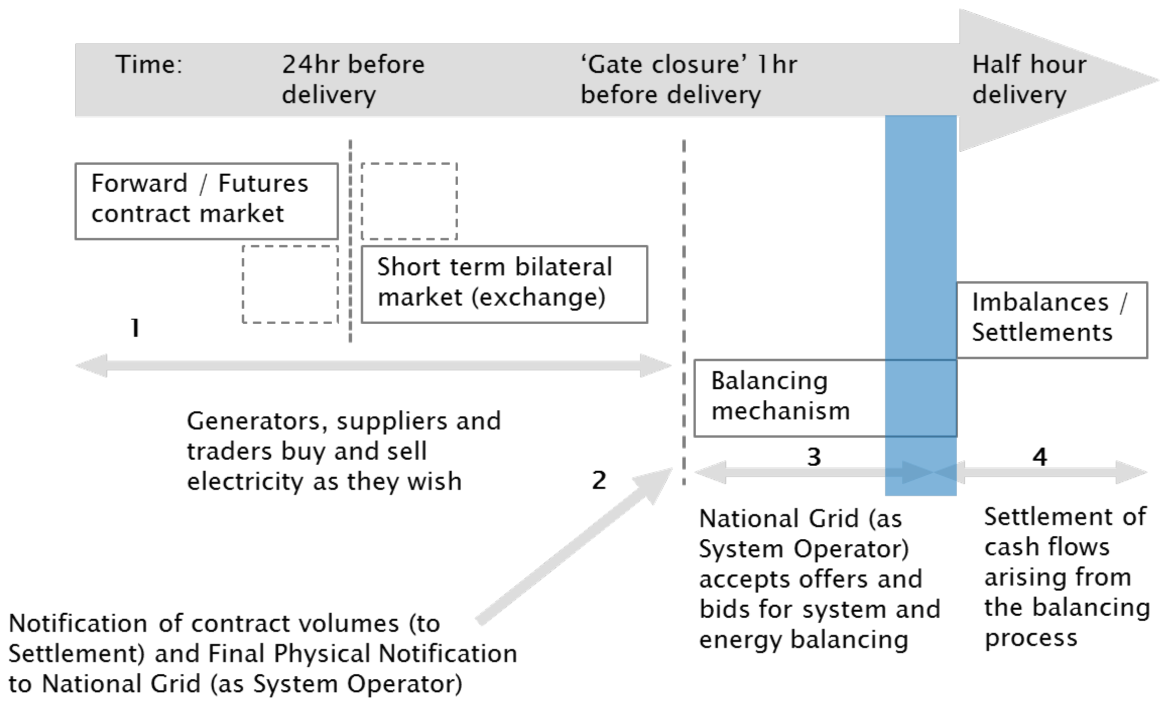
The decarbonisation of the electricity grid is highly dependent on the rate at which carbon intensive sources are substituted by renewables and clean energy technologies. The UK electricity grid is currently made up of a mix of carbon intensive fuels, nuclear and renewable energy. The challenge for the future is to increase the penetration of renewable and clean energy sources on the electricity grid.

This Chapter will discuss the current UK electricity market structure, how the demand and supply of the energy sector is achieved and discuss the layout of the transmission and distribution network that transmits this power from the generator to the end-user. Future projections of the expected increase in electricity demand and how this will be supplied is also discussed in this Chapter.

2.2.1 Electricity market in the UK

UK electricity is currently governed by the British Electricity Trading and Transmission Arrangements (BETTA). These were introduced on 1 April 2005 and replace the previous codes and licences in England, Wales and Scotland, as well as the British Grid System Agreement (BGSA). Under BETTA, arrangements are based on bilateral trading between generators, suppliers, traders and customers across a series of markets operating on a rolling half-hourly basis (National Grid, 2011a). An overview of the market structure can be seen in Figure 2-2. Changes introduced by BETTA to the market structure include three stages to the wholesale market and a post-event settlement procedure.

Figure 2-2: Overview of BETTA market structure (National Grid, 2011a)



This new arrangement means that generators of electricity self-despatch their plant to the System Operator, rather than the inverse. Generators are required to take part in Settlements, but can opt as to whether they will partake in the Forward / Futures Contract Market, Short-term Bilateral Markets and Balancing Mechanism. All generators have to inform the System Operator of their intended physical position by 'Gate closure' one hour prior to real time delivery. After this point, no further contracts can be made and generators have a legal obligation to deliver their stated plant availability.

2.2.1.1 Forwards and Futures Contract Market

The Forwards and Futures Contract Market allows generators and suppliers to enter in to contracts to deliver or take delivery of a given quantity of electricity at a certain point in time at a fixed price. These are usually carried out a year or more ahead of real time, and no shorter than 24 hours before delivery. This constitutes the majority of traded volumes of electricity in the UK. The exact quantity varies from year to year, however in 2011 this market accounted for 70% of the baseload, circa 10% of the off-peak load and 40% of the peak load (ofgem, 2011).

2.2.1.2 Short-term Bilateral Markets

This market operates in a similar way to the Forwards and Futures Market; however, the trading is mainly concentrated in the last 24 hours before delivery. Also referred to as Power Exchanges, participants are able to trade in standardised blocks of electricity, usually units of MWh over a specified period. This enables the fine-tuning of the rolling half-hour trade contract position as forecasts become more accurate.

2.2.1.3 Balancing Mechanism

The period from ‘Gate closure’ to real time is managed by National Grid in its role as the National Electricity Transmission System Operator (NETSO). Their role is to ensure that demand is met by supply in real time. Offers and bids can be made to National Grid on a 'pay as bid' basis to resolve any shortfalls. In this instance, ‘offers’ are proposed to increase generation or decrease demand, whereas ‘bids’ are trades to lower generation or increase demand. This process is run within operational standards and limits. Care is taken to ensure that the transmission system is operated in an efficient, economic and coordinated way. In order to facilitate this, all participants have to inform the System Operator of their planned physical flows of electricity onto and off the grid. The final notification required before 'Gate closure’ is called Final Physical Notifications (FPNs).

2.2.1.4 Imbalances and Settlements

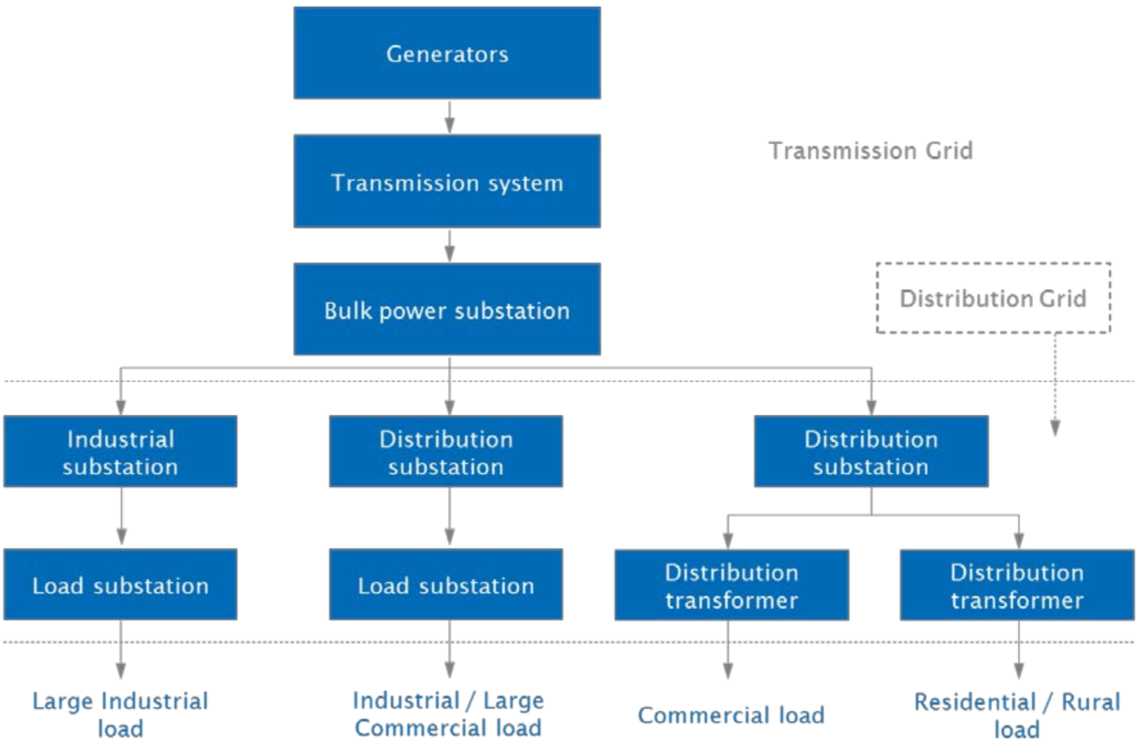
The power flows are measured in real time to record the actual generated and consumed electricity at each location. This determines any imbalances between participants’ contractual position at ‘Gate closure’ and the recorded physical flow. Imbalance volumes are then settled at a System Buy Price (SBP) or System Sell Price (SSP). This dual tariff is in place to give an incentive to participants to try and balance their contractual energy position as accurately as possible.

2.2.2 UK transmission and distribution network

The electricity grid is a national infrastructure that enables the flow of electricity from generation to source. The grid is made up of 25,000 kilometres of high voltage (HV) overhead lines (transmission) and 800,000 kilometres of overhead and underground cables (distribution). The transmission network operates at 275kV and above (132kV in Scotland and offshore wind) and transmits energy from the generator at HV over long distances. The distribution network then distributes lower voltage energy regionally to the end user normally at 11kV, 33kV, 66kV and 132kV (except for offshore wind and Scotland). Figure 2-3 illustrates the differences between the two networks on the grid. The distribution network requires substations in order to reduce the voltage from the transmission network (EMFs.info, 2012). The first stage (HV substation) transforms the 400kV and 275kV lines to 132kV. The second stage (medium voltage (MV) substation) transforms the 132kV lines to 33kV and 11kV. The final stage (low voltage (LV) substation) typically transforms the 11kV lines to 230V to be used by the end-user. However, some end-users such as industry and commerce require higher voltage.

For a detailed map of the UK transmission network, see Appendix A – UK Electricity Supply Map 2012 (DECC, 2012f). This shows the HV network alongside the major power stations and substations in the UK as of 2012.

Figure 2-3: Block diagram of a conceptual electrical power system, distinguishing between transmission and distribution grids



Electricity generators tend to connect on to the transmission network, but can also connect to the distribution grid. In England and Wales, National Grid owns the transmission network, whereas Scottish Power Transmission and Scottish Hydro Electric Transmission Limited share ownership of the transmission grid in Scotland (DECC, 2012b). The grid in Northern Ireland is owned by Northern Ireland Electricity. It is the responsibility of these groups to build and maintain their respective networks to a safe and efficient standard.

The distribution network is divided into fourteen licensed distribution network operators (DNOs) which are each responsible for a distribution service area. These DNOs are currently owned by six separate groups.

As well as the UK electricity grid, there are four existing interconnectors that link the UK network with the transmission network of France, Northern Ireland and the Netherlands:

- The England-France Interconnector (IFA) is the largest interconnector with a capacity of 2,000MW. It is a high voltage direct current (HVDC) link that is connected to the transmission network and was commissioned in 2001;
- The BritNed Interconnector, commissioned in 2011, has a HVDC capacity of 1,000MW and connects to the Netherlands;
- The Moyle interconnector has been operational since 2002 and connects England with Northern Ireland. It has a capacity of 450MW export and 80MW import; and
- A 500MW interconnector linking to the Republic of Ireland, known as the East West interconnector, commissioned in 2012.

All of these links allow for two way flows of energy and facilitate competition in the EU wholesale electricity market (National Grid, 2012c). There are a number of other interconnectors which are at various stages of planning which could add another 2.7GW of interconnections with Norway and Belgium. Interconnectors also have the added future benefit of managing fluctuations in supply from RES, ensuring that there is a secure supply of energy at all times.

As stated, the interconnectors are HVDC circuits. This is a result of the benefits that this technology has over the existing AC network: HVDC impose no limits to the transmission distances that need to be covered and the required right of way, that is the physical footprint needed, is much smaller than HVAC for the same transmitted power (Battaglini et al., 2009). Added benefits to HVDC technology over HVAC are the lower investment costs for long distance projects and lower losses. However, the terminal stations are expensive due to the requirement for conversion from AC to DC and vice versa, but this is balanced against lower transmission costs and operation and maintenance costs as well as lower losses (Larruskain et al., 2005). National Grid (NG), the transmission system operator (TSO) for the UK, owns and operates the transmission network as detailed in Appendix A. To enable a better understanding of the demand requirements within this network, NG has divided the network into 17 boundaries. These boundaries confine areas or zones within the grid that are considered as blocks that have supply and demand requirements. Figure 2-4 illustrates the existing boundaries and zones within the UK network as defined by National Grid. The relationship between the boundaries and zones can be appreciated in Table 2-3.

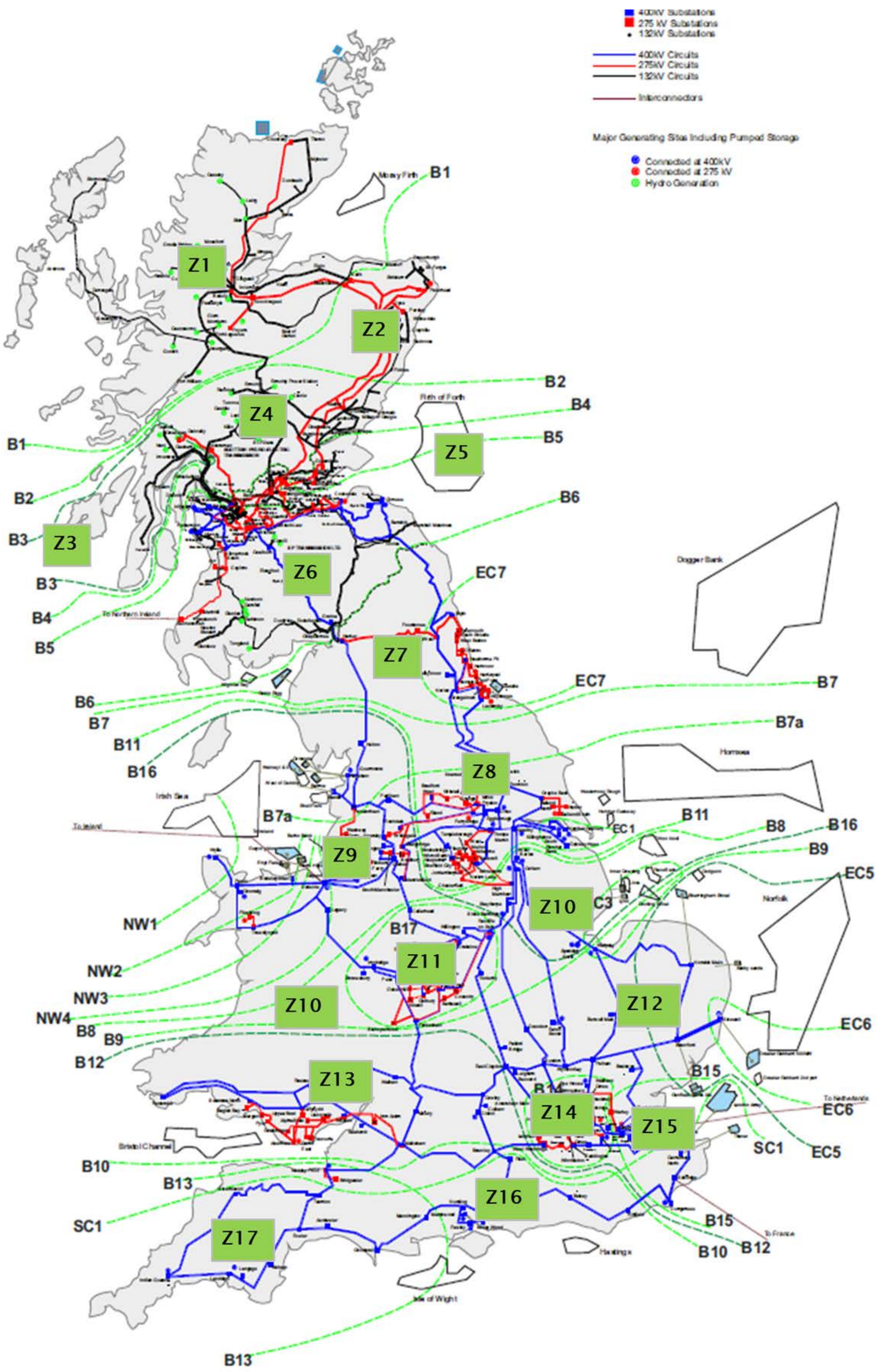
It is important to note that these zones can change over time as they are defined by the particular generation mix and location of electricity generation. In a fully renewable electricity grid scenario, it is to be expected that these boundaries and zones would differ from what is currently the case. However, it is assumed that this remains unchanged in the present study in order to understand the challenges the grid would face in a fully renewable future.

Table 2-3: GB Transmission System Boundaries (National Grid, 2013a)

GB Transmission System Boundaries	
Boundary number	Zone number
B1	Z1
B2	Z1, Z2
B3	Z3
B4	Z1, Z2, Z3, Z4
B5	Z1, Z2, Z3, Z4, Z5
B6	Z1, Z2, Z3, Z4, Z5, Z6
B7	Z1, Z2, Z3, Z4, Z5, Z6, Z7
B8	Z1, Z2, Z3, Z4, Z5, Z6, Z7, Z8, Z9
B9	Z1, Z2, Z3, Z4, Z5, Z6, Z7, Z8, Z9, Z10, Z11
B10	Z16, Z17
B11	Z1, Z2, Z3, Z4, Z5, Z6, Z7, Z8
B12	Z13, Z16, Z17
B13	Z17
B14	Z14
B15	Z15
B16	Z1, Z2, Z3, Z4, Z5, Z6, Z7, Z8, Z10
B17	Z11

Each zone has a number of electricity generators within it. Not all generation supplied in each zone is consumed in that zone; therefore there is transmission of that generation to other zones towards where the demand is. This produces power flows between the zones around the network. In some cases, there are extreme pressures on the existing grid, known as bottlenecks, where there is an excess of generation in a zone that needs to be transmitted to the rest of the network but is constrained by the transmission capacity. This can be principally seen between Scotland and England where there is a high level of renewable generation in the form of hydro and wind and not much demand. As a general rule, the main demand in the UK is from the South and city centres. Appendix B – UK Power Flow Diagram 2012/13 (National Grid, 2013b) illustrates the expected electricity flows around the network for 2012. This diagram also shows the proposed offshore wind farms that will need to connect in the near future, creating more constraints on the network.

Figure 2-4: UK Transmission System Boundaries (National Grid, 2013b)



It is clear that the UK electricity grid will need to be strengthened in the coming years in order to meet the delivery targets. In order to reduce the risk of planning permissions delays it has been proposed that planning applications are taken forward by the grid operators without commitment from generators. Careful strategic planning can highlight areas where savings in network upgrades can be made. However, these upgrades will need to be weighed against employing different market structures such as distributed generation, demand-side management and energy storage

2.2.3 UK Electricity Demand

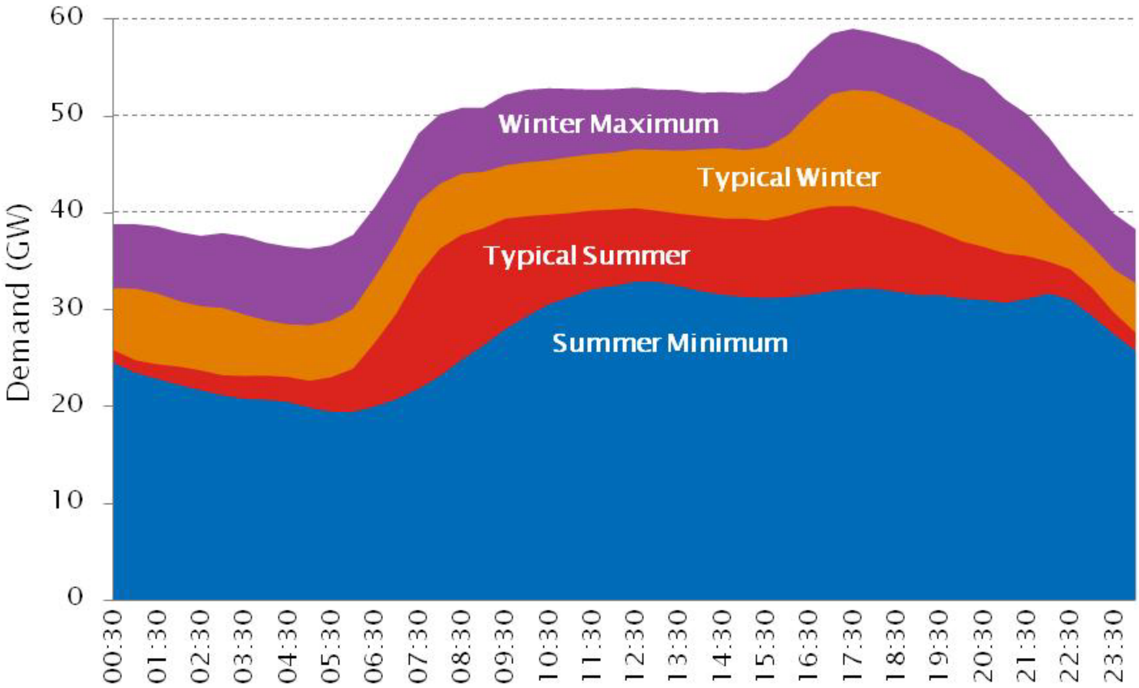
The energy market in the UK has to ensure that demand is met. As has been discussed previously, electricity is offered to the System Operator by the generator, who in turn ensures that there is enough to supply the real time demand. This demand however, is not constant which makes forecasting difficult. The UK electricity demand varies throughout the day, although there is a certain level of understanding as to how it will vary. Figure 2-5 illustrates some typical daily demand profiles that occurred over the 2010-11 period. Maximum demand occurrences take place mainly during a winter week day, where low ambient temperatures and early evenings create an increase of demand for electricity on top of working day loads. On the other hand, extreme lows primarily occur on summer weekends where there is no demand for heating, there are longer evenings and minimal load from industry. The typical daily load profile has a few key occurrences (National Grid, 2011a):

- 00:00 – 05:00 hours: demand is mostly from time-switched storage heating and water heating equipment;
- 06:00 - 08:30 hours: morning load and build up to the working day;
- 09:00 – 16:00 hours: primary demand from commercial and industrial sectors, and
- 16:30 – 17:30: peak in daily demand mainly attributed to demand from artificial lighting and rise in domestic demand.

There are also external events that increase the load on the electricity grid which can be forecasted to a certain extent, for example the final of the World Cup or the final of the men’s 100 metre sprint at the London 2012 Olympics.

As well as the variations that occur within a 24 hour period, there are seasonal variations throughout the year. Figure 2-5 also illustrates these variations between typical winter and summer demand. This variability needs to be monitored carefully to ensure demand is met at all times.

Figure 2-5: Average UK summer and winter daily demand profiles in 2010-11 (National Grid, 2011a)



With some exceptions, once electricity is produced it needs to be transmitted to the end user to be consumed. In order for the electricity grid to function, the System Operator needs to maintain the grid voltage at a fixed frequency of 50Hz (EC, 2003a). The movement of power on and off the grid affects this frequency, for example a generator coming online and transmitting electricity to the grid. To ensure that there is no overload of the grid which could lead to power disruptions; this frequency has to be maintained within +/-0.5Hz (National Grid, 2012a). This is achieved by ensuring that the instantaneous generation of electricity matches the system demand.

2.2.4 UK Electricity Supply

As has been discussed earlier, the demand for electricity in the UK is variable by nature. There is also a varied generation base that supplies this demand, made up of a mix of different technologies using different energy sources and fuels. In total, the UK had an installed electricity generation capacity of 89.1GW in 2011 (DECC, 2012f). The main contributors to this capacity were coal and gas with 39% and 36% respectively of the total share. Table 2-4 shows the breakdown of the full UK installed capacity for 2011.

Table 2-4: UK plant capacity in 2011 (DECC, 2012c)

Source	Installed capacity – 2011 (GW)	Share
Coal	34.7	39%
Gas	32.1	36%
Nuclear	10.7	12%
Oil & OCGT	1.5	2%
Pumped Storage	2.7	3%
Hydro	1.5	2%
Wind	2.7	3%
Other Renewables	3.1	3%
TOTAL	**89.1**	**100%**

Not all generation plant operate under the same conditions; in order to achieve the best efficiencies some plant like nuclear are best suited for baseload generation (e.g. constant output), whereas plant such as pumped storage (PS) and open cycle gas turbines (OCGT) can be operated with a variable load (e.g. to provide power during peak demand events). For these reasons, the contribution that each plant type has on the daily electricity demand is decided by response time and availability. Figure 2-6 and Figure 2-7 illustrate this behaviour throughout the daily demand in a typical winter day and typical summer day.

Figure 2-6: Supply of a UK winter demand profile, 2010 (National Grid, 2012a)

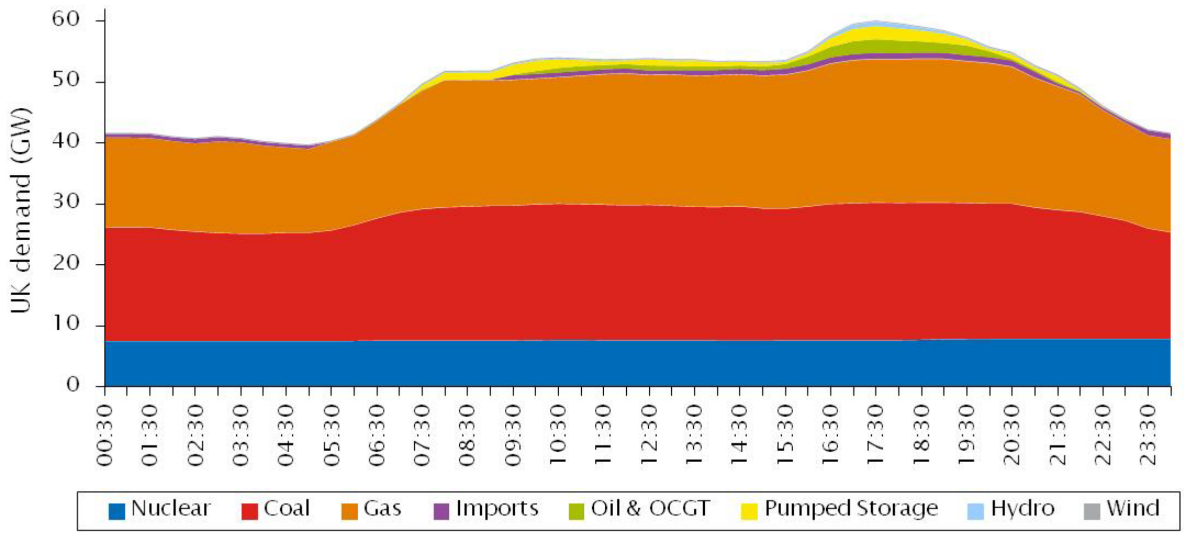
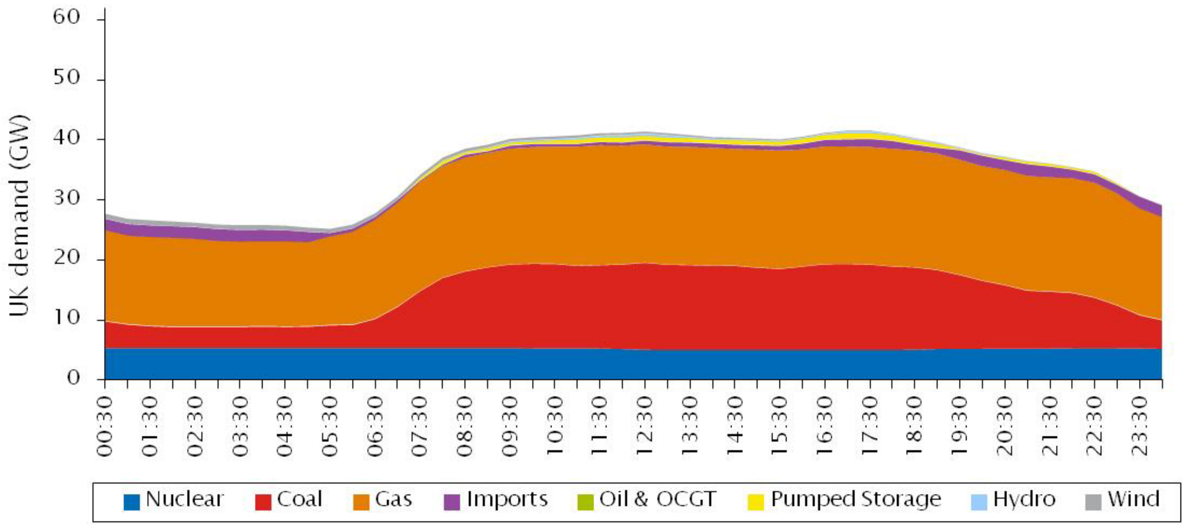


Figure 2-7: Supply of a UK summer demand profile, 2010 (National Grid, 2012a)

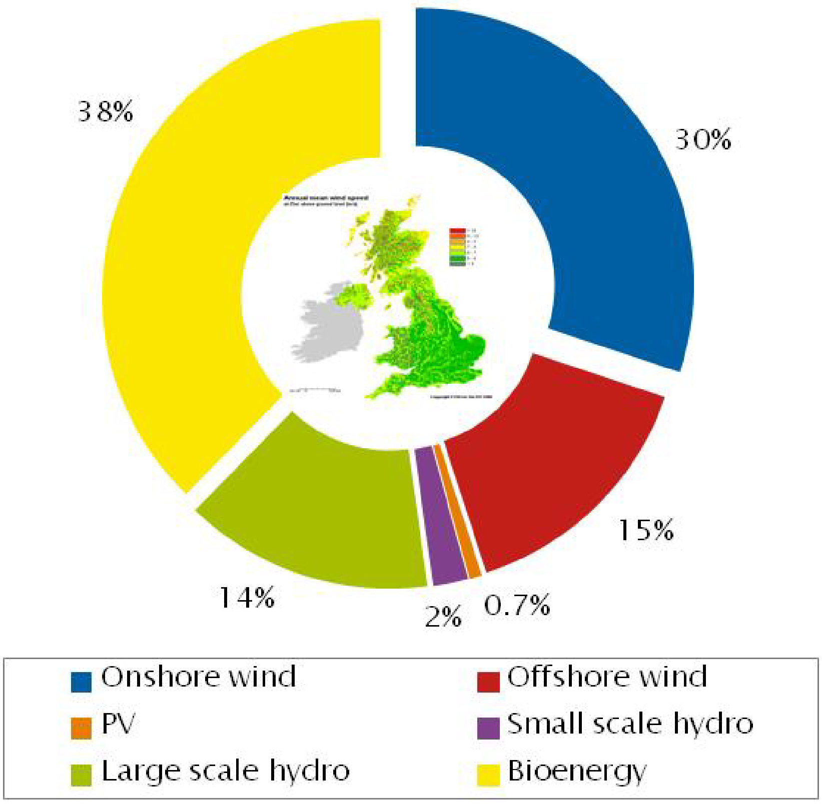


Electricity generation in the UK totalled 364,897GWh in 2011 (DECC, 2012k). A total of 34,410GWh, or 9%, of that electricity was generated from renewable energy sources (RES), a 33% increase on 2010.

The main contributor was bioenergy with a 38% share of the generation. Bioenergy is defined as energy derived from landfill gas, sewage sludge digestion, solid waste combustion, animal biomass, anaerobic digestion and plant biomass. The second largest generator is wind, with onshore wind contributing 30%, a 45% increase on 2010, and offshore contributing 15%, also a 68% increase on the previous year. An increase in installation of wind farms and higher average winds speeds contributed to this. The remainder of generation was made up of hydro and solar photovoltaics (PV), 16% and 1% respectively (Figure 2-8).

Even though the contribution from PV was relatively minor, there was nearly a seven-fold increase in generation from 33GWh in 2010 to 252GWh in 2011. This can be attributed to PV being included in the Feed-in Tariff (Strbac et al.) scheme, a support mechanism for renewable technologies up to a capacity of 5MW (Feed-In Tariffs, 2012). The scheme requires the System Operator to make payments to the generator depending on the generated electricity and financially support the export of excess electricity to the grid.

Figure 2-8: Mix of renewable sources in the UK, 2011 (DECC, 2012d)



There has been a clear increasing trend in generation from RES over the last few years. In order to meet the UK commitments to reduce GHG by 80% by 2050, renewables will need to provide a substantial portion of the electricity generation. The only conventional alternatives are nuclear power or fossil fuels plants with carbon sequestration. However, as has been discussed, this Thesis considers these to be unviable.

2.2.5 Planned UK Future Generation and Transmission

The UK transmission network operator, National Grid, regularly review the network capacity and assesses the generation plant in view of changes in demand needs. In these assessments there is also a future projections chapter which will be discussed below.

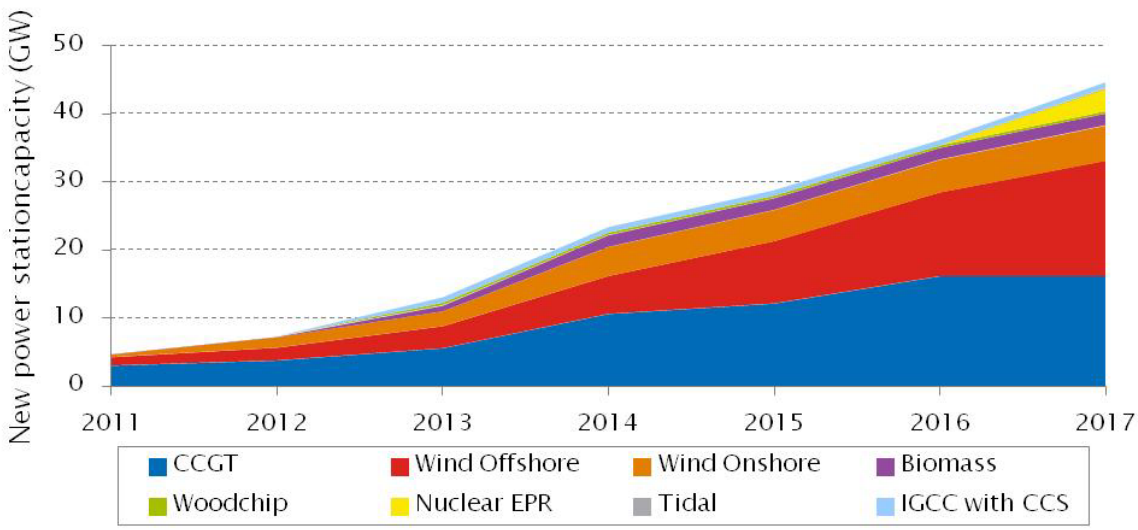
In addition to this, the UK Government has a National Infrastructure Plan (NIP), which oultines the pipeline spend on major infrastructure such as transport, flood alleviation, communications, waste and energy. This is underpinned by a public and private investment of GBP 460 billion, of which an estimated GB 275 billion is for energy projects (HM Treasury, 2014). Since 2010, investment from the NIP has led to nearly 20GW of new electricity generation in the UK. The pipeline of new investment aims to support interconnectors, new nuclear power plant and the Swansea Tidal Lagoon project.

2.2.5.1 Pipeline of new generation capacity

Looking forward, it is clear that electricity demand will increase in the future through the increase of demand from transportation and heating, but also from the increase in domestic entertainment equipment as discussed in Chapter 2.2.3. Energy efficiency measures will also play a large role in the future grid demand. In 2010, up to 24% of electricity generation was lost through the transformation of primary energy to electricity and the transmission and distribution network (DECC, 2012h). These losses are usually in the form of heat due to the physics of transporting electricity through cables, but also from the efficiency losses in converting fuel into electricity. These losses on the distribution and transmission networks are accounted for through the use of Line Loss Factors (LLFs) and Transmission Loss Multipliers (TLMs) respectively (ELEXON, 2013b).

Nevertheless, there will be a requirement to install new grid capacity to replace existing generation plant that are coming to the end of their generating life as well as increasing capacity from RES. A review of existing plant has concluded that 13.45GW of existing generation capacity will be offline by 2016 (National Grid, 2011a). On top of this, the UK is required to meet the EU target of generating 15% of its electricity from RES by 2020. The National Grid Seven Year Statement report reflects this: the only new conventional contracted generation plant is from natural gas combined cycle gas turbines (CCGT), whereas the remainder is to come from renewable or clean energy sources (Figure 2-9). There will still be a large legacy of conventional thermal power stations during this time; however, the main objective will be to phase these out in favour of carbon sequestered fossil fuels, nuclear and renewable generation.

Figure 2-9: New contracted power station generation capacity 2011-2017 (National Grid, 2011a)



The long term aim of the grid is to provide the end-user with a secure, clean and efficient source of electricity. If these projections are met, the carbon intensity of the electricity grid could fall from around 560gCO_2/kWh in 2011 to around 310gCO_2/kWh by 2020 (CCC, 2008). This will set the UK on track to meeting its 80% GHG emissions reduction by 2050 of 155MtCO_2e per annum and meeting the target of a grid carbon intensity of 50gCO_2/kWh of electricity generated.

2.2.5.2 New transmission requirements

A challenge for the UK transmission network is to identify solutions which enable the increase in generation from renewable energy sources. The majority of electricity flow on the UK transmission network is from North to South. The majority of the demand in North Scotland is met by a number of hydro plants, wind farms and conventional power stations. However, the predominance in the region is to export power towards central Scotland which in turn puts pressure on the 275kV network there (Donnelley, 2009). The links between Scotland and England are operating at maximum capacity and the forecasted increase in development of renewable sources in Scotland will only put more strain on these. There is also expected to be an increase in the development of offshore and onshore wind farms throughout England and Wales which will in turn put pressure on the network in the South.

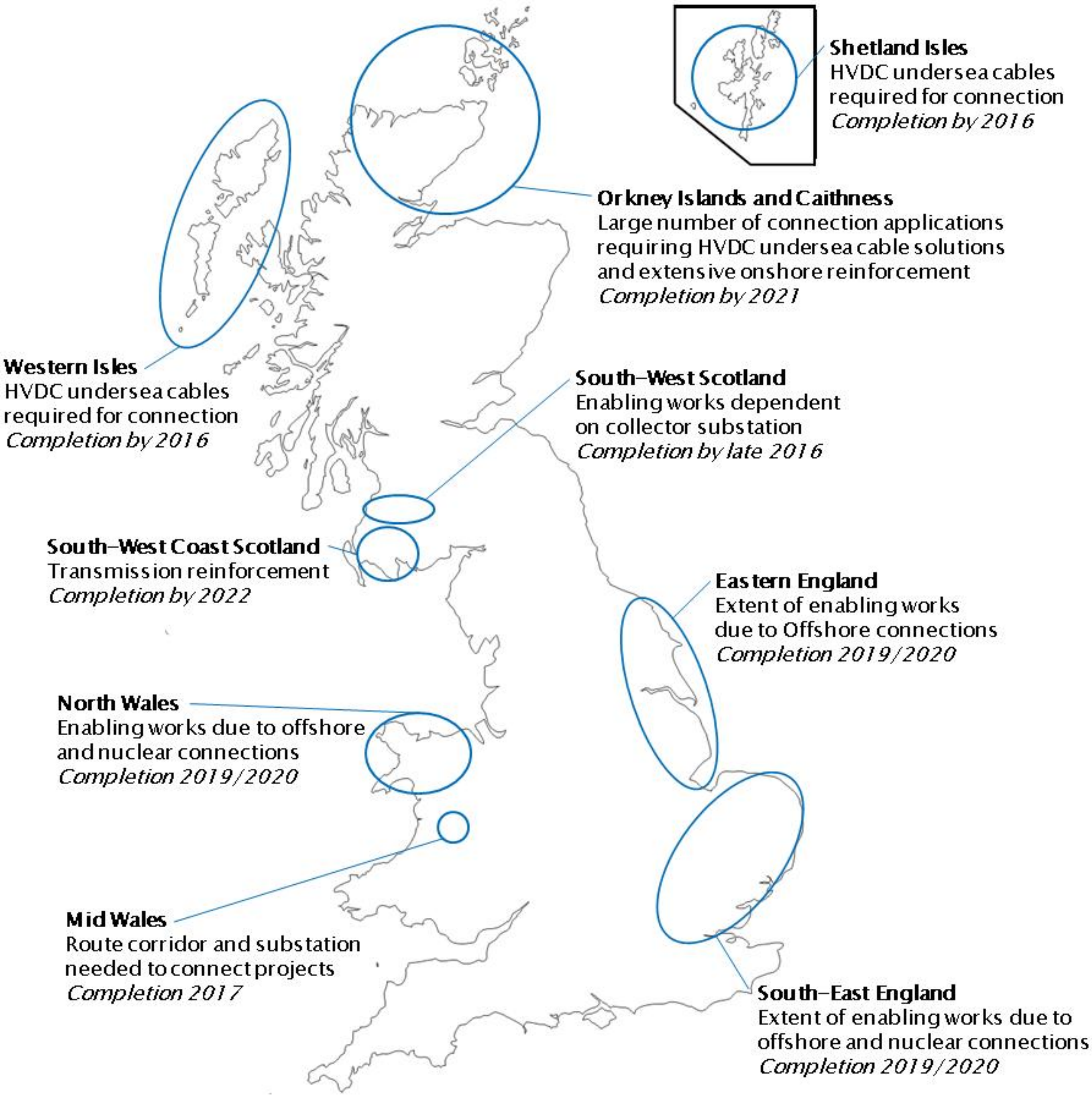
To get a scale of the improvements that the UK transmission network needs to undertake, in 2009, it was estimated that to accommodate an extra 45GW of generation capacity the total cost of reinforcements would come to £4.7 billion (ENSG, 2009). As of 2012, a total of nearly 90GW of grid capacity is contracted to connect to the UK network by 2025 (National Grid, 2012d). This is split in to six different regions and over 158 separate projects. Table 2-5 has a breakdown of this new transmission capacity.

Table 2-5: Share of new connection projects and contracted capacity (National Grid, 2012b)

Region	N° of projects	MW
Northern Scotland	59	9,608
Southern Scotland	41	8,239
Northern England	15	17,845
Central England and North Wales	13	15,008
South-West England and South Wales	11	12,623
South-East England	19	26,657
TOTALS	158	89,980

Some of the key areas that have been highlighted as being constraint points on the UK transmission network are illustrated in Figure 2-10. It can be seen that the majority of these difficulties are due to the increase in capacity from offshore wind farms, as well as potential new nuclear capacity. In Northern Scotland, there are also a number of new connections required between the Isles and the mainland.

Figure 2-10: Illustrative connection timescales and areas of local difficulty (Adapted from: (NationalGrid, 2013b); Image source:(d-maps.com, 2007))



2.3 Renewable Energy Sources

As has been discussed in Chapter 2.2.4, renewable energy sources (RES) in the UK supplied 9% of electricity demand in 2011 (DECC, 2012k). RES have been identified as one of the key technology groups that will lead to the de-carbonisation of the UK electricity sector and in doing so, reduce UK greenhouse gas (GHG) emissions in order to meet the 2008 Climate Change Act target: an 80% reduction in GHG emissions on 1990 levels by 2050 (DECC, 2008).

This Chapter will define what RES are and describe the main technologies capable of generating electricity from renewable sources. The benefits of using RES as well as the effect that variability of supply has on the existing electricity network will be examined. The proposed forecasts of future RES capacity in the UK will also be discussed.

2.3.1 Definition

All forms of renewable energy derive directly or indirectly from the Sun, even the fossil fuels that are used daily are derived from this source. The Earth receives about 175 petawatts of solar irradiation at the upper atmosphere every day (Angelis-Dimakis et al., 2011). This is over four orders of magnitude above global daily energy consumption. This energy is converted into different forms due to the atmosphere and the dynamics of the Earth itself: differential heating of the air temperature creates wind, the evaporation of water forms clouds which replenish storage reservoirs of hydroelectric dams when they rain, and the biological processes that happen within plants rely on Solar energy. There is also energy within the Earth's core itself and the gravitational pull of the Moon on the Earth create tides and, when combined with the wind, waves. Including the direct energy from the Sun, all of these sources can be converted into electricity through mechanical or chemical process.

There are various definitions for renewable energy. The Dictionary of Energy defines renewable energy as "any energy source that is naturally regenerated over a short time scale and either derived directly from solar energy (solar thermal, photochemical, and photoelectric), indirectly from the sun (wind, hydropower, and photosynthetic energy stored in biomass), or from other natural energy flows (geothermal, tidal, wave, and current energy)" (Elsevier, 2006). On the other hand, the European Commission (EC) simply designates RES as "renewable non-fossil energy sources (wind, solar, geothermal, wave, tidal, hydropower and biomass, landfill gas, sewage treatment plant gas and biogases)" (EUR-Lex, 2001). A caveat that needs to be added to these definitions is that it is possible that some renewable sources like geothermal or bioenergy may be exhausted through overuse (Verbruggen et al., 2010).

Unlike conventional stores of fossil fuels, renewable energy sources are characterised by being spatially distributed (Angelis-Dimakis et al., 2011), with the exception of run of river hydro where the 'source' is stored in a reservoir and replenished by rainfall. This distribution makes exploiting these resources more complex. Wind and solar resources are also termed as being non-dispatchable since generation cannot be provided on demand. Sources of dispatchable generation, or predictable generation, include conventional thermal power plants, hydro, bioenergy, geothermal and tidal stream plant.

As with conventional generation, RES cannot convert all the potentially available energy into electricity. Therefore there are three distinguished values:

1. **Potential/kinetic energy** - The amount of energy available to be converted to electricity, for example total energy from a given wind speed at a wind farm;
2. **Theoretical energy** - The fraction of that energy that can be converted by the technology taking in to account technical constraints, efficiencies, location, etc.; and,
3. **Exploitable energy** - The final amount of energy that can be exploited taking in to account the economic, environmental and logistical issues.

Other important factors to take in to account are the respective metrics used for characterising the quantity and capacity of each energy source (Verbruggen et al., 2010). Since the conversion from source to usable electricity differs between source, its respective technology and the intended end use, these factors need to be taken in to account to enable the assessment of the benefits and disadvantages of each RES.

2.3.2 Benefits

RES are essential to the de-carbonisation of the energy supply sector. There are also a number of additional benefits that can be achieved by exploiting the available natural renewable resources (Johansson et al., 1993). These are now defined.

Social and economic development: The increase in generation from renewable sources will need new technologies which in turn will create employment from manufacturing and installation. This may however replace existing jobs in the sector. Biomass will also help provide economic development in rural areas which would reduce the flux of urban migration. Cheap renewable energy can also provide electricity to communities that previously could not, due to their isolation or poverty, increase their living standards.

Land restoration: Biomass for use in energy can be grown on de-forested or over-cultivated lands in order to restore these lands. This would help support a better ecosystem for wildlife and help prevent excessive erosion.

Reduced air pollution: By offsetting the need for conventional thermal generation, there will be a reduction in the pollutants that are emitted from the generation of electricity. The use of fuels such as methanol or hydrogen for transportation will also reduce emissions associated with urban air pollution and acid deposition.

Fuel supply diversity: Increasing the generation from RES will increase the variation in energy sources and reduce the current dependence on fossil fuels, relieving international conflict. It is also expected that interregional energy trade in a renewables-intensive energy future will help alleviate issues of low resource availability. This diversity of supply will lead away from a single energy monopoly and reduce the incidence of supply disruptions.

2.3.3 Technologies

The various technologies that convert renewable energy sources into electricity for consumption are described below. One of the defining characteristics of an electrical generation plant is the load factor. This is the capacity rating of the generation plant minus the power consumed by the plant itself, and reduced by a specified factor that takes in to account any downtime (planned or unplanned). This represents the nominal maximum capability of a plant to generate electricity and is presented as a percentage. For RES, other factors such as resource availability come in to play due to the variability of supply. For the purpose of this report, the yearly load factor of a generation plant is calculated in terms of the installed capacity and is expressed as the average hourly quantity of electricity generated as a percentage of the average of the capacities at the beginning and end of the year (RenewableUK, 2010a). Equation 2-1 provides the calculation method to achieve the load factor of a specific generator (DECC, 2011a).

Equation 2-1: Load factor calculation (DECC, 2011a)

$$\frac{Yearly\ electricity\ generation\ (kWh)}{\big(Installed\ capacity\ at\ year\ start\ (kW) + Installed\ capacity\ at\ year\ end\ (kW)\big) \times 0.5 \times 8{,}760\ (hours)}$$

Table 2-6 provides average load factor values for different energy generation technologies, both conventional thermal generation and renewable, based on plant usage in the UK in 2011 (DECC, 2012c). It is important to note that these factors are affected by resource availability, demand and maintenance requirements amongst others, on a yearly basis. As an example, to replace an equivalent 10GW of coal capacity (which has a load factor of 41%) with onshore wind would require an installed capacity of 15.2GW. This is because onshore wind has a load factor of 27%.

Table 2-6: Average load factors by energy technology (DECC, 2012d)

Energy Technology	Average Plant Load Factor
Open Cycle Gas Turbine (OCGT)	35%
Combined Cycle Gas Turbine (CCGT)	48%
Coal	41%
Nuclear	66%
Onshore wind	27%
Offshore wind	37%
Hydro	39%
Bioenergy	43%
Solar	5.5%

Another factor that affects the generation output of RES is the variability of supply that exists due to the nature of these sources. Unlike conventional thermal plants that are supplied by fossil fuels or nuclear power, natural resources cannot generally be stored and supplied on demand. Exceptions to this rule are hydro, as water is stored in a reservoir and can be dispatched to generate electricity on demand, geothermal, as there is a constant source of heat available, and bioenergy, so long as there is enough feedstock available.

Large scale integration of variable RES onto the grid introduces added complexity to the task of balancing supply and demand. As has been discussed previously, the electricity grid needs to be maintained at a frequency of 50Hz to avoid blackouts and potential costly damage to generation plant. The existing generation mix has built in flexibility, the ability to run at part load in order to provide an increase or decrease in output (Gross et al., 2007). Substituting this conventional generation plant with generation from RES increases the risk of imbalances on the electricity network. To avoid this, there needs to be a robust system in place that ensures there is enough spare generation capacity or storage for excess generation. These systems will be explored in the next Chapters.

2.3.3.1 Wind energy

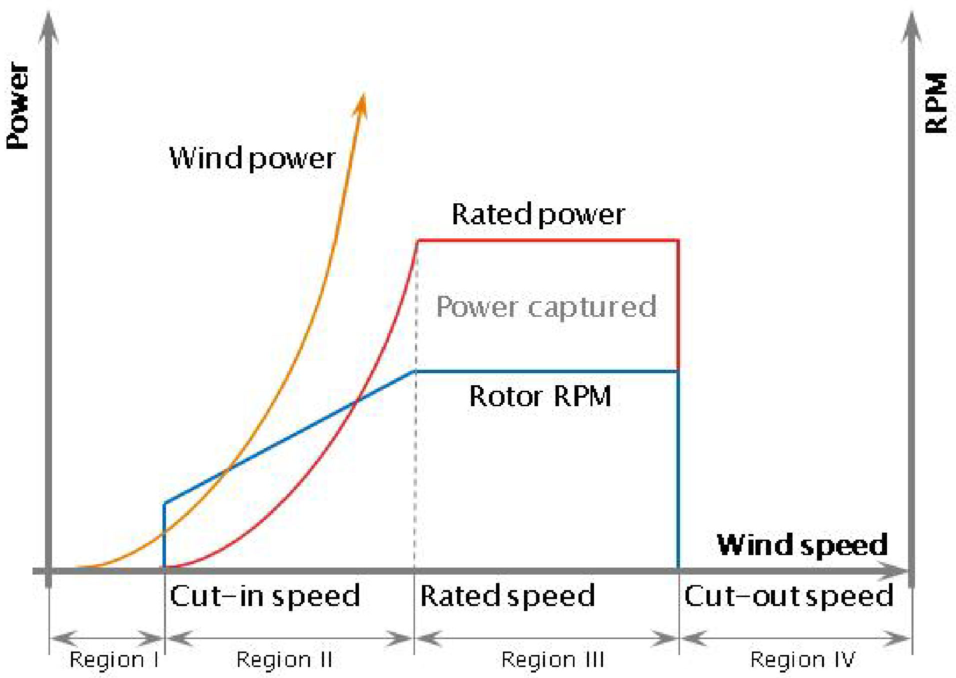
Wind energy is the conglomeration of uneven heating of the Earth's surface, pressure changes and gravitational forces. It is also affected by the inertia of air and ground friction as it passes over varying terrain (Boehme et al., 2006). In order to convert the winds kinetic energy into mechanical energy, wind turbines (WT) are necessary. Wind turbines use the power of the wind to drive a generator that in turn converts the mechanical energy into electricity (RenewableUK, 2010b). Because wind energy is widely distributed, turbines can be located onshore and offshore, each with their respective benefits and disadvantages.

Onshore wind turbines: one of the oldest used renewable energy technologies. Typically these turbines have power ratings up to 3MW and rotor diameters in the 80–100m range. Sizing of onshore WT are currently constrained by the logistics of transportation and installation and they also face considerable opposition from members of the public.

Offshore wind turbines: until recently installations have used standard onshore turbines that are adapted to cope in the marine environment. However, in this case, capacity output of offshore turbines is typically between 5–10MW. Maintenance and operating costs are higher due to access issues, and installation costs need to take into account complex foundations and underwater power collection and transmission systems. The typical arrangement of a WT consists of three rotor blades that rotate around a horizontal hub on top of a tower ('horizontal axis' machine). The blades are connected to a gearbox and generator which are located in the nacelle. The yaw mechanism ensures the wind turbine is facing the direction of the wind with the use of sensors located on top of the nacelle. The capacity of the turbine depends on the diameter of the rotor blades: the larger the swept area, the larger the output.

The output of a WT is defined by its power curve as shown in Figure 2-11 (Department of Energy, 2008). Most turbines have a minimal operating wind speed of 4–5m/s (cut-in speed). Power generation starts in Region II and increases with wind speed until rated speed is reached. This is the point at which the WT will produce its designated rated power (Region III), nominally around 15m/s. Rated power is maintained by employing passive stall control or active blade pitch angle adjustments to ensure the generator and gearbox are not overloaded. At higher wind speeds of 25–30m/s (cut-out speed), the WT will shut down to prevent damage to structural components and limit machine loading. The potential energy produced from the wind is directly proportional to the cube of the wind speed (DECC, 2011a); therefore the 'windiness' of a site is an important factor to consider when locating wind farms.

Figure 2-11: Conceptual power curve for a modern wind turbine (Department of Energy, 2008)



Wind speed is, as stated previously, affected by the roughness or friction of the terrain. For this reason wind speed varies by vertical height, therefore site characteristics are also very important. The output of a wind turbine can be calculated using Equation 2-2 and is given in units of Watts (W).

Equation 2-2: Wind turbine output calculation (Boehme et al., 2006)

$$P = \frac{1}{2} c_p \, \eta \, \rho \, A \, v^3$$

Where c_p is the power coefficient (bounded by the Betz limit 0.593 (DWIA, 2003 #285)), η is the overall efficiency of the wind turbine, ρ is the air density (1.225kg/m^3 at 15˚C), A is the swept area of the blades ($A = \pi \, r^2$ where r is the turbine radius) and v is the wind speed measured in metres per second (m/s).

Onshore wind turbines are either generating or waiting for wind 98% of the time. Repair and maintenance time takes up 2% of the time over an average year. For offshore wind turbines, availability values are around 94% with the corresponding 6% downtime being for repair and maintenance. Losses attributed to the transformers and low voltage interconnections are typically in the region of 2–3%. As wind turbines will generally be grouped into wind farms or parks, the effects of being in the wake of another wind turbine upstream can add up to around 8% losses. This effect is highly dependable on the specific site topography and layout.

Wind resource follows a seasonal pattern, but is generally greater during the winter months in the UK (RenewableUK, 2010b). This coincides with higher electricity demand, making wind power a suitable source of energy for countries like the UK. As well as this seasonal variation, wind speed varies from year to year and it is also influenced by the North Atlantic Oscillation (NAO) (Enloe, 2012). It is generally assumed that taking a 10 year period is representative of the wind profile in the area. The UK has more than 7.5GW of installed onshore capacity as of end of 2013 and a load factor of 28.9% (DECC, 2014d). The offshore wind resource in the UK is the largest in the World and has an installed capacity of 3,696MW at the end of 2013 and a load factor of 38.9% (DECC, 2014d). This is expected to be the focus for new installations as offshore wind is more consistent than onshore and as such will be able to produce more electricity.

The cost of electricity generated from wind is generally driven by capital cost (installation) and performance (energy production, lifetime, operation and management (O&M) costs) over the operating life. The installed costs of onshore wind turbines can be up to 75–80% of the lifetime investment, whereas offshore turbines are roughly 50–100% higher. Economies of scale have been achieved through the installation of large projects by spreading the development costs and the specific supporting infrastructure (e.g. interconnection, O&M facilities). Technological advancements have contributed to lowering the cost of components and increasing the amount of time that wind turbines are available, reducing the overall cost of electricity generated from wind.

2.3.3.1.1 Future wind energy resource

In terms of onshore wind resource, it is estimated that the total amount of practical resource is 58TWh per annum or an installed capacity of just over 19GW (Watson et al., 2002). Even though, the same study estimated that the total accessible onshore resource is close to 110GW of installed capacity, with a calculated yield of 318TWh per annum. This however would never be achievable due to the footprint required to install enough wind turbines in this case.

A study conducted into putting a valuation on the UK's offshore renewable energy resource considered the currently allocated capacity and additional practical resource within the UK's Exclusive Economic Zone. The resources considered were offshore wind, both seabed mounted and floating, tidal stream, tidal range and wave. The study suggests that there is up to 241TWh (Helweg-Larsen, 2010) of practical offshore wind resource, which is seabed mounted. If floating resource were considered, this would add an additional 1,533TWh of yearly resource by 2050. In comparison, the total UK generation in 2013 only amounted to 374TWh (DECC, 2014a). This highlights the amount of energy that can be exploited in the seas that surround the UK. This is the cornerstone of the UK's renewable energy resource and it has an almost limitless boundary. The key issues are around harnessing this energy and getting it to the electricity network.

2.3.3.2 Hydropower

Energy generated from the kinetic energy of a volume of water is the most mature form of exploiting renewable energy. This can be achieved from run of the river installations, which uses the energy in the river flow to create electricity, or by storage, storing water in a reservoir. In the case of a storage plant, the volume of water stored behind the dam structure enables the generator to produce electricity on demand. Therefore this technology has a high degree of dispatchability.

The potential energy of the stored water is converted into kinetic energy as the water is forced through a penstock. This kinetic energy is directed to a turbine which converts it into mechanical energy as the water spins the turbine. The turbine is mechanically connected to a generator which produces the electricity (see Figure 2-12). The electrical capacity of the plant depends on the water flow rate (q), typically measured in cubic meters per second, the hydraulic head (h), which is the measured height between the water level in the reservoir and the water level at the outlet in meters, the water density (ρ), around 1,000kg/m^3, and the acceleration of gravity (g), which is 9.81m/s^2. The theoretical power output can be calculated using Equation 2-3 and is measured in Watts (W).

Equation 2-3: Calculation for the theoretical power output from hydro generation (ToolBox, 2013)

$$P_{th} = \rho \cdot q \cdot g \cdot h$$

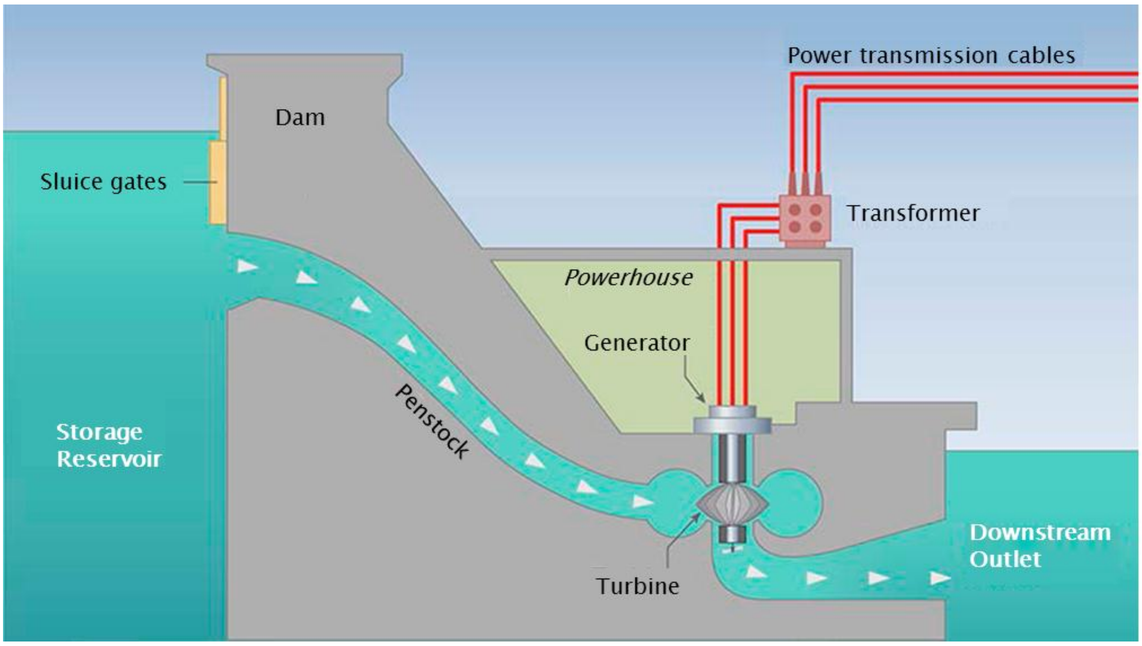
The practicable power output from hydro is constrained by energy losses and therefore is less than the theoretical power output. Typical efficiencies (μ) for a hydro plant are in the range of 0.75–0.95. Thus Equation 2-3 becomes:

Equation 2-4: Calculation for the practicable power output from hydro generation (ToolBox, 2013)

$$P = \rho \cdot q \cdot g \cdot h \cdot \mu$$

Hydro plants vary in size and can be classified by their electrical generation capacity: plants with a capacity greater than 20MW are large-scale hydro, plants generating less than 20MW are small-scale hydro, while plants with a capacity under 100kW are classed as micro-scale hydro (DECC, 2012d). Overall, hydro plants can range from 1kW to over 6GW.

Figure 2-12: Schematic cross-section of a large scale hydroelectric generation plant (Augustine et al., 2012)



The majority of suitable sites for hydro plants in the UK were developed in the 1950s and 1960s and are generally located in the Scottish Highlands. Future exploitation of these resources in the UK is limited by environmental concerns as well as by the lack of economically attractive locations. It has been estimated that there is viable potential for an additional 850–1,550MW of hydro capacity, which would represent an extra 1–2% of UK's current generating capacity (DECC, 2012d).

As of 2011, the UK has a total installed capacity of over 1.5GW (1.453GW from large-scale schemes and 198MW from small-scale installations), around 2% of the total generating capacity (DECC, 2011a), and a load factor of nearly 40%. These values reflect the increase in rainfall during 2011 compared to 2010.

Hydro generation schemes generally have long lifetimes and as such the costs of building and running these plants are usually recovered within their serviceable lifetime. This means that the cost of electricity generated from hydro can be extremely competitive once the installation debts have been settled. The main barriers to the installation of new hydro plants are the high capital costs and the long lead time for the construction of the scheme which involve licensing and approval processes and extensive studies on the environmental impacts of the new installation.

2.3.3.2.1 Future hydro energy resource

The potential for additional hydro resource in the UK is relatively limited since the majority of suitable sites are already developed. ETSU estimates that the total physical resource is around 40TWh per annum or 13GW of installed capacity (Watson et al., 2002). This is arrived at by considering the mean annual rainfall areas, land area and potential elevation in locations. However, it is also noted that the majority of this resource is not practical due to geographical and environmental constraints. In Gardner (2011), it is suggested that a hydro capacity of 4GW can be installed in the future in the UK. On the other hand, it was found that the additional future economically feasible capacity in England and Wales is estimated at up to only 248MW, or around 0.8TWh (DECC and WAG, 2010) and for Scotland up to 657MW, or 2TWh (Forrest et al., 2008).

2.3.3.3 Bioenergy

Bioenergy comprises the production of electricity from biomass; this is any organic material such as plants and waste materials that can be used in one form or another to produce electricity. There are many different streams of biomass that are used as the basis to manufacture other products. These are denominated as feedstocks and can be roughly divided into agricultural and energy crops and waste and opportunity fuels (Byrnett et al., 2009).

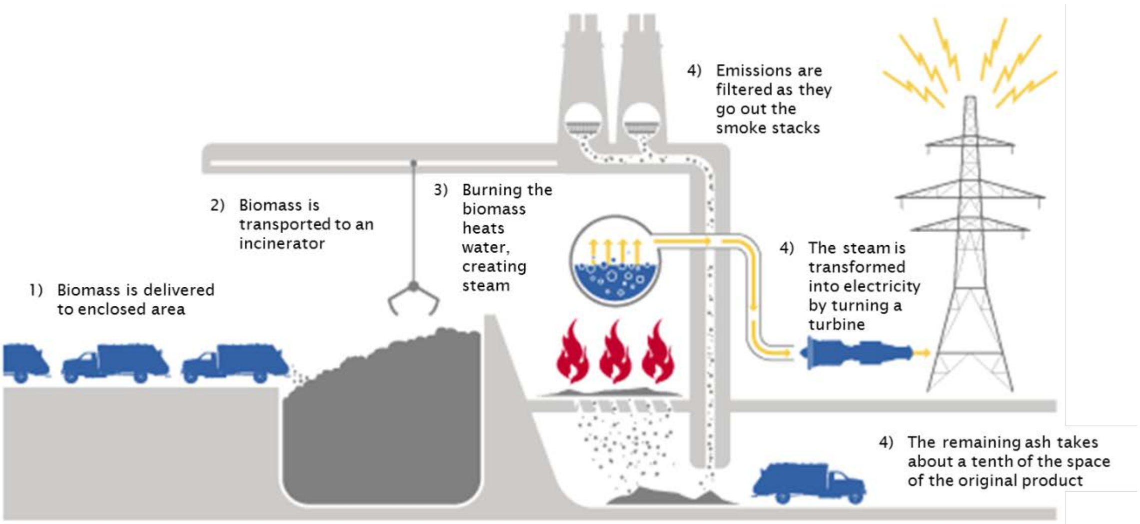
Agricultural and energy crops: include crops that are currently cultivated for food and other uses such as corn, rapeseed, sorghum, soybean, sugarcane, and crops that are specifically grown for energy use such as microalgae, poplar and willow trees.

Waste and opportunity fuels: include biomass from various wastes such as wood waste from wood mills, municipal wastes, manure, land fill gas, restaurant waste, crop residue and methane from wastewater treatment plants.

Due to the wide variety of biomass sources, there are many technologies in use that convert these feedstocks into useable energy for the production of electricity. Bioenergy can be directly combusted, either on its own or co-fired with coal or natural gas, in a furnace to produce steam which in turn is used to drive a steam turbine linked to a generator (Figure 2-13) (Brat, 2008). Alternatively, solid biomass sources can also be converted to an intermediate gas or liquid fuel through thermal gasification, thermal pyrolysis and anaerobic digestion. The product is then used to produce electricity in a steam turbine generator, gas turbine generator or in an internal combustion engine generator to produce electricity.

Depending on the availability of feedstocks, generation from bioenergy is considered dispatchable. This type of plant can be operated in much the same way as conventional coal or gas power plant (McKendry, 2002). This offers a source of dependable electricity generation for the renewable grid, so long as there is a readily available source.

Figure 2-13: Schematic diagram of a direct-fired bioenergy facility (Brat, 2008)



As has been discussed, there are many sources of useable biomass that can be used in the production of electricity. However, biomass suffers from low conversion efficiency and high price of some feedstocks, particularly when the feedstock is also being used for food or animal feed. Water availability is also expected to be an issue if there is a high uptake of generation from biomass (Scarlat and Dallemand, 2011). To mitigate this, extensive infrastructure and logistical planning will be required to ensure that there is enough biomass for bioenergy use as well as for the existing uses (SETIS, 2012).

At the end of 2011, the total installed bioenergy capacity in UK was 3.2GW, operating at an average load factor of 43.1% (DECC, 2011a). In addition to this, there was also an installed capacity of 338MW supplied by co-firing of biomass with fossil fuels.

The cost of bioenergy technology has been static for the past 15 years. This has enabled a comparison of installed bioenergy plant and the system components costs. Overall capital cost for a bioenergy plant can be divided into 6–7% for the feed handling and processing, 44–47% for the boiler and air quality assurance, 33–35% for the steam turbine and its auxiliaries, and 13–14% for the balance of plant (McGowin, 2007). O&M costs are split into fixed cost (price per yearly capacity (kW-yr)) and variable cost (price per energy unit produced (MWh)).

2.3.3.3.1 Future bioenergy resource

Gardner (2011) provides an estimated bioenergy resource for the UK based on availability of resource and available land area required to sustain the biomass supply chain. The maximum exploitable UK bioenergy capacity is given as 23GW or 178TWh. However, due to the uncertainty in the amount of biomass available and competition of land area, this has been restricted to a resource capacity of 12GW and 95TWh of annual generation.

2.3.3.4 Solar energy

As has been discussed, most renewable energy sources derive from solar energy. Therefore, technologies that harness this energy directly have access to a large resource. Solar energy can be used to produce electricity, but it can also be used to displace electricity demand by heating water, providing heating and cooling, and reduce the amount of artificial lighting required by using solar tubes to bring light in to the building. This study will focus on technologies that use solar energy for the generation of electricity.

Solar photovoltaics (PV): A PV installation would typically include multiple modules connected in an array, dependent on the required generation output. All modules are rated in terms of their peak power (W_p) which is the output reached under standard test conditions (Wind&Sun, 2011). However, these values are rarely reached as output in real-life conditions depends on the amount of solar radiation, temperature of the module, condition of the modules and the voltage load levels within the cells.

The PV market is currently dominated by silicon based technologies, mainly multi-crystalline and mono-crystalline PV modules. They represent up to 85% of the global market (Augustine et al., 2012). Costs for the installation of PV projects are generally divided into module cost and balance of systems cost. The latter include the inverters, wiring, mounting (with or without solar tracking), construction and installation.

Concentrated solar power (CSP): Another technology group that harnesses the solar energy are concentrating solar power installations. Unlike PV, CSP use mirrors or lenses to focus sunlight onto a receiver which typically contains a fluid which is heated. The energy from the heated fluid is then conducted to an electrical generator through a heat engine (SEIA, 2014). In order to obtain the maximum solar energy available, these concentrators employ tracking mechanisms to continually focus the sunlight on to a fixed point. CSP installations can be oversized and have the ability to store the excess energy within the fluid to use it during periods of prolonged cloud cover or during the night to continue producing electricity. This means that load factors of CSP plants are higher than PV and the electricity which is produced is highly dispatchable.

The only class of electrical generation from solar energy installed in the UK currently is PV. As of 2011, total installed PV capacity in the UK was 994MW (DECC, 2012d) and by 2013 there was a total installed capacity of 2.8GW (DECC, 2014d). The majority of this installed capacity resulted from the installation of PV projects less than 5MW which was supported by the Feed-in-Tariffs introduced in April 2010 (Feed-In Tariffs, 2012). Since CSP projects depend highly on the amount of direct sunlight that is available, they are currently only economically viable in areas that receive large quantities of sunlight. For this reason, it is unlikely that this type of technology will be installed in the UK in the future.

Sunlight data is readily available and is provided in terms of 'mean daily peak sun hours' at a given site in units of kWh/m^2. From this it is possible to calculate the expected output for a given installation given the available sun, or solar irradiance, at any given site. The Joint Research Centre (JRC, 1995-2013) provides an online calculator which enables the calculation of monthly PV output from sunlight data anywhere in Europe and Africa.

Electricity generated from PV and CSP will become more competitive through continued reductions in cost and improvements in performance, solar PV especially as it is still a relatively new technology. Until then, mass uptake of this technology in the UK will be constrained to installations up to 5MW which benefit from the economic incentives of FiTs.

2.3.3.4.1 Future solar energy resource

The nature of solar energy is such that the total amount of solar energy arriving on the surface of the UK is more than enough to provide all of the UK's electricity requirements. However, this is not technologically and economically feasible. The total amount of practical generation from solar resources has been placed at 266TWh per annum in 2025 (Watson et al., 2002). This accounts for electricity generated by solar PV installed on all available domestic and non-domestic buildings. It also includes an allowance of 10% for non-suitable surfaces and 25% for shading from surrounding buildings or vegetation.

2.3.3.5 Marine energy

The main marine energy sources that are applicable to the UK are outlined below.

Natural wave energy: Wave energy generally increases with latitude and is most abundant at 30–60 degrees from the equator. Waves are influenced mainly by wind blowing across the surface of the ocean, i.e. the fetch. The total amount of wave energy depends on the linear length of the crest of the wave, the height and period. The measure of wave energy resource is given by the wave power density. A wave's power density can be calculated using Equation 2-5.

Equation 2-5: Wave energy power density calculation (Boehme et al., 2006)

$$P_w = \frac{\rho\, g^2}{4\,\pi} H^2{}_{rms} T_e$$

Where ρ is the density of water (999.97kg/m^3), g is the acceleration due to gravity (9.81m/s^2), H_{rms} is the root-mean-square wave elevation and T_e is the energy period of the wave.

Wave energy converters have power limitations relating to the wave elevation and energy period, much the same as wind turbines have a rated power. There are also electrical and array losses incurred which amount to 2% and 1 % respectively. On average, it is expected that wave converters will be offline for maintenance around 8% of the time (Boehme et al., 2006).

There are a number of different methods for harnessing the energy from waves: point absorbers, overtopping devices, oscillating water columns, attenuators and inverted pendulum devices (Augustine et al., 2012). The majority of these methods are under development, with a few that have been deployed in the sea to date such as the Pelamis and Oyster devices which have been tested in increasingly challenging conditions (Krohn et al., 2013).

Natural tidal energy: The movements of the tides can be accurately predicted as they depend on the relative position of the Moon and the Earth. Other forces at play include the orbit of the Earth around the Sun which creates spring and neap tides. Tidal movements are affected by bathymetry, creating faster flows when there is a narrowing passage, and also the sea bed friction. This increase in velocity, and resultant flow, creates high kinetic energy which can be harnessed much like the energy from the wind. The main difference in Equation 2-6 is the higher water density ρ (999.97kg/m^3).

Equation 2-6: Tidal energy output calculation (Boehme et al., 2006)

$$P = \frac{1}{2} c_p\, \eta\, \rho\, A\, v^3$$

Availability of this technology is assumed to be 96% with total downtime for maintenance and repairs being 4%. Electrical interconnection losses are in line with other renewable sources at 2% and wake losses for currents are assumed at 5% due to the nature of water (Boehme et al., 2006).

Salinity gradient energy: This method relies on the mixing of freshwater and saltwater. Energy is released from this mixing process which results in a small increase in water temperature. There are two concepts under development which intend to convert this energy into electricity through reverse electrodialysis and pressure-retarded osmosis (Jones and Finley, 2003). However, these are still at the experimental stage and are unlikely to contribute significantly to the electricity network.

The use of marine energy to generate electricity is relatively new, with many methods still undergoing testing. A reflection of this is the total installed capacity in the UK in 2011 of 3.11MW (DECC, 2011a). Even so, the UK has high wave and tidal energy due to its location and geography. It is estimated that the available UK marine resource could be up to 67TWh per annum (DECC, 2012d). As a result of this resource potential and the extensive on-going research and development into marine energy, the UK is considered the world leader in wave and tidal energy.

There is insufficient data on the costs of installing and operating marine technology at present. As a result it is not an area which is expected to be operational and contributing to UK electricity generation before 2020. Investment into research and development and for commercial deployment is key to deploying this technology in the future.

2.3.3.5.1 Future marine energy resource

As has already been alluded to in Chapter 2.3.3.5, the UK's marine energy potential has been estimated for tidal stream, tidal range and wave energy. It has been proposed that the total amount of practical resource from these technologies is 189TWh per annum by 2050 (Helweg-Larsen, 2010). However, it has been estimated that the UK receives an abundant wave resource which could be in the region of 700 to 840TWh per year if it could be exploited fully (Watson et al., 2002). It has also been estimated that the UK's tidal resource could provide up to 50TWh of generation per year. It is important to highlight that due to this relatively new technology, costs are likely to be very high and therefore penetration of this technology is expected to be limited.

2.3.3.6 Geothermal energy

Geothermal energy uses the thermal energy that is stored in rocks and fluids under the Earth's crust. Electricity is produced using the thermal energy; therefore the amount of electricity that can be produced from this source depends on the temperature of the available fluid. This resource is found at geological anomalies, where the heat from the Earth's core has reached a shallow depth beneath the crust. In order to exploit this resource, wells need to be drilled into the geothermal reservoir at a depth of around 2km. The energy is then used to create high-temperature steam or pressurised water that is used to generate electricity. The factors required to make a geothermal installation viable are expressed in Equation 2-7.

Equation 2-7: Geothermal energy production calculation (Huddlestone-Holmes and Hayward, 2011)

$$P = c_p \cdot F \cdot \Delta T \cdot \eta - losses$$

Where c_p is the specific heat of the working fluid (which tends to be water of varying degree of salinity with a capacity in the order of 4,000J/kg °C), *F* is the flow rate from the production well (in the order of 100-500 m^3/h), ΔT is the sensible heat that can be extracted from the working fluid (in the order of 50°C to 150°C depending on the reservoir) and η is the efficiency with which the heat energy can be used (circa 10%).

Geothermal plant typically have a capacity of between 10–100MW (Augustine et al., 2012), although this resource is uncommon in the UK with only a few source located between 1.5 and 3km beneath the Earth's crust. Only one such site is in use at Southampton, with two schemes in Cornwall that have been granted planning permission during 2010 (DECC, 2012d).

Costs of geothermal generation plants are highly dependent on the specific site characteristics. Historically it has been found that drilling and power plant development contribute the major part of the cost; therefore typically shallow high-temperature resources tend to be the cheapest installations. Extensive development of this resource in the UK is highly unlikely and as a result is not expected to contribute to the generation of electricity from RES.

2.3.3.6.1 Future geothermal energy resource

The total geothermal potential in England and Wales has been investigated by Sinclair Knight Merz (SKM, 2012). The findings of the study investigated the main geothermal resources and classified them according to their generation capacity from electrical energy and thermal energy. It concludes that there is up to 9.5GW of recoverable electrical capacity (or around 63TWh) for 25 years. This is due to the average lifetime of the geothermal plant, however the resource is generally exploited at a level that it can maintain constant production over longer periods. This potential is located mainly in Cornwall, the north Pennines and the Lake District.

2.3.4 Summary of Renewable Energy Potential

The previous Chapters highlight the multiple and varied resources of renewable energy available to generate electricity. There is also estimation as to the scale of generation that is achievable in the UK. Table 2-7 provides a summary of the total UK generation from renewable sources. It is estimated that the renewable potential in the UK is up to 2,500TWh per year. However, in some cases, only the lower estimate may be practical and this has the potential to yield 950TWh of generation per year. In comparison, the total UK generation in 2013 only amounted to 374TWh (DECC, 2014a). This highlights the potential for the UK to be fully supplied solely by renewable sources.

Table 2-7: Summary of total UK potential generation from renewable energy sources

Technology	Total UK potential (TWh)
Onshore wind	58 – 318
Offshore wind (including floating)	241 (1,533)
Hydro	40
Bioenergy	95 – 178
Solar PV	266
Marine	189
Geothermal	63
TOTAL	**952 – 2,587**

The proposed generation mix and how much installed capacity is required to meet a fully renewable UK electricity grid will be discussed in Chapter 3.3.1. This is where the proposed future electricity demand scenarios will be introduced which determine the amount of renewable energy required. These future scenarios will take into account the constraints on each of the technologies described above and will adhere to the maximum resource potentials discussed.

2.4 Review of Grid Solution

The electricity grid of the future will need to incorporate variable renewable sources in order to meet GHG reduction targets and legislation. In order to achieve this, electricity grids will need to become 'smarter grids' that integrate communication systems and real-time balancing between supply, demand and energy storage (Crossley and Beviz, 2010).

Building on the information on renewable energy sources, this Chapter introduces the concept of distributed generation, its benefits and challenges.

Whilst the focus of this study is on integrating renewable generation on the electricity grid with the help of energy storage technologies or interconnection, it is important to understand how demand side technologies can benefit an electricity supply network that has high penetration of variable generation. However, the technologies discussed here will not be considered further in the study. It should be noted that the options discussed later in this study are considered as key enabling technologies for distributed generation.

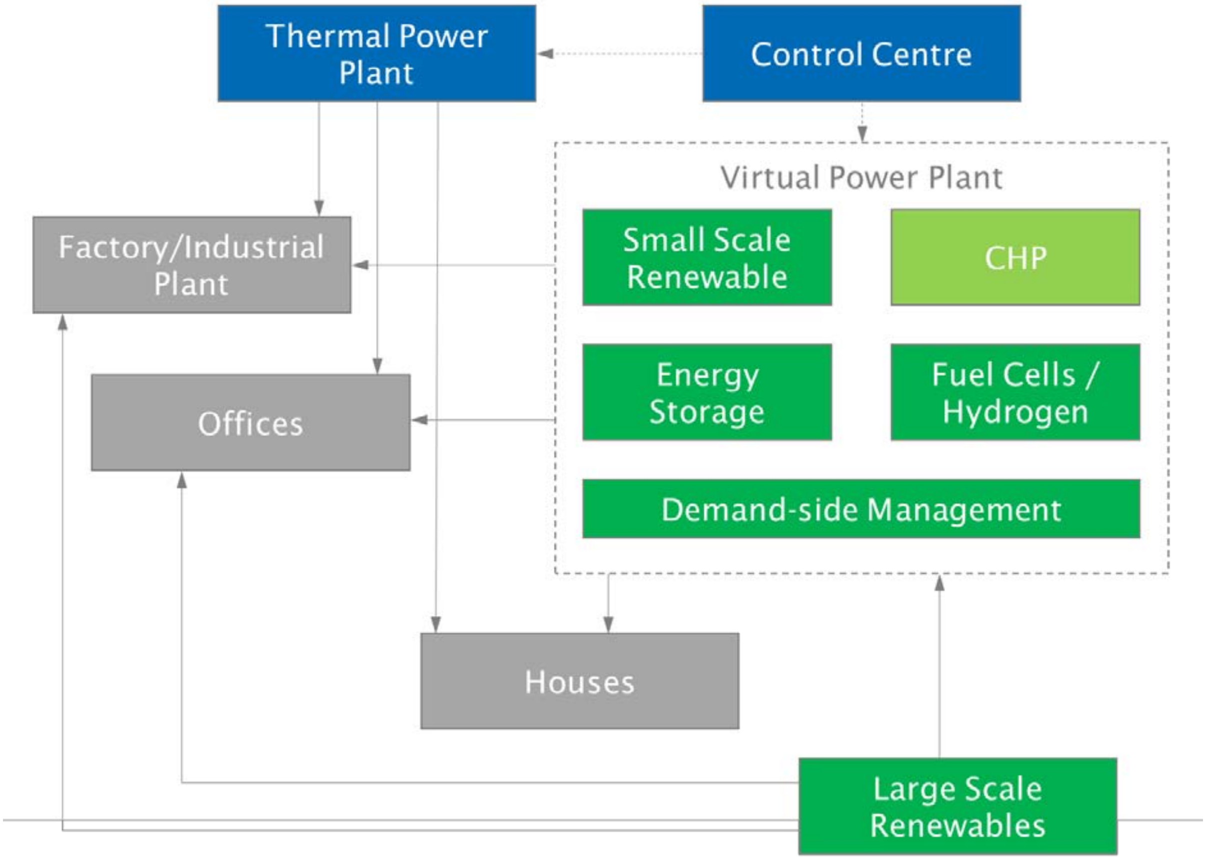
2.4.1 Distributed Generation

In the future electricity grid, distributed generation (Poortinga et al.) plays a key role. The term distributed generation has a variety of definitions; the European Commission defines DG as 'generation plants connected to the distribution system' (EC, 2003b), whereas the United States Department of Energy's definition is 'small and modular electricity generators sited close to the customer load that can enable utilities to defer or eliminate costly investments in transmission and distribution systems upgrades, and provide customers with better quality, more reliable energy supplies and a cleaner environment' (Department of Energy, 2011). Not only is there an inconsistency in the definition of DG, there is no consistency among EU countries with regards to the size of the generation plant included or the connection limits of these. A proposed definition of DG which is widely accepted is 'the integrated or stand-alone use of small, modular electricity generation sources, installed within the distribution system or a customer's site by utilities, customers or any other third parties to meet specific capacity and reliability needs in applications that benefit the electricity system, specific end-use customer, or both' (Sanchez Jimenez, 2006). The consensus is that distributed generation technologies are small sources of electric power generation or storage, in the range of less than a kW to tens of MW, which are connected to the distribution grid, but are not part of the central power generation system (Purchala et al., 2006). They are also located close to the point of use, on the customer side of the electricity meter.

Contrary to the traditional centralised generation model, DG covers a wide range of technologies. This model also minimises the transmission and distribution of electricity around the network: losses of around 7% are associated with the transmission of electricity on the distribution network due to line losses over distance. This amounts to more than 30% of the total cost of electricity to UK consumers (EC, 2003a). Enabling technologies such as energy storage devices and management systems such as demand-side management (DSM) will ensure DG provides all the customers' needs. Energy storage as an enabler will be discussed in the next Chapter; however, DSM aims to match the demand of an electricity system to the available supply by monitoring appliances connected to the grid (Rhodes and Wentworth, 2008). To enable this, it is necessary to install metering and communication systems at the consumer level to ensure the control of demand. Appliances that are suitable for DSM are water heaters and fridges, which are not affected by short electricity outages of up to 20 minutes. Another application of DSM is to reduce peak demand of electricity and optimise off-peak usage (Naish et al., 2008).

The integration of these technologies is known as distributed energy resources (DER), the efficient combination of which is essential to the effective integration of DG into the energy market (Karkkainen, 2008). Figure 2-14 illustrates a model grid where electricity from a thermal power plant is integrated to a network of RES, virtual power plants and energy storage systems.

Figure 2-14: Future electricity grid showing integration of thermal power plant with RES and virtual power plant containing energy storage devices (EC, 2006)



To address the variable generation from RES, a number of DER units are aggregated into what is called a Virtual Power Plant (VPP) (Saboori et al., 2011). The VPP is the conglomeration of a number of small scale electricity generators that can be operated similarly to a conventional centralised power plant (E-harbours, 2011). This enables intermittency from RES generation to be levelled out by allowing the VPP to coordinate the varied production facilities to produce predictable and stable electricity. VPP also rely on DSM to control consumer demand depending on the available generation capacity.

Future distribution grids will have to accommodate large amounts of bi-directional flows of energy with the increase in consumer generated electricity from RES. Alongside the network operators, the electricity consumer will become a network asset for DSM and also a source of generation with micro-generation (Hewicker et al., 2011). This entails moving away from the distribution network transmitting the energy solely to the end user from large generating plants, and integrating the growing generation of energy from households back to the grid. The future grid will also have to be able to accommodate changes in generation technology and address issues with reliability, sustainability and cost effectiveness.

2.4.2 Advantages

There are a number of benefits that arise from the integration of DG within the energy grid; the grid needs to be able to provide two-way communication between the generators and the operators to be able to manage the supply and demand of electricity, which in turn allows for DSM to become a form of indirect generation. It will also increase the overall grid efficiency and create savings in energy generation. At present each user of energy on the grid is seen as a 'sink' for electricity, however, with DG, the user will be able to behave as both a sink and a source of electricity (EC, 2006). These advantages are:

2.4.2.1 Energy efficiency and quality

The location of DG close to the point of use will increase the electricity efficiency by greatly reducing transmission losses (L'Abbate et al., 2007). It could also play a role in the reduction of distribution losses. Efficiency can also be greatly improved by replacing the transmission infrastructure with high-voltage DC lines (EC, 2006).

It will be necessary to coordinate local energy management with the existing centralised generation. With the right protocols and management, this will enable the end user to specify the quality of electricity desired through the use of smart metering and other information and communication technologies (ICT) (EC, 2006). The integration of advanced power electronics will facilitate running generators and motors at their most efficient point and maintain electricity quality levels. DG can also provide network support and ancillary services to further improve quality of supply to the consumer.

2.4.2.2 Reliability and security of supply

By ensuring that DG provides a flexible source of generation to minimise the risk of blackouts, and the roll out of an optimal and strategic grid expansion, the customer receives the required services without interruption for maintenance and operation (Sanchez Jimenez, 2006). Another benefit of flexibility is that operators can expand capacity with more ease due to the modularity of DER systems. As seen in recent outage events, distribution systems play a key role in helping to restore power supply. However, the main reason for these outages usually is due to the lack of communication and coordination between TSO and DSO (L'Abbate et al., 2007). DG can also improve continuity of supply of systems connected to a DG system, by isolating these from power disruptions in the main upstream network. The ultimate goal of a truly distributed grid lies in creating a harmonised legal framework that enables the trading of energy with neighbouring countries in the EU, creating a pan-European electricity grid. This enables energy to be traded to areas that are momentarily lacking in RES to supply their demand. Likewise, this can enable any excess generation to be stored in, for example, pumped hydro-power, thereby further enhancing the overall strength and safety of the electricity grid. One example of this is the NorNed cable that runs over 580km between the Netherlands and Norway (TenneT, 2013). This cable has a capacity of 700MW and is capable of transmitting electricity between the two countries. Electricity produced in the Netherlands is transmitted to Norway for storage at pumped hydro sites during the night and re-transmitted for use during the day. This way, both countries complement each other with regards to the production and consumption of electricity and only have a small reliance on imports of fossil fuels.

Overall, the grids will be divided up into numbers of interconnected nodes, integrated at all levels of transmission and distribution. This will provide the consumer with a highly secure supply of electricity at the most cost-effective rate, at all times guaranteeing that the environment is taken in to consideration. To facilitate this, it is important to recognise that flexible and regular interaction with stakeholders is required in order to respond to the challenges and opportunities that will arise in the future (EC, 2006).

2.4.3 Challenges

The main objective that the future grid has to address is the uncertainty that exists with issues such as primary energy mix, new electricity flows created by liberalising the electricity market, instantaneous and uncontrolled power output that is provided by renewable energy generation, regulatory frameworks and investment remuneration for the new technologies. System reliability and power quality also have to be ensured in the new network; this includes the increased complexities that arise from hourly and daily transactions and the increase in the number of contributors in the generation system. The challenges to be addressed are outlined in the next sub- Chapters.

2.4.3.1 Power reliability and quality

With the introduction of power into the grid at the distribution level, the electricity flows are changed. This affects the stability of the network and power quality. The mains electricity in the EU is supplied at a fixed frequency of 50Hz (EC, 2003a). At present, variations in voltage are currently monitored and corrected by the grid operator with ancillaries such as fast-responding gas fired plants or sources of stored energy. These technologies are known as ‘spinning reserves’ and their function is to re-establish the balance between load and generation (Rebours and Kirschen, 2005).

Another related issue is grid harmonics. This is a measure of the distortion of the voltage and affects the power quality on both the supply and demand side. Harmonics can be produced as an undesired effect of electrical equipment that is connected to the network and is most notable with wind generators and solar PV. However this can be reduced with the installation of bespoke filters (L'Abbate et al., 2007).

Distributed energy resources (DER) can compensate for the intermittent nature of RES and ensure reliability of supply with energy management tools such as DSM. These programs include load shifting and energy efficiency and conservation. However, it is necessary to combine DER with weather forecasting facilities that provide information on the potential wind or solar resources in order to enable the efficient management of the required energy storage and spinning reserves for the grid.

2.4.3.2 Information and communication technology (ICT)

ICT will be used exclusively for all communications on the DG network with significant amounts of information being transferred between the generators and consumers. New technologies such as high-temperature superconducting (HTS) materials can enable large amounts of traffic in existing conductors as they are able to conduct more current than traditional copper cables and they are more space-efficient (EC, 2003a). There are also advancements in using the existing power lines (PLC) as channels for wide bandwidth information exchange. These technologies that enable the necessary transfer of information in the future grids need to undergo cost reduction to ensure a cost-effective system. Another issue that needs to be addressed is the safety and privacy of consumer and company’s information such as billing and strategic information (E-harbours, 2011). Development of cyber-security packages that provide security of information being transferred by ICT will need to be secure to give the DG users peace of mind.

2.4.3.3 Power systems technologies

New control systems and standards for generator and storage systems need to be formulated to enable instantaneous supply of demand in a predictive and cost-effective way (EC, 2003a). These controls must be supervised and must also enable the connection of other networks to ensure a pan-European electricity trading network. The grid also has to be able to handle consumers becoming producers of electricity in the event that there is a surplus of local generation.

Alongside the efficient management of the power network, it will also be required to have communication channels that allow the exchange of information regarding production and consumption of energy, and to enable power balancing. One of the developed tools that enable this is supervisory control and data acquisition (SCADA) systems that have become feasible as a result of developments in ICT (in4ma, 2007). This tool is used for monitoring and controlling plant or equipment remotely, as well as logging and displaying specific plant data and usage. However, increasing integration of DER mean that existing ICT may not be able to handle the large amounts of information.

2.4.3.4 Enabling technologies

These will facilitate the development of interactive energy networks with high power quality and reliability. For this, it is essential that low-cost technologies that can integrate the use of RES and connect the grid to the pan-European network are brought to the market (EC, 2003a).

One of the main enabling technologies for DG are energy storage devices. These enable smoothing of transient or intermittent loads from RES, and can enable the downsizing of the baseload produced in centralised plants. This can create substantial energy and cost savings in the existing electricity network. Some of the storage technologies include batteries, supercapacitors, fuel cells, flywheels, thermal storage and compressed air energy storage (CAES). These technologies will be covered in greater detail in Chapter 2.6.

Metering services such as smart meters and automated meter management (Saboori et al.) will provide the consumer with the ability to play a key role in the management of local electricity demand (EC, 2006).

2.4.3.5 Commercial and regulatory

Using all these novel and innovative technologies will reduce the cost of connection and operation. However, this will also mean that the existing infrastructure will need to be used more fully. This presents a situation whereby, there will be new ways of charging for the use of these networks and services which at the moment do not exist in the market. Moreover, at present it is legally prohibited to exchange electricity between companies, or between consumers in the UK, unless a private wire network is in place (E-harbours, 2011). If excess electricity is produced, there is no legal framework that enables this energy to be used by another consumer with the required demand. Energy regulators will need to develop new approaches and organisational logic in order to address these challenges and allow installations that have combined access to the electricity grid. Deployment of DG and RES also face delays and opposition due to public acceptance issues (Hewicker et al., 2011).

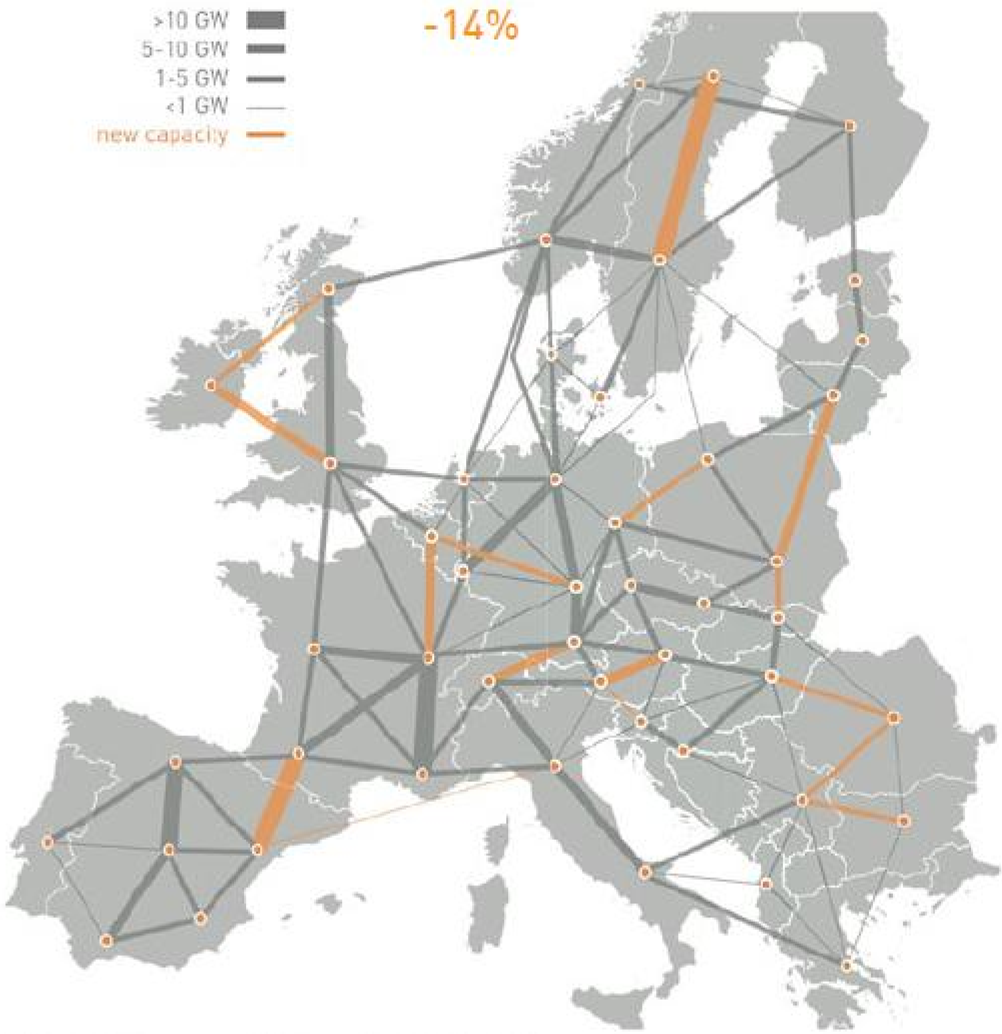
One of the main barriers that DG is facing stems from the fact that utilities have not dealt with small-scale projects or customer-generator interconnection requests before (Sanchez Jimenez, 2006). Coupled with this inexperience, there is no consensus on technical connection standards or assurances for consumers and operators on specific charges and remuneration. Under this context, the viability of integrating renewable energy sources onto the electricity grid using interconnectors or energy storage technologies will now be considered. Another barrier that is currently present is the availability of cheap fossil fuels, such as natural gas, which render these systems uneconomical.

2.5 Review of Interconnector Technology

The 'Power Perspectives 2030' report (Hewicker et al., 2011) highlights the need for continual development in DER and DG. One of the main areas looked at in this report were the interconnection links between member countries of the EU and what future connections are required in order to meet the 2050 GHG reduction targets. The study also confirms the economic benefit of upgrading and developing these links. It was estimated that by implementing demand response measures of up to 10% of daily peak load, total cost savings obtained from the decrease in grid capacity and backup capacity would be in the region of GBP 5.6 billion and GBP 19.8 billion respectively. Furthermore, demand response also has the potential to reduce the amount of RES that is curtailed on the grid. Another finding of the report was that by implementing energy efficiency measures, for example lowering the electricity demand of 700TWh in 2030 by 14%, the need for grid capacity would decrease by 55% and backup capacity by 31%, saving a total of €299 billion of new generation requirements.

The European market is committed to increasing network capacity and interconnections in order to meet their three objectives: integration of the European markets, RES balancing and security of supply (entso-e, 2012). A total additional capacity of approximately 64GW is expected in 2020, 54% of which is expected to come from new interconnections (Hewicker et al., 2011). The remainder of this capacity is to be made up of RES. In order to truly obtain the maximum benefit from the new interconnections, demand response and energy efficiencies will need to be implemented. An illustrative EU network in 2030 can be seen in Figure 2-15. This illustrates the grid connections that would be necessary when efficiency measures and demand response have been implemented.

Figure 2-15: EU grid transmission capacity required in 2030 with demand response and energy efficiency measures implemented (Hewicker et al., 2011)



New grid capacity in this scenario would be reduced by 14% and the transmission capacity would be reduced by around 49GW with respect to the business-as-usual (BAU) scenario. This illustrates the need for a unified push toward implementing DER and the interconnections between DG sites around Europe.

Dispersing the available RES over larger distances can also improve the energy security for customers (Glasnovic and Margeta, 2011). However, it is important to note that this does not guarantee that supply will meet demand at any given time, only an electricity grid with some form of suitable EES can avoid this situation.

Studies have also shown that the interconnection of RES that are geographically dispersed helps to ‘smooth’ out the generated output, making it more manageable for the grid operators (see Kahn (1979); Palutikof et al. (1990); Katzenstein et al. (2010)).

In the case of interconnected wind farms, Palutikof et al. (1990) shows that dispersion of sites of up to a few hundred kilometres can reduce the hours of zero output if the sites are connected. However, this study highlights that this phenomenon faces diminishing marginal benefits, meaning that above an optimum number of connected sites, each additional site will provide less benefit than the last.

The same has been seen with interconnected PV sites; a comprehensive review by Mills and Wiser (2010) states that "the clear conclusion from this body of previous research is that with ‘enough’ geographic diversity the sub-hourly variability due to passing clouds can be reduced to the point that it is negligible relative to the more deterministic variability due to the changing position of the sun in the sky".

For these reasons, it is expected that the creation of a pan-European grid will help pave the way for the mass integration of RES onto the electricity grid and therefore solving many of the issues faced from the variability of supply from these sources. However, this in itself poses new issues. The large distances that would need to be covered in order to ensure that the pan-European grid is suitable for everyone’s needs need to be considered. At present, the additional costs of long distance HVDC transmission on top of conventional costs, for distances covered on land, range from GBP 0.002/kWh to GBP 0.02/kWh, with a best estimate of about GBP 0.006/kWh (Delucchi and Jacobson, 2011). Clearly, the costs of the additional transmission requirements, not to mention the planning, funding and operational issues, would be a major constraint for this option unless tackled correctly.

Another potential pitfall faced is to do with weather systems that affect output from RES. Adverse weather systems can spread over the whole of Europe given the right conditions. These systems can be made up of dense cloud cover, intense calm and cold for up to a week (Lenzen, 2010). A report details such a period in which the UK had negligible generation from wind farms and no supply from PV (Oswald, 2006). During this period, UK electricity demand also reached its highest yearly peak. This could mean that in a system without any form of backup, there would be supply shortfalls which would impact large areas.

This highlights the benefits and challenges of creating an integrated electricity grid throughout Europe. In this scenario, trading of electricity from RES could ensure that variability of supply is mitigated by creating a wide portfolio of generation connected to the grid and it could also avoid unnecessary curtailment of generation from RES. However, as has been discussed, upgrading the network, whether it is at a local, national or European level, can be a prohibitively expensive proposition and would need more consideration of backup in case of adverse weather systems. It is important to note that the success in de-carbonising the electricity grid lies in the integration of distributed generation, virtual power plants, demand-side management and transmission network upgrading with energy storage systems.

2.5.1 Review of cost of interconnectors

It is difficult to get exact costs for interconnectors as it is a highly commercially sensitive area. Costs also differ greatly depending on the type of technology that is used and the equipment necessary at each landing point. Other factors that are difficult to quantify are the effect of water depth on the cost of installing subsea cables and the potential risks of working offshore.

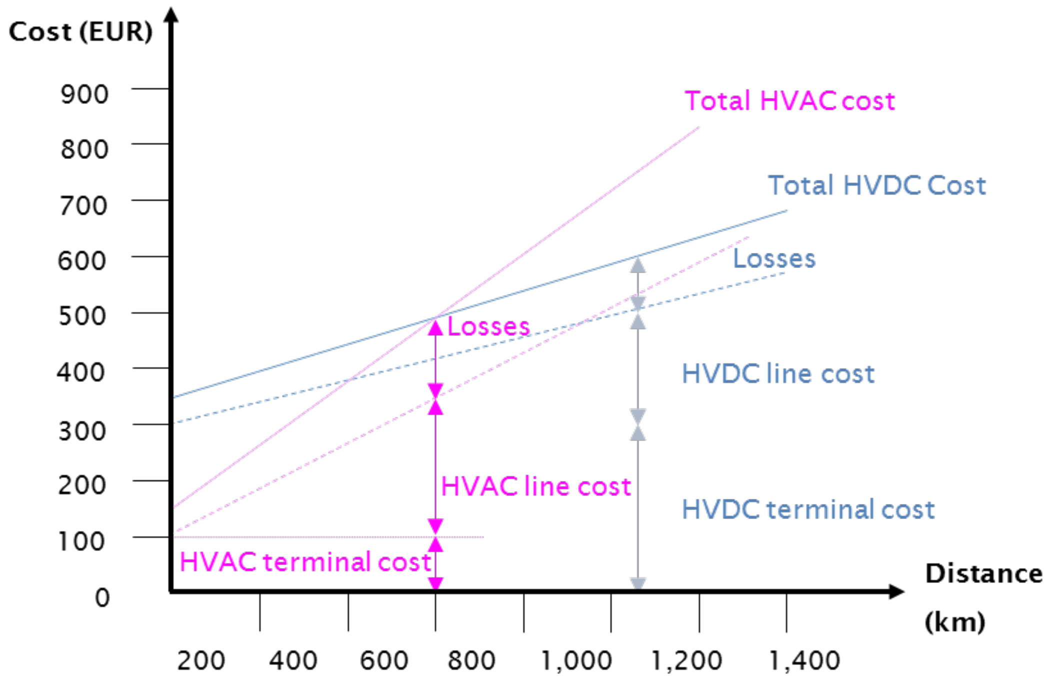
One thing that is known is the benefits of using high voltage direct current (HVDC) as the preferred technology over high voltage alternating current (HVAC) for mass transportation of electricity over large distances. This is due to the capacitance of an HVAC cable. This effectively reduces the capacity of the cable due to the charging current that it creates. Also, the charging current is proportional to the length of cable. Therefore, over long distances the amount of power that the cable can transmit is severely reduced. In the case of HVDC cables, the capacitive reactance is infinite and therefore there is no capacity penalty for transmitting power over large distances.

When talking about HVDC transmission, it is important to discuss the landing terminal and the conversion technology that this will use. The landing terminal serves as the interconnection between the power on the network, usually AC, and the transmission of DC power to a neighbouring grid. There are two major technologies of which current source converter (CSC) HVDC is the oldest technology. This technology has been in use since the 1950s and has evolved with development of power converter technology. CSC-HVDC became the state-of-the-art technology for transmitting electricity over long distances with the advent of thyristors in the 1970’s. The second technology, voltage source converter (VSC) HVDC became prevalent in the 1990’s after breakthroughs in insulated gate bipolar transistors (IGBT) and gate turn-off thyristors (GTO). This meant that VSC-HVDC could switch from blocking state to on-state and vice versa enabling self-commutation whereas CSC-HVDC could only be line commutated (Bahrman, 2008).

For this reason, depending on the technology used for power conversion, HVDC technology can be divided into two main categories, the benefits of each are discussed below.

There is a cost difference between these technologies that also comes into the equation when considering one technology over the other. The cost of the landing terminal, which includes the linkages and transformers to connect to the local electricity network, for HVDC technology is relatively high compared to HVAC terminals, which do not require as much equipment. This however is countered by the lower cost of the HVDC power cable. Therefore, there is a break-even distance whereby above a certain distance, it is more economical to install HVDC cables. This can be appreciated in Figure 2-16. This example shows a break-even distance for HVDC cables of 600km, at which point it is more economical than HVAC cables (Larruskain et al., 2005). It is also stated that this distance is much smaller for subsea cables, typically about 50km. These values are dependent on several factors such as transmission medium and different local aspects.

Figure 2-16: Comparison of AC versus DC costs (Larruskain et al., 2005)



A European consortia project, Research Methodologies and Technologies for the Effective Development of Pan-European Key Grid Infrastructures to Support the Achievement of a Reliable, Competitive and Sustainable Electricity Supply (REALISEGRID) has studied in detail the uses of HVDC interconnectors to better understand the role that this technology can play in the future renewable electricity network (Ruberg et al., 2010). Part of this study also investigated the cost of HVDC technology. These costs have been arrived at through a review of the available literature, internal knowledge and surveys (Table 2-8). The costs provided have been supplied related to voltage level and power rating as well as for a typical subsea HVDC cable pair, VSC terminal and CSC terminal. The costs have been provided in terms of a cost per unit which enables these to be used in further analysis. The minimum and maximum cost is based on high and low labour costs which could be encountered in Europe. It can be appreciated that the range of costs for the VSC terminals is quite large and this is related to the relatively new nature of the technology.

Table 2-8: Summary of HDCV cable costs and terminal costs (Ruberg et al., 2010)

System component	Voltage level (kV)	Power rating (MW)	Minimum cost (GBP)	Maximum cost (GBP)	Unit
HVDC subsea cable pair	350	1,100	840	1,680	1,000's GBP/km
HVDC VSC terminal, bipolar	150 – 350	350 – 1,000	50.4	105	1,000's GBP/MW
HVDC CSC terminal, bipolar	350 – 500	1,000 – 3,000	63	92	1,000's GBP/MW

It is noted that the costs provided in Table 2-8 can vary widely from actual costs due to changes in technological parameters of the cables, environmental constraints and geographical characteristics. These are also influenced by the material and manpower costs; however these have been accounted for in the range provided. These costs are also assumed to include the cost of installation, equipment and project engineering required.

2.5.2 Benefits of DC interconnectors

The main benefits of using HVDC technology for interconnectors have been discussed above. In addition to these, there are a number of secondary benefits that further justify the choice of HVDC for this application. The asynchronous nature of HVAC lines often makes it difficult to connect two neighbouring HVAC networks due to instability. There is no such issue with HVDC technology. In addition, it is even possible to connect two networks that have different nominal frequencies, for example a 50Hz network with a 60Hz one. Another factor benefiting HVDC technology is the degree of control over active power that the technology affords and the lower losses that HVDC cables have for the same capacity as HVAC cables. A further benefit is the, often overlooked, more efficient utilisation of existing power plants and the ability to increase the transmission capacity for the existing rights of way if replacing HVAC cables (Larruskain et al., 2005). There is also a lower environmental impact as the electromagnetic field emissions are not pulsating and can be reduced to a minimum.

As has been discussed, there are two major HVDC technologies: line-commutated CSC and self-commutating VSC. The differences between them that have been discussed also highlight some of the advantages of VSC technology (Ruberg et al., 2010). In the case of a VSC station, this is connected to the power grid through a standard transformer that transforms the rated voltage of the network to the required entry voltage of the self-commutating converter. On the other hand, a CSC station would require a phase shift and therefore would require a further transformer. VSC stations are also able to inject reactive power into an AC network which contributes to voltage stability.

For these reasons, VSC-HVDC technology has a lot of interest in the interconnection of electrical networks. Through the use of this technology it is possible to transfer high capacities, fully control power flow in two directions, prevent the propagation of faults, improve the low frequency and voltage stability, as well as reduce network losses due to active power. However, further advancements in control and design technologies and new power materials and electronics are required for this technology to be fully exploited.

A further important factor in benefit of HVDC technology is the high overall availability of the technology. It is claimed that for both CSC and VSC technology availability is 98% (CIGRÉ, 2009).

The overall benefit of interconnecting electricity grids is to increase the security of supply by enabling more flexibility of generation and supply. In order to be able to maximise this transfer of electricity over often long distances it is of greater benefit to use HVDC technology. It is also the main technology that is used in existing subsea interconnectors for many of the reasons outlined above. Therefore, HVDC technology, using VSC stations, is considered as the key technology in this study.

2.5.3 Interconnection in a 100% renewable system

There are a number of studies that consider grid interconnection as an option to enable fully renewable systems. There have been some studies that look at the benefits and drawbacks of interconnection on a European scale and also looking at smaller scale island grids.

Steinke et al. (2013) conducted a study on the European system where the sun and wind supplies 100% or more of the energy requirements. In the study it was found that median backup capacity required to ensure energy demand is met throughout the year was 40% of the energy consumption in the situation where no grid extension or energy storage is considered. This is thought to be unsustainable seeing as in a fully renewable system backup generation would need to be provided by dispatchable sources of energy such as biomass which has been shown to be limited to 10% of the average energy consumption. Follow on investigations looked into the effects of energy storage and transmission upgrades on backup generation requirements. It was found that by increasing the grid infrastructure backup capacity could be reduced to 20% of demand and optimally sizing energy storage to provide 7 to 30 days storage would provide a secure system. However, the technical viability of current energy storage technologies is questionable in this scenario. Further research into the interactions between different energy storage technologies could provide a viable solution to the fully renewable European network.

The requirements of upgrading the electricity network have also been discussed in detail for the expected increases in renewable supply across the European network. It was estimated that an additional extension to the European electricity network of 52,300km was necessary at a cost of up to GBP 82.4 billion, of which GBP 18.2 billion was for subsea HVDC cables (entso-e, 2012). Additionally, it has been found that modification of 24,500km of existing HV cables need to be carried out at an estimated cost of GBP 21.8 billion (Landlinger et al., 2014). This highlights the amount of investment required to enable greater penetration of renewable generation on the European network. However, the studies conclude that network upgrading alone will not be a suitable solution.

A study carried out on some islands in the north Aegean Sea also considered the benefits of energy storage versus installing a supergrid (Xydis, 2013). In this case, the islands are relatively isolated and have a good natural resource meaning a fully renewable supply is feasible. However, there are still issues with the variability of supply and therefore balancing mechanisms need to be assessed. It was found that a system that fully utilises available resources with the addition of energy storage can supply the required demand and that installing a supergrid that connects the islands to mainland Greece and neighbouring Turkey to meet demands actually reduces the Island's system efficiency. Nevertheless, some of the benefits of having connectivity between the surrounding energy markets could provide several additional benefits like added system stability and ability to trade between electricity markets.

In reality, a combination of both energy storage and interconnection would be employed to achieve maximum benefits in the fully renewable electricity system. An extreme case of this is the proposed DESERTEC concept which in essence involves linking high solar resource areas such as the Sahara desert with Europe's varied resources to create a zero carbon network (DESERTEC, 2013). This would involve large investments in interconnection and renewable generation capacity, but is generally accepted as being a suitable approach to providing carbon free energy to Europe.

The interconnector technology and characteristics discussed here will be taken forward as a solution that can be employed to ensure supply and demand is met on the future UK electricity grid. The proposal is to assume existing interconnectors are upgraded and new ones are installed. The overall interconnection capacity will be increased to enable trading in the European electricity markets and potentially further afield. This will be further investigated at a later stage. As of 2014, the UK has 4GW of interconnection through four interconnectors: 2GW to France, 1GW to the

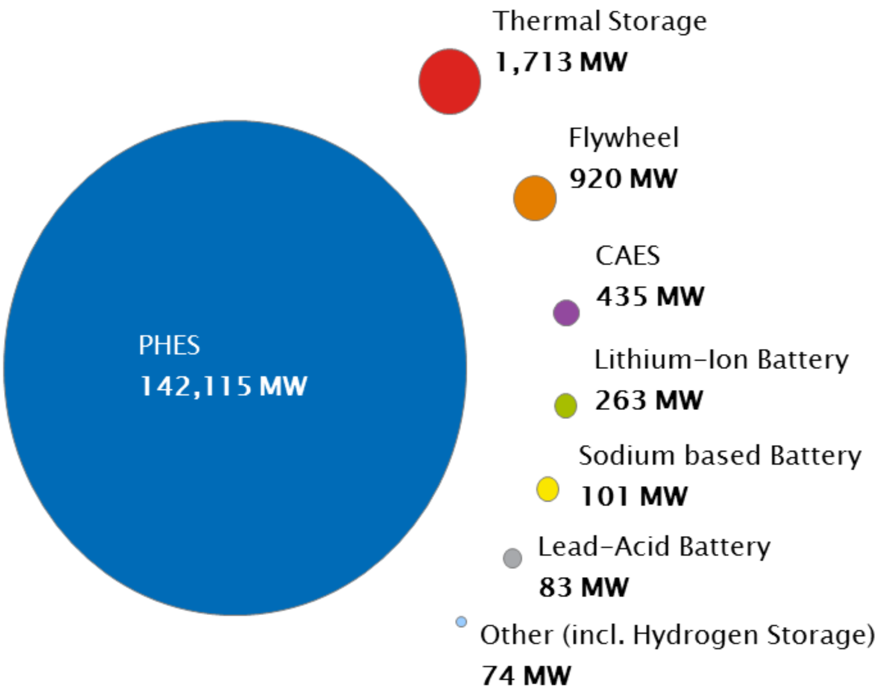
Netherland) and two links of 500MW each to the Irish grid (DECC, 2013a). The key impact that these interconnectors have on the UK electricity grid are a reduction in system inertia and system strength, a greater variability of power flows, and the ability to restore the system following a potential blackout (National Grid, 2014). In addition, these and future interconnectors can provide frequency response and reserve, reactive power reserve and constraint management services. Interconnectors also allow for fast power ramp up/ramp down rates, usually in the 5 minute per MW range (Baker and Gottstein, 2012).

2.6 Review of Energy Storage Technologies

As has been discussed in Chapter 2.5, in order to transform the existing grid and enable large scale integration of RES, energy storage systems (ESS) are one of the key enabling technologies. These will address issues with grid stability and reliability by providing the grid with flexibility to respond to fluctuating and escalating electricity demands. Cost-effective development of energy storage technologies is essential to sustain the pace of increasing electricity demand and increase in roll-out of DG and generation from RES (Rastler, 2010).

There are a number of on-going ESS projects globally; however, very few of these are installed in grid-integrated systems at present. The installed capacity is invariably used as a systems management tool that operates alongside the existing generation plants. Figure 2-17 illustrates that the most widely used form of energy storage worldwide as of 2015 is pumped hydro with a total installed capacity of around 142GW (Department of Energy, 2012). Other main technologies include thermal storage with 1.7GW, flywheels with 920MW, compressed air energy storage (CAES) with 435MW and Lithium-Ion batteries with 263MW. The remainder of technologies make up a total of less than 258MW. It is interesting to note that in 2015, there was a total operational capacity of hydrogen storage of circa 3MW.

Figure 2-17: Worldwide installed and operational storage capacity for electrical energy as of 2015 (Department of Energy, 2012)



One of the major roles that ESS will undertake in the future electricity network is in the integration of electricity generated by RES (Naish et al., 2008). The variable nature of RES introduces reliability of supply concerns to the electricity grid operator. ESS are in a position to minimise these concerns by evening out the generation output of these sources. Another factor to include in using RES is the often remote geographic location of these sources which can introduce issues with the transmission and distribution network. In this respect, energy storage devices are well suited to help offset problems caused by variable electricity generation.

Energy storage systems can, by nature of their conception, provide a variety of short-, mid- and long-term storage options that serve a multitude of applications. The benefits that arise from these include balancing services, supplying power during outages, deferral of transmission and distribution network upgrades, and enhancing the reliability and resilience of the electricity grid (Lichtner et al., 2010b). An in-depth look at the suitability of different ESS to provide support to the electricity grid will be discussed in this Chapter.

2.6.1 Benefits to the electricity grid

Energy storage systems have been identified as being able to increase grid flexibility and enable the mass integration of renewable energy sources on to the grid. This Chapter will look at how they can be used to stabilise the voltage and frequency, offset the need to build new generation and transmission infrastructure, cover blackout events due to stress on the electricity grid and integrate and support RES into the existing network (Denholm et al., 2010). There are five main benefits to the electricity grid that energy storage devices can provide, and these can be divided into short-duration power applications and long-duration energy applications.

2.6.1.1 Area and frequency regulation (short duration)

At present, the electricity network operates large coal fired or combined cycle gas turbines (CCGT) thermal plants to provide balancing services for the shifting load fluctuations from changes in frequency (Rhodes and Wentworth, 2008). These are paid to run below full capacity so that they can provide reserve for frequent and small fluctuations in grid frequency. These turbines use fossil fuels and, by being run inefficiently, produce more pollution from burning more fuel. For less frequent imbalances, diesel generators and open-cycle gas turbines (OCGT) are installed on the grid to be run on demand. These are generally smaller plants with higher running costs that also run on fossil fuels (Rhodes and Wentworth, 2008).

Energy storage devices have the potential to provide this balancing service in a more efficient way as they can quickly vary output within a matter of seconds and provide discharge duration of 15 minutes to 2 hours (Lichtner et al., 2010b). It has been shown that an energy storage device installed in place of a coal fired thermal plant in a grid balancing capacity could potentially displace as much as 0.25 tonnes of CO_2/MWh (Naish et al., 2008). This value is only achievable assuming the electricity that supplies the energy storage device comes from a renewable source.

There must be an effective communication structure in place to optimise this efficiency and response time. Metrics to take into account include the system cost, lifetime and response time and roundtrip efficiency in order to be adopted by the electric power industry.

2.6.1.2 Renewable energy grid integration (short duration)

Energy storage systems are well placed to integrate generation from RES as they can minimise the risk on the grid of the intermittent nature of this energy source. Integration issues fall under two general headings: short-duration (that is ramp-up/ramp-down of generation) and long-duration (electricity energy time shift to match output from RES) (Lichtner et al., 2010b). The long-duration issues will be discussed under ‘Electric energy time shift’.

Energy storage can be used to smooth the power from RES, by providing the electricity grid with a constant flow of energy which is easier to manage. It will also enable RES to command a higher electricity price by making it more dispatchable (Naish et al., 2008). Storage devices for the integration of RES need to have a high round-trip efficiency (75–90%) and a range of 1MW to several hundred MW (Rastler, 2010). Other metrics that need to be considered include system lifetime and response time.

2.6.1.3 Transmission and distribution upgrade deferral and substitution (long duration)

Currently, the transmission lines experience low capacity utilisation as they are sized for high loads and also to be the most efficient as possible in peak conditions (Lichtner et al., 2010b). Upgrading of existing transmission and distribution (T&D) lines, due to the increase in demand, can be postponed, or in some cases eliminated, by using energy storage technology to store energy produced at times of low demand and using this when the demand is high. Locating these storage devices closer to the point of use also helps reduce the load on transmission and distribution lines (Denholm et al., 2010).

Typical discharge durations are in the region of 2–6 hours, with a 1–100MW capacity and lifetime of 15–20 years (Rastler, 2010). More metrics include system costs and reliability. An important feature is safety: these systems must be failsafe and include cyber security protection in order to secure the distribution of electricity. These metrics must be in place to justify using this technology as a more cost-efficient way of improving the existing grid and accommodating future increases in electricity demand.

2.6.1.4 Load following and voltage regulation (long duration)

Load following provides a change of power output in response to the changing balance between the electricity supply and demand in a given area as a result of fluctuations in power demand (Lichtner et al., 2010b). This variation in output usually results in increased maintenance requirements, since this service is provided typically by turbines operated at part-load.

In this case, energy storage devices can insulate the grid from changes in net supply in comparison to demand. This is possible since many storage technologies can be operated at part-load without compromising the system performance. Load following devices require discharge durations of 2–6 hours and capacity of around 1MW (Rastler, 2010). Other metrics are capital, maintenance and operational costs. There also has to be an effective communication infrastructure in place to be able to respond quickly and effectively to the grid needs.

2.6.1.5 Electric energy time shift (long duration)

Energy storage systems can make the most of low electricity prices by charging a storage device at times of low demand, and subsequently using this energy when demand, and hence price, is high (Lichtner et al., 2010b). This is also known as energy arbitrage which involves purchasing and selling energy at different times in order to benefit from a price discrepancy. Storage of excess energy could also reduce vulnerability to shortages of supply (Naish et al., 2008). Energy storage technologies that are used in this scenario need to have round-trip efficiency of 70–80% and have good discharge duration of 2–6 hours. An important factor to consider is the environmental impact of the energy storage device. If all these metrics are met, this could be adopted as a means of taking advantage of the fluctuating price and supply of renewable electricity.

It is important to note that energy storage systems have to meet a set of metrics in order to offer the optimal combination of performance and cost-effectiveness required for market acceptance and widespread commercial deployment (Lichtner et al., 2010a). This set of realistic and achievable metrics for energy storage systems are summarised in Table 2-9. Note that in most cases, energy storage capacity can be provided in either MW or MWh, depending on the specific storage technology and duration.

Table 2-9: Targets for energy storage technologies for use in grid storage applications (Lichtner et al., 2010a)

Application	Purpose	Key Performance Metrics
Area and Frequency Regulation (short Duration)	Reconciles momentary differences between supply and demand within a given area Maintains Grid frequency	Service cost: GBP 0.01/kW per h System lifetime: 10 years with 4,500-7,000 cycles/year Discharge duration: 15 min - 2 h Response time:>1 second Roundtrip efficiency: 75- 90%
Renewables Grid Integration (Short Duration)	Offsets fluctuations of short-duration variation of renewable generation output	Roundtrip efficiency: 75-90% System lifetime: 10 years Power: 1-20MW Response time: 1-2 seconds
T&D Upgrade Deferral and Substitution (Long Duration)	Delays or avoids the need to upgrade transmission and/or distribution infrastructure using relatively small amounts of storage Reduces loading on existing equipment to extend life	Cost: GBP 320/kWh Discharge duration: 2-4 hours Power: 1-100MW Reliability:99.9% System lifetime: 10 years
Load Following (Long Duration)	Changes power output in response to the balance between supply and demand Operates at partial output or input without compromising performance or increasing emissions Responds quickly to load variations	Cost: GBP 960/kW or GBP 320/kWh for 3 hour duration Operations and maintenance cost: GBP 0.31/kWh Discharge duration: 2-6 hours
Electric Energy Time Shift (Long Duration)	Stores inexpensive energy during low demand periods and discharges the energy during times of high demand (often referred to as arbitrage) Accommodates renewables generation at times of high grid congestion by storing energy	Cost: GBP 960/kW or GBP 320/kWh Operations and maintenance cost: GBP 0.16-0.31/kWh Discharge duration: 2-6 hours Efficiency: 70-80% Response time: 5-30 minutes

These metrics come with a caveat: storage system costs depend on the size, location and application in which it is being used (Rhodes and Wentworth, 2008). The complexity of metrics illustrates the need for both developers and industry to recognise the imprecise nature of these targets. Highest revenues will be achieved from storage devices that aggregate several services across multiple categories (Rastler, 2010). Therefore actual cost must reflect the value of storage being used in both single and multiple grid applications simultaneously.

2.6.2 Barriers

There are a number of limitations that currently hinder the large-scale uptake of energy storage technologies in the electricity generation sector. These must be overcome in order to unlock the many opportunities and solutions that storage devices present to the existing grid. It is important that energy storage systems are able to deliver a reliable supply, cost-effectively and that meets the carbon reduction targets (Radcliffe, 2011). These challenges are interrelated and need to be solved from both the individual and high-level system approach to enable widespread commercial deployment.

2.6.2.1 Deficient market structure

As has been discussed, the current electricity market divides the wholesale markets into generation, transmission and distribution (Lichtner et al., 2010b). However, storage technologies are able to support all of these markets. Therefore it is difficult to assess them from a regulatory point of view and to assess their value in comparison to the existing infrastructure. Appropriate pricing mechanisms and long-term contracts need to be in place to ensure stakeholders will see compensation for the benefits of energy storage. The market for energy storage is also highly dependent on economic environment; in most cases the value of combined benefits from energy storage is needed to overcome the initial cost of storage (Radcliffe, 2011).

In order to attract the necessary investment in this technology, the compensation structure needs to be in place to ensure the return on investment (ROI) of the investors. It has been shown that returns from storage can vary year-on-year (Grunewald et al., 2011). This can have the effect of deterring potential investors.

2.6.2.2 Limited large scale demonstrations

There are a number of energy storage systems in service at present. Examples of this are pumped hydro facilities such as: Dinorwig in Wales capable of providing 1,728MW for 5 hours when full (Rhodes and Wentworth, 2008); and a 250kWh flywheel system installed to mitigate wind power variations operation by Fuji Electric in Japan (Inage, 2009). However, only a few can accommodate grid-scale systems. The majority of projects are in the demonstration phase and this limits the amount of performance data on system cost, efficiency, durability, reliability and safety required for widespread commercialisation of the technology (Lichtner et al., 2010b). In order to be able to define storage application for specific devices and to attract investment, this validation of the technology needs to be carried out to prove the benefits of grid-scale storage.

Permits for large grid-scale storage can delay integration of energy storage to the grid as they may require complex interagency approvals and long processes. Long payback times also curb the uptake in energy storage projects (Rhodes and Wentworth, 2008).

2.6.2.3 Insufficient technical progress

Historically, technical advancements in ESS have been linked to energy crises (Lichtner et al., 2010b). When energy prices stabilise, interest in energy storage is curtailed and cheaper technologies such as OCGT are chosen to provide grid services (Rhodes and Wentworth, 2008). This is the reason why a number of technologies have not reached a level of maturity conductive to commercial deployment. This in turn leads to scepticism on behalf of the electricity industry and stakeholders of the value of energy storage. Energy storage systems need to be able to demonstrate that they can supply a range of energy services and provide reliable power when integrated in a network with significant RES at an economic price (Naish et al., 2008).

Alongside the development of the storage technology, control systems and communication systems need to be developed to ensure the effective and efficient integration in to the electricity grid.

2.6.2.4 Lack of standards and models

Due to the limited data available from demonstration facilities, there is a lack of standards and models that can help storage system developers and the industry to design and integrate reliable and high-performing energy storage technologies (Lichtner et al., 2010b). Operators of the grid also lack dispatch strategies and operational models that make it difficult to assess both the impact and benefits of storage on the wholesale and resale market. From a regulatory point of view, energy storage is not seen as an asset class. Instead, it is viewed as generation and therefore cannot be controlled by system operators due to EU competition rules (Radcliffe, 2011). Through the recent Electricity Market Reform (EMR) consultation on capacity mechanisms, it is expected that energy storage, alongside demand-side response, can compete with power generation (DECC, 2012e). However, the value of grid-scale storage needs to be understood by system planners and engineers, as well as being able to evaluate the integration of energy storage devices against other supply, delivery and demand-side options.

2.6.2.5 Weak stakeholder understanding

The benefits that energy storage systems can provide are not well known by stakeholders (Lichtner et al., 2010b). Without this, it will be impossible to achieve the support and level of deployment necessary to provide substantial improvements to the electricity network. There is also a lack of awareness of the value and applications that energy storage can provide within the energy industry. This lack of knowledge also stops regulators from considering energy storage. One of the main issues comes from the lack of knowledge and uncertainty of market potential (Radcliffe, 2011). Business models that show the potential of energy storage to capture revenue, modernise the existing electricity grid and reduce GHG are required as evidence that there is a viable business case for energy regulators.

Another drawback of the weak understanding is the potential problems that can arise from public objection to the location of energy storage installations. However, apart from large scale storage like pumped-hydro or CAES, most energy storage devices are small and modular and can therefore be installed in discreet locations (Rhodes and Wentworth, 2008).

2.6.3 Technologies

Energy storage technologies are extensive and varied. To enable a direct and objective comparison of the variety of technologies, a number of terms have been recommended to describe their specific characteristics (Naish et al., 2008). These characteristics are:

- **Power rating:** expressed in kW or MW, determines the power capacity of a device;
- **Energy rating:** expressed in kWh or MWh, determines how long a device can supply energy for. In combination with the power rating of a device, it determines the amount of energy that can be released in a set time;
- **Discharge time:** the period of time over which the stored energy is released. It is related to the power rating of the device;
- **Roundtrip efficiency:** the amount of energy that returns after one charge-discharge cycle;
- **Lifetime:** calendar life of the technology, and
- **Cost:** the cost of energy storage is often quoted in terms of life cycle cost/kWh or installation cost/kW. It depends on the intended application and gives a measure of how economically feasible a device is.

Storage technologies are also divided into two main categories depending on their discharge time (Lichtner et al., 2010b):

- **Power management applications:** These technologies are usually used for short discharge durations from less than a second up to an hour. Power application technologies are used to address faults and operational issues that can cause voltage disturbances and flickers.
- **Energy management applications:** Technologies used in energy management applications tend to store excess electricity during low demand periods in order to release it later during periods of high demand. The discharge duration of these technologies usually exceed an hour, and can be used to reduce peak load and to integrate renewable energy into the distribution grid.

It is important to point out that although the majority of the energy storage technologies that will be described in this Chapter are stationary technologies, there are some which can be seen as 'mobile' storage solutions. This is the case of batteries; the battery market is split into primary (used in watches, remote controls, toys, etc.) and secondary (rechargeable batteries used for laptops, mobile phones, EV, etc.) batteries. The market share of these is 23.6% and 76.4% respectively. In terms of grid-scale applications, only batteries from plug-in electric vehicles (PEV) have the potential to provide services such as load balancing whilst the vehicle is connected to the grid for charging. This is known as vehicle-to-grid (V2G) (Denholm et al., 2010). There is great potential for this to be implemented in the future distributed grid, for example PEV can be plugged in to the electricity network overnight or while the user is at work. It has been estimated that between 92% and 95% of vehicles are stationary during the day. This means that there is a high availability for use in V2G application if these vehicles are plugged-in when stationary (Kempton et al., 2001). And since they are mobile and will connect at different parts of the network, this provides a degree of flexibility in the applications that these batteries can provide. However, effective communication infrastructures between the EV and the grid operators, and the appropriate incentives for the vehicle owner have to be in place before this can be considered for mass commercialisation.

Table 2-10 summarises the main energy storage technologies available and classifies them in terms of suitability for power management or energy management applications.

Table 2-10: Overview of energy storage technologies available for power and energy management applications (Adapted from: (Lichtner et al., 2010b))

Storage Technology	Main Advantage (relative)	Disadvantage (relative)	Power Application	Energy Application
Batteries	Low capital cost, high power and energy density	Limited cycle life, cost, control circuitry	⊕	◎
Vanadium Redox Flow Cell	Independent power and energy	Medium energy densities	◎	⊕
Flywheels	High power	Low energy density	⊕	⊖
Electrochemical Capacitors	Long cycle life	Very low energy density	⊕	⊖
Pumped Hydro	High energy, low cost	Special site requirements	⊖	⊕
Compressed Air Energy Storage	High energy, low cost	Special site requirements	⊖	⊕
Liquid Air Energy Storage	High energy, low cost, flexible	Relatively new technology	⊖	⊕
Hydrogen	Flexibility, seasonal storage	Storage medium needs development	⊖	⊕
SMES	Instantaneous power, reliability	Cost, requirement to run at low temperatures	⊕	⊖

⊕ Fully capable and reasonable   ◎ Reasonable for this application   ○ Feasible but not quite practical or economical   ⊖ Not feasible or economical

It can be seen that some energy storage technologies can have very specific applications, whereas others are suitable to provide support for multiple applications. These main technologies are explored in more detail below.

2.6.3.1 Batteries

There are a number of different cell chemistries and types that provide unique characteristics. Batteries are built using three basic components – anode, cathode and electrolyte. Current is drawn from the battery from the flow of electrons that flow from the anode through the electrolyte to the cathode. That is to say, the voltage in the cell drops as the anode and cathode undergo electrochemical changes. These technologies are recharged by the reversal of the discharge process (NREL, 2011). The main battery chemistries are Lead-Acid (PbA), Sodium-Sulphur (NaS), Lithium-Ion (Li-Ion), nickel-based and Vanadium Redox flow cell batteries. These technologies are the most commonly used in grid-scale systems (Denholm et al., 2010). Typically prices are dependent on the specific application it is being used for and can be in the range of GBP

640/kW to more than GBP 3,200/kW (Radcliffe, 2011). Batteries typically only deliver energy for short periods up to hours. The exception to this is redox flow cells which can store and deliver energy for up to half a day. A flow cell uses the properties of two separate electrolyte fluids passed through a membrane to generate electricity through a chemical reduction and oxidation reaction. The amount of energy stored is determined by the total amount of active chemical species in the electrolyte solution (ESA, 2015). It is therefore possible to store large quantities of each electrolyte in separate containers to tailor to the energy storage need of the specific application.

2.6.3.2 Electrochemical capacitors

Capacitors store electrical charge in an electric double layer at a surface-electrolyte interface, mainly in a high-carbon material (Miller and Burke, 2008). These devices are capable of very fast charging and discharging times of less than 30 seconds and as such are best suited to providing transient voltage stability on the grid (Denholm et al., 2010). Capacitors have been tested that can provide up to 10MW and are capable of lifetimes of up to 500,000 cycles (Inage, 2009). These systems cost GBP 960–1,600 per kW.

2.6.3.3 Flywheels

Flywheels store energy by accelerating a rotor to high speeds and maintaining the energy as rotational energy (Beacon, 2011). This is a form of mechanical storage, where the kinetic energy of a spinning cylinder contains the stored energy (Naish et al., 2008). Modern flywheels are typically supported on magnetically levitated bearings which increase system lifetime due to a reduction in the wear of components and are operated in vacuums to reduce losses from air friction. The energy can be stored from either electrical or mechanical sources, making them flexible as energy storage devices, and can be spun up to speeds in excess of 20,000 revolutions per minute (Radcliffe, 2011). This technology features rapid response and high efficiency which makes them suitable for frequency regulation services (Denholm et al., 2010). Flywheels can provide a continual storage capacity of 5MWh and pulse power of up to 20MW over 30 minutes (Lichtner et al., 2010b). Although this technology in its current format is in the demonstration phase for grid scale storage, these systems have an estimated cost of GBP 1,280 per kW or GBP 5,120 per kWh (Radcliffe, 2011).

2.6.3.4 Pumped storage

Also known as hydro-electric storage, it converts large quantities of electrical energy to potential energy by pumping water into a reservoir at a higher elevation. Here it can be stored until electricity is demanded, whereby the water is released and passed through hydraulic turbines to produce electrical energy (McGraw-Hill, 2002). Pumped hydro plants can provide power from 250MW to 1.5GW, with discharge durations of up to 10 hours and capacity up to 14GWh (Lichtner et al., 2010b). The main benefit provided to the grid is load levelling; however pumped hydro is also used for ancillary services (Denholm et al., 2010). This is one of the most mature storage technologies; however, capital costs are high mainly due to location and construction. Estimates of total costs are GBP 960-1,728 per kW (Radcliffe, 2011).

2.6.3.5 Compressed air energy storage

Compressed air energy storage (CAES) stores energy as potential energy of a compressed gas (Gardner and Haynes, 2007). This is mainly done by pumping air into a storage tank or a naturally occurring underground reservoir. Any excess energy is used to run air compressors and when electricity is required, the compressed air is expanded through conventional gas turbine expanders. This is usually combined with a conventional gas turbine to improve its efficiency, with proven gas consumption reductions of 60% relative to conventional gas turbines (Naish et al., 2008). The performance of a CAES plant is based on its energy ratio and its fuel use (Denholm et al., 2010). CAES plants can provide 100-300MW over a period of 2-24 hours (Inage, 2009) and system costs are estimated at GBP 640 per kW and GBP 80 per kWh (Radcliffe, 2011). Despite the relative benefits for use in integration of RES onto the grid, CAES are geologically constrained at present due to the need of a suitable cavern. In 2012, there are only two CAES plants in operation globally, in Germany and Alabama (Naish et al., 2008).

2.6.3.6 Superconducting magnetic energy storage (SMES)

These devices store energy in a magnetic field in a coil of superconducting material (Denholm et al., 2010). SMES have the ability to release its power immediately (1 second) and provide 1-3MW (Inage, 2009); therefore their main use is in frequency regulation (Naish et al., 2008). Costs of these devices are estimated at GBP 250-500 per kW (Radcliffe, 2011).

2.6.3.7 Liquid air energy storage (LAES)

There are many non-conventional energy storage technologies that are at various stages of development. Some of these technologies are more advanced than others. This is the case of cryogenic energy storage; electricity can be used during periods of low demand to liquefy air or nitrogen that is used at a later time to produce electricity. An example of this is the Highview Cryo Energy System (Highview, 2012). In this system, air is liquefied and stored using off-peak electricity. Energy is recovered by pressurising, vaporising and heating the liquid in order to use the subsequent gas in a turbine to generate electricity. The resultant cold energy from this process is captured and used in the liquefaction process to increase the round-trip efficiency of the process. These systems can provide 10-200MW capacity over a 2-5 hour discharge period with an expected round-trip efficiency of 60-70% (Brett, 2011). This technology is currently being tested on-site; however, expected costs are GBP 573.4-1,193.6/kW or GBP 163.8-341.1/kWh.

2.6.3.8 Hydrogen

Hydrogen is the most abundant molecule on Earth. However it is seldom found on its own. The most commonly found form of hydrogen is in combination with oxygen that creates water (H_2O). Hydrogen has the highest energy to weight ratio of all conventional fuels, almost double that of natural gas and gasoline. However, it has a low energy to volume ratio. Some of the major reasons for using hydrogen are that it combusts and it can also produce electricity when combined with oxygen in a fuel cell, all the while, without creating carbon emissions at point of use. There is however, a large amount of energy required to create molecular hydrogen in the first place which traditionally is via fossil fuelled processes. This can be substituted in large part by excess renewable energy therefore increasing the environmental credentials of hydrogen as a fuel. This also adds to the flexibility of the fuel as both a source of energy, when combusted or combined in a fuel cell, and a storage medium of excess renewable generation (Haemer et al., 2006). Some of the main advantages of hydrogen are:

- Uncoupling of primary energy sources and utilisation;
- Hydrogen is a gas and thus is easier to store than electricity;
- Hydrogen enables decentralisation and could be used as an energy vector for the transportation and heating sectors as well as for electricity; and
- Very efficient when used in fuel cells, between 40% and 70% depending on fuel cell technology (Haemer et al., 2006).

Hydrogen can be produced through electrolysis, a process whereby a source of electricity is used to split water into its component parts, hydrogen and oxygen. This process uses a lot more energy than some of the more common hydrocarbon processes such as steam reformation or partial oxidation. However, the ability to use electricity from renewables makes this the most attractive method in a fully renewable future. The Mission hYdrogen & Renewable for the inTegration on the Electrical grid (MYRTE) project has been designed specifically to test the full scale coupling of a solar power plant with hydrogen energy storage. The solar plant is a 560kW PV installation connected to a hydrogen electrolyser producing 10Nm^3 per hour, separate storage tanks for hydrogen and oxygen of 1,400Nm^3 and 700Nm^3 respectively, and a fuel cell of 100kW (Marseille et al., 2012). Follow on stages included upgrading the electrolyser to 150kW and the flow rate of the electrolyser to 23Nm^3 per hour. Excess solar energy is used to convert hydrogen through electrolysis and is stored alongside oxygen. When there is a need from the local network, the hydrogen and oxygen are combined in the fuel cell which injects the resulting electricity back in to the grid. This has been demonstrated successfully and safely during the different stages of the project which is currently undergoing its third stage.

Hydrogen also offers some flexibility as to how it is stored. There are two main categories of hydrogen storage: physical and chemical. Of the physical storage category, this encompasses salt caverns, aquifers, depleted oil and gas fields, conventionally mined rock caverns, abandoned conventional mines and pipe storage (Kruck et al., 2013). On the other hand, chemical storage tends to focus around metal hydrides.

There are a number of physical hydrogen storage facilities in operation covering the breadth of methods introduced above. Whereas the majority are being used for the storage of natural gas, the operation of these to store hydrogen is not too dissimilar. A review of these facilities has identified the potential costs of storing hydrogen by these methods (Kruck et al., 2013). Storage of hydrogen in salt caverns is estimated to cost GBP 35.9 per m^3, whereas in depleted gas fields this is likely to be in the region of GBP 7 per m^3. This is due to higher costs to develop salt caverns over pre-existing gas fields which have the necessary infrastructure set up. The study also suggests that hydrogen storage within rock caverns ranges from GBP 94.7 to 432 per m^3. The higher costs here reflect the development work required to ensure the airtightness of the cavern, which may require lining, and to create the cavern. On the other hand, pipe storage of hydrogen is estimated at between GBP 0.6 to 1.7 per m^3. These costs are low due to the relatively simple implementation and construction of this method. However, it is important to note the much lower storage capacity of this method over the geologic methods.

A further iteration to the hydrogen storage process is the power-to-gas process whereby the produced hydrogen is stored in the natural gas network. This method has been investigated in GRHYD, a research project carried out in France aimed at injecting hydrogen into a natural gas network and using it to heat a neighbourhood of 200 people (GDFSuez, 2012). There are some issues surrounding the amount of hydrogen that can be integrated into the natural gas network. These relate to the Wobbe Index, which indicates the interchange ability of fuel gases, including hydrogen, and is the best indicator of similarity with natural gas (Altfeld and Pinchbeck, 2013). Due to this, it is known that a higher percentage of hydrogen per volume of natural gas has an effect on the efficiency of combustion and therefore affecting processes that rely on fuel combustion. A number of European countries have a high interest in investigating limits on the quantity of hydrogen volume allowable within the natural gas network, such as Germany, Denmark, the Netherlands, France, Belgium and the UK, and initial conclusions suggest that mixes of up to 10% by volume of hydrogen to natural gas is possible with very few modifications

(Melaina et al., 2013). Concentrations above this would need to consider safety issues such as material durability, integrity management, leakage and downstream extraction. This solution does provide the potential for bulk energy storage over long periods if combined with stationary fuel cells for electricity generation alongside the uses in the heating sector.

As technologies are developed, there will be an increasing number of storage solutions that can be implemented in the distributed grid, providing increased flexibility of choice for grid operators. However, a number of caveats have to be highlighted (Denholm et al., 2010). Firstly, only a couple of these technologies are technically mature namely pumped-hydro and some battery technologies. Secondly, the round-trip efficiency of some of the technologies is not directly comparable due to the device storing different energy: in some cases the device stores AC electricity and in others DC, with the standard measure of efficiency being the AC to AC round-trip efficiency. Lastly, and related to the technological maturity, the costs of energy storage devices in large scale applications is not fully understood. Therefore, there are large variations in the cost estimates provided from year to year.

As has been highlighted in this Chapter, many of the storage technologies have not been validated in their suggested applications. ESS need to be evolved to a ‘grid-ready’ state where they can provide maximum benefit to the electricity grid. For this, industry stakeholders need to create an action plan to advance the market integration of energy storage technologies. This will help unlock the multiple benefits of energy storage devices and will provide the electricity sector with the support required to meet commitments to reducing GHG emissions by 2050. Some of the main considerations that need to be taken into account are the capacity, cost, round trip efficiency and conversion efficiency if considering changing energy vectors. These aspects will be taken into consideration when applying energy storage in later discussions.

2.7 Review of 100% Renewable Energy Grids

In this Chapter a review of some of the main studies of high penetration renewable sources or 100% renewable energy scenarios is presented. Discussions are made on the suitability of each study and the steps taken to overcome the various technical barriers presented.

2.7.1 The 100% renewable scenario – case studies

The main problem arising from the use of renewable energy sources (RES) for electricity generation, except in the cases of bioenergy, geothermal and run of the river hydro, is their variable nature. When considering maximising the use of RES generation to meet demand in an electricity grid, it is imperative to control this variability to ensure demand is met.

Analysis of 100% renewable energy systems have been conducted in many studies and the overall conclusion is that the development of such systems with existing technology is possible and 'it is not a matter of technology, but rather a matter of making the right choices today to shape tomorrow' (Zervos et al., 2010). This is to say that if issues related to public perception of renewable technologies, such as visual aesthetic, and the upfront capital cost are placated, then the current technology is capable of delivering the required energy demands. However, it is important to investigate the various case studies to understand the particularities of each case. These studies have been done in a variety of methods from a global (Glasnovic and Margeta, 2011) and continental (Heide et al., 2010, Trainer, 2013, Steinke et al., 2013) scale, as well as for countries: Denmark (Lund and Mathiesen, 2009), Macedonia (Cosic et al., 2012), Croatia (Krajacic et al., 2011b), Portugal (Krajacic et al., 2011a), Ireland (Connolly et al., 2011), New Zealand (Mason et al., 2010), and Australia (Elliston et al., 2012); municipalities: Aalborg (Ostergaard et al., 2010); cities: Frederikshavn (Ostergaard and Lund, 2011); islands: Island of Mljet (Krajacic et al., 2009), Island of S. Vicente (Segurado et al., 2011) and Island of Porto Santo (Duic and da Graca Carvalho, 2004). These studies of fully renewable scenarios can be grouped by modelling tool:

- The EnergyPLAN tool, developed by Aalborg University, is an input/output model used for the annual analysis of regional and national energy systems in one hour time steps. Input data typically include demands, RES, generation, unit capacities, storage capacities, fuel consumption in private and industry sector, fuel costs, investment, variable and fixed operation and maintenance costs, CO_2 emissions factors and regulation strategies. Output data from the model include annual, monthly and hourly values of electricity production, electricity import and export, import expenditures and export revenues, fuel consumption, CO_2 emissions and the share of RES (Cosic et al., 2012). Studies conducted using this tool are generally done on a closed energy system, all electricity and heat demand is supplied by own production.
- The H_2RES tool, developed jointly by the Instituto Superior Técnico of Lisbon and the University of Zagreb, was designed to support the ADEG/RenewIslands methodology which considers renewable generation on islands or isolated grids with hydrogen (Krajacic et al., 2009). It is primarily used to balance the hourly time series of water, electricity, heat and hydrogen demand, as well as the appropriate levels of storage and supply. It integrates basic technical data for equipment and meteorological data to estimate renewable output.

Whilst these are only two of a wide range of computer tools available which analyse the integration of renewable energy into various energy systems, it is important to note that a study by Connolly et al. (2010) reviewed 68 available energy tools and found that out of these, only seven tools were capable of modelling 100% renewable energy systems including EnergyPLAN and H_2RES. Each tool has a specific application in mind and therefore requires different inputs or specifies individual technologies. Therefore, it is imperative that the right tool is chosen given the study constraints. For example, in the case of modelling tools INFORSE, In*vert* and LEAP, these tools focus on multi-year discussions and as such only have a resolution of 1 year time step; whereas the modelling tools EnergyPLAN, H_2RES, Mesap PlaNet and SimREN have an hourly resolution. There are also a multitude of modelling tools that apply to specific technologies and applications. However, these on their own are not capable of modelling a fully renewable energy system and as such are not explored further.

Each study has their own particular characteristics due to the locally available resources and constraints. These will now be discussed in further detail.

In the case of Denmark (Lund and Mathiesen, 2009), wind supplied 20% of electricity in 2009 and 15% of the country's primary energy supply (PES) came from renewable sources including biomass and waste incineration. The long term strategy is to become 100% independent from fossil fuels and nuclear power. This will be achieved through demand side energy savings, efficiency improvements in energy production and the by integrating sources of renewable energy by the year 2050. EnergyPLAN was used to carry out the energy balances, fuel consumptions and CO_2 emissions of the system and the socio-economic feasibility study. The outcome of the study was that it is physically feasible, but care must be taken to not over-rely on biomass resources or wind power as the knock on effects on farming areas or need for large scale storage would be detrimental to the overall system.

In a similar study conducted for Macedonia (Cosic et al., 2012), most of the energy production was from low quality lignite (coal) and there is a high degree of inefficiency in the production of energy. Different levels of wind penetration combined with biomass to cover periods of non-generation from wind on the system were analysed and it was found that a wind production of 7TWh and biomass requirements of 5.5TWh were optimal to supply a 100% renewable system in 2050. However, issues arise around the amount of biomass required and therefore further studies are needed to understand the levels of energy storage required to enable a sustainable 100% renewable system.

Similarly in a study of Ireland (Connolly et al., 2011), EnergyPLAN was used to investigate a 100% renewable grid under four scenarios: mainly based on biomass (BES), mainly based on hydrogen (HES), mainly based on maximising usage of renewables (PES) and a combined scenario of the above (COMBO). It was found that out of all the scenarios, the BES scenario has the highest PES, whilst the lowest was the BES. This is due to the high levels of biomass required to replace fossil fuels in transportation and the efficiency gains in transferring all energy requirements to electricity. The HES scenario also has high PES as the hydrogen economy has a high demand on resources due to inefficiencies in the system. When the COMBO scenario was analysed, it was found that the optimal mix of biomass, renewable energy and hydrogen reduced the PES by 20% and the amount of biomass is reduced by 71%. However, in this scenario the lower requirements of biomass may still be higher than the total potential available in Ireland.

At a smaller scale, the Aalborg Municipality study (Ostergaard et al., 2010) examines the potential of utilising the geothermal resource to cover heat demands against using wind farms combined with compression heat pumps. It was found that the best scenario was to maximise the use of geothermal energy to supply heat demand mainly due to the reverse aesthetic effect of increasing the number of wind turbines. The cost comparison of both technologies remained relatively unaffected in the different scenarios. It was also found that it would be possible to design a renewable system at a comparable cost to fossil-fuelled scenarios. However, in this study it was found that the system relied heavily on imports from neighbouring grids for power balancing. This highlights the difficulties of considering a small geographic area with limited resources. In the case of the municipality of Frederikshavn (Ostergaard and Lund, 2011), it was found that under the specific case study constraints, the optimal renewable system would run the geothermal plant at full load for 65% of the year, contributing to large reductions in CO_2 emissions that would have ensued in a business as usual case.

When studying the case of Croatia, Krajacic et al. (2011b) used a combination of EnergyPLAN and H_2RES to conduct a detailed energy system analysis of the system in 2030. The aim was to investigate the use of energy storage and how this could improve and guide the development of an actual energy system. The study involved hydro, biomass, wind, photovoltaics (PV), solar thermal, heat pumps, heat storage and pumped hydro storage. The conclusion of the study was that an independent energy system by 2030 was difficult. However, the share of RES in the system reached 78%, reducing CO_2 emissions by 20 million tonnes.

As stated earlier, the H_2RES tool was developed to investigate island or isolated grid systems. This is the case of the studies of Mljet (Krajacic et al., 2009), S. Vicente (Segurado et al., 2011) and Porto Santo (Duic and da Graca Carvalho, 2004). Many different scenarios have been investigated with the aim to optimise maximal usage of renewable energy. Islands have many unique characteristics: many require desalination plants for the production of water which have high energy demands and can have high fuel costs due to their isolation. The substitution of conventional sources for renewables in these cases can be beneficial as the high technological costs of renewables is compensated by high fuel costs. Another potential benefit for islands is the hydrogen economy. In the case of Porto Santo (Duic and da Graca Carvalho, 2004), it was found that to maximise the use of wind power, hydrogen storage with a two-week capacity would be required to cover demands. However, existing diesel plant was used as backup generation meaning a 100% renewable system was not achieved. On the island of S. Vicente (Segurado et al., 2011), a maximum renewable penetration of 65% and 6% hydro was achieved, highlighting the difficulties of intermittent sources. In all cases, the scenarios which were considered to be most economical were those with generation from multiple sources of renewables.

In Krajacic et al. (2011a), the H_2RES model was expanded to consider how a larger power system could be modelled to provide a 100% renewable electricity supply in Portugal. The system was considered as an isolated grid (from mainland Spain) and also with interconnection. The model also included a wave module to accommodate the potential for generation from this source within Portugal. The simulations of the year 2020 found that there is a heavy reliance on hydro energy. Another outcome was that achieving 100% renewable supply in a closed or isolated system requires a concerted effort and is more financially demanding than an open system, i.e. with transmission to neighbouring systems. This is mainly due to the higher number of installations for backup and storage that would only be operated for a limit amount of time throughout the year.

Studies have also been carried out without using the aforementioned tools. This is the case of the study of a New Zealand system (Mason et al., 2010), where the objective was to increase the use of existing resources of hydro, wind, geothermal and biomass. Energy storage systems were investigated including pumped hydro storage. However, it was deemed that the favourable combination for New Zealand was for wind to generate electricity directly and for hydro to fill in the gaps instead of using wind to pump water for storage. In this way, a solution using the available resources was found that is able to displace the 32% of fossil-fuelled generation currently on the system. However, due to the generation mix selected, it was found that spillage of wind energy occurred and was an inevitable consequence of variable supplies of energy. A further study by Mason et al. (2013) investigated the security of supply of a renewable electricity grid whilst minimising the spillage of energy from hydro and wind. The study also included the identification of appropriate peak generation options. This study was carried out over a period of 5 years and incorporates a period of significantly dry weather in order to investigate the effects of this on electricity production. The modelling included controlling lake levels between specified levels to ensure water levels are safe. It was found that substituting some wind generation, which is highly variable, with fully dispatchable biomass generation would minimise the amount of renewable energy spillage and also ensure the water levels through a dry period do not reach critical levels. The increase in flexibility from introducing dispatchable biomass generation to the system means that the 100% renewable electricity grid can be optimised to fully utilise generation and minimise curtailment.

Elliston et al. (2012) consider a similar study for Australia, matching variably sourced generation from wind, PV, concentrated solar thermal, hydro (with and without storage) and gas turbines fired with biofuels. In this case, it was found that generation reliability was maintained from having multiple sources of generation over large expanses of land, with peak-load generators and substantial storage. However, as mentioned before, this solution is specific to the study as there is a large amount of available space that can be utilised in this case.

In all these studies, the energy demands modelled were assumed to be the same as the year in which the study was carried out or the year from which meteorological data was acquired. Some adjustments have been made for the electrification of heating demands and transportation, however no extensive work on the likely future demand increases have been carried out.

When considering larger expanses of land, with multiple sources of renewable supply, it is possible to optimise generation from various sources in order to meet the required demand. In this way, the optimal mix of wind and solar in Europe has been investigated (Heide et al., 2010). In this study it was found that wind power output correlates with the seasonal load behaviour whilst solar power output anti-correlates with the load behaviour. If all other renewable sources are ignored, it was calculated that the optimal mix of sources for Europe was 55% of wind and 45% of solar. This mix would require a maximum stored energy of 1.5 times the monthly load for electricity and 1.8 times the monthly load for hydrogen in order to fulfil a 100% renewable electricity system. In a follow on study, Heide et al. (2011) calculated that the minimum energy storage required amounted to 400-480TWh a year for the optimum mix presented above, based on a yearly European demand of 3,200TWh. With present technologies, this presents a huge challenge. By altering the mix of renewable sources it is possible to reduce the amount of storage required by changing the storage timeframe. However, this has the reverse effect of increasing the amount of excess generation which will bring with it a financial penalty due to the extra installed capacity required. These studies assume that Europe acts as a whole unit, with no barriers to the movement of energy and the energy flows around different parts of the grid are not considered. In this situation, it would in reality be necessary to look at the flows in and out of different regions in order to ensure that there is enough transmission capacity. It is also important to make sure that there is enough mismatch between generating regions and regions with energy storage systems to ensure these are charged and discharge appropriately.

A prominent study that has been carried out on a global scale investigates the feasibility of supplying all energy requirements from renewable sources, or more specifically from wind, water and sunlight (WWS) (Jacobson and Delucchi, 2011a). In the first part, an investigation into the technologies, resources, infrastructure requirements and materials was carried out. The focus of this study was mainly on the energy supply, although mention was made of some of the demand-side energy conservation measures that should be employed where possible. The proposed scenario to supply the global energy from WWS includes 3.8 million 5 MW wind turbines (50% of demand in 2030), 49,000 300MW concentrated solar power (CSP) power plants (20%), 40,000 300MW solar PV power plants (14%), 1.7 million 3kW rooftop PV systems (6%), 5,350 100MW geothermal power plants (4%), 900 1,300MW hydro power plants of which 70% already in place (4%), 720,000 750kW wave devices (1%) and 490,000 1MW tidal turbines (1%). These figures were arrived at by considering the location and availability of natural resources and factoring in some constraints such as removal of remote locations and only considering land mass between 50˚N and 50˚S for solar resources. The equivalent footprint required for all this installed capacity is roughly 0.74% of global land area. If existing hydro capacity is taken into consideration and the fact that a majority of the wind resource is located offshore, the footprint reduces to about 0.41%. It is noted that the development of this scenario is not likely to be constrained by availability of materials, although some degree of recyclability of rare earth materials will be required.

In order to implement this scenario, the existing grid infrastructure would need extensive expansion to accommodate new renewable generation and consumers' behaviour toward the use of alternative vehicles and efficiency measures would have to significantly be altered (Jacobson and Delucchi, 2011b). The installed renewable generation capacity would need to exceed the maximum peak demand requirements and complementary generation from various sources need to be considered in order to ensure that demand is met at all times. Excess generation produced when demand is low would be put toward other uses such as producing hydrogen for transportation. The scale of transformation of the whole energy sector to renewable energy is comparable, in size at least, to past projects that have been undertaken in recent history. For example, the Apollo Space programme successfully put a man on the moon in the space of 10 years at an estimated cost of GBP 64 billion (Lafleur, 2010) or around 1% of the US GDP in 2012 (TheWorldBank, 2013). To put this into context, the 2012 Department of Energy budget was GBP 18.9 billion, of which GBP 3.6 billion is dedicated to energy resources (DOE, 2013). These projects may differ in economic, political and technical aspects, but they suggest that large scale projects can be undertaken given the right governance and political backing.

There have been two studies that consider the fully renewable system in the UK. The first study considered the county of Cornwall and was chosen to test the In*vert* model's strengths and limitations (Ragwitz et al., 2005). One of the main findings was that the particular policy structure in the UK was not compatible with the model and would require adaptation in order to provide a policy making tool. On the other hand, the INFORSE tool was selected to model the whole of the UK in the Zero Carbon Britain 2030 study (Kemp and Wexler, 2010) in which a fully integrated solution to climate change is explored in order to meet an 84% chance of avoiding a 2°C warming over pre-industrial temperatures. This study focused on energy demand, energy supply and land use to provide a carbon free scenario along with the need to increase efficiency of transportation and buildings, behavioural changes and increased usage of waste resources. The report highlights the need to adopt electricity as an energy carrier to replace fossil fuels in transportation (although there are limitations to the penetration in this sector) and buildings. Additionally, renewable generation is expected to play a key role of replacing fossil fuels for electricity generation, with wind being highlighted as providing up to 80% of generation. In order to maintain balance, this capacity will need to be backed up, which the report concludes could be from biogas and demand side management. It is also envisaged that renewables will also be used to generate alternative energy carriers such as hydrogen which can be used in the transportation, domestic and energy sectors. One of the conclusions from this report was that it will require a high political will to implement these changes in the energy system, but ultimately the economic, environmental and social benefits will bring about a brighter and sustainable future.

However, there are many issues that remain uncertain in the fully renewable system. Three main factors that need to be taken into account in these studies are the embodied energy costs of generating energy from renewable sources, the transmission penalties of energy over long distances, and the amount of backup generation required to ensure demand is met when conditions are not favourable for renewable generation (Trainer, 2013). More key issues with the planning methodology used that highlight the flaws in technical and technological limitations of renewable energy sources are that variable sources by nature cannot provide continuous energy supply to consumers, requiring large amounts of energy storage (Glasnovic and Margeta, 2011). It is also important to note that RES do not substitute conventional power stations unless there is sufficient storage available to ensure peaking plant is not required. The regional dispersion of RES can have the effect of smoothing power output and increasing security of supply, but there is no way to ensure that electricity demands will be guaranteed unless installed capacity is much greater than the average output required. This though would have a high economic penalty and would also lead to reduced efficiencies in the system. Moreover, Trainer (2010) argues that relying on renewable energy as a ‘technical fix’ that will ensure current affluent lifestyles are maintained in the carbon constrained future will not be achievable unless there is a radical change in the social, political, economic and cultural systems.

These are some of the issues that need to be further investigated when considering a fully renewable electricity grid. However, it has been noted that the main barriers to a 100% renewable system are not technical, but in fact depend on the political, societal and economic constraints that exist in the current energy sector.

2.8 Summary and Discussion

Chapter 2: introduced the background to the main question of the thesis. In it the outline of the UK electricity network, demand and supply issues are discussed and presented. There is also a discussion on the proposed future upgrades to this network and on the projections for new installed capacity.

The various renewable energy resources are introduced and in the context of the UK, the maximum amount of available resource is provided. This illustrates the energetic position in which the UK is located in terms of the amount of electricity that can be harnessed if exploited fully. If the lower estimate for electricity generation from renewable energy is achievable, it has been calculated that this is still over twice the electricity demand in 2013.

The grid solutions for the integration of renewable generation have been introduced. The challenges and potential benefits of the distributed grid is discussed and the applications in this thesis considered.

The technological advances that have made electricity transmission over great distances have been discussed. The benefits of using HVDC technology to interconnect various electricity networks have been highlighted and the expected costs to implement this are given. The feasibility of using interconnection technology to integrate a massive penetration of renewable electricity onto an electricity network has been investigated.

A third technological solution, energy storage has been described. Details of different technologies and costs along with the needs from the electricity network and the solutions that energy storage can provide have been investigated. The assumption going forward with energy storage is that the technologies to be considered will need to be able to cope with large amounts of electricity and also be able to store this electricity over extended periods of time.

Going into Chapter 3:, the technical aspects and assumptions introduced in this Chapter will be drawn upon to provide light on the possibilities of each technology described.

Chapter 3: The UK of the Future

This Chapter considers the electricity demand scenarios in the future that are taken forward in this study and the resultant generation capacity required to meet these. The concluding discussion is on the resultant balancing issues arising from the supply-demand profiles. The scenarios introduced and their respective variability studies will be taken forward to illustrate potential technological solutions in the next Chapters.

3.1 Introduction

Understanding how the future electricity grid will develop and cope with rising pressures from government policies, carbon emissions constraints and energy security is important for the electricity industry. The transition to using new sources of energy and electricity generation such as renewables is a complex issue as it necessarily draws upon technology innovation, society and economics amongst others (van den Bergh and Bruisma, 2008).

Developments in technology are often conservative and incremental rather than revolutionary. This is mainly due to the very high expectations in reliability of the end product, in this case electricity, which the industry faces. Added to this is the fact that conventional plant have long lifetimes which means that the pace at which the existing technologies will be replaced and superseded by renewable generation is most likely to be slow.

There have been many studies looking into the evolution of the electricity grid in the future and what technologies are likely to be employed. These generally focus on the near to mid-term timescale up to 2030.

A report by Sustainability First (Hesmondhalgh, 2012) has conducted a demand-side model for the UK electricity grid in 2010 and 2025. This model looks at demand reduction and flexibility in the UK electricity grid up to 2025. A consortium made up of industry and academic experts have published the ‘Zero Carbon Britain 2030’ report (Kemp and Wexler, 2010) in which a fully integrated solution to climate change is explored. This involves looking at energy demand, energy supply and land use to provide a carbon free scenario. One of the key conclusions from this report is that it will require a lot of effort to implement these changes, but the economic, environmental and social benefits will bring about a brighter and sustainable future.

The UK transmission grid operator National Grid has published analysis on likely scenarios of future grid developments up to the year 2030. National Grid has defined three pathways: Slow

Progression, Gone Green and Accelerated Growth (NationalGrid, 2012). Each of these scenarios aims to meet the UK and EU legislation targets for renewables and greenhouse gas emissions. However, the Gone Green scenario has been derived as the central scenario, which means that the scenario has been put together in order to ensure targets are met within the set timescales, and the Slow Progression and Accelerated Growth scenarios have slower and faster timescales respectively. The key characteristics of these scenarios are described in Table 3-1. As discussed earlier, the contribution from renewable energy sources is limited by the existing generating plant operating in the electricity grid. However, these scenarios pave the way to increasing the amount of renewable generation on the electricity grid.

Table 3-1: Summary of National Grid future scenarios characteristics (Collated from information in (National Grid, 2013a))

Scenario name	Peak Demand 2030 (GW)	Installed Capacity 2030 (GW)	Renewable Contribution (%)
Slow Progression	57	102	29%
Gone Green	61	126	41%
Accelerated Growth	66	149	46%

This analysis also makes assumptions on the amount of interconnector capacity that will be available to the electricity grid. The range anticipated is from 6.6GW for the Slow Progression scenario to 11.6GW for the Accelerated Growth scenario. It is expected that due to the increase in renewable generation, the UK will become a net exporter of electricity to Ireland and continental Europe. The importance and potential future requirements of interconnectors for the purpose of this Thesis will be discussed in Chapter 4:.

As discussed, this Thesis looks at the post-2050 future electricity grid scenario where all electricity generation is met by renewable energy sources. A set of demand scenarios up to 2050 have been developed as part of a collaborative research project: the SUPERGEN - Future Network Technologies. This project encompassed electricity industry and engineering companies, government and university researchers. The objective is to find engineering solutions to the problems faced by the high reliance on renewable energy sources (EPSRC, 2003). As a result of this programme, four scenarios have been developed for 2020 (Ault et al., 2006) and six scenarios have been developed for 2050 (Elders et al., 2006) based on a set of technical, economic, environmental and regulatory possibilities. Due to the short time-scale and the limited penetration of renewable energy sources of the 2020 scenarios these are not discussed further. The 2050 scenarios have been considered with the following key parameters:

- **Economic growth**: influence factors such as increase in energy demand and investment in energy technology. This parameter is considered using the following range:
    - Low growth – growth is significantly less than recent levels, or 0.25% per annum

    - High growth – growth is somewhat higher than current levels, or 1% per annum
- **Technological growth**: influences the uptake of new technology in the electric power networks. This parameter is considered using the following range:
    - Revolutionary development – radical new technologies are developed and applied, such as a high uptake of renewable generation, energy storage solutions and advanced power-electronics, and a move away from centralised electricity production
    - Evolutionary development – technological advance is restricted to gradual improvements of current technologies, with a small switch to other energy sources due to the increase in fuel costs and maintaining the centralised electricity system
- **Environmental attitudes**: the strength or weakness of prevailing environmental attitude determines factors such as emissions constraints and incentives for power networks to accept renewable sources. This parameter is considered using the following range:
    - Weak – environmental concern reduces in comparison to current UK situation
    - Strong – popular and governmental concern for environment is strengthened significantly from current situation
- **Political and regulatory attitudes**: concerns the attitude of government and society in general to manage and develop the energy industries. Two policies are considered:
    - Liberalised – preference for light regulation and a market-driven approach
    - Interventionist – centrally directed model of management and development adopted

With this approach, a wide range of possible future scenarios has been captured and it provides a view of possible development paths. These parameters have been combined to yield the six scenarios described in Table 3-2 below. It could be argued that by limiting future scenarios to the six described, very radical scenarios or technologies are not accommodated. However, it is intended that the majority of potential future developments are covered within the range selected. In the present market, and taking into consideration the inherent conservative approach of the electricity industry, it is highly unlikely that there will be 'game changing' technology developments in the foreseeable future.

It is important to note at this point that the exploitation of shale gas reserves is not covered by the scenarios outlined above and it is likely to change the energy policies in the near term. Whilst this can be seen as a ‘game changing’ resource, it is still a finite resource and, as discussed in the drivers for this Thesis, the object is to understand the effects of energising the UK electricity grid solely through renewable resources. This would only delay the uptake of a fully renewable electricity grid. As such, the scenarios introduced will be carried forward.

Table 3-2:Names and key parameters of UK electricity industry scenarios for 2050 (Elders et al., 2006)

Scenario name	Economic growth	Technological growth	Environmental attitudes	Political and regulatory attitudes
Strong Optimism	More than recently	Revolutionary	Stronger	Liberalised
Business as Usual	Same as recently	Evolutionary	As present	Liberalised
Economic Downturn	Less than recently	Evolutionary	Weaker	Liberalised
Green Plus	Same as recently	Revolutionary	Much stronger	Liberalised
Technological Restriction	More than recently	Evolutionary	Stronger	Liberalised
Central Direction	Same as recently	Evolutionary	Stronger	Interventionist

For the purpose of this Thesis it has been decided to consider two of the scenarios introduced above to illustrate how demand can be met by renewable energy sources and the requirements needed to maintain security of supply. The selected demand scenarios are Business as Usual (BAU) and Green Plus (GP). This selection provides two fundamentally different, albeit realistic, demand scenarios for discussion:

- **Business as Usual (BAU) scenario**: as the name suggests, this scenario represents a continuation of current trends. There is an increase in energy demand driven by an economic growth of 1% per annum. Total demand for the UK in 2050 is approximately 540TWh/year. The contribution from renewable sources is 30% and existing interconnectors are upgraded to accommodate further import/export with Europe.
- **Green Plus (GP) scenario**: strong application of efficiency measures reduces the demand from energy services, however demand increases by 0.25% to 2050. Demand in 2050 is approximately 390TWh/year. Renewable contribution in this scenario is 80% and there is an expansion of interconnectors with Europe.

The characteristics of the chosen scenarios are summarised in Table 3-3.

Table 3-3: Summary of electricity demand scenario characteristics (Elders et al., 2006, DECC, 2014a, DECC, 2014b)

Scenario name	Average annual demand growth	2050 Electricity demand (TWh)	2050 Installed capacity (GW)
Business as Usual	+1%	540	110
Green Plus	+0.25%	390	110
Present (2013)	-	373	85

These demand scenarios have been chosen for further analysis into the grid requirements in the future as they represent two realistic and fundamentally different pathways.

In addition to this study, The Department of Energy and Climate Change (DECC) published the 2050 Pathways Analysis (DECC, 2010). In this report the focus is not only on electricity, but also on transportation. Alongside the report, there is a freely accessible tool, the '2050 Calculator' (DECC), in which users can calculate the impact of differing uptakes and constraints of various technologies and lifestyle choices. The output is presented in terms of the demand for energy by sector, the supply of that energy by source and the UK greenhouse gas emissions of the pathway created. Whilst this study and tool provide a good view of possible future pathways and enables the user to experiment with a wide variety of parameters, there is no possibility to source all energy from renewable sources. Also, whilst the understanding is that energy security is not compromised in the pathways, there is no mention of how the electricity grid will manage the increase in variable generation.

Yet another long-term study is the ‘Powering the Future’ report (Wilson et al., 2009) which analyses potential paths to a low carbon future in 2050. This report, like the others, still limits the penetration of renewable energy sources in favour of existing and next generation fossil fuel plant.

The above studies provide a suit of least cost optimisation models that provide a view on future technology pathways. However, they do not consider the spatial implications for energy across the UK. A dynamic spatial model of the UK electricity network has been constructed that considers the evolution in supply and demand between 2010 and 2050 (Allen and Varga, 2014). This model achieves the required 80% reduction in carbon emissions by 2050, however it also includes the pipeline of closures and new capacity that is planned. The model provides six scenarios which cover a range of assumpions from high levels of offshore wind, with varying levels of cost levels for technology and CO_2 tax, to low levels of wind and high nuclear. All but one of the scenarios have been shown to meet the carbon reductions required both financially and technologically.

However, a limitation or barrier in all these studies is that it is either assumed or necessary (as these are transitional analyses) that conventional fossil fuel plant will still be available to cover demand at times when supply is not met by renewable energy sources.

The aim of this chapter is to investigate what a viable future UK electricity mix using only renewable energy sources (RES) might look like. It will also highlight the issues of variable supply from these resources and how these can be mitigated to ensure electricity demand is met. The end purpose is to ensure that electricity 'security of supply' is maintained or improved in the future.

3.2 Factors Increasing Electricity Demand in the Future

As introduced in Chapter 3.1, the electricity industry has to adapt to climate change. Traditional projections for how demand would increase in the future are being substituted by energy scenarios that represent a wide spectrum of potential future scenarios. Consumption of electricity is also projected to be used in transportation, for example in electric vehicles (EV), and heating is expected to be supplied by electricity in the future rather than natural gas and other fossil fuels. This will further increase the demand on the grid.

In the following Chapters the effects on electricity demand of electrification of transportation and heating will be discussed.

3.2.1 Electrification of transportation in the UK

The transport sector is the second largest emitter of GHG emissions (SDC, 2006). The challenge with this sector is to reduce the dependency on fossil fuels, gasoline and diesel. Road transport is the principal source of GHG emissions in the UK. The total number of vehicles on the road in the UK is around 31.3 million in 2010, emitting a total of 67.4MtCO_2 (SMMT, 2012). However, vehicle emissions have fallen 10.2% from 2000 due to lower new vehicle CO_2 emissions, better fuel economy and increasing numbers of alternative fuelled vehicles (AFV). The total number of new registered AFV in 2011 is 25,456 (SMMT, 2012). The majority of these were petrol-electric hybrids, 92%, with electric being 4.3%, petrol-alcohol hybrids 3.5%, petrol-gas hybrids 0.3% and diesel-electric hybrids 0.1%. The current numbers of plug-in electric vehicles (PEV), defined as all electric vehicles that draw electricity from the grid, are relatively small. However, projections predict that market saturation of PEV, 75% of new car sales, will have to be achieved by 2027 in order to meet the 2050 CO_2 reduction targets (National Grid, 2011b).

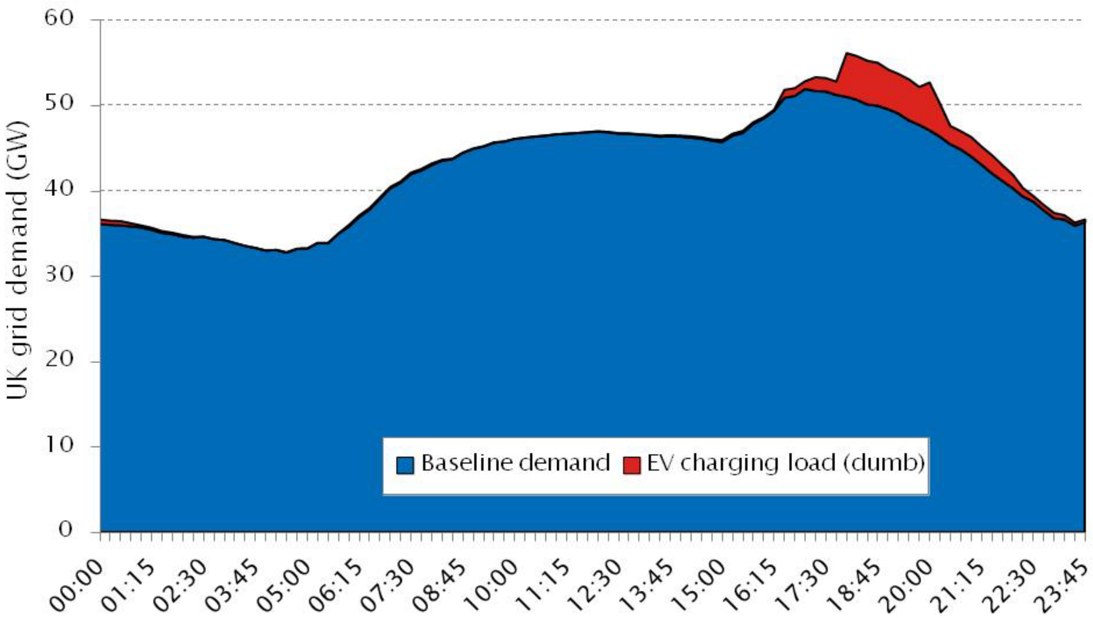
The capability of the electricity grid to incorporate these levels of PEV depends on the base electricity demand and how the charging of said vehicles is carried out. The two main charging models are 'dumb' charging and 'smart' charging.

- **'Dumb' charging**: This scenario assumes that all vehicles are plugged in, and begin charging, immediately when they return from their last journey of the day. This is the most straightforward scenario, with no smart control of charging by the utility, and no smart usage of low tariff electricity by the vehicle owner.
- **'Smart' charging**: This scenario assumes that a control system can be put in place that can instruct specific chargers to begin or stop charging, or limit charge rate, so that the total demand for EV charging at a particular time can be dictated by the system. This scenario represents the ideal situation where the overall load on the grids is levelled, so that valleys of demand are filled and existing peaks are not increased.

To illustrate these scenarios, a study has been done on the UK grid (Downing and Ferdowsi, 2010). The study is conducted on the average grid demand for the winter months of 2009, assuming a 10% penetration of PEV in the UK vehicle fleet, average daily trips of 40 kilometres and using a battery charge rate of 3kW (i.e. a 30kWh battery which is charged over a period of 10 hours).

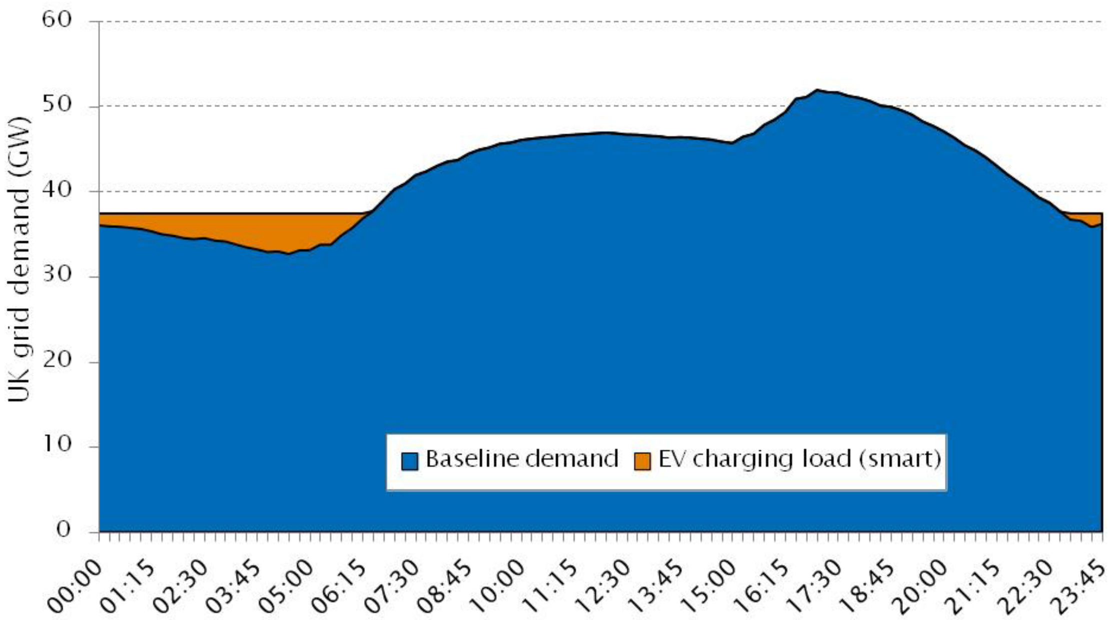
In the case of a 'dumb' charging scenario, the effects of all PEV charging at the end of the working day is an increase in peak electricity demand to 56.2GW from a baseline of 52GW, with the peak demand from charging being close to 5.6GW (Figure 3-1).

Figure 3-1: Effect of 'dumb' charging on UK electricity demand - winter 2009 (Downing and Ferdowsi, 2010)



The impact of the 'smart' charging scenario is illustrated in Figure 3-2. It can be seen that the preferred scenario is for the PEV to charge during the valley period, when there is the least demand on the network. This would also make use of cheaper electricity prices. In this instance, the peak evening load remains unchanged. However the peak demand from charging is only 4.7GW, 15% lower than in the 'dumb' charge scenario. This reduction in peak charging demand is achieved thanks to time-of-use tariffs or smart control systems.

Figure 3-2: Effect of 'smart' charging on UK electricity demand - winter 2009 (Downing and Ferdowsi, 2010)



The ‘smart’ charging scenario has the least impact on the electricity grid and allows for greater integration of PEV. It also has the added benefit of providing load levelling to the grid. However, in order to be able to implement this, extensive investment and work has to be carried out to develop safe and secure technology that will enable this. A further benefit of having this increased control over the charging capability of PEV is the potential to be able to use the storage capacity within the vehicles to balance renewable generation on the electricity grid, thereby reducing the need for costly investment in new transmission and distribution capacity.

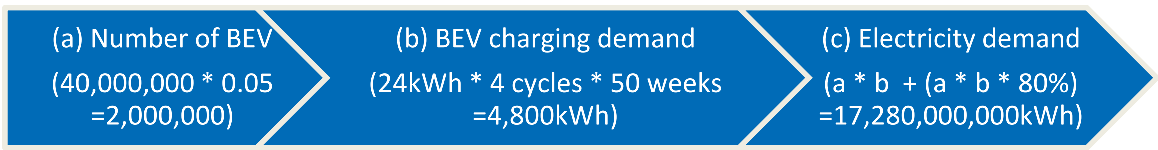
3.2.1.1 Uptake of PEV in the UK

For the purpose of this thesis, it has been assumed that electric vehicles that plug into the electricity grid will feature in the fully renewable electricity grid. To enable the calculation of the uptake of vehicles in the UK, it has been proposed that an existing projection of 458,850 battery electric vehicles (BEV) and 1.529 million plug-in hybrid vehicles (PHEV) by 2030 is used (Hassett et al., 2011). These projections have been made with the assumption that the UK vehicle parc in 2030 is 40 million vehicles. The above projections would be 1.15% and 3.82% of the vehicle park respectively for BEV and PHEV. For the scenario under consideration, it is assumed that the uptake of BEV and PHEV accelerate and would account for a total of 5% of the vehicle park being BEV and 12.5% being PHEV. This growth would mean that for an assumed vehicle parc of 40 million vehicles, 2 million would be BEV and 5 million would be PHEV.

In order to calculate the annual electricity demand, and hence the amount of energy storage that may be available as storage, it has been assumed that the average battery capacity of a PHEV is 9kWh (based on the average of the battery capacity of the Toyota Prius plug-in, Chevy Volt and BMW i8) whereas for a BEV battery capacity it is assumed to be 24kWh (based on the Nissan Leaf (Nissan, 2014)). It is also assumed that the battery charging and discharging efficiency is 80% for both BEV and PHEV (Valoen and Shoesmith, 2007) and that UK vehicle usage averages out at 50 weeks per year, with four full charge/discharge cycles per week.

With the above assumptions, it is possible to calculate the total amount of electricity demand from both BEV and PHEV using the process illustrated in Figure 3-3.

Figure 3-3: Methodology for calculating the yearly electricity demand from charging BEV in the future electrified scenarios



Using this methodology, it is possible to calculate that the yearly electricity demand required for charging BEV is 17,280,000,000kWh. The demand for charging PHEV can also be calculated using this methodology, though the percentage of vehicle parc will be higher (12.5%) and the battery capacity will be lower (9kWh). However, due to the higher number of vehicles, the electricity demand for PHEV is 16,860,000,000kWh. Therefore, it is calculated that the total yearly electricity demand expected from charging both BEV and PHEV is in the order of 34TWh per annum.

3.2.2 Electrification of thermal loads in the UK

Heating of the 26.7 million domestic household and around 3 million commercial and public buildings in the UK in 2011 required over 500TWh per year, around a third of all UK energy demand in that year (DECC, 2012i). In order to meet GHG targets there will need to be significant cuts in emissions from heating. Currently the main fuels used to supply UK heat are natural gas and oil which emit large CO_2 emissions. There are solutions to help reduce these emissions through building and energy efficiency, for example by improving insulation, or by reducing the carbon intensity of heating. One option for reducing the carbon intensity of heating is to switch to heat pumps which run on electricity to convert heat from a cold source to useable heat on a 1:3 ratio (one unit of electricity to produce three units of low grade heat). A simple calculation has estimated that for every 10TWh of annual heat load provided by heat pumps, an extra 0.75GW of additional electricity capacity is required to be supplied by the electricity grid (BAU). Due to the low grade heat that is delivered with this technology, only around 200TWh of the UK's heat demand can be provided by heat pumps. From the estimated calculation above, this equates to an added electricity capacity of 15GW per annum on top of the annual capacity required for electricity demands. It is important to note that while this extra capacity is required year round, the energy to run these heat pumps would only be required through the winter months due to the nature of heating demand.

3.2.2.1 Uptake of heat pumps in the UK

For this study it has been assumed that there is a mass uptake of domestic heat pumps to supply all space heating. This can be supplied by a number of heat pump technologies, however in this case it has been assumed that the technology used is air source heat pumps (ASHP) with a coefficient of performance (COP) of 3.5 as detailed in Cabrol and Rowley (2012). This assumption has been made as ASHP technology poses the least constraints in terms of site specific requirements and can be readily retro-fitted to existing building stock. As well as supplying space heating, it has also been assumed that ASHP can supply a portion of domestic hot water demand that will be discussed later.

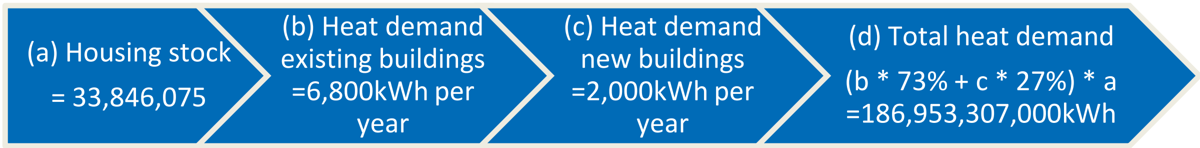
To calculate the future heat load associated with housing, future projections of the make-up of the domestic housing stock have been used. The current projections put the number of houses in 2050 to increase to circa 34 million properties. This figure has been calculated, taking into account a demolition rate of 0.1% per year on the 2011 housing stock of circa 26 million (ONS, 2012, GRO-Scotland, 2012) and a new build rate of 9 million properties as given in Arran and Slowe (2012). Using the methodology in Figure 3-4, this equates to 27% of the future stock being new build whereas 73% are made up of existing buildings.

Figure 3-4: Methodology for calculation of future UK housing stock in 2050

The zonal distribution of the building stock in 2050 has been assumed to be linearly scaled from the 2011 census information (ONS, 2012, GRO-Scotland, 2012).

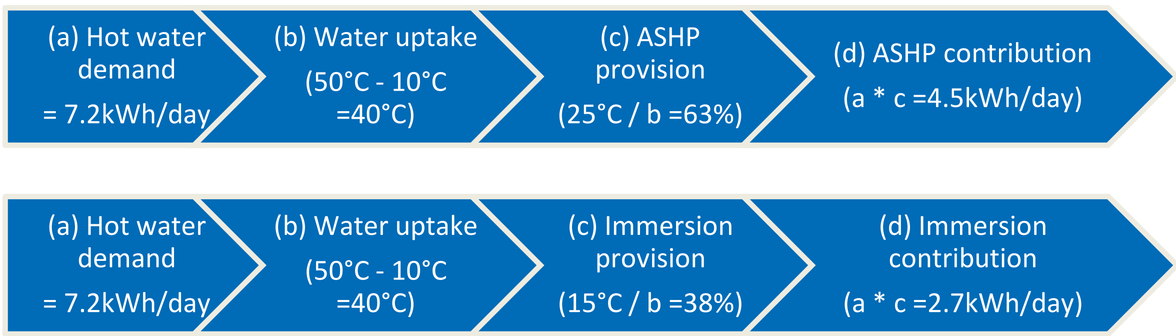
From Boardman et al. (2005) it has been taken that heat demand from existing buildings is 6,800kWh per dwelling per year whereas for new build this is 2,000kWh per dwelling per year. Taking into account the spread of housing given, this equates to a total heating demand of around 187TWh per year in the UK (Figure 3-5). As it is proposed that all this demand be supplied by ASHP, the total electricity demand to supply the heat demand is calculated to be 53TWh/year after taking into account the COP of 3.5 and due to the increased efficiencies of this technology.

Figure 3-5: Methodology for calculating heating demand from buildings (in kWh per year)



For hot water contribution, it has previously been estimated that daily hot water demand in the UK is 7.2kWh per day per house (Boardman et al., 2005). This is calculated on the assumption that hot water usage per household is 123 litres per day, that the energy content of water at 40°C is 2,225kWh/year per household and also accounting for a distribution loss of 393kWh/year per household (BRE, 2009). It has been assumed for this calculation that hot water is delivered at 50°C and that the inlet water temperature to the household is 10°C (EST, 2008). This gives an uptake temperature requirement of 40°C from inlet temperature to delivered hot water. It is further assumed that the ASHP can provide a maximum uptake of 25°C, with the remaining 15°C being supplied by efficient electricity immersion heaters. Therefore in terms of electricity demand, the ASHP will require 4.5kWh/day, calculated as 63% of the 7.2kWh/day hot water demand and immersion heaters will require 2.7kWh/day to top up the hot water requirements (Figure 3-6).

Figure 3-6: Methodology for calculating the ASHP and immersion heater electricity demand for hot water (in kWh/day)



However, as with heating, the ASHP has a COP of 3.5 which means the electricity demand required for the calculated hot water contribution from ASHP becomes 1.28kWh/day. Therefore, as this is a two stage heating system, the total demand per household will be 3.97kWh/day, which is the sum of the ASHP electricity demand (1.28kWh/day) and the immersion heater demand (2.7kWh/day). The total yearly electricity demand for hot water is therefore circa 49TWh/year for a building stock of 34 million properties.

This gives a total figure of 102TWh/year of electricity demand for heating (54TWh) and hot water (49TWh). This demand will have to be added to the yearly demand profile in the two scenarios that will consider electrification of heating and therefore increase the overall electricity demand.

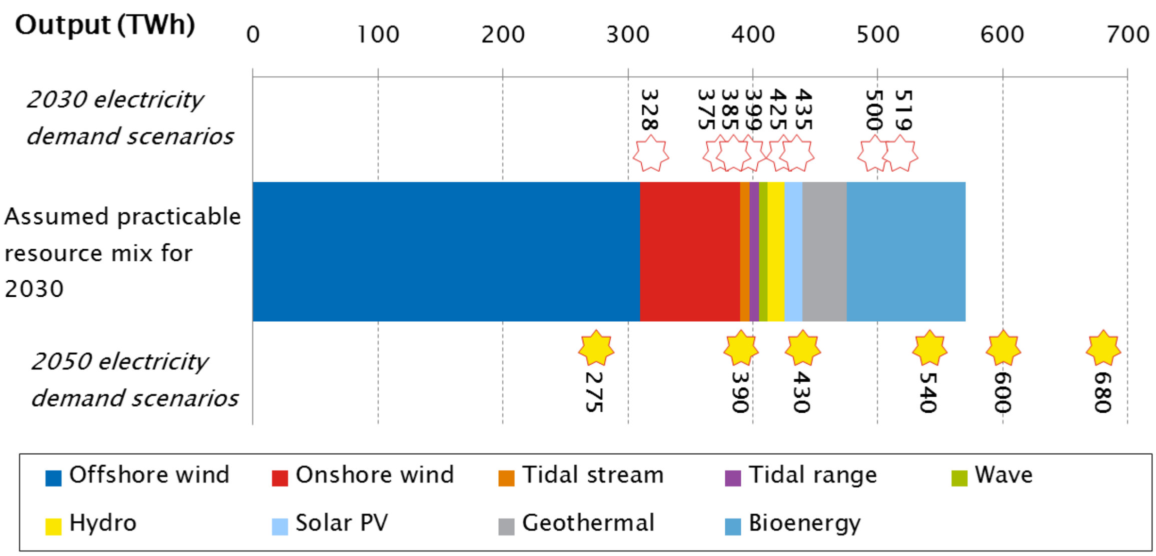
For this discussion, it has been assumed that ASHP in domestic properties can be regulated by a central operator in order to reduce or increase the electricity demand from the systems to be able to balance the variable supply from renewable generation throughout the year. A study conducted on the integration of variable renewable generation through balancing with ASHP has shown that in the case of Germany between 20-30% of electricity demand for domestic heating can be shifted during the winter months so long as there is dedicated control systems (Fischer et al., 2014), showing that this could be feasible in the future scenarios. However, this will only be available for the demand contribution from ASHP. From the calculations above, we have estimated that the ASHP heating demand is 53TWh per year and that the contribution that ASHP can provide to the hot water demand is 16TWh per year, taking into account that only 1.28kWh/day is from ASHP. Therefore the total amount of demand that can be controlled from the through the electrification of heating and hot water will be circa 69TWh/year.

3.3 Future UK Electricity Supply and Demand

In this Chapter the main assumptions and calculations are undertaken relating to the future electricity supply and demand scenarios.

As stated, the future electricity grid will be fully supplied by renewable energy sources. A study of the future available renewable energy in the UK suggests that there is enough capacity to generate up to 570TWh per year from renewable sources (Gardner, 2011). However, this report only considers up to the year 2030. Figure 3-7 illustrates the practicable resource mix from this work which is based on what is technically achievable. As well as this, the figure shows the projections of future electricity demand required in 2030 and 2050 as introduced in the studies in Chapter 3.1.

Figure 3-7: Development of renewable capacity in the UK to 2030 and projected annual UK annual demand requirements for 2030 and 2050 illustrated as stars (Gardner, 2011)



It can be seen that, in many cases, the proposed mix of renewables by the Gardner (2011) study can supply forecasted demand scenarios in 2030 and in most cases of forecasts for 2050. For that reason, it is determined to use the RES mix from this study as a suitable baseline that satisfies a wide range of forecasted demand projections.

From this information, it is possible to build up a picture of the expected capacity of RES that would be required and where these would be located on the UK network.

To start with, data from existing renewable energy generators in the UK is collected and analysed. The most comprehensive database found comes from the Renewable Energy Foundation (REF, 2013). This contains information on sites across the UK which generate electricity from renewable sources under the Renewables Obligation (RO) (ofgem, 2013). Information supplied include generator name, capacity (in kW) and technology (see Appendix C – Sample of UK Renewables Obligation Generators 2013). From this information it is possible to locate each generator within the National Grid designated zones (as introduced in Chapter 2.2.2) and classify these by technology. This provides a picture of the existing renewable generation capacity throughout the UK which will be used in Chapter 3.3.3.

From this base, it is possible to increase the amount of capacity from each technology to match the baseline output calculated by Gardner (2011) (see Table 3-4). It is assumed that extra capacity would be provide at sites of existing generation plant with three exceptions, onshore and offshore wind and PV which will be discussed in further detail below. In all cases, planned increases in RES generation from National Grid contracted background capacity mix up to 2032 (National Grid, 2012b) are included. It is also assumed that all conventional thermal power plant and nuclear is phased out completely.

Table 3-4: Assumed practicable resource mix for 2030 (Gardner, 2011)

Resource	Assumed practicable resource mix for 2030	
	Capacity (GW)	Generation (TWh)
Offshore wind	82	310
Onshore wind	30	80
Tidal stream	2	7
Wave	3	7
Hydro*	4	13
Solar PV	18	15
Geothermal	5	35
Bioenergy	12	95
TOTALS	**156**	**562**
Total dispatchable	*18*	*133*
Total non-dispatchable	*138*	*429*

*Note that Gardner (2011) assumes that 75% of hydro capacity is run-of-river, and hence non-dispatchable, and remaining 25% capacity is reservoir, and hence dispatchable.

Onshore wind generation. The majority of existing generation from wind comes from onshore sites. As of 2011, the total UK capacity from onshore wind capacity was 4.6GW (DECC, 2012d). In order to satisfy the future grid needs, onshore capacity needs to total 30GW (see Table 3-4). It has been assumed that the extra capacity required will come from the development of existing wind farms. This has been carried out by assuming an up-scaling of capacity of each wind farm to meet the required 30GW capacity.

Offshore wind generation. Due to the interest in this technology and the potential that this resource has to provide a large part of the UK's electricity demand, there is extensive information about the planned exploitation of this source. The majority of future wind farm development in the UK will be seen at offshore sites (The Crown Estate, 2012) (see Appendix D – UK offshore wind projects under development). As of 2010, there is up to 47GW of offshore wind capacity either in the planning or development stage in the UK. As can be seen in Table 3-4, a baseline offshore capacity of 82GW is required to meet the Gardner (2011) scenario. The additional capacity is assumed to come from further development of the planned sites identified by The Crown Estate (Arwas et al., 2012). Please note at this stage, that the assumed required capacity of 82GW is only a baseline required to meet the Gardner (2011) scenario. As will be discussed later, a higher offshore generation capacity will be required in order to meet the demand scenarios discussed in the following Chapter. It is proposed that any extra renewable generation capacity will come from offshore wind as this potentially proposes the least constraints for expansion in terms of public opposition and geographical footprint.

PV generation. As has been explained in Chapter 2.3.3.4, it is unlikely that there will be solar installations based on concentrated solar power in the UK in the future. Therefore, calculating capacity increase from PV is carried out in a different way to the other renewable technologies. The required capacity from PV to meet the Gardner scenario is 18GW. The installed PV capacity in 2011 in the UK is 975MW. The majority of this capacity is generally from private households, though there are a number of centralised PV farms with capacities of up to 45MW, like the East Hanney Solar Farm in Oxfordshire (Mallet, 2013). However, for this thesis it is proposed that only domestic scale PV systems are modelled. In this case, it is possible to calculate the potential PV capacity based on the UK housing stock. Installation data of PV systems up to 4kW shows that 1.5% of the building stock across the UK installed PV systems in 2013 (DECC, 2013c). This suggests that the proposed target is achievable if current uptake is maintained. Further discussion on this will be given in Chapter 109.

3.3.1 Future electricity supply

To build the supply model, hourly or half-hourly data has been collected where possible for electricity demand and generation from renewable energy sources (RES) on the UK electricity network. The year 2011 has been chosen as the baseline as it provides an up to date dataset and is found to be an 'average' year, based on the ratio of the yearly minimum to maximum demand compared with the previous 10 years (see Appendix E: UK Demand Profiles 2002-2012 (National Grid, 2013d)). In terms of the weather, 2011 is found to be 0.5°C above the 1971-2000 average temperature (MetOffice, 2011). It is also found that the average wind speed of 4.6m/s in 2011 is 0.05m/s higher than the 10 year mean (2002 to 2011), however, it is shown to be less windy than average in the first quarter of the year and the reverse is observed in the final quarter of the year (DECC, 2012m). These factors make the 2011 demand profile representative of 'normal' operation of the electricity network. The main sources of data collected for this study and the way in which they are used are described in Table 3-5. Data collected necessarily come from varying sources. For this reason, in some cases data used for profiles has been provided in half hour increments or hour increments, depending on what was available. All data has been converted to hourly time steps for analysis.

Table 3-5: Sources of data to model the 100% renewable UK electricity grid

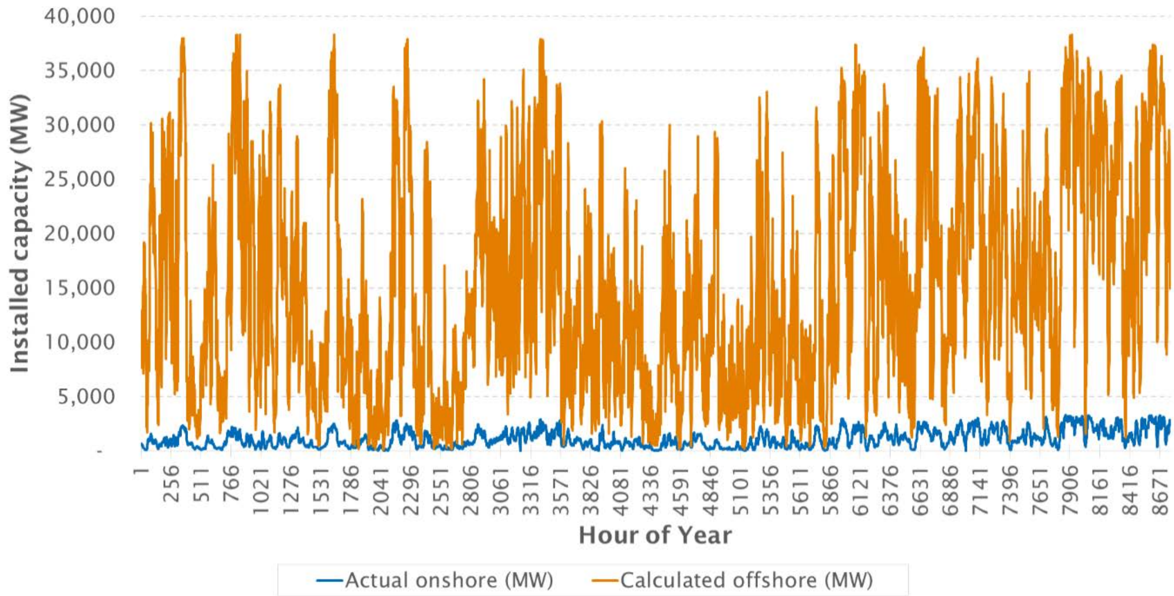
Data collected	Use in modelling	Source
Half-hourly electricity demand data for the UK in 2011	Data averaged to produce an hourly demand profile for the UK which has subsequently been scaled up for future scenarios	(National Grid, 2013d)
Half-hourly electricity generated from onshore wind data for the UK in 2011	Data averaged to produce an hourly generation profile from wind which has been scaled and used for future onshore wind supply	(ELEXON, 2013a)
Hourly wind data at selected UK weather stations for 2011	Data used in the calculation of potential output from future offshore wind farms	(MetOffice, 2012)
Hourly simulation output from High Resolution UK Continental Shelf (UKCS) Model of Pentland Firth (2001)	Data used to calculate potential future output from tidal stream technology	(NERC, 2013)
Hourly solar irradiation, air temperature, wind speed and dew point data from Cambourne (Cornwall), Heathrow (London), Church Fenton (Yorkshire) and Edinburgh (GRO-Scotland) weather stations for 2011	Data required for input into TRNSYS (Transient Systems Simulation Program) model to create an hourly PV output profile for use in future scenarios	(MetOffice, 2012)

3.3.1.1 Future onshore wind generation

For the purpose of this study, the 2011 wind generation profile obtained from ELEXON (the UK balancing and settlement code company (ELEXON, 2013a)) is used as the onshore wind generation profile. This is the basis on which the future scenarios will be extrapolated, using the average load factor for 2011 to calculate the generation output. The ELEXON data provides the actual hourly generation from the installed wind capacity for 2011. This capacity is made up of 4GW of installed onshore wind capacity and 1.3GW of installed offshore wind capacity (DECC, 2011b).

Although the load factor from offshore wind farms will be on average higher than onshore, it has been assumed that with improvements in the future onshore wind turbines and aggregation of the overall installed capacity, these higher efficiencies ae attainable. Therefore, the full hourly profile provided by ELEXON has been utilised to represent the future onshore capacity. The extra required capacity is assumed to be located in existing wind farms across the UK and will be a combination of refurbishment of existing turbines and extensions. In order to obtain the future onshore generation profile, the 2011 hourly generation profile (seen in Figure 3-8) has been linearly scaled to meet the future required capacity. The calculation methodology is: hour X in 2050 = hour Y in 2011 times a scaling factor of 6.92.

Figure 3-8: 2011 hourly wind generation profile (onshore) plus calculated generation profile for offshore wind generation



3.3.1.2 Future offshore wind generation

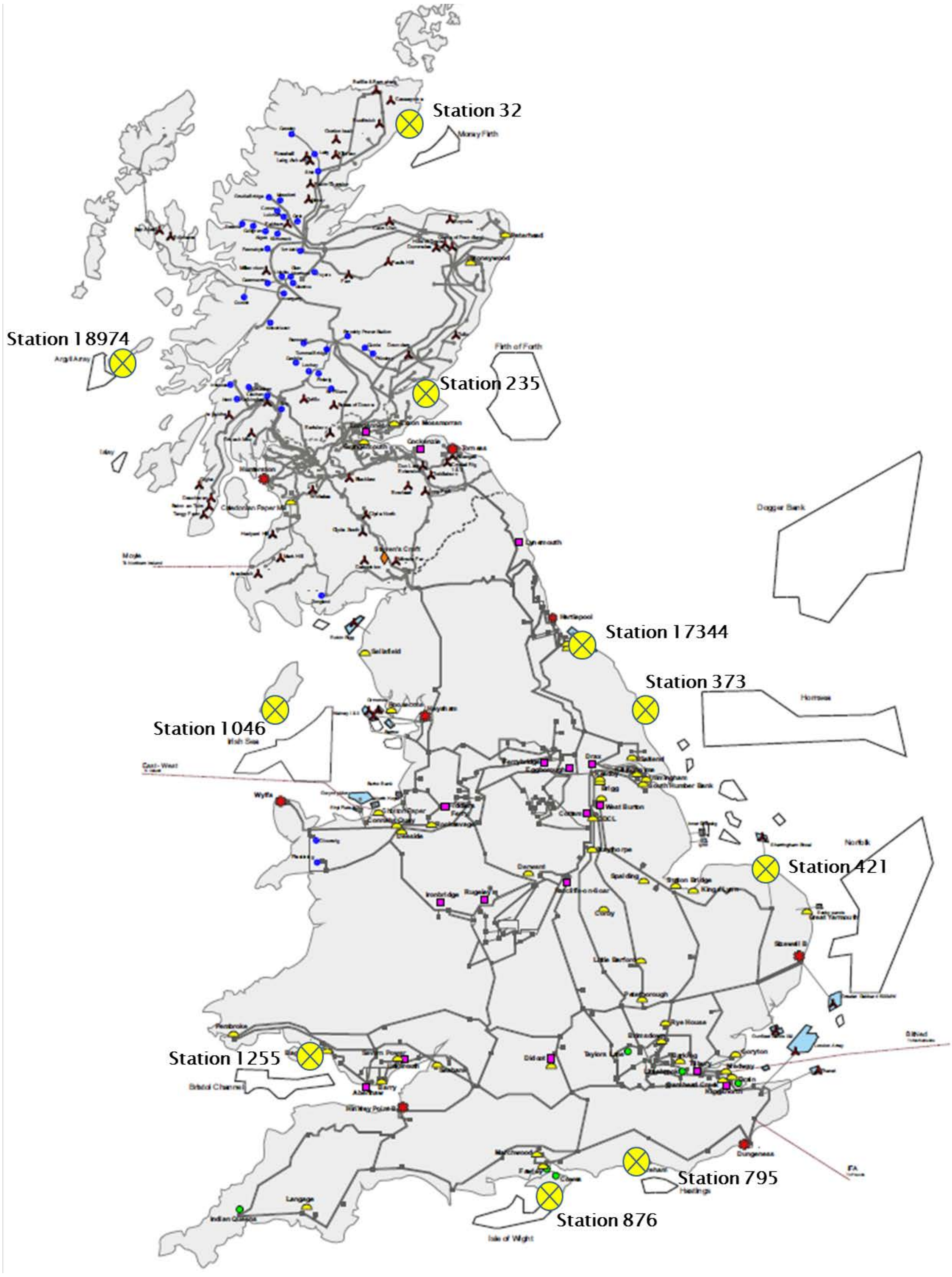
On the other hand, due to the higher wind speeds and low level of development to date, the offshore wind generation profile has has to be calculated. To do this, the Round 3 offshore wind farm locations set out in the UK Offshore Wind Report have been assumed to be the location for all future offshore wind capacity (The Crown Estate, 2012). In order to estimate the wind yield from these sites, a number of weather stations have been identified to obtain actual hourly wind speed data that can be employed to calculate expected generation (MetOffice, 2012).

Figure 3-9 illustrates the Round 3 offshore wind farm locations and also the location of the weather stations. Since there was no offshore wind speed data available for these locations, the weather stations have been chosen as they have a full year's data, are close to the proposed Round 3 locations and are, crucially, on flat ground and on the coast (Table 3-6).

Table 3-6: Summary of weather stations and Round 3 offshore wind farm sites (MetOffice, 2012, The Crown Estate, 2012)

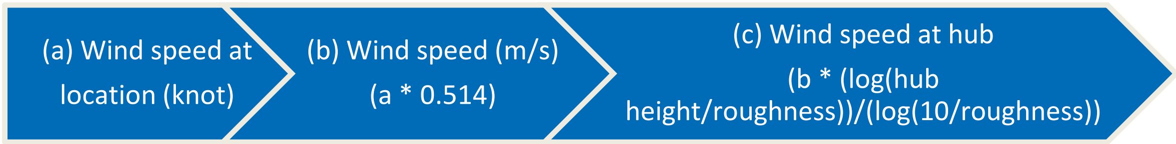
Station ID	Station name	Associated offshore Round 3 site	Observation
421	Weybourne	Norfolk	Coastal greenfield site North of Norwich
17344	Loftus	Dogger Bank	Coastal greenfield site East of Middlesbrough
32	Wick Airport	Moray Firth	Coastal airfield North of Wick
373	Bridlington MRSC	Hornsea	Coastal greenfield site near Bridlington
235	Leuchars	Firth of Forth	Coastal airfield North of St Andrews
1255	Mumbles Head	Bristol Channel	Coastal site West of Swansea
1046	Ronaldsway	Irish Sea	Coastal airfield near Castletown
795	Shoreham Airport	Hastings (Rampion)	Airfield in Shoreham-by-Sea
18974	Tiree	Argyll Array	Coastal airfield on Tiree
876	Wight: St Catherine's Point	Isle of Wight	Coastal greenfield site at St Catherine's Point

Figure 3-9: Location of UK weather stations and Round 3 offshore wind farm locations (The Crown Estate, 2012, MetOffice, 2012))



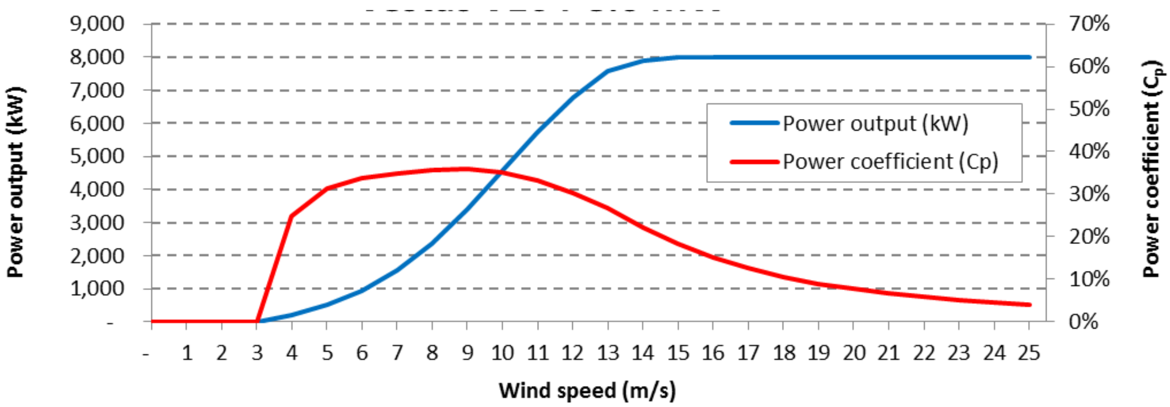
Generation profiles have been calculated using available information of the proposed wind turbines to be used in each of the Round 3 sites available online. For this, the equations for calculating energy from wind provided in Chapter 2.3.3.1 are used. Using wind speed data (calculated using the methodology given in Figure 3-10) and a power curve of expected wind turbines, it is possible to calculate the expected yearly generation and also the load factor from the various locations given. It is also possible to provide an estimate of the number of turbines required at each site.

Figure 3-10: Methodology for calculating wind speed at the hub of a turbine from available data



As an example, the information available for the Norfolk site indicates that the wind turbines to be installed are Vestas V164-8.0 MW (4COffshore, 2013). This model turbine has a hub height of 120 meters and a rotor diameter of 164 meters. The power curve for this model turbine is illustrated in Figure 3-11. With this information, it is possible to calculate the expected hourly generation from this turbine given a wind profile using Equation 2-2. This then provides the total generation available from this model turbine in the specified area

Figure 3-11: Vestas V164-8.0 MW power curve



This process is undertaken for each of the Round 3 locations separately, as there are differing makes and model turbines being proposed for different sites (shown in Table 3-7). It is also possible to calculate the number of turbines required per site based on the proposed installed capacity of each Round 3 location by dividing it by the capacity of the proposed wind turbine (also shown in Table 3-7).

The summary of these calculations is given in Table 3-7. Note that the load factors, calculated as the total generation expected over the theoretical maximum for the site, provided here are calculated based on the extrapolated wind speeds from onshore weather stations. It should also be noted that to calculate the generation output from these sites losses of 11% have been added to account for icing (2%), wake effects (5%) and collector losses (4%).

Table 3-7: Summary of size of turbine, location, number of turbines, calculated annual offshore wind generation (GWh) and load factor

Offshore wind location	Zone	Assumed size of turbine (MW)	Number of turbines	Total yearly generation (GWh)	Load factor
Norfolk	12	8	900	26,391	46%
Dogger Bank	7	10	1,280	45,610	58%
Moray Firth	1	8	188	4,685	40%
Hornsea	8	6	667	9,643	31%
Firth of Forth	5	7	498	8,815	34%
Bristol Channel	13	8	188	5,958	48%
Irish Sea	9	6	698	16,083	47%
Hastings (Rampion)	16	7	95	1,810	35%
Argyll Array	1	10	180	8,786	47%
Isle of Wight	17	8	150	4,265	44%

The total generation calculated from offshore wind, using the above methodology, is 132,045GWh per annum, at an average load factor of 43%. This is relatively high, but expected to be reasonable for offshore locations and the larger wind turbines proposed.

As discussed, the Round 3 sites as they stand do not provide enough installed capacity for the future demand levels modelled. For this reason, the capacity within each location is linearly scaled for each scenario in order to meet the calculated demand. It is to be noted at this point that some of these sites have since been discarded or have had planning revoked on environmental grounds. However, it is assumed that these concerns will be overcome in the future from a necessity to meet a rapidly decarbonising electricity sector.

Another point to consider with this expansion of Round 3 offshore sites to account for the required capacity is the increase in operations and maintenance (O&M) costs due to the accessibility of these turbines. It is expected that these turbines will be located further from shore and as such will require new logistical solutions in order to carry out O&M, based on helicopter support and potentially offshore-based working in the future. It is expected that O&M for the offshore wind industry will be worth up to GBP 2 billion per annum by 2025 (Phillips et al., 2013). Whilst this is an opportunity for the UK industry, this cost will have to be accounted for in the development of offshore wind farms. Therefore, it is likely to be constraining development in the short term as the overall cost would be prohibitive unless the effects of climate change or the cost of electricity/carbon mean alternatives are comparatively more expensive.

3.3.1.3 Future PV generation

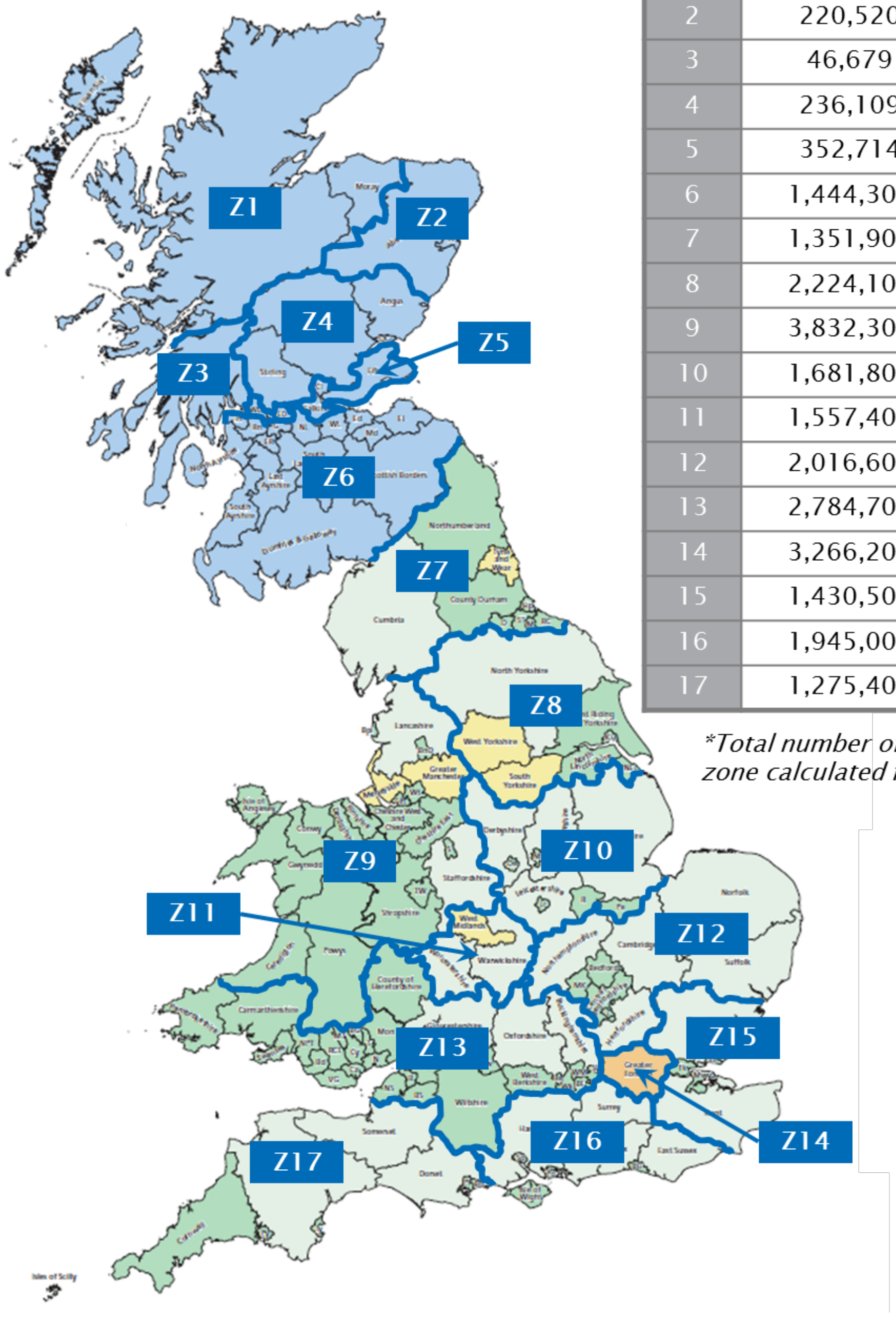
For the purpose of this study, it has been assumed that solar photovoltaic (PV) capacity will be distributed rather than at concentrated installations or solar farms due to land cover issues and planning constraints (DCLG, 2013). Additionally, this stance has been taken to reflect government policy that is looking at biasing installation of PV systems to rooftops in the future (DECC, 2014c). For these reasons, the future UK PV capacity has been calculated assuming that a third of UK households, calculated as being circa 26 million in 2011 for the whole of the UK (GRO-Scotland, 2012, ONS, 2012), install PV on their rooftops. This number has been chosen to account for unsuitable roof spaces, orientations and flats.

The distribution of the UK housing stock can be appreciated in Figure 3-12 and has been categorised, as closely as possible, to match with the electricity network zones introduced in Chapter 2.2.2.

Figure 3-12: Total number of households by zone in the UK and the proportion that has been assumed to have a 3kW PV system. Adapted from (GRO-Scotland, 2012, ONS, 2012)

Zone	N° households*	Apportioned
1	188,173	82,113
2	220,520	96,228
3	46,679	20,369
4	236,109	103,030
5	352,714	153,913
6	1,444,301	630,246
7	1,351,900	589,926
8	2,224,100	970,526
9	3,832,300	1,672,292
10	1,681,800	733,883
11	1,557,400	679,599
12	2,016,600	879,979
13	2,784,700	1,215,153
14	3,266,200	1,425,264
15	1,430,500	624,224
16	1,945,000	848,735
17	1,275,400	556,543

*Total number of households by zone calculated from 2011 census



The proposed installed system per household would be 3kW, taking up a total of 21m^2 per roof, assuming the use of present day monocrystalline technology. Based on installation data of PV systems up to 4kW, it is shown that 1.5% of the building stock had installed a PV system in the UK in 2013 (DECC, 2013c). If this trend is maintained, the proposed target of a third of all buildings having a PV system installed is achievable. In order to calculate the amount of generation available throughout the year in the UK, it is necessary to obtain actual weather data for 2011

(MetOffice, 2012). The weather stations chosen have been selected after consideration of the yearly horizontal irradiation map provided by Suri et al. (2007) for the UK as seen in Figure 3-14. The four stations have been chosen as representative of the four distinct insolation bands that can be seen in the UK. From this each zone is assigned to the nearest of the four weather stations as detailed in Table 3-8.

Table 3-8: Distribution of zone and weather station (MetOffice, 2012, JRC, 1995-2013)

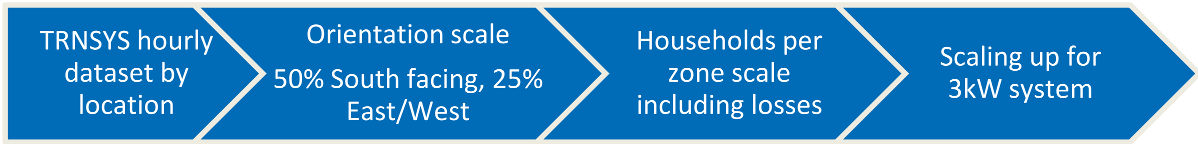
Weather Station	Encompassing Zones	Irradiance on horizontal (kWh/m^2 per annum)
Edinburgh (Scotland)	Z1-Z6	1,110
Church Fenton (Yorkshire)	Z7-Z11	1,180
Heathrow (London)	Z12-Z16	1,270
Cambourne (Cornwall)	Z17	1,340

As provided in Figure 3-12, each zone is broken down into a number of houses based on the housing stock information and a assumed third of households in those areas will have a 3kW PV system installed. It is important to note at this stage that the total installed capacity of the proposed methodology is 33.8GW (based on 11.3 million households installing 3kW PV systems). This level far exceeds the required capacity introduced by the Gardner scenario (Gardner, 2011) in Chapter 3.3 of 18GW. However, as has been discussed, further installed capacity is required to meet the proposed future demand scenarios, and this is a feasible solution to increasing the installed renewable capacity in the UK.

From the data provide above, it is possible to calculate the PV generation from each zone using the weather data from the stations identified and a software package called TRNSYS. TRNSYS is an extremely flexible graphically based software that can simulate the behaviour of a transient system (TRNSYS, 2013). This package allows the user to model the real output from a PV module given the cell characteristics, the geographical location, weather characteristics and irradiance. All input datasets have to be on an hourly timeline for the software to model real world conditions, simulating sun rise and sun set, as well as environmental effects such as wind speed and temperature. The total estimated irradiance on South, East and West facing roofs is provided by PVGIS (JRC, 1995-2013) and the weather data includes global irradiance on the horizontal plane, air temperature, wind speed and dew point, which are available for each of the weather stations highlighted in Figure 3-14 (MetOffice, 2012).

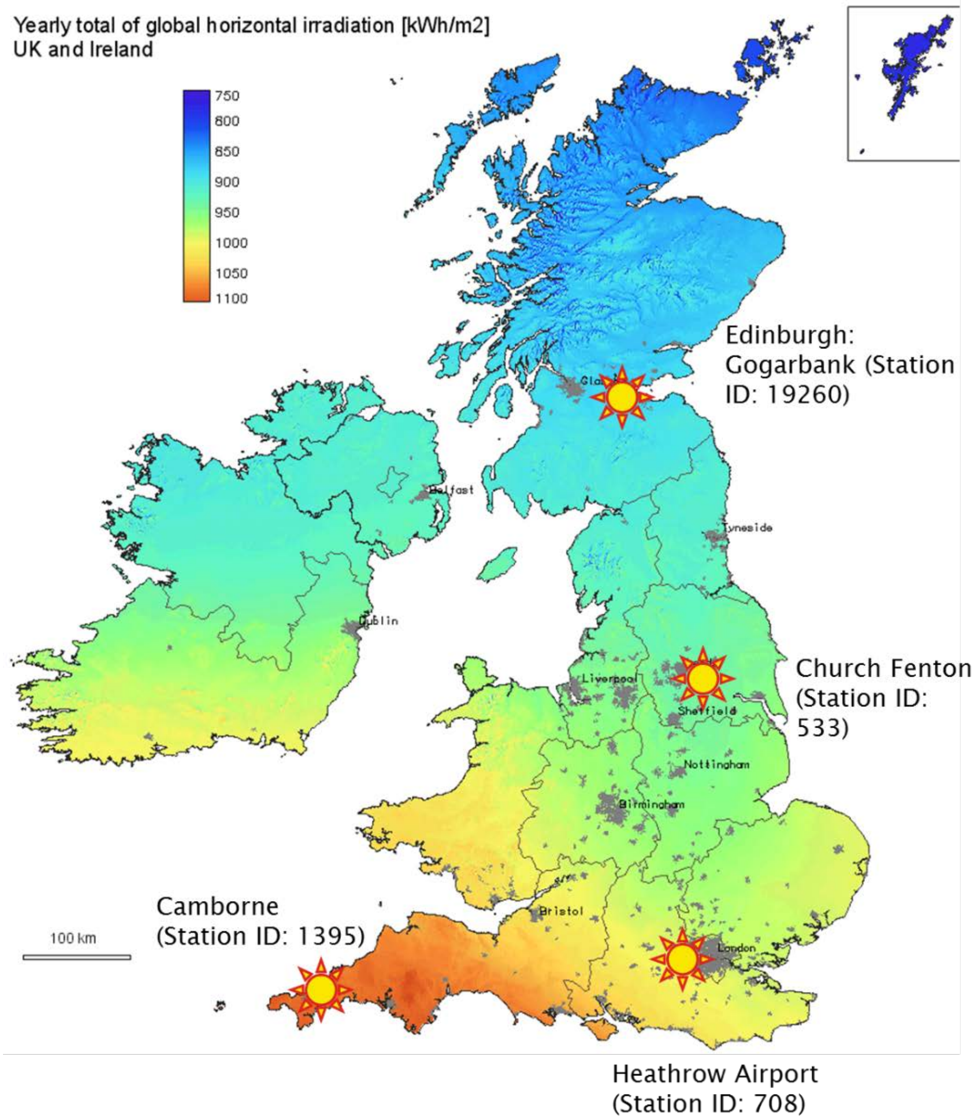
The output from TRNSYS, as introduced above, is for a single PV cell and for irradiation on the horizontal plane. As the PV systems will be installed on the rooftops of domestic properties, the data provided needs to be scaled using the methodology given in Figure 3-13. Note that at this point, losses attributed to the DC converter, inverter efficiency and dirt have been applied. The inclusion of these losses means only 84% of the potential generation is exported.

Figure 3-13: Methodology for scaling up the output from TRNSYS



With these considerations the TRNSYS model outputs a full hourly generation profile for a year based on actual weather data. The average load factor calculated is 13% and ranges from 12% in the North to 14% in the South. The resultant yearly output for the UK, calculated by summing up the individual zones, is 37,477GWh per year. The generation profile can be seen in Chapter 3.4.

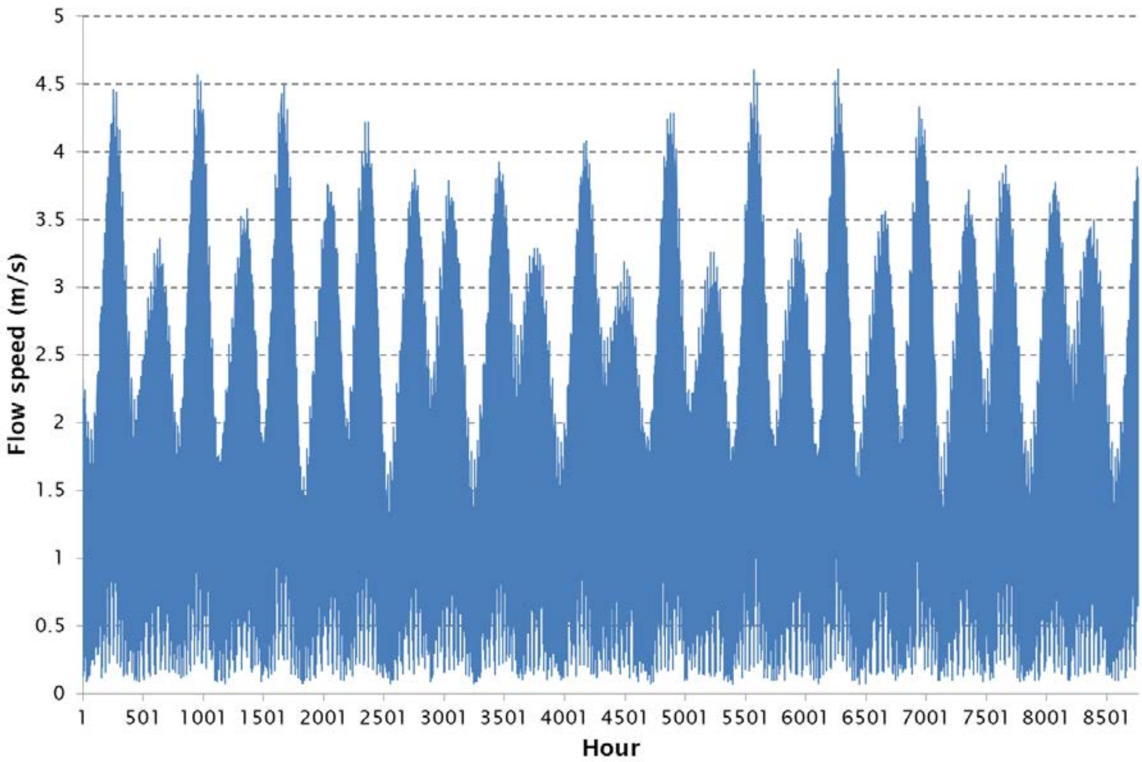
Figure 3-14: UK weather stations and yearly horizontal irradiation map (Suri et al., 2007, MetOffice, 2012))



3.3.1.4 Future tidal generation

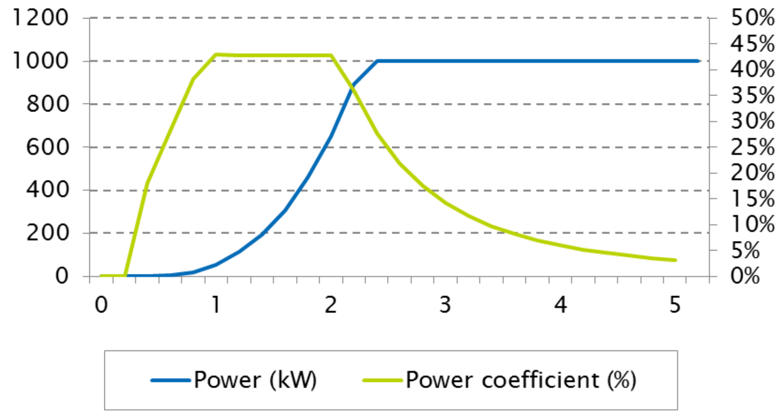
The tidal resource in the UK is estimated to be one of the best in Europe, with around 50% of the European resource in UK waters (NOC, 2013). However, due to environmental constraints and the difficulty in extracting the resource, it has been assumed that generation is restricted to the Pentland Firth in Scotland, as this is one of the best resources available and poses least constraints in terms of exploiting the resource. An hourly generation profile has been calculated based on modelling output provided by the National Oceanography Centre's High Resolution UKCS model for the Pentland Firth (NERC, 2013). The output of this model is an hourly profile of the tide flow speed for this location (Figure 3-15).

Figure 3-15: Modelled hourly flow speed at Pentland Firth, Scotland (NERC, 2013)



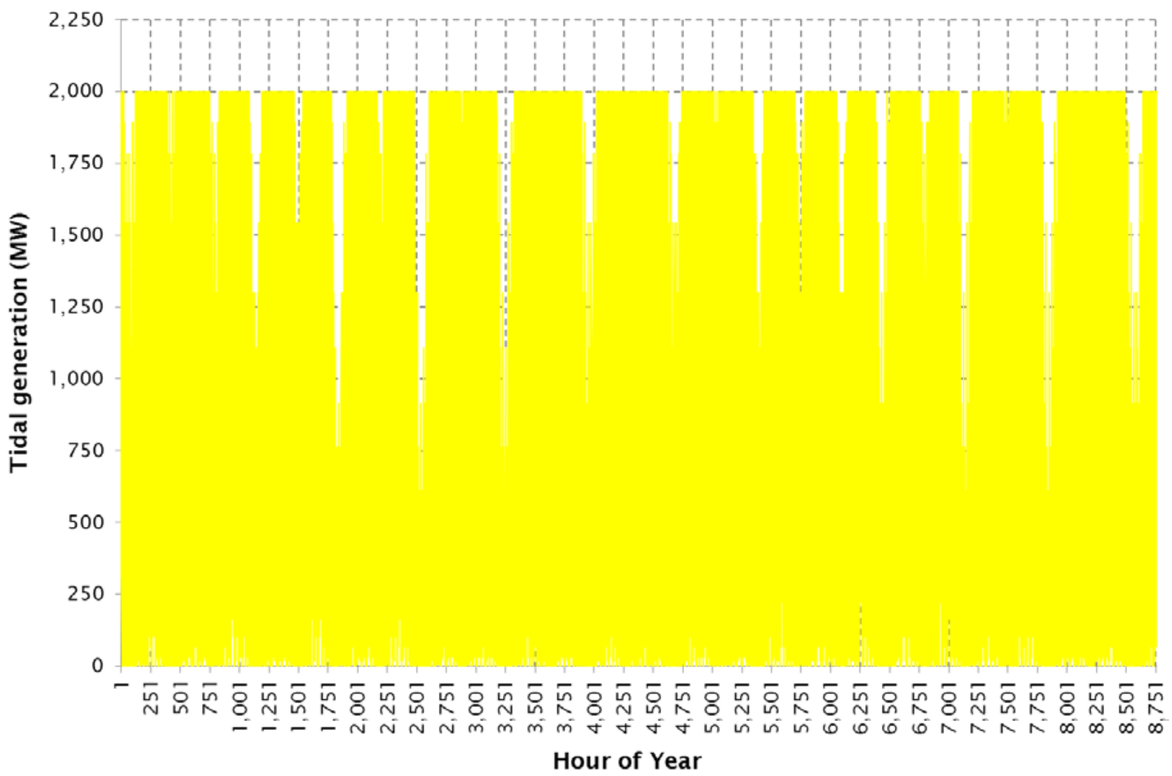
From this hourly dataset, and using the tidal current conversion characteristics introduced in Chapter 2.3.3.5 and given in Hardisty (2011), it is possible to generate an hourly generation profile from tidal energy. For this, it is necessary to use a power curve for a tidal energy conversion device, much like is done for calculating energy from wind. In this case, the characteristics of a SeaGen tidal stream turbine given in Boehme et al. (2006) are used (see Figure 3-16). The SeaGen has a blade radius of 18 meters and the overall losses assumed, which include the turbine, drivetrain and generator losses, mean that only 89% of the resource is converted to electricity.

Figure 3-16: Power curve of a 1MW SeaGen tidal energy converter (Boehme et al., 2006)



Resolving the power curve for the flow speed given in Figure 3-15 provides an hourly output profile from the turbine. This generation profile can then scaled up to the desired annual yield of 7,000GWh. This provides an hourly generation profile (as seen in Figure 3-17) from tidal resource that, although is specific in terms of location, has the resource potential necessary and is the most likely location for tidal projects in the UK.

Figure 3-17: Future UK tidal generation profile based on Pentland Firth resource



These technologies, onshore wind, offshore wind, distributed PV and tidal, make up the variable generation of the future scenarios considered in this study.

3.3.1.5 Future dispatchable generation

It has been assumed for this study that the available capacity from hydro, bioenergy and geothermal are available as fully dispatchable generation and are operated only when the output from wind generation is less than the demand profile. The yearly generation output for these technologies is carried over from the Gardner report (Gardner, 2011); however the installed capacity has been adjusted to reflect the new operation regime. Bioenergy capacity is assumed to be located at centralised plant that has been converted from coal burning plant (Drax, 2013). The increased capacity of 14GW is still within the estimated maximum exploitable UK bioenergy capacity of 22GW (Gardner, 2011). The geothermal potential in the UK has been investigated by Sinclair Knight Merz (SKM) (SKM, 2012). The findings of this report conclude that there is enough capacity to supply the 5GW of resource required for this study and also provides an estimate of the output by region. Gardner (Gardner, 2011) suggests that a hydro capacity of 4GW is required in the future, however it is found that the additional future capacity in England and Wales is estimated at up to only 248MW (DECC and WAG, 2010) and for Scotland up to 657MW (Forrest et al., 2008). Given the operating schedule of hydro in this study, a lower capacity of 2GW is chosen, including existing installed capacity, which is within future additional resource estimates.

3.3.1.6 Renewable technology costs

The estimated capital expenditure (CAPEX) costs per technology are based on projected technology capital costs for 2030. (Arup, 2011) provides cost data that includes the construction costs, the electrical systems infrastructure required and pre-development costs for 2010. In addition, these costs have been extrapolated to 2030. This has been done assuming three technology build rates: low, medium and high. The low scenario constitutes the maximum amount of renewables that can be installed by 2030 in the UK given the current constraints on the availability of the supply chain, planning consents, electricity grid development and reinforcement and availability of suitable sites. The medium scenario represents the maximum capacity that can be installed with some constraints relaxed. Meanwhile, the high scenario constitutes the capacity that could be installed given relaxed constraints. (Ernst&Young, 2010) provide example costs of tidal generation based on pre-demonstration costs in 2010 and the 2030 projections that are calculated assuming economies of scale from potential uptake scenarios. In all cases, it has been assumed that the cost projections scenario taken is the median, or most likely, for 2030. The full range of total costs for each technology is provided in Table 3-9, including baseline CAPEX for natural gas and coal plant.

Table 3-9: Summary of capital costs (CAPEX) per technology used in this study (Arup, 2011, Ernst&Young, 2010, Mott MacDonald, 2010)

Technology	CAPEX – 2010 (GBP/MW)	CAPEX – 2030 (GBP/MW)
Onshore wind	1,524,000	1,336,000
Offshore wind	2,669,000	1,784,000
PV	2,710,000	1,326,000
Bioenergy	2,879,500	2,690,500
Hydro	2,307,000	2,338,000
Tidal	8,600,000	3,300,000
Geothermal	5,363,000	3,704,000
Natural Gas (CCGT)	1,189,800	941,000
Coal	1,747,500	1,577,500

Please note that for this study, it is assumed that these costs will be used to calculate a representative cost and will represent the full cost of installing the required future renewable capacity if it were to be commissioned and installed in one year. The cost of operation and management (OPEX) for each technology has not been considered in this study. This choice has been made as the discussion is centred on the technological feasibility of the fully renewable electricity network and uses the installation cost to enable comparisons between scenarios and technologies rather than discuss the economic feasibility of such scenarios.

Also, it is worth noting that the wholesale cost of installed PV in the UK has dropped rapidly in recent years to a median of GBP 1,850/kW for installations sized up to 4kW and GBP 1,330/kW for installations between 10kW and 50kW (DECC, 2013b).

3.3.2 Future electricity demand

As discussed, the report by Gardner (2011) has estimated the total UK renewable energy resource capacity as well as the practicable capacity that can be exploited. The capacities discussed have been used as the base from which the four scenarios have been calculated. It is found however that, given the demand projections used in this study, more installed capacity would be required than has been calculated in the scenarios used by Gardner (2011). Differences were also found in load factors and generation yield from investigations of actual weather data. It has been assumed that for the purposes of this study the capacity of offshore wind will be scaled to meet the respective demand scenarios whilst the balance of the installed capacity (onshore wind, PV, tidal, bioenergy, hydro and geothermal) remains unchanged across all four scenarios and that the calculated load factors and yield from existing weather data are used.

As introduced, for the purposes of this study it is decided to consider two future demand scenarios that have been provided by Elders et al. (2006) to illustrate how demand can be met by renewable energy sources and the requirements needed to maintain security of supply. In addition, a further two demand scenarios that consider the effects of electrification of heating and transport, as discussed above, are formulated. The selected demand scenarios used and their respective demands are given in Table 3-10. This selection provides four fundamentally different, yet plausible demand scenarios for discussion.

Table 3-10: Scenario characteristics for use in study (Elders et al., 2006, DECC, 2014a, DECC, 2014b))

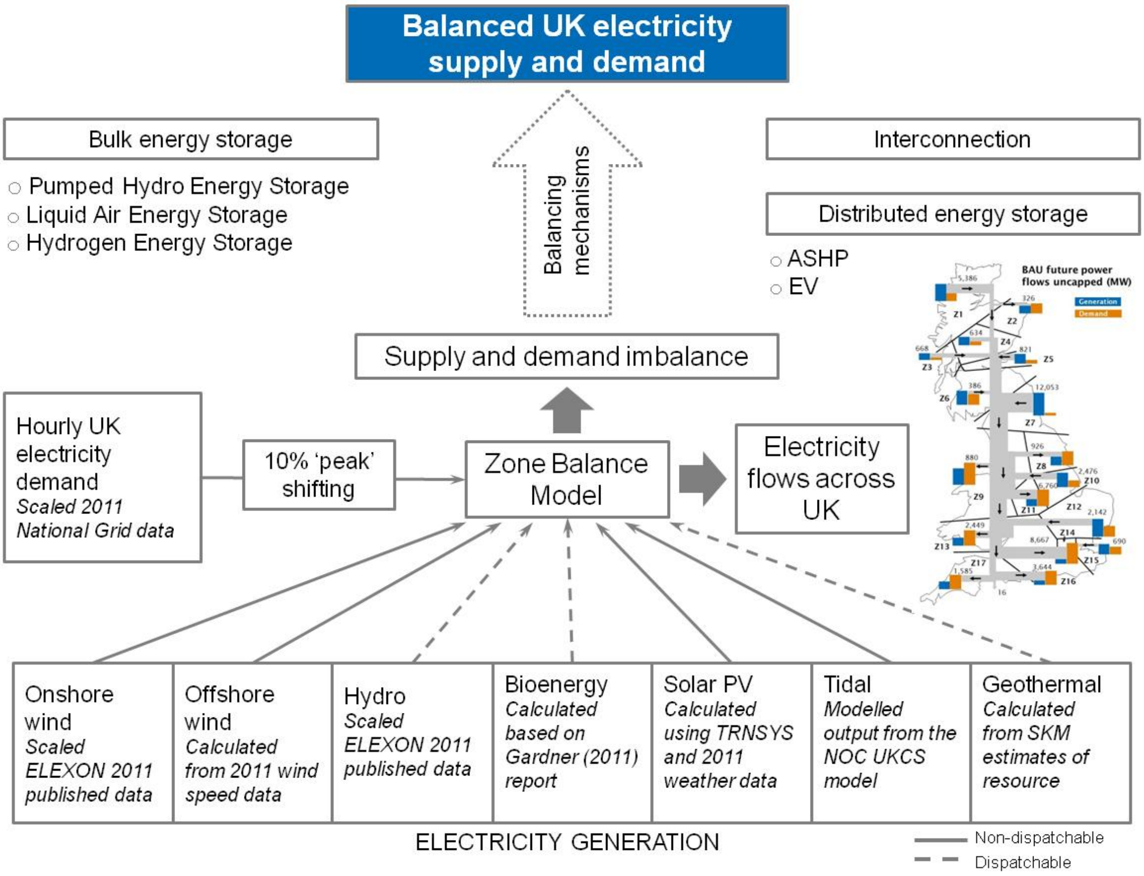
Scenario name	Average annual demand growth	2050 electricity demand (TWh)
Business as Usual (BAU)	+1%	540
Green Plus (GP)	+0.25%	390
BAU + ASHP & EV	+2%	677
GP + ASHP & EV	+1%	527
Present (2013)	-	374

The hourly 2011 demand profile determined from actual data has been linearly scaled to match the projected future annual electricity demands in each of the scenarios introduced. In the case of the original scenarios with ASHP and EV, it has been assumed that heating demand only occurs during the six winter months (October through to March), whereas hot water demand and vehicle charging demand will occur uniformly throughout the year. It has been proposed that demand-side management of the electricity load will be used in the future in order to control daily peak loads. This means shifting flexible loads, such as washing machines and fridges within households, and some industrial processes, from peak times of the day to reduce the stress on the network. Blecourt (2012) suggests that up to 16% of the domestic peak can be shifted to the ‘valley’ hours during the night using smart appliances. A review of past and present demand-side trials has concluded that flexible loads have the potential to reduce peak demand between 1% and 12% (FrontierEconomics and SustainabilityFirst, 2012). It has been assumed for this study that 10% of the demand of the top six hours in each day can be shifted to the lowest six hours using flexible loads in the domestic and industrial sectors, thereby reducing peak demand requirements.

The analysis carried out provides a view of how much RES capacity there will be in the future grid and where it will be located. It also provides a view of the demand requirements around the UK. This will enable discussions on issues such as power flow constrictions on the network and where energy storage would be best located within the network.

Figure 3-18 illustrates the model inputs and outputs considered for this study. It is assumed that there would be a degree of demand-side management available to help reduce the effects of peak demand throughout the day. For this study it is assumed that 10% of the demand load of the six peak hours could be ‘time-shifted’ to the valley hours, the six hours when demand is at its lowest.

Figure 3-18: Schematic of the balanced UK electricity supply and demand model inputs and outputs



3.3.3 Future scenario discussion

This Chapter will describe each of the four scenarios introduced above. It will be possible to see how renewable capacity is scaled and altered to meet the specific demand from each scenario. Therefore, each scenario will have its specific characteristics and requirements which will be carried through the further investigation at a later stage.

This Chapter will also investigate the generation that occurs in each zone of the network. The capacity can be converted in to yearly generation from RES using the load factors for each technology. The load factors used by Gardner (2011) were employed to calculate the annual output from each zone with the exception of onshore and offshore wind and PV. The load factors used to calculate the expected generation from each resource are given in Table 3-11.

Table 3-11: Average load factors used to calculate the generation from each resource

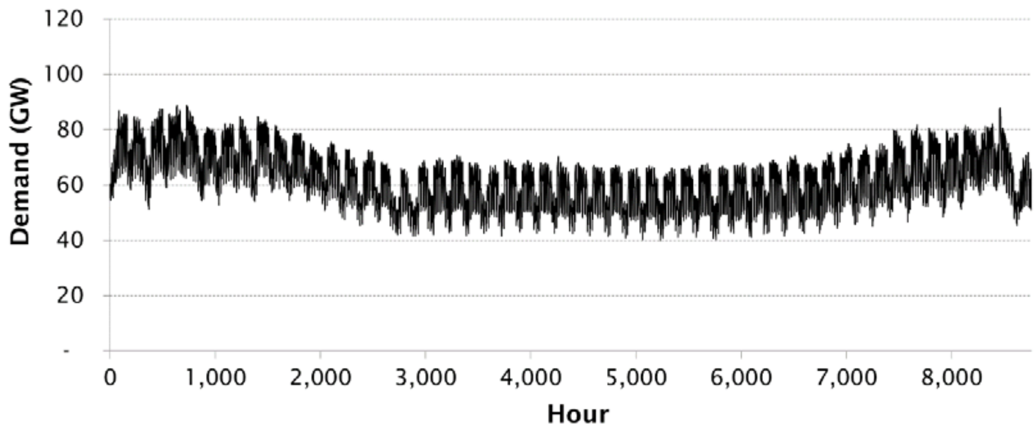
Resource	Load factor
Onshore wind	27%
Offshore wind	43%
Solar PV	13%
Bioenergy	90%
Hydro	37%
Tidal	40%
Geothermal	76%

It has been assumed that bioenergy plant is being run as a baseload and hence the proposed load factor of 90%. Likewise with geothermal, however hydro is constrained by the amount of resource available and therefore is assumed to run at a load factor of 37%. In the case of onshore wind an average capacity factor of 27% is used as the average from UK installed wind capacity in 2011. For offshore wind, generation was calculated from actual wind energy yield analysis carried out as described in Chapter 2.3.3.1 and varies from site to site. However, the average for offshore wind farms is calculated to be 43%. Similarly for PV, generation has been calculated through TRNSYS using actual weather data as described in Chapter 3.3.1.3 and the average is calculated to be 13%.

3.3.3.1 Business as Usual (BAU)

This scenario has been defined as representative of a continuation of current trends. In this case, electricity demand for the UK in 2050 reaches approximately 540TWh/year. The hourly profile of the demand has been calculated based on the actual 2011 demand profile to which a scale up factor of 1.69 has been applied. In Figure 3-19, the 1st of January at 00:00 is depicted as hour zero and the rest of the year follows on an hourly basis for the BAU scenario. As can be seen, there is a clear weekly variation in demand as well as an overall higher demand in the winter months compared to the summer months. The peak hourly demand is 89GW which is reached in December.

Figure 3-19: Calculated hourly UK electricity demand profile for the BAU scenario



Using the methodology introduced in Chapter 3.3.1, it is possible to calculate the amount of capacity required in each zone of the electricity grid in order to meet the required annual demand. The zonal distribution is provided by the existing UK installed capacity in the case of onshore wind, bioenergy, hydro and geothermal. Offshore capacity has been modelled based on the Round 3 offshore wind farm locations and the landing points have been assumed to be the closest on the electrical grid. Tidal generation is assumed to be constrained to the Pentland Firth, off the northern coast of Scotland. Finally PV has been distributed across the zones as given in Chapter 3.3.1.3. Each technology has been scaled in order to meet the required demand scenario capacity.

Table 3-12 shows the calculated capacities by zone and technology. It can be seen that the most geographically dispersed sources are wind and PV, whereas hydro, tidal and geothermal are very concentrated. The total grid RES capacity has been calculated as 174GW, 67% of which is from wind.

Table 3-12: Calculated RES capacity by zone in GW required to supply the future electricity demand in the BAU scenario

Zone	Onshore wind	Offshore wind	PV	Bioenergy	Hydro	Tidal	Geothermal	∑ capacity (GW)
1	4.60	7.47	0.25	-	1.34	2	-	15.65
2	0.92	0.17	0.29	-		-	-	1.38
3	0.85	1.20	0.06	-	0.06	-	-	2.16
4	2.26	1.57	0.31	-	0.23	-	-	4.37
5	0.43	6.78	0.46	0.01	-	-	-	7.68
6	11.66	-	1.89	0.56	0.14	-	-	14.25
7	1.39	22.67	1.77	0.20	-	-	4.55	30.58
8	1.06	7.73	2.91	2.63	-	-	-	14.33
9	2.94	11.10	5.02	0.90	0.18	-	0.28	20.42
10	0.54	3.47	2.20	2.78	-	-	-	8.99
11	-	-	2.04	1.02	-	-	-	3.06
12	1.06	16.77	2.64	0.11	-	-	-	20.58
13	0.89	2.60	3.65	1.78	-	-	-	8.91
14	0.04	-	4.28	1.00	-	-	-	5.31
15	0.41	1.73	1.87	2.81	-	-	-	6.82
16	-	1.15	2.55	0.44	-	-	0.02	4.17
17	0.95	2.08	1.67	-	-	-	0.40	5.09
TOTALS	**30.00**	**86.47**	**33.85**	**14.24**	**1.95**	**2**	**5.25**	**173.75**

Table 3-13 shows the calculated generation by zone and technology. This has been calculated using the load factors for each technology which have been calculated and given in Table 3-11. The total generation from all RES is calculated to be 540TWh/year for the BAU scenario. The total generation from this mix of renewables is enough to meet the total demand over the year from UK electricity users. It is important to note that at this stage, the calculation is only accounting for yearly electricity demand and not, as has been calculated for the demand (Figure 3-19), the hourly demand requirements.

Table 3-13: Calculated RES generation by zone in TWh required to supply future electricity demand in the BAU scenario

Zone	Onshore wind	Offshore wind	PV	Bioenergy	Hydro	Tidal	Geothermal	∑ generation (TWh/year)
1	11.92	23.76	0.27	-	8.93	7	-	51.87
2	1.99	0.43	0.31	-	-	-	-	2.73
3	1.91	4.08	0.07	-	0.39	-	-	6.44
4	4.58	3.85	0.33	-	1.53	-	-	10.30
5	0.90	16.67	0.50	0.71	-	-	-	18.14
6	25.35	0.00	2.04	3.76	0.95	-	-	32.11
7	2.52	95.66	1.96	1.34	-	-	30.35	131.84
8	1.88	17.78	3.23	17.57	-	-	-	40.45
9	6.17	38.09	5.56	6.01	1.21	-	1.86	58.90
10	1.06	8.41	2.44	18.56	-	-	-	30.47
11	0.00	0.00	2.26	6.81	-	-	-	9.08
12	2.02	56.73	2.84	0.71	-	-	-	62.30
13	1.51	9.16	3.93	11.86	-	-	-	26.46
14	0.06	0.00	4.61	6.64	-	-	-	11.31
15	0.85	4.19	2.02	18.72	-	-	-	25.78
16	0.00	2.92	2.74	2.96	-	-	0.15	8.77
17	1.83	6.69	2.03	-	-	-	2.64	13.19
TOTALS	**65**	**288**	**37**	**95**	**13**	**7**	**35**	**540**

It is also possible to calculate the expected investment required to meet the installed capacity necessary for this scenario. To calculate this, the CAPEX values given in Chapter 3.3.1.6 have been used. It has been assumed that the existing installed capacity will not need replacing and therefore will offset the cost of installing the full capacity required. Table 3-14 shows the installed capacity required by technology and the existing installed capacity (as of 2012). It also summarises the CAPEX costs for each technology used in this study. It has been calculated that the cost of capacity required for the BAU scenario is GBP 280 billion.

Table 3-14: Summary of new capacity required and cost of the future BAU scenario

Technology	2012 installed capacity (MW)	Required future capacity (MW)	Difference (MW)	CAPEX unit (GBP M/MW)	Scenario CAPEX (GBP M)
Onshore wind	5,893	30,000	24,107	1.34	32,207
Offshore wind	2,995	86,475	83,480	1.78	148,928
PV	1,706	33,846	32,140	1.33	42,618
Bioenergy	3,251	14,239	10,988	2.69	29,562
Hydro	1,686	1,948	262	2.34	614
Tidal	4	2,000	1,997	3.30	6,588
Geothermal	-	5,246	5,246	3.70	19,430
TOTALS	**15,535**	**173,754**	**158,219**		**279,947**

The total cost to install the required renewable capacity is very high by conventional standards. Investigation into the UK's gross domestic product (GDP) found that in 2012 UK's GDP was in the region of GBP 1,556 billion (countryeconomy, 2013). This means that the total cost to install this scenario would be 17% of the UK's GDP in 2012. However, it is important to stress that these costs have been calculated with the assumption that all the required capacity is installed in one year. In reality, this cost will be drawn out over an extended period of time. It is expected that revenues being accrued from newly installed renewable capacity can be used to fund the costs of subsequent capacity being installed. This capacity will also provide security of supply to the UK's electricity network which would in the long run provide a more stable electricity price and have a positive impact on the UK economy.

3.3.3.2 Green Plus (GP)

The second scenario has been defined. In this case, electricity demand for the UK in 2050 reaches approximately 390TWh/year. As with the BAU scenario discussed above, the hourly profile of the demand has been calculated based on the 2011 demand profile to which a scale up factor of 1.22 has been applied (Figure 3-20). The peak demand reached in this scenario is 64GW.

Figure 3-20: Calculated hourly UK electricity demand profile for the GP scenario

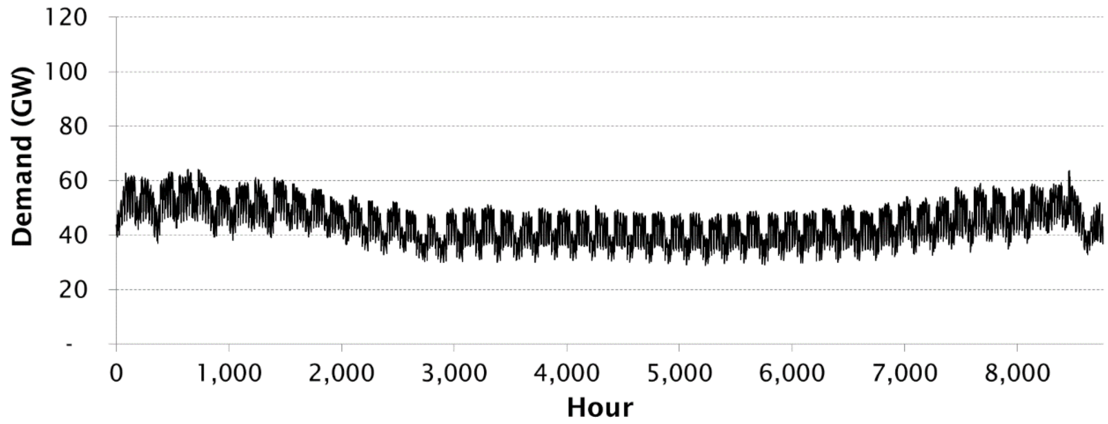


Table 3-15 shows the calculated capacities by zone and technology. In this case the amount of offshore wind capacity required is reduced to meet the required demand. The total grid RES capacity in this case has been calculated as 129GW, of which 56% is now the share from wind.

Table 3-15: Calculated RES capacity by zone in GW required to supply the future electricity demand in the GP scenario

Zone	Onshore wind	Offshore wind	PV	Bioenergy	Hydro	Tidal	Geothermal	∑ capacity (GW)
1	4.60	3.58	0.25	-	1.34	2	-	11.76
2	0.92	0.08	0.29	-		-	-	1.29
3	0.85	0.57	0.06	-	0.06	-	-	1.54
4	2.26	0.75	0.31	-	0.23	-	-	3.55
5	0.43	3.25	0.46	0.01	-	-	-	4.15
6	11.66	0.00	1.89	0.56	0.14	-	-	14.25
7	1.39	10.87	1.77	0.20	-	-	4.55	18.78
8	1.06	3.70	2.91	2.63	-	-	-	10.31
9	2.94	5.32	5.02	0.90	0.18	-	0.28	14.64
10	0.54	1.66	2.20	2.78	-	-	-	7.19
11	0.00	0.00	2.04	1.02	-	-	-	3.06
12	1.06	8.04	2.64	0.11	-	-	-	11.85
13	0.89	1.25	3.65	1.78	-	-	-	7.56
14	0.04	0.00	4.28	1.00	-	-	-	5.31
15	0.41	0.83	1.87	2.81	-	-	-	5.92
16	0.00	0.55	2.55	0.44	-	-	0.02	3.57
17	0.95	1.00	1.67	-	-	-	0.40	4.01
TOTALS	**30.00**	**41.46**	**33.85**	**14.24**	**1.95**	**2**	**5.25**	**128.74**

Table 3-16 shows the calculated generation by zone and technology. Total generation from all RES in this scenario is calculated at 390TWh/year.

Table 3-16: Calculated RES generation by zone in TWh required to supply future electricity demand in the GP scenario

Zone	Onshore wind	Onshore wind	PV	Bioenergy	Hydro	Tidal	Geothermal	∑ generation (TWh/year)
1	11.92	11.39	0.27	-	8.93	7	-	39.50
2	1.99	0.20	0.31	-	-	-	-	2.51
3	1.91	1.96	0.07	-	0.39	-	-	4.32
4	4.58	1.85	0.33	-	1.53	-	-	8.29
5	0.90	7.99	0.50	0.71	-	-	-	9.46
6	25.35	0.00	2.04	3.76	0.95	-	-	32.11
7	2.52	45.87	1.96	1.34	-	-	30.35	82.04
8	1.88	8.52	3.23	17.57	-	-	-	31.20
9	6.17	18.26	5.56	6.01	1.21	-	1.86	39.07
10	1.06	4.03	2.44	18.56	-	-	-	26.09
11	0.00	0.00	2.26	6.81	-	-	-	9.08
12	2.02	27.20	2.84	0.71	-	-	-	32.77
13	1.51	4.39	3.93	11.86	-	-	-	21.69
14	0.06	0.00	4.61	6.64	-	-	-	11.31
15	0.85	2.01	2.02	18.72	-	-	-	26.60
16	0.00	1.40	2.74	2.96	-	-	0.15	7.25
17	1.83	3.21	2.03	-	-	-	2.64	9.71
TOTALS	**65**	**138**	**37**	**95**	**13**	**7**	**35**	**390**

Table 3-17 shows the installed capacity required by technology and the existing installed capacity (as of 2012). It has been calculated that the cost of capacity required for the GP scenario is around GBP 200 billion.

Table 3-17: Summary of new capacity required and cost of the future GP scenario

Technology	2012 installed capacity (MW)	Required future capacity (MW)	Difference (MW)	CAPEX unit (GBP M/MW)	Scenario CAPEX (GBP M)
Onshore wind	5,893	30,000	24,107	1.34	32,207
Offshore wind	2,995	41,461	38,466	1.78	68,623
PV	1,706	33,846	32,140	1.33	42,618
Bioenergy	3,251	14,239	10,988	2.69	29,562
Hydro	1,686	1,948	262	2.34	614
Tidal	4	2,000	1,997	3.30	6,588
Geothermal	-	5,246	5,246	3.70	19,430
TOTALS	**15,535**	**128,740**	**113,205**		**199,676**

As with the previous scenario, it has been calculated that the total cost to install the required capacity would be 13% of the UK's GDP in 2012.

3.3.3.3 Business as Usual + EV & ASHP (BAU+EV&ASHP)

The third scenario has been calculated using the BAU scenario as a baseline to which there has been added the electricity demand calculated from the uptake of electric vehicles and the uptake of electrified heating. The 2011 demand profile has been scaled up by a factor of 1.95. The marked step change during the beginning of the year and the end is due to the heating and hot water demand (69TWh) which has been assumed to only occur over the winter months, that is January to March and October to December. In this case, electricity demand for the UK in 2050 reaches approximately 623TWh/year. As with the previous scenarios, the hourly profile of the demand has been calculated based on the 2011 demand profile (Figure 3-21). The peak demand reached in this scenario is 109GW.

Figure 3-21: Calculated hourly UK electricity demand profile for the BAU+EV&ASHP scenario

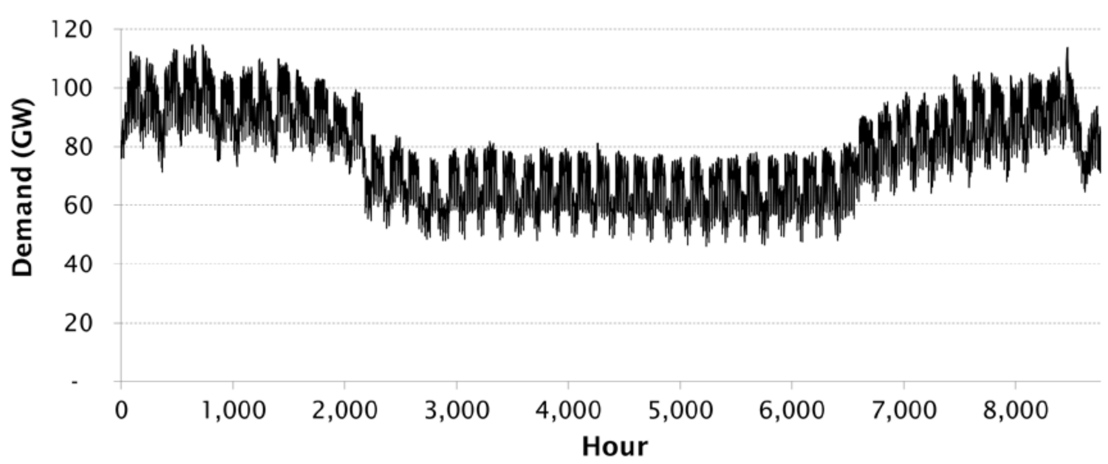


Table 3-18 shows the calculated capacities by zone and technology. In this case the amount of offshore wind capacity required is increased to meet the required demand. The total required grid RES capacity in this case has been calculated to be 215GW, of which 73% is now the share necessary from wind to meet the required capacity.

Table 3-18: Calculated RES capacity by zone in GW required to supply the future electricity demand in the BAU+EV&ASHP scenario

Zone	Onshore wind	Offshore wind	PV	Bioenergy	Hydro	Tidal	Geothermal	∑ capacity (GW)
1	4.60	11.00	0.25	-	1.34	2	-	19.18
2	0.92	0.26	0.29	-		-	-	1.46
3	0.85	1.76	0.06	-	0.06	-	-	2.73
4	2.26	2.31	0.31	-	0.23	-	-	5.11
5	0.43	9.99	0.46	0.01	-	-	-	10.89
6	11.66	0.00	1.89	0.56	0.14	-	-	14.25
7	1.39	33.39	1.77	0.20	-	-	4.55	41.31
8	1.06	11.38	2.91	2.63	-	-	-	17.98
9	2.94	16.35	5.02	0.90	0.18	-	0.28	25.67
10	0.54	5.10	2.20	2.78	-	-	-	10.63
11	0.00	0.00	2.04	1.02	-	-	-	3.06
12	1.06	24.71	2.64	0.11	-	-	-	28.52
13	0.89	3.83	3.65	1.78	-	-	-	10.14
14	0.04	0.00	4.28	1.00	-	-	-	5.31
15	0.41	2.54	1.87	2.81	-	-	-	7.63
16	0.00	1.70	2.55	0.44	-	-	0.02	4.71
17	0.95	3.06	1.67	-	-	-	0.40	6.08
TOTALS	**30.00**	**127.39**	**33.85**	**14.24**	**1.95**	**2**	**5.25**	**214.67**

Table 3-19 shows the calculated generation by zone and technology. Total generation from all RES is calculated at 677TWh/year.

Table 3-19: Calculated RES generation by zone in TWh required to supply future electricity demand in the BAU+EV&ASHP scenario

Zone	Onshore wind	Offshore wind	PV	Bioenergy	Hydro	Tidal	Geothermal	∑ generation (TWh/year)
1	11.92	35.01	0.27	-	8.93	7	-	63.12
2	1.99	0.63	0.31	-	-	-	-	2.93
3	1.91	6.02	0.07	-	0.39	-	-	8.38
4	4.58	5.68	0.33	-	1.53	-	-	12.12
5	0.90	24.56	0.50	0.71	-	-	-	26.03
6	25.35	0.00	2.04	3.76	0.95	-	-	32.11
7	2.52	140.93	1.96	1.34	-	-	30.35	177.10
8	1.88	26.19	3.23	17.57	-	-	-	48.86
9	6.17	56.11	5.56	6.01	1.21	-	1.86	76.92
10	1.06	12.38	2.44	18.56	-	-	-	34.45
11	0.00	0.00	2.26	6.81	-	-	-	9.08
12	2.02	83.57	2.84	0.71	-	-	-	89.15
13	1.51	13.50	3.93	11.86	-	-	-	30.80
14	0.06	0.00	4.61	6.64	-	-	-	11.311
15	0.85	6.18	2.02	18.72	-	-	-	27.76
16	0.00	4.30	2.74	2.96	-	-	0.15	10.15
17	1.83	9.85	2.03	-	-	-	2.64	16.35
TOTALS	**65**	**425**	**37**	**95**	**13**	**7**	**35**	**677**

Table 3-20 shows the installed capacity required by technology and the existing installed capacity (as of 2012). It has been calculated that the cost of capacity required for the BAU+EV&ASHP scenario is around GBP 353 billion.

Table 3-20: Summary of new capacity required and cost of the future BAU+EV&ASHP scenario

Technology	2012 installed capacity (MW)	Required future capacity (MW)	Difference (MW)	CAPEX unit (GBP M/MW)	Scenario CAPEX (GBP M)
Onshore wind	5,893	30,000	24,107	1.34	32,207
Offshore wind	2,995	127,391	124,396	1.78	221,923
PV	1,706	33,846	32,140	1.33	42,618
Bioenergy	3,251	14,239	10,988	2.69	29,562
Hydro	1,686	1,948	262	2.34	614
Tidal	4	2,000	1,997	3.30	6,588
Geothermal	-	5,246	5,246	3.70	19,430
TOTALS	**15,535**	**214,670**	**199,136**		**352,942**

In this case, it has been calculated that the total cost to install the required capacity for this scenario would be 23% of the UK's GDP in 2012. This investment spread out over an investment timeframe of 25 years, for example, would equate to an investment of circa 1% of UK's GDP in 2012 per annum.

3.3.3.4 Green Plus + EV & ASHP (GP+EV&ASHP)

The final scenario has been calculated using the GP scenario as a baseline to which there has been added the electricity demand calculated from the uptake of electric vehicles and the uptake of electrified heating. The 2011 demand profile has been scaled up by a factor of 1.48. Similarly to the previous scenario, the step change in demand during the beginning of the year and the end is due to the heating and hot water demand. In this case, electricity demand for the UK in 2050 reaches approximately 473TWh/year. As with the previous scenarios, the hourly profile of the demand has been calculated based on the 2011 demand profile (Figure 3-22). The peak demand reached in this scenario is 83GW.

Figure 3-22: Calculated hourly UK electricity demand profile for the GP+EV&ASHP scenario

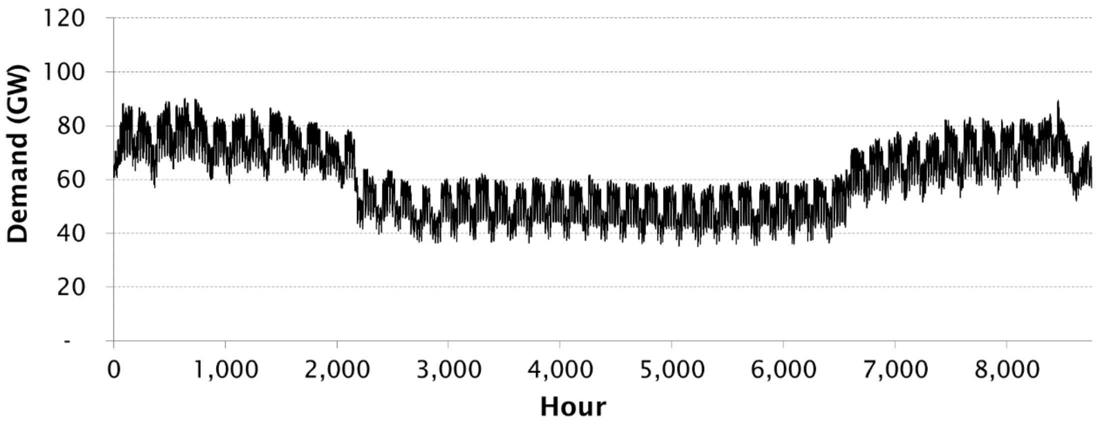


Table 3-21 shows the calculated capacities by zone and technology. In this case the amount of offshore wind capacity required is increased to meet the required demand. The total required grid RES capacity in this case has been calculated to be close to 170GW, of which 66% is now the share necessary from wind to meet the required capacity.

Table 3-21: Calculated RES capacity by zone in GW required to supply the future electricity demand in the GP+EV&ASHP scenario

Zone	Onshore wind	Offshore wind	PV	Bioenergy	Hydro	Tidal	Geothermal	∑ capacity (GW)
1	4.60	7.12	0.25	-	1.34	2	-	15.30
2	0.92	0.17	0.29	-		-	-	1.37
3	0.85	1.14	0.06	-	0.06	-	-	2.11
4	2.26	1.49	0.31	-	0.23	-	-	4.29
5	0.43	6.47	0.46	0.01	-	-	-	7.37
6	11.66	0.00	1.89	0.56	0.14	-	-	14.25
7	1.39	21.60	1.77	0.20	-	-	4.55	29.52
8	1.06	7.36	2.91	2.63	-	-	-	13.96
9	2.94	10.58	5.02	0.90	0.18	-	0.28	19.90
10	0.54	3.30	2.20	2.78	-	-	-	8.83
11	0.00	0.00	2.04	1.02	-	-	-	3.06
12	1.06	15.99	2.64	0.11	-	-	-	19.80
13	0.89	2.48	3.65	1.78	-	-	-	8.79
14	0.04	0.00	4.28	1.00	-	-	-	5.31
15	0.41	1.64	1.87	2.81	-	-	-	6.74
16	0.00	1.10	2.55	0.44	-	-	0.02	4.11
17	0.95	1.98	1.67	-	-	-	0.40	4.99
TOTALS	**30.00**	**82.42**	**33.85**	**14.24**	**1.95**	**2**	**5.25**	**169.70**

Table 3-22 shows the calculated generation by zone and technology. Total generation from all RES is calculated at nearly 530TWh/year.

Table 3-22: Calculated RES generation by zone in TWh required to supply future electricity demand in the GP+EV&ASHP scenario

Zone	Onshore wind	Offshore wind	PV	Bioenergy	Hydro	Tidal	Geothermal	∑ generation (TWh/year)
1	11.92	22.65	0.27	-	8.93	7	-	50.76
2	1.99	0.41	0.31	-	-	-	-	2.71
3	1.91	3.89	0.07	-	0.39	-	-	6.25
4	4.58	3.67	0.33	-	1.53	-	-	10.12
5	0.90	15.89	0.50	0.71	-	-	-	17.36
6	25.35	0.00	2.04	3.76	0.95	-	-	32.11
7	2.52	91.18	1.96	1.34	-	-	30.35	127.35
8	1.88	16.94	3.23	17.57	-	-	-	39.62
9	6.17	36.30	5.56	6.01	1.21	-	1.86	57.11
10	1.06	8.01	2.44	18.56	-	-	-	30.07
11	0.00	0.00	2.26	6.81	-	-	-	9.08
12	2.02	54.07	2.84	0.71	-	-	-	59.64
13	1.51	8.73	3.93	11.86	-	-	-	26.03
14	0.06	0.00	4.61	6.64	-	-	-	11.31
15	0.85	4.00	2.02	18.72	-	-	-	25.58
16	0.00	2.78	2.74	2.96	-	-	0.15	8.63
17	1.83	6.37	2.03	-	-	-	2.64	12.87
TOTALS	**65**	**275**	**37**	**95**	**13**	**7**	**35**	**530**

Table 3-23 shows the installed capacity required by technology and the existing installed capacity (as of 2012). It has been calculated that the cost of capacity required for the GP+EV&ASHP scenario is around GBP 273 billion.

Table 3-23: Summary of new capacity required and cost of the future GP+EV&ASHP scenario

Technology	2012 installed capacity (MW)	Required future capacity (MW)	Difference (MW)	CAPEX unit (GBP M/MW)	Scenario CAPEX (GBP M)
Onshore wind	5,893	30,000	24,107	1.34	32,207
Offshore wind	2,995	82,418	79,423	1.78	141,691
PV	1,706	33,846	32,140	1.33	42,618
Bioenergy	3,251	14,239	10,988	2.69	29,562
Hydro	1,686	1,948	262	2.34	614
Tidal	4	2,000	1,997	3.30	6,588
Geothermal	-	5,246	5,246	3.70	19,430
TOTALS	**15,535**	**169,697**	**154,163**		**272,711**

In this final scenario, it has been calculated that the total cost to install the required capacity would be 17% of the UK's GDP in 2012.

3.3.4 Summary of Scenarios

The renewable installed capacity and yearly generation mix given by Gardner (2011) and the calculated capacity and generation mix by scenario of this study are summarised in Table 3-24. These capacities have been calculated as the minimum installed mix required to meet the yearly electricity demand for each scenario and do not, at this stage, consider the hourly variation of generation and demand.

It can be seen that the most expensive scenario is the business as usual combined with the uptake of air source heat pumps and electric vehicles. This is to be expected though as this scenario carries the highest electricity demand and hence the highest installed capacity.

Table 3-24: Assumed practicable resource capacity (GW) and generation (TWh) from Gardner (2011) and calculated mix for each scenario: Business as Usual (BAU), Green Plus (GP), BAU with electrification of heating and transportation (BAU+EV&ASHP) and GP with electrification of heating and transportation (GP+EV&ASHP)

Technology	Gardner (2011)* (GW/TWh)	BAU (GW/TWh)	GP (GW/TWh)	BAU + EV & ASHP (GW/TWh)	GP+ EV & ASHP (GW/TWh)
Onshore wind	30/80	30/65	30/65	30/65	30/65
Offshore wind	82/310	86/288	41/138	127/425	82/275
Solar PV	18/15	34/37	34/37	34/37	34/37
Tidal	2/7	2/7	2/7	2/7	2/7
Bioenergy	12/95	14/95	14/95	14/95	14/95
Hydro	4/13	2/13	2/13	2/13	2/13
Geothermal	5/35	5/35	5/35	5/35	5/35
Total	153/555	173/540	128/390	214/677	169/527
Dispatchable	*18/133*	*21/143*	*21/143*	*21/143*	*21/143*
Non-dispatchable	*135/422*	*152/397*	*107/247*	*193/534*	*148/384*
Estimated scenario CAPEX (GBP Bn)	249	280	200	353	273

*Note that wave has been excluded from the technology mix previously show in Chapter 3.3.

These scenarios will be developed further to investigate the hourly variation in generation and how this matches with the hourly demand profiles that have been constructed. This will be discussed in the following Chapter.

3.4 Analysis of Variability

As discussed, this study focuses on the fully renewable UK electricity grid. Having such a scenario means that it is inevitable that generation of electricity will be variable due to the nature of these resources. One of the main issues that occurs is that generation from RES does not meet the demand and hence balancing mechanisms need to be put in place during these events (Gross et al., 2007).

Using the data, future demand and renewable yield estimate approaches discussed in Chapter 3.3.2 and Chapter 3.3.3, representative generation profiles from the various renewable energy technologies have been generated below. The key rules followed to obtain these profiles are given in Equation 3-1 and are calculated in GW.

Equation 3-1: Renewable electricity generation profile rules

$$Variable\ generation = Gen_{wind} + Gen_{solarPV}$$

$$Dispatchable\ generation = Gen_{hydro} + Gen_{bioenergy} + Gen_{geothermal}$$

$$Dispatchable\ generation\ run \rightarrow Variable_{gen} < Demand$$

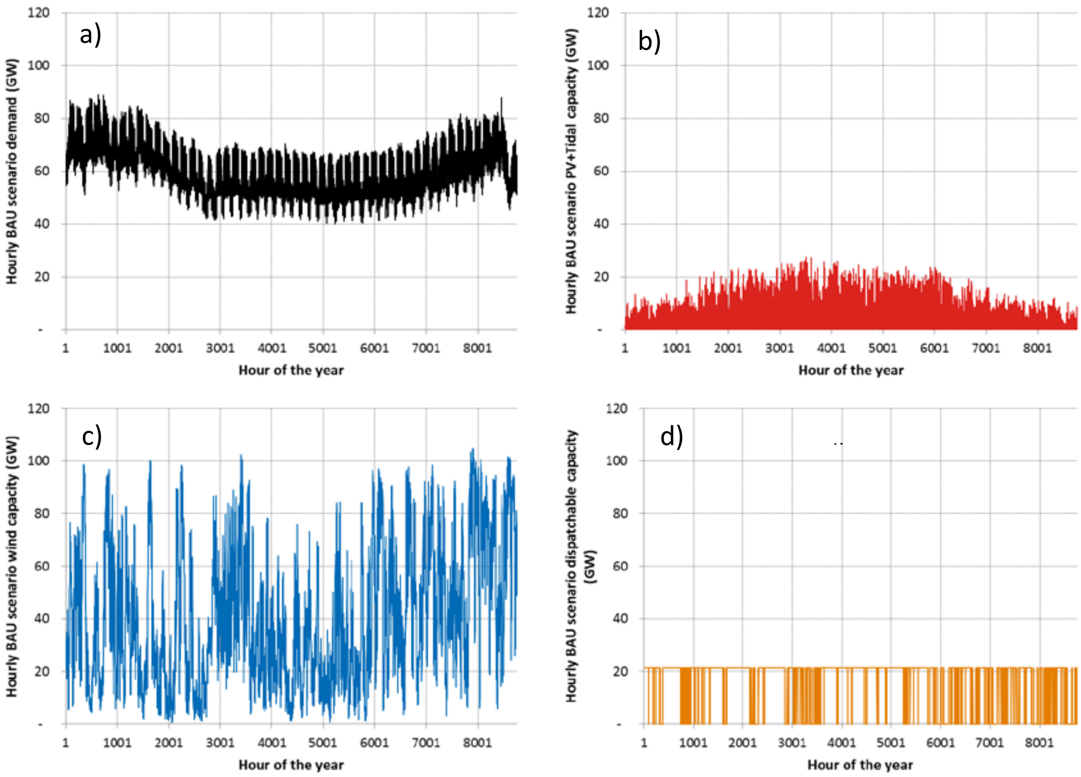
Yearly profiles for generation, or output, from the various renewable sources have been generated based on the raw weather data available. Using hourly wind profiles it is possible to estimate a yearly hour by hour wind generation profile based on the technological assumptions and methodology given in Chapter 3.3.1.1 and 3.3.1.2. Likewise, the same is applicable for PV which is uses weather data such as global irradiation, temperature, wind speed and dew point to generate a yearly hour by hour generation profile, as discussed in Chapter 3.3.1.3.

The following chapter illustrates the generated hourly profiles which are to be used to investigate the variability

3.4.1 BAU Scenario

Figure 3-23 depicts the demand profile for the BAU scenario that has a maximum demand of 89GW during the winter and minimum of 40GW during the summer. It also illustrates the generation profile from wind, onshore and offshore combined, the variable generation from solar PV and tidal, and the total dispatchable generation from hydro, bioenergy and geothermal. It can be seen that the main generation comes from wind with a peak output of 105GW. However, there are large portions of the year during which wind output is less than the minimum demand. The overall contribution from PV and tidal is relatively small with a maximum output of 28GW during the summer. The total dispatchable generation that is available when the variable generation is below demand is 21GW.

Figure 3-23: a) calculated BAU demand profile; b) calculated combined PV and tidal output profile; c) calculated wind output profile; d) calculated combined dispatchable (bioenergy, hydro and geothermal) output profile



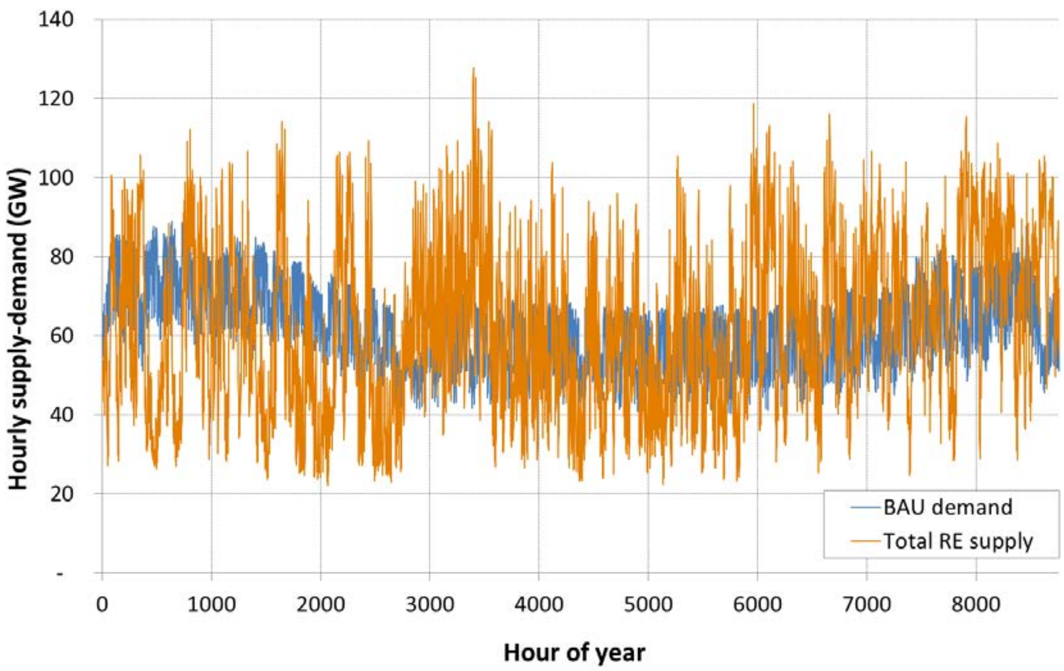
It should be noted that the maximum output predicted from RES in this scenario is almost double the required demand in that period. This illustrates the magnitude of the generation and demand imbalance challenge throughout the year.

Figure 3-25 illustrates the sum of all generation from renewable sources, given in b), c) and d) of Figure 3-23. The profile has been calculated using the methodology given in Figure 3-24 for each hour of the year. For comparison, the demand profile for the scenario has also been provided.

Figure 3-24: Methodology for creation of combined yearly generation profile

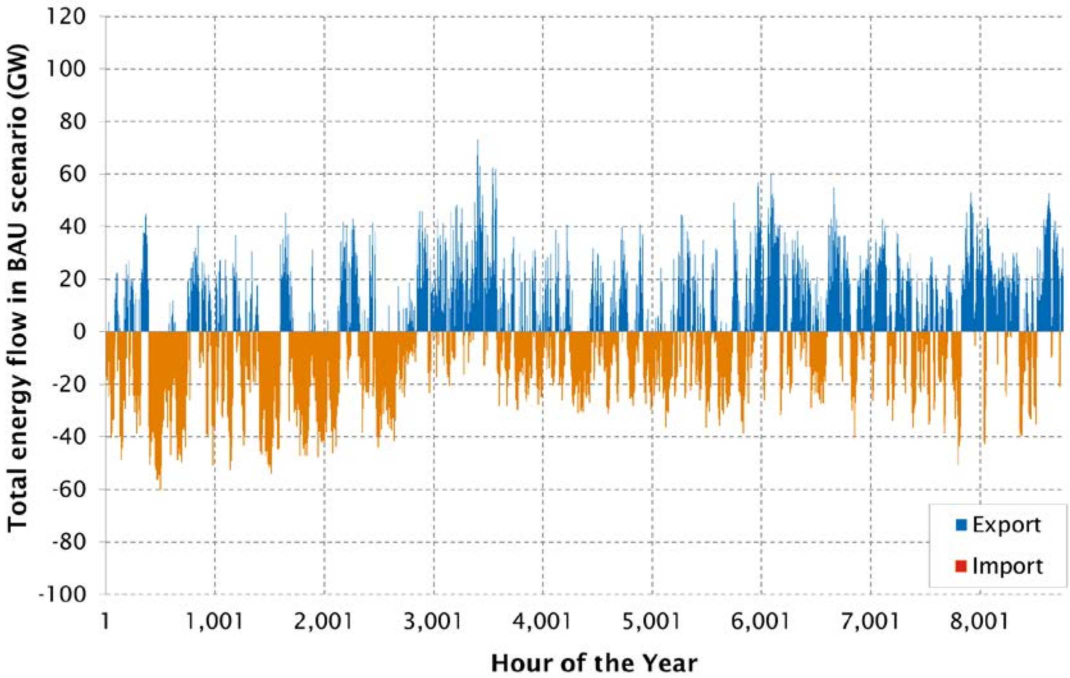
This serves to highlight the difference between the hourly demand profile of the BAU scenario and the calculated hourly generation, or supply, profile of the required capacity. It can be seen that during periods of the year, there is not enough generation to supply the demand at that specific hour whilst in others there is an excess of generation. This is due to the variable nature of renewable resources, particularly wind and solar. Although there is an amount of dispatchable capacity installed, there is insufficient generation form this to cover the required demand when output from wind and solar is low.

Figure 3-25: Illustration of the UK supply-demand issue in the fully renewable BAU scenario



Resolving the supply and demand for each hour gives an hourly breakdown of the imbalance. This can be used to obtain the energy flows required to maintain grid supply of electricity in the BAU scenario. This is illustrated in Figure 3-26.

Figure 3-26: Calculated UK total energy flow in the BAU scenario



The same analysis and methodology has been used to investigate the supply and demand imbalance for the remainder of the scenarios.

3.4.2 GP Scenario

Figure 3-27 depicts the demand profile for the GP scenario that has a maximum demand of 64GW during the winter and minimum of 29GW during the summer. The main generation comes from wind with a peak output of 61GW. The total installed dispatchable generation that is available when the variable generation is below demand is 19GW.

Figure 3-27: a) calculated GP demand profile; b) calculated combined PV and tidal output profile; c) calculated wind output profile; d) calculated combined dispatchable (bioenergy, hydro and geothermal) output profile

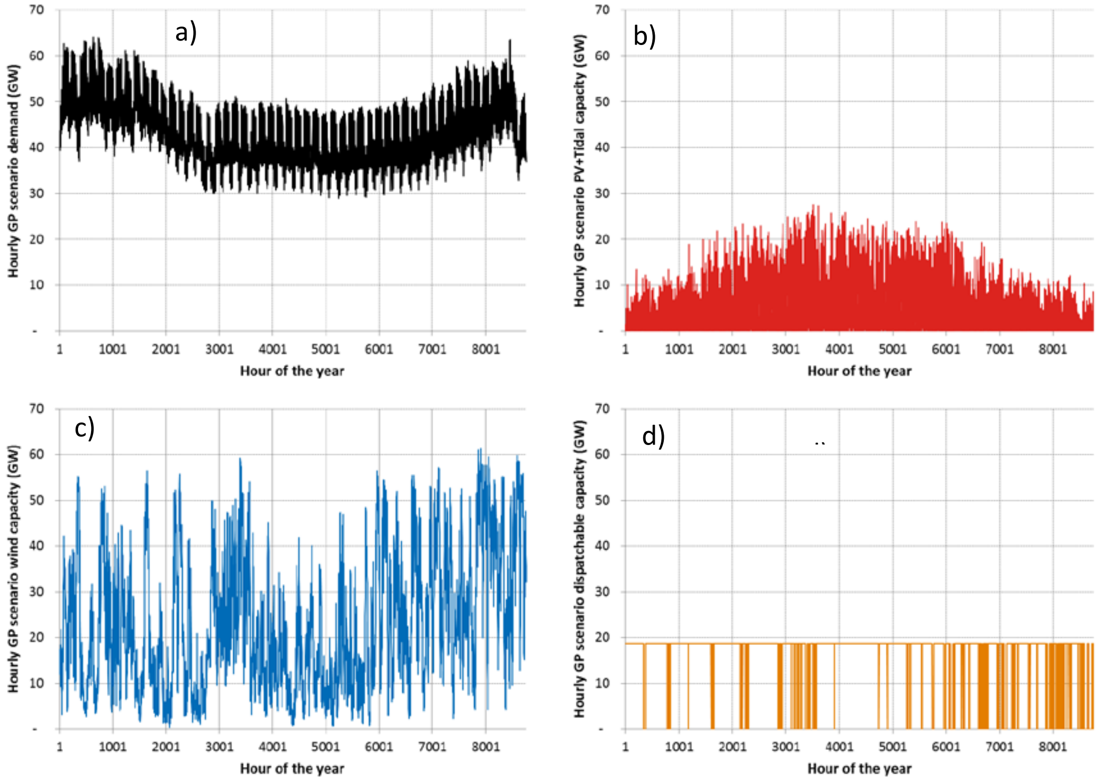
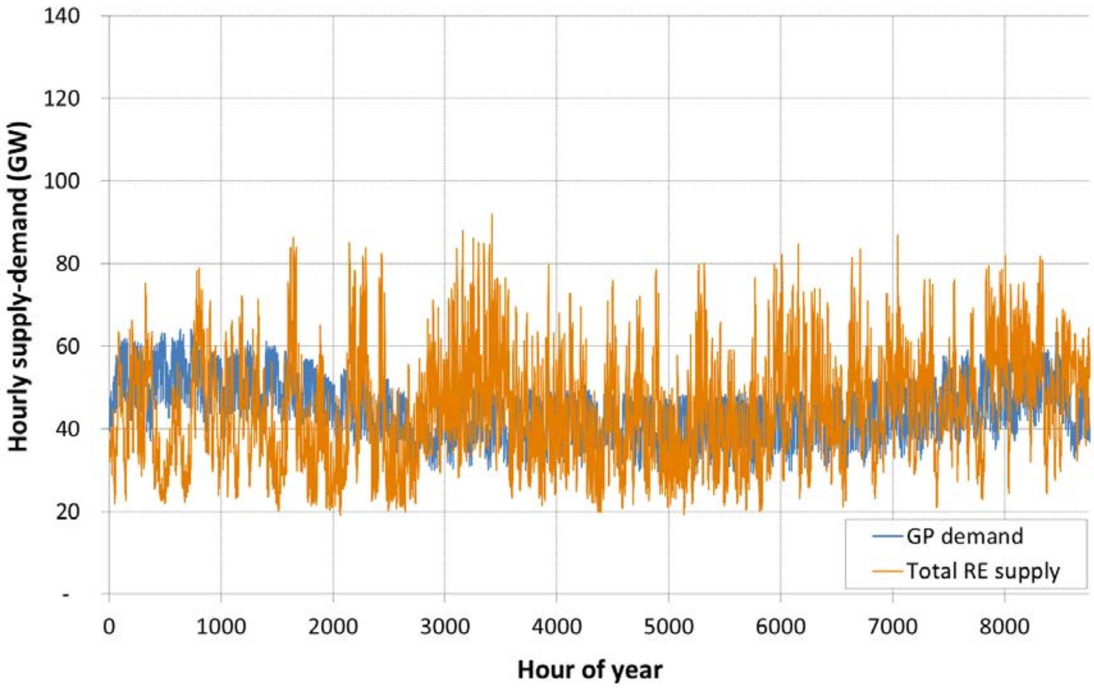


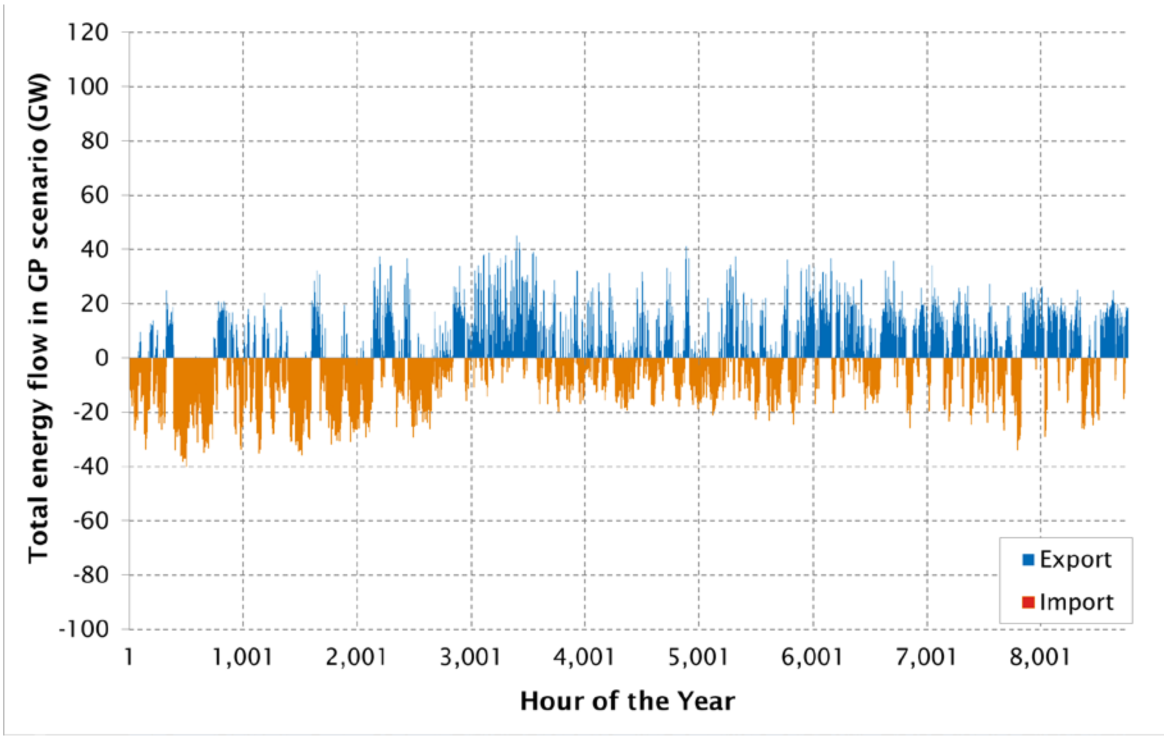
Figure 3-28 illustrates the sum of all generation from renewable sources, given in b), c) and d) of Figure 3-27, and the demand profile for the scenario. It serves to highlight the difference between the hourly demand profile of the GP scenario and the calculated hourly generation, supply, profile of the required capacity. In this case, even though the demand is lower, there is still not enough dispatchable generation in periods of calm. It can be appreciated that in this scenario, the size of the 'gap' between generation and demand is lower than in the BAU scenario.

Figure 3-28: Illustration of the UK supply-demand issue in the fully renewable GP scenario



Resolving this supply and demand imbalance provides an hourly breakdown of the energy flows required to maintain grid supply of electricity in the GP scenario. This is illustrated in Figure 3-29.

Figure 3-29: Calculated UK total energy flow in the GP scenario



3.4.3 BAU+EV&ASHP Scenario

Figure 3-30 depicts the demand profile for the BAU+EV&ASHP scenario that has a maximum demand of 115GW during the winter and minimum of 46GW during the summer. In this scenario wind has a peak output of 144GW. The total dispatchable generation that is available when the variable generation is below demand is 23GW.

Figure 3-30: a) calculated BAU+EV&ASHP demand profile; b) calculated combined PV and tidal output profile; c) calculated wind output profile; d) calculated combined dispatchable (bioenergy, hydro and geothermal) output profile

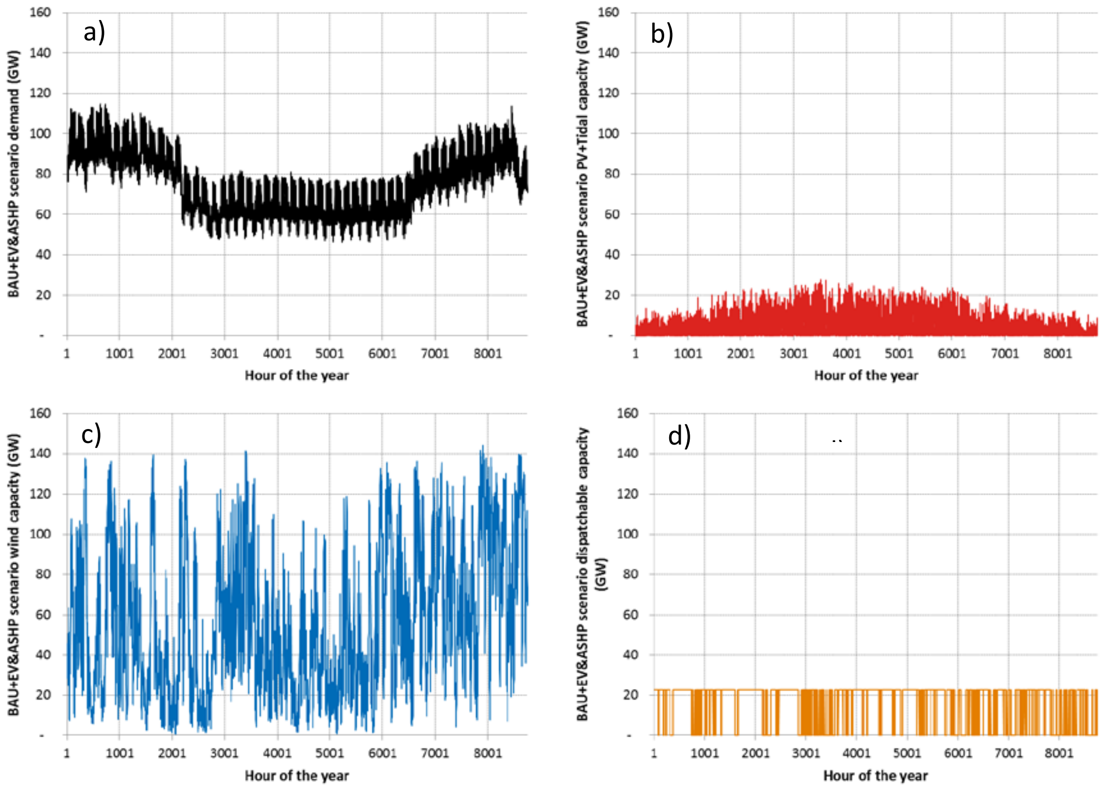
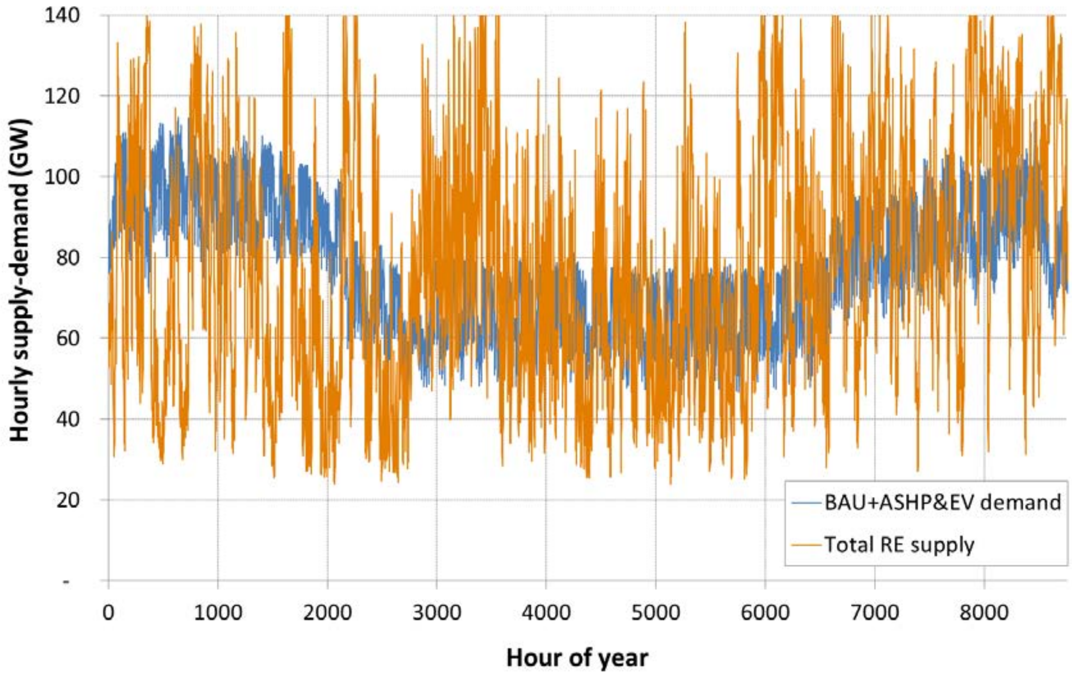


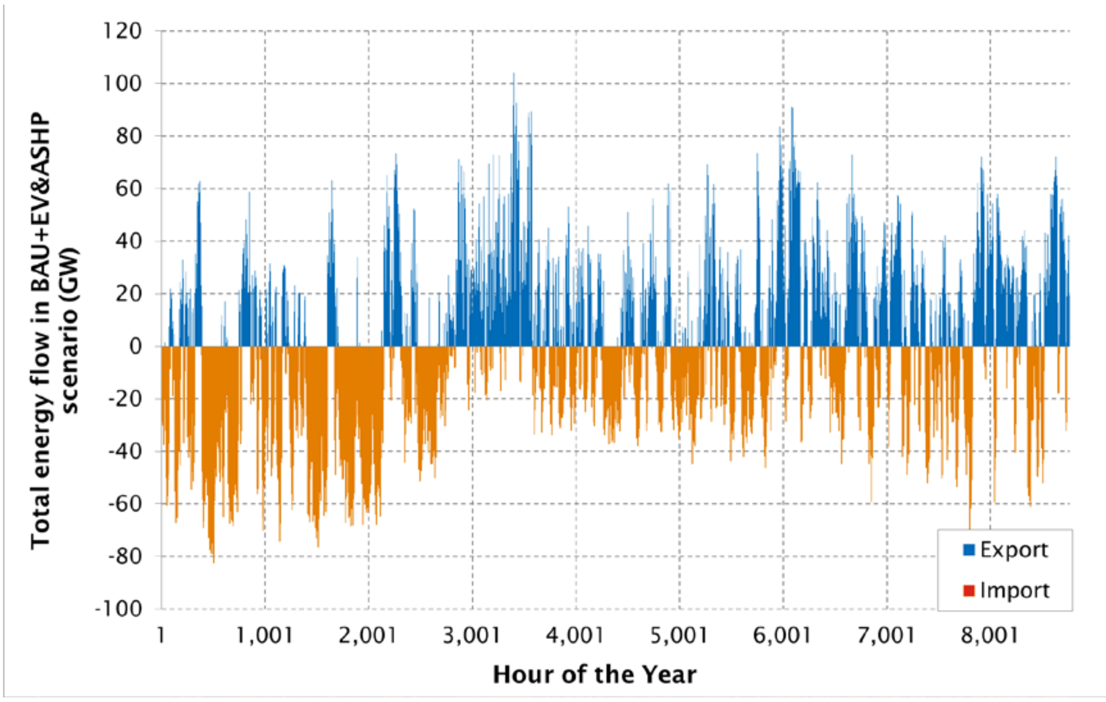
Figure 3-31 illustrates the sum of all generation from renewable sources, given in b), c) and d) of Figure 3-30, and the demand profile for the scenario. It serves to highlight the difference between the hourly demand profile of the BAU+EV&ASHP scenario and the calculated hourly generation, supply, profile of the required capacity. Due to the increase in demand from heating and electric vehicles, the overall ‘gap’ between supply and demand is exacerbated. The main impact of this is the amount of excess electricity generated due to the increase in capacity to meet the demand.

Figure 3-31: Illustration of the UK supply-demand issue in the fully renewable BAU+EV&ASHP scenario



Resolving this supply and demand imbalance provides an hourly breakdown of the energy flows required to maintain grid supply of electricity in the BAU+EV&ASHP scenario. This is illustrated in Figure 3-32.

Figure 3-32: Calculated UK total energy flow in the BAU+EV&ASHP scenario



3.4.4 GP+EV&ASHP Scenario

Figure 3-33 depicts the demand profile for the GP+EV&ASHP scenario that has a maximum demand of 90GW during the winter and minimum of 35GW during the summer. Wind has a peak output of 101GW and the total dispatchable generation that is available when the variable generation is below demand is 21GW in this scenario.

Figure 3-33: a) calculated GP+EV&ASHP demand profile; b) calculated combined PV and tidal output profile; c) calculated wind output profile; d) calculated combined dispatchable (bioenergy, hydro and geothermal) output profile

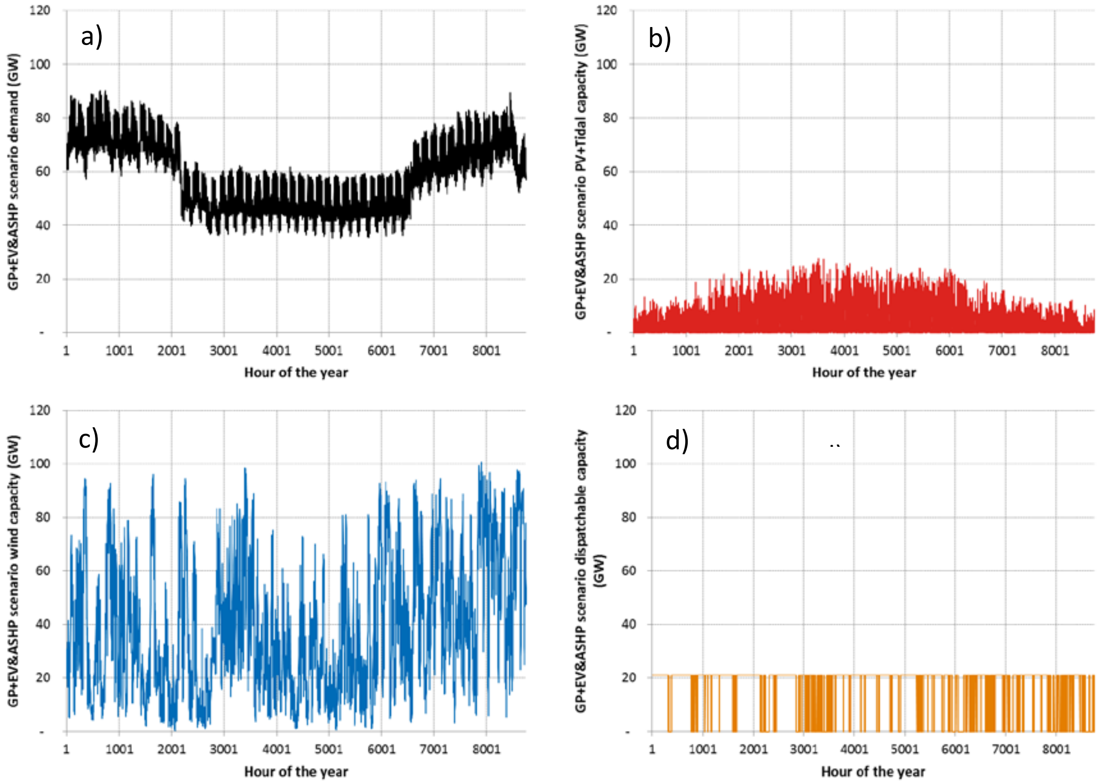
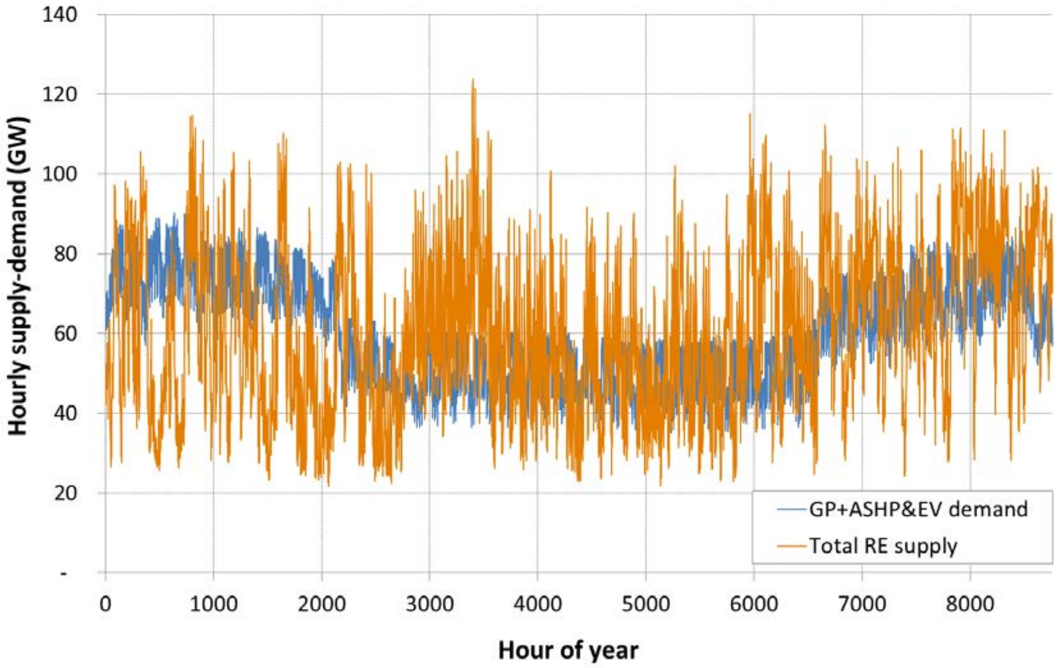


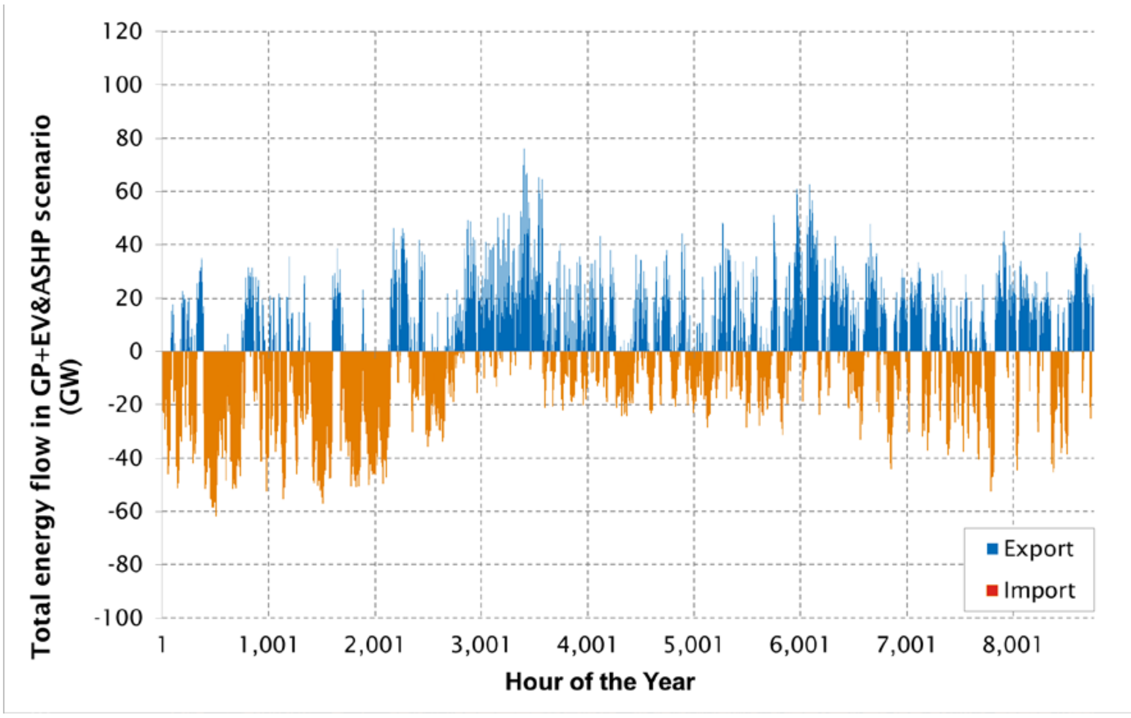
Figure 3-34 illustrates the sum of all generation from renewable sources, given in b), c) and d) of Figure 3-33, and the demand profile for the scenario. It serves to highlight the difference between the hourly demand profile of the GP+EV&ASHP scenario and the calculated hourly generation, supply, profile of the required capacity. Like the scenario above, the overall ‘gap’ between supply and demand is exacerbated. However, the overall imbalance is lower.

Figure 3-34: Illustration of the UK supply-demand issue in the fully renewable GP+EV&ASHP scenario



Resolving this supply and demand imbalance provides an hourly breakdown of the energy flows required to maintain grid supply of electricity in the GP+EV&ASHP scenario. This is illustrated in Figure 3-35.

Figure 3-35: Calculated UK total energy flow in the GP+EV&ASHP scenario



These datasets provide the specification of the generation and demand balance that must be achieved through technological options. These calculations will be used to inform the discussion on the amount of interconnection required (see Chapter 4:) and energy storage (see (Chapter 5:) in each scenario.

3.5 Summary and Discussion

This Chapter sets out the electricity demand scenarios that are used to investigate the future fully renewable electricity grid. The two main scenarios are a Business as Usual (BAU) scenario which assumes electricity demand increases with a growth rate of 1% per annum in line with existing growth, and the Green Plus (GP) scenario which assumes the rate of demand increase is reduced to 0.25% per annum and represents a scenario in which there is an increase in consumer awareness of energy consumption and environmental issues.

It then sets out two technological advances that are likely to see an increased uptake in the future: electrification of transportation and heating. It discusses the projections for uptake of plug-in electric vehicles in the UK and the increase in demand due to their charging requirements. There is also a calculation on the increase of demand due to the uptake of heat pumps for domestic heating and hot water demand. It is noted that whilst demand for transportation is assumed to be constant over the course of the year, the electrical demand for heating is assumed to be prevalent over the winter months, from October through to March.

The Chapter then introduces the supply necessary to meet the required electricity demand. The calculations and assumptions made to estimate the amount of capacity and generation from a mix of renewable technologies have been given along with the estimated cost to install the required capacity in the future.

The demand profiles are then discussed in detail. The BAU scenario and GP scenario have been developed based on the actual 2011 hourly demand data and linearly scaled up to meet the future proposed levels. In addition, the effects of electrification of transportation and heating discussed previously have been added to these two scenarios to create a further two scenarios for discussion: BAU+EV&ASHP and GP+EV&ASHP. The different scenarios have been presented and compared to illustrate the differences in installed capacity and cost.

The next steps included comparing the hourly demand profiles and hourly generation profiles for each scenario to investigate the mismatch and the variability between supply and demand in the proposed future scenarios.

Going forward into Chapter 4:, the variability calculated for each scenario will be further investigated to provide technological solutions to balance the supply and demand to ensure that demand is met throughout the year across the UK.

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Chapter 4: Option 1 – Interconnection

4.1 Introduction

A potential solution to balancing the variability of generation from RES is by using neighbouring electricity grids as a source that can provide generation when RES generation is below demand, and a source of demand when there is excess generation from RES. In the UK, this is already achieved at a limited level through sub-sea HVDC cables known as interconnectors to France, Ireland and Belgium. Due to the physical process of transmitting electricity via HVDC interconnectors, this typically carries a loss penalty of 2% of the transmitted electricity, which is related to the length of the cable (Saguan et al., 2011). Additionally, there is a fixed loss from the AC-DC and DC-AC conversion at either end of the interconnector. The current installed capacity is 4GW and it provides a balancing mechanism between the UK grid and the grid of the connected countries (National Grid, 2012c). The use of interconnectors to integrate large quantities of RES has been investigated widely and has been highlighted as a major contributor to enabling high penetrations of variable generation on the electricity network (Purvins et al., 2011, Battaglini et al., 2009). A major study of future wind penetration scenarios and the enabling characteristics of interconnection found that investing in interconnection for scenarios with high levels of wind power reduced network constraints and maximised the use of RES (Hulle, 2009). Work by Czisch and Giebel (2007) also points to the possibility of creating a 'supergrid' of HV interconnection to maximise integration of large renewable resources over large footprints in order to ensure security of supply.

The main technology characteristics used in this Chapter and the costs employed in the analysis were introduced in Chapter 2.5. This study considers interconnection as a solution to the generation-demand imbalance from a fully renewable electricity generation network as one possible solution, assuming the interconnector is able to balance the active and reactive power in the system, like a slack bus. A slack bus is used to absorb or emit active and reactive power on the electricity grid, however it has an inherent drawback when dealing with variable generation as the slack bus must be able to absorb all uncertainties and hence must have a wide nodal power probability distribution in the system to cope with this (Dimitrovski and Tomsovic, 2004).

4.2 Interconnector Requirements for each Scenario

In this Chapter, the variability of supply and demand calculations that have been presented in Chapter 3.4 are analysed further to investigate the amount of interconnector capacity that would be required for each scenario in order to balance the supply and demand profile over the year.

The findings for each of the scenarios are now presented.

4.2.1 BAU interconnector requirements

The energy flow for the whole year in the BAU scenario needed to maintain a balanced grid has been calculated in Chapter 3.4.1. This translates readily into the import and export capacity requirements of an interconnector. The data has been split into import (orange line) and export (blue line) for each hour of the year. From this, it is possible to calculate the maximum export requirement, 73GW, and also the maximum import requirement, 60GW.

4.2.2 GP interconnector requirements

The energy flow for the whole year in the GP scenario needed to maintain a balanced grid has been calculated in Chapter 3.4.2. In this scenario, it was found that the maximum export capacity is 45GW whereas the maximum import capacity is 40GW.

4.2.3 BAU+EV&ASHP interconnector requirements

The energy flow for the whole year in the BAU+EV&ASHP scenario needed to maintain a balanced grid has been calculated in Chapter 3.4.3. In this case, the maximum export capacity reached is 104GW and the maximum import requirement is 83GW.

4.2.4 GP+EV&ASHP interconnector requirements

The energy flow for the whole year in the GP+EV&ASHP scenario needed to maintain a balanced grid has been calculated in Chapter 3.4.4. In this scenario the maximum export capacity is calculated to be 76GW whereas the maximum import is 62GW.

4.2.5 Summary of interconnector requirements

The required interconnector capacities for all four scenarios are summarised in Table 4-1. To account for the AC-DC and DC-AC conversion losses and the losses due to the cable length that are incurred in the transmission of electricity via the interconnector, the installed offshore wind capacity has been increased to account for this.

Table 4-1: Calculated import and export requirements for each scenario

Scenario	Import capacity (GW)	Export capacity (GW)
BAU	60	73
GP	40	45
BAU+EV&ASHP	83	104
GP+EV&ASHP	62	76

It is noted that in all four cases, the export capacity is greater than the import capacity. This will be discussed in greater detail in Chapter 4.4. It is also of interest that the maximum export is reached during the summer months whereas the import capacity reaches its maximum at the beginning of the year. This is predominantly the case in this study due to the specific weather profile. In this case, there was a less than average wind speed during the beginning of the year which correlates with a high demand for electricity. On the other hand, the high export requirement during the summer is representative of a high wind yield coupled with a low electrical demand.

Whilst every effort has been made to ensure that the year modelled is representative of average UK conditions and demand, there are characteristics within each year that differentiate one from the next. Additionally, the intention is to model a scenario based on 'real' conditions. For this reason, the scenarios developed have this defined profile.

4.3 Interconnector Zonal Analysis

As discussed in Chapter 2:, the UK network is divided into 17 individual zones, within which there is a specific electricity demand and electricity generation. Using these zones, it is possible to determine the future renewable generation by zone for each scenario based on the location of existing and proposed installations that has been calculated in Chapter 3. The demand for each zone has been calculated for the future scenarios by linearly scaling the existing 2011 demand (National Grid, 2011a). Using this approach, it is possible to investigate the power flows that occur around the UK network and where the demand and generation centres are. It also highlights potential bottlenecks in the network that would require transmission upgrades to cope with the higher power flows.

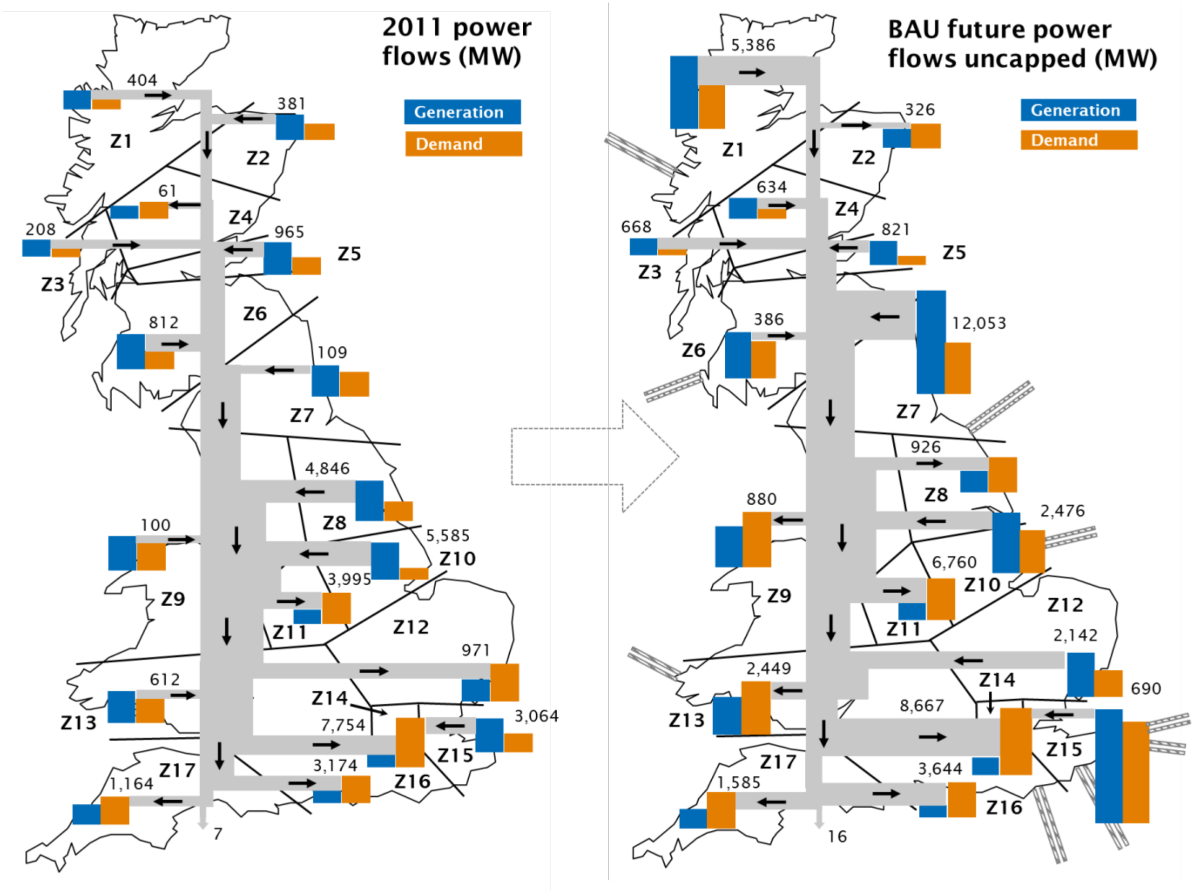
Analysis has been carried out to investigate the effect of a large increase in interconnector capacity connecting to the UK electricity network. In order to carry out this analysis it is necessary to investigate the current interconnector capacity in the UK (discussed in Chapter 2.2.2) and also the propose future interconnector capacity *(National Grid, 2014)*. An assumption has been made on the location of the landing points of some of the interconnectors, as many of the proposed interconnectors are at the feasibility stage. Table 4-2 summarises the existing and proposed interconnectors on the UK electricity network and their individual capacity. These total 9.9GW at present. However, as is demonstrated in Chapter 4.2.5, the minimum interconnector capacity required in the proposed BAU and GP scenarios is circa 60GW and 40GW respectively to ensure that the electricity supply-demand is balanced. In order to achieve this, a scale up factor of 6.05 and 4.05 respectively has been applied linearly across the existing and proposed interconnectors in order to reach the required capacity.

Table 4-2: Existing and proposed UK interconnector capacity and location, and future capacity in BAU scenario (National Grid, 2014)

Existing and proposed interconnector locations		Existing and proposed capacity (MW)	Future capacity BAU scenario (MW)	Future capacity GP scenario (MW)
France-UK	Z15	2,000	12,092	8,106
Northern Ireland-UK	Z6	500	3,023	4,053
Ireland-UK	Z13	500	3,023	4,053
Belgium-UK	Z15	1,000	6,046	5,674
Netherlands-UK	Z15	1,000	6,046	4,458
France-UK 2	Z16	1,000	6,046	4,053
Denmark-UK	Z10	1,400	8,464	2,026
Norway-UK	Z7	1,400	8,464	2,026
Iceland-UK	Z1	1,100	6,651	5,674
	TOTAL	**9,900**	**59,855**	**40,124**

This analysis can be seen illustrated in Figure 4-1. It is possible to see the power flows around the UK network in 2011 and the calculated power flows for the future 2050 BAU scenario. What is clear is that the power flows remain broadly the same with the main flow of electricity being from North to South. However, it is important to note that interconnectors allow flow of energy in both directions, and hence the total amount of 'generation' in a zone with interconnector can also be seen as 'demand'.

Figure 4-1: Average electricity power flows across the UK network in 2011 (National Grid, 2011a) and calculated for 2050 BAU+EV&ASHP scenario



4.4 Analysis of Cost versus Interconnector Capacity

In order to maintain grid stability and ensure demand is met, the crucial capacity that would need to be delivered is the import capacity. For the occasions when there is excess generation over the capacity limit of the interconnector, it is assumed that the electricity can be sold to industry to produce hydrogen, for example, or the generation can be shed through reducing the output from wind farms. As has been discussed, the present interconnector capacity is 4GW so proposing scenarios with up to 83GW of interconnector capacity is difficult to envisage at present, even if the European grid's capability is not considered as a limitation. The economics of such a scenario have been investigated. To estimate the capital costs of the interconnectors, it has been assumed that existing and proposed future UK-Europe interconnector routes are used. These include connecting the UK with France, Belgium, Norway and Iceland (SKM, 2010).

Cost estimates provided by the Research Methodologies and Technologies for the Effective Development of Pan-European Key Grid Infrastructures to Support the Achievement of a Reliable, Competitive and Sustainable Electricity Supply (REALISEGRID) project (Ruberg et al., 2010) as provided in Chapter 2.5.1 have been used to give the interconnector costs based on distance between countries, capacity, technology used and landing terminals at either end. The technology chosen in this analysis is HVDC technology with VSC landing terminals as the most likely technology to be used. By using the calculated interconnector import and export capacity for each scenario given in Table 4-1 it is possible to estimate a likely future cost for each proposed solution.

These calculated costs are also compared to the UK gross domestic product (GDP) in 2012 of GBP 1.5 trillion (Chote et al., 2012) to give an estimation as to the level of investment required. The summary of interconnector costs can be seen in Table 4-3.

Table 4-3: Calculated UK interconnector cost for each scenario (% of UK GDP in 2012 also shown)

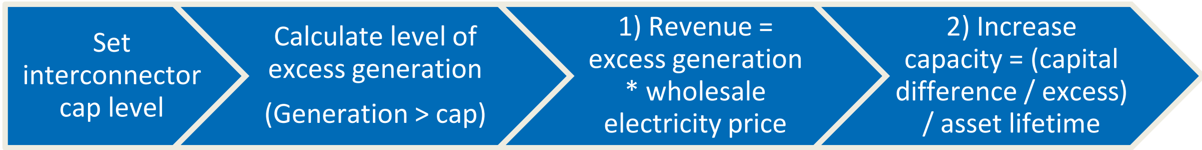
Scenario	Import capacity cost in GBP Bn (%GDP)	Export capacity cost in GBP Bn (%GDP)
BAU	60 (3.6%)	73 (4.4%)
GP	40 (2.4%)	45 (2.7%)
BAU+EV&ASHP	83 (4.9%)	104 (6.2%)
GP+EV&ASHP	62 (3.7%)	76 (4.5%)

As can be seen, there is a large difference between the costs calculated and it further highlights that the import requirements are lower than the export requirements. Further analysis suggests that there is no economic case for adding interconnector capacity beyond the import requirement as will be discussed for each case separately below.

For the purpose of this analysis, it has been assumed that the wholesale electricity price of GBP 70/MWh can be obtained from selling excess electricity produced from renewable energy sources (DECC, 2012j) and the asset lifetime is 40 years. As a comparison, the Strike Price given to the Hinkley Point C nuclear power plant is GBP 89.50/MWh, or GBP 92.50/MWh should the Sizewell C site not go ahead (DECC, 2014e).

In order to calculate the amount of excess generation that would be generated in the case that the interconnector is capped at the maximum import capacity, a cap has been put on the interconnector requirements introduced in Chapter 3.4. This then gives a level of excess generation that cannot be export due to the cap across the year. Therefore, to calculate the amount of revenue that can be achieved from sale of this excess generation and the cost to increase the interconnector is calculated using the methodology given in Figure 4-2.

Figure 4-2: Methodology for calculating revenue and cost to increase interconnector capacity



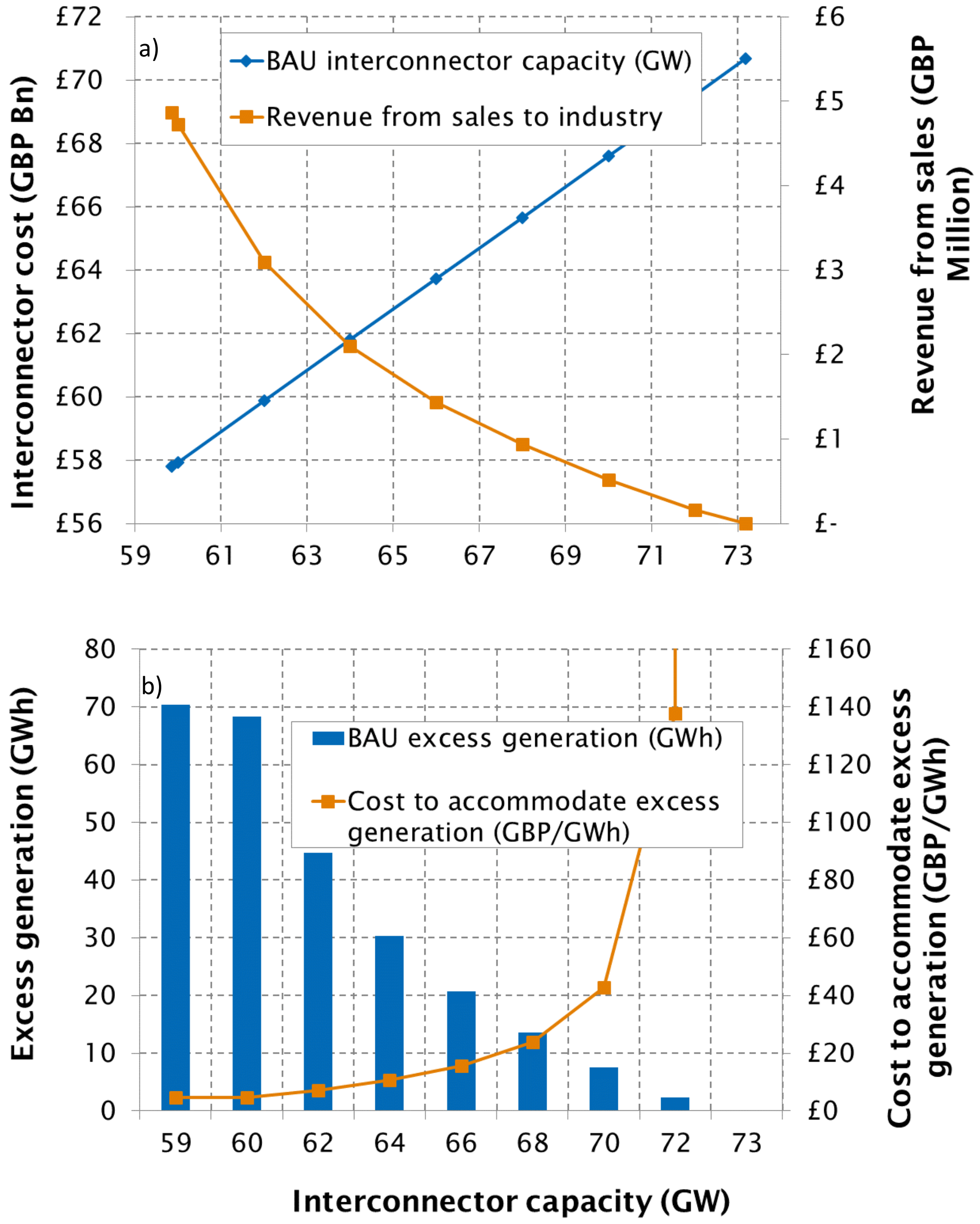
4.4.1 BAU interconnector cost analysis

Figure 4-3 a) shows that for the capped interconnector it is possible to obtain revenue from the sale of excess electricity generation to UK industry; however, these revenues are at most an order of magnitude lower than the interconnector cost. Revenues of nearly GBP 5 million (orange line) per annum could be realised from sales of the excess renewable generation that is not covered by the export capacity of the interconnector. Although, it is important to note that this additional revenue from excess electricity would have to be from a new demand source or commercial venture such as hydrogen production through electrolysis. Conversely, Figure 4-3 b) shows the level of excess generation there would be if the interconnector is capped and the cost of increasing the capacity of the interconnector. It is found that the lowest cost to increase the interconnector capacity in the BAU scenario is GBP 4,500/MWh. This is due to the capacity factor of the interconnector decreasing as the interconnector capacity increases (interconnector is needed for a smaller percentage of the time). See Table 4-4 for a summary of the capping calculations for the BAU scenario. In this case, it can be seen that the initial interconnector capacity is the maximum import capacity, 60GW, and the final capacity being the maximum export capacity, 73GW. The steps in between are arbitrary cap levels of the interconnector used to investigate the financial performance. This methodology is used for the remaining demand scenarios, with the main difference being the interconnector capacity and capping levels

Table 4-4: BAU interconnector capping calculations

BAU interconnector capacity (MW)	Excess generation (MWh)	Revenue from sales of excess electricity (GBP)	Cost to increase interconnector capacity (GBP/MWh)
59,855	70,347	4,869,446	4,577
60,000	68,315	4,728,749	4,713
62,000	44,671	3,092,138	7,207
64,000	30,349	2,100,780	10,608
66,000	20,713	1,433,758	15,544
68,000	13,521	935,903	23,812
70,000	7,521	520,583	42,809
72,000	2,340	161,949	137,610
73,191	1	69	321,956,044

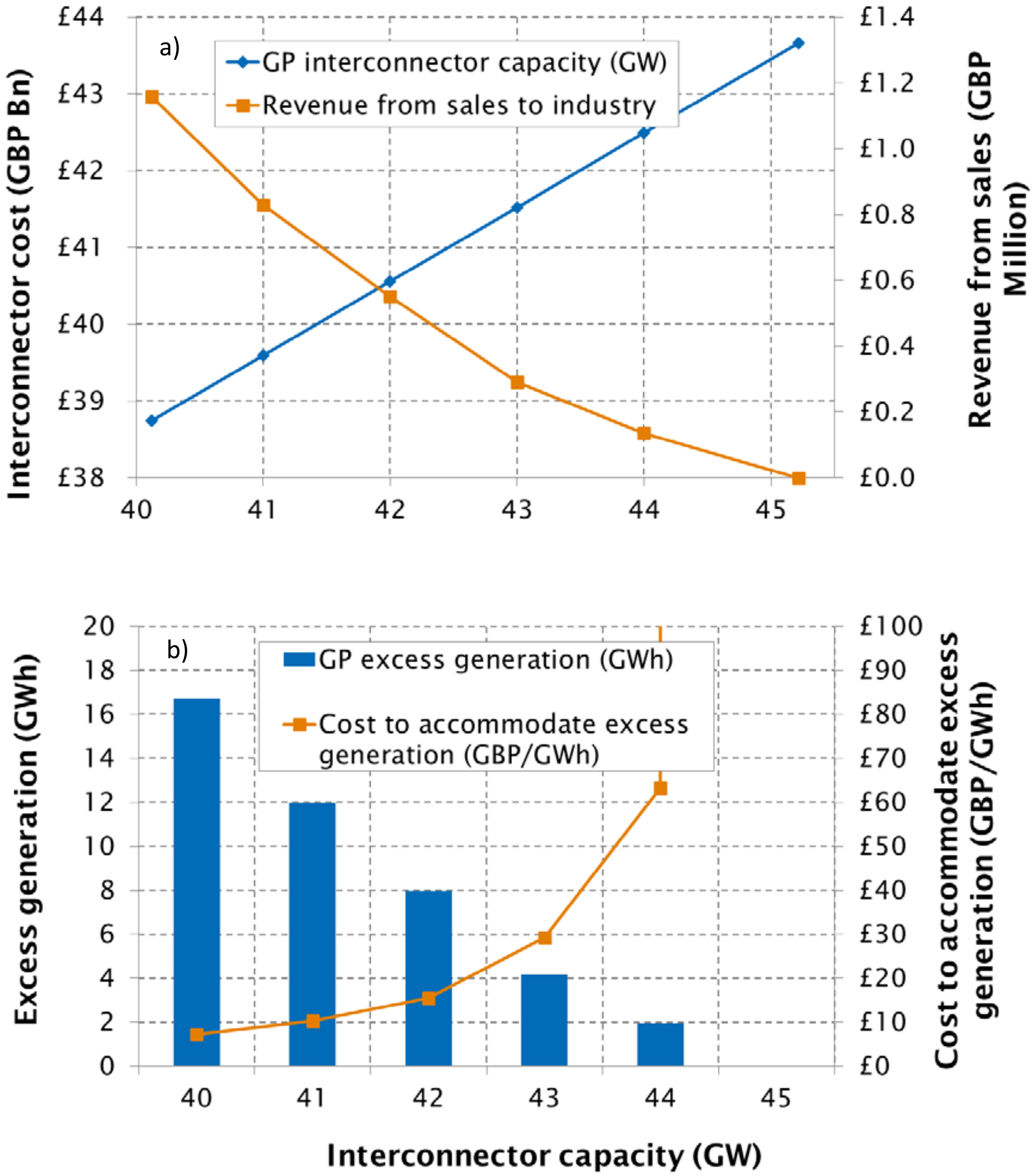
Figure 4-3: a) Calculated BAU interconnector capital cost versus estimated revenue from UK electricity sales; b) excess electricity from capped interconnector versus cost to increase interconnector capacity



4.4.2 GP interconnector cost analysis

Figure 4-4 a) shows that annual revenues of around GBP 1 million (orange line) could be realised from sales of the excess renewable generation to UK industry that is not covered by the export capacity of the interconnector. On the other hand, Figure 4-4 b) shows the level of excess generation there would be if the interconnector is capped and the cost of increasing the capacity of the interconnector. It is found that the lowest cost to increase the interconnector in the GP scenario is GBP 7,300/MWh.

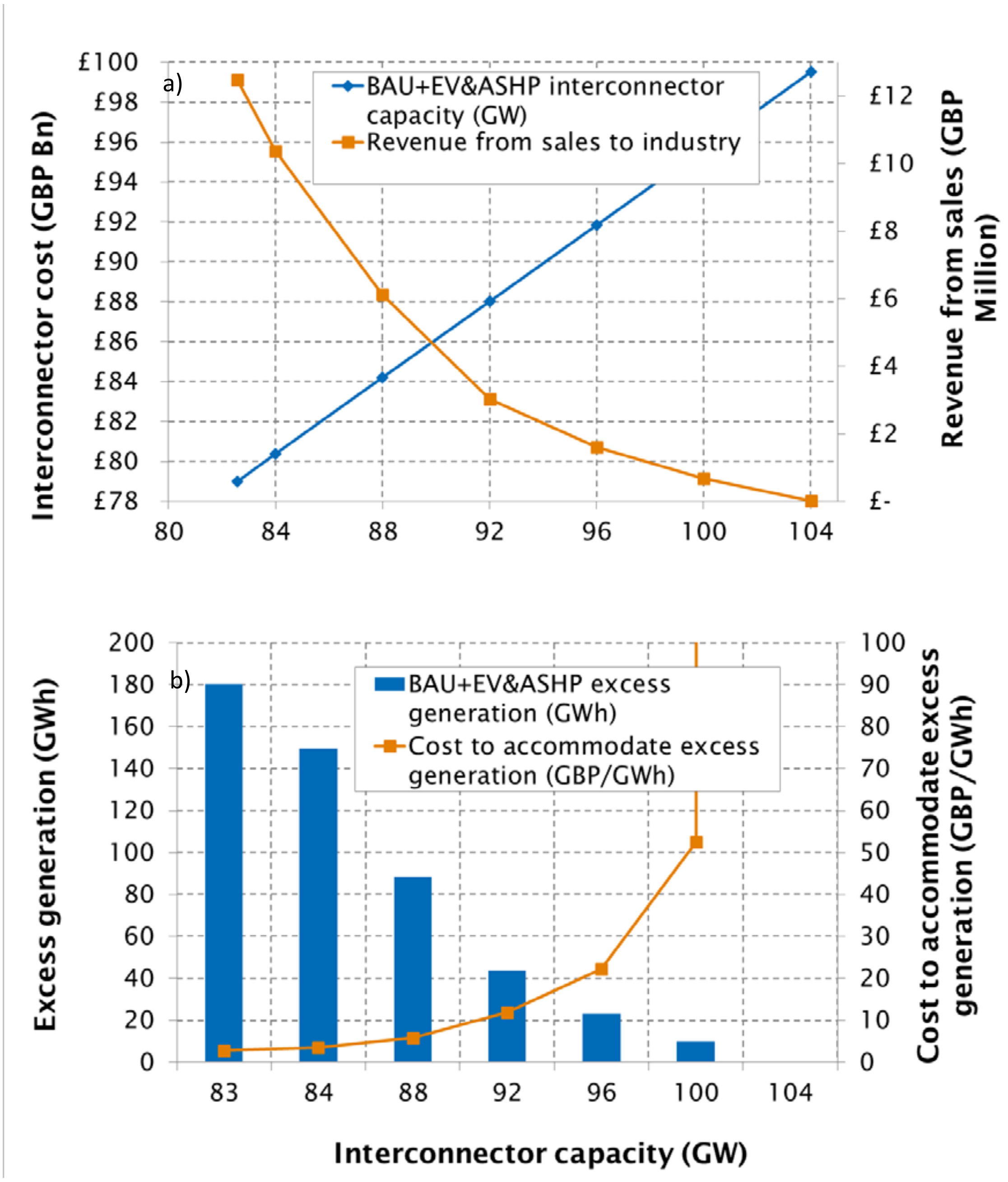
Figure 4-4: a) Calculated GP interconnector capital cost versus estimated revenue from UK electricity sales; b) excess electricity from capped interconnector versus cost to increase interconnector capacity



4.4.3 BAU+EV&ASHP interconnector cost analysis

Figure 4-5 a) shows that annual revenues of around GBP 12.5 million (orange line) could be realised from sales of the excess renewable generation that is not covered by the export capacity of the interconnector. Whereas, Figure 4-5 b) shows the level of excess generation there would be if the interconnector is capped and the cost of increasing the capacity of the interconnector. It is found that the lowest cost to increase the interconnector in the BAU+EV&ASHP scenario is GBP 2,900/MWh.

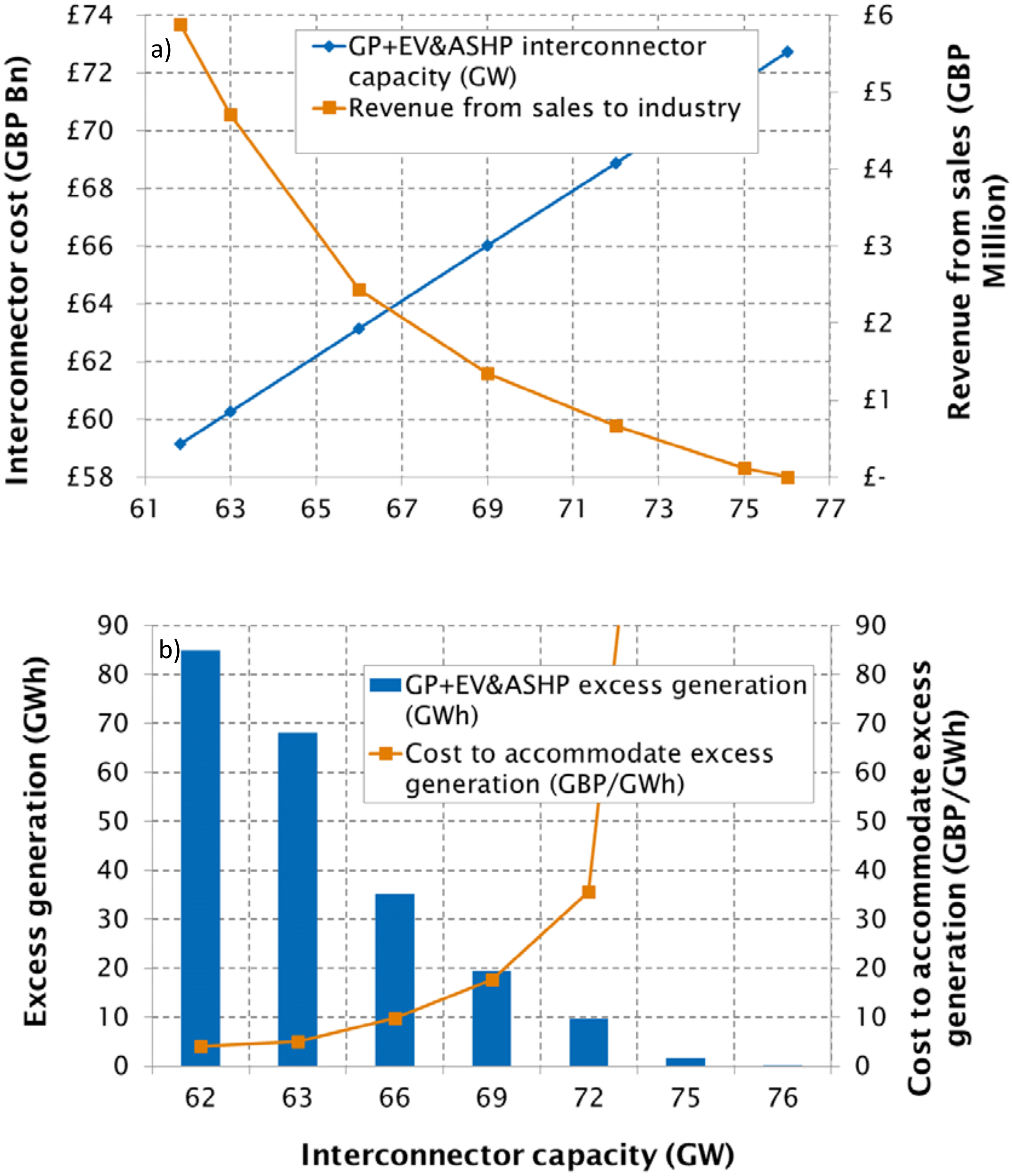
Figure 4-5: a) Calculated BAU+EV&ASHP interconnector capital cost versus estimated revenue from UK electricity sales; b) excess electricity from capped interconnector versus cost to increase interconnector capacity



4.4.4 GP+EV&ASHP interconnector cost analysis

Figure 4-6 a) shows that annual revenues of nearly GBP 6 million (orange line) could be realised from sales of the excess renewable generation that is not covered by the export capacity of the interconnector. Figure 4-6 b) though shows the level of excess generation there would be if the interconnector is capped and the cost of increasing the capacity of the interconnector. It is found that the lowest cost to increase the interconnector in the GP+EV&ASHP scenario is GBP 4,000/MWh.

Figure 4-6: a) Calculated GP+EV&ASHP interconnector capital cost versus estimated revenue from UK electricity sales; b) excess electricity from capped interconnector versus cost to increase interconnector capacity



4.4.5 Summary of interconnector cost analysis

In summary, it is shown that in order to maintain grid stability it is only necessary to install the maximum import requirement in each scenario. Further analysis investigated whether there is a financial reasoning for increasing the installed capacity in order to be able to export some of the excess generation when renewable generation is higher than demand. The calculations show that there is no financial benefit to increasing capacity. However, there is an alternative revenue stream that could be exploited through selling excess electricity at wholesale price to large UK users or for conversion into hydrogen. Table 4-5 summarises the findings from this analysis.

Table 4-5: Summary of excess generation, cost to increase interconnector and sales revenue for each scenario

Scenario	Excess generation (MWh)	Cost to increase interconnector (GBP/MWh)	Annual revenue from electricity sales (GBP M)
BAU	70,347	4,577	4.9
GP	16,728	7,348	1.1
BAU+EV&ASHP	180,311	2,870	12.5
GP+EV&ASHP	84,998	4,031	5.9

It is important to note that this technological solution is highly dependent on the European electricity network being capable of accommodating these levels of import and export throughout the year. Available data for 2011 suggests that the maximum yearly average consumption across the European grid was 62GW, whereas the maximum monthly consumption recorded by country was 72GW in France (entso-e, 2014). Taking France as an example, the minimum monthly consumption in 2011 was 44GW. This suggests that if the European grid maintains its current levels of demand and generation, this would not be a feasible solution. However, it is to be expected that the European grid develops in a similar way to the UK in order to be able to meet future greenhouse gas emissions targets.

A wider study on the impacts and feasibility of having these levels of capacity transmitted across the wider European network would need to be carried out in order to discuss whether these levels of interconnection are feasible.

4.5 Discussion and Conclusions

This Chapter investigates the interconnector capacity required to ensure that the electricity supply and demand is balanced throughout the year. The analysis here assumes that the interconnector is able to balance the active and reactive power in the system, like a slack bus.

In the first instance, it is found that the excess generation is greater than the shortfall during the year. For this reason, it is possible to look at two levels for the interconnectors: full export capacity and capped capacity at import requirement. This approach enables the financial reasoning behind installing interconnectors to accommodate all the import and export requirements or solely for the import requirements to be explored.

In all the scenarios investigated, it is found that the maximum import requirement is during the winter months at the beginning of the year whereas the maximum export requirement is during the summer months. This is to be expected as during the winter months demand is higher and in this instance the amount of renewable generation available was low. During summer, the reverse occurs whereby demand is now low and output from renewables is comparatively high. In this case, generation from wind is lower than during the summer but the imbalance between supply and demand is greater as demand is low.

A zonal analysis was conducted on the UK electricity network. This showed that the zones in which potential future interconnectors may land have a large ‘generation’ and also ‘demand’ as these will allow the flow of electricity in two directions.

In order to ensure that supply and demand are met, the absolute minimum capacity of interconnector required under these conditions is the import requirement, since any quantity of generation above this is surplus to the running of the electricity network. The estimated costs for installing the import capacity required for each scenario was found to be GBP 58 billion for the BAU scenario, GBP 39 billion for the GP scenario, GBP 80 billion for the BAU+EV&ASHP scenario and finally GBP 60 billion for the GP+EV&ASHP scenario. This is equivalent to 3.6%, 2.4%, 4.9% and 3.7% of the UK’s GDP level in 2012.

The second part of the analysis considers the financial reasons behind increasing the interconnector capacity to accommodate and export some of the excess generation throughout the year. In this case, it is demonstrated that the costs per MWh of excess electricity ranges from GBP 2,800 to GBP 7,600/MWh which makes this financially unappealing. On the other hand, it is shown that the excess electricity could be sold to new commercial ventures, such as the hydrogen market, at wholesale price to obtain revenue in the range of GBP 1.1 to GBP 12.5 million. This excess electricity could then be converted to heat or hydrogen for use in the heating or transportation sectors.

This technological solution is highly dependent on the European electricity network being capable of accommodating these levels of import and export throughout the year. Available data for 2011 suggests that the maximum yearly consumption across the European grid was 62GW, with a maximum to minimum monthly consumption range in France of 72GW to 44GW respectively. This suggests that if the European grid maintains its current levels of demand and generation, this would not be a feasible solution.

In Chapter 5: a second option will be discussed that considers a technological solution to maintain electricity supply and demand balance within the borders of the UK.

Chapter 5: Option 2 – Energy Storage

5.1 Introduction

The second potential solution investigated to enable grid balancing of the highly variable renewable generation is energy storage. The benefits of energy storage in electricity networks have been investigated by numerous authors, especially when considering high penetrations of variable generation from renewables (Black and Strbac, 2006). Grant-Wilson et al. (2010) investigated the optimum size of energy storage in the UK network and the potential benefits or drawbacks when compared in conjunction with interconnection or carbon capture and storage (CSS). A further study highlights the ability of energy storage to provide multiple services to the electricity network and not only for the integration of renewable generation (Grant-Wilson et al., 2011). The applications for energy storage in the UK are investigated in Taylor et al. (2012), the conclusion of which is that the UK network will need a combination of large scale and small, decentralised, energy storage including thermal storage. However, energy storage will only become beneficial when there are increased levels of renewable generation.

There are a number of studies that review the various energy storage technologies and applicability of these for the integration of renewable energy sources into electricity grids as well as other ancillary services that they can provide (Connolly et al., 2012, Evans et al., 2012, Koohi-Kamali et al., 2013, Kouskou et al., 2014). One important study considers compressed air energy storage (CAES) to enable the integration of wind generation onto the electricity grid in the United States (Denholm and Sioshansi, 2009). In the study, the benefits of the location of the CAES system on the network relative to the generation site is calculated and compared to the cost of installing additional transmission capacity to remote off-network areas. This approach is not considered in the specific case of this study as it assumed that the majority of renewable generation will be from offshore wind farms. Therefore it is assumed that the cost of installing connections to the grid network will be a necessity and there are substantial technological issues with co-locating storage with generation off-shore.

It is proposed for this study to only consider technologies capable of storing large quantities of electricity over long periods, as likely storage requirements are of the order of 43TWh, as will be discussed later. It is further assumed that, at this stage, only three large scale technologies that connect directly to the high voltage (HV) network are discussed for comparison, therefore discounting technologies such as flywheels, batteries and supercapacitors, even if aggregated in such a way as to provide the required storage requirements.

5.2 Investigation of Ideal Energy Storage Requirements for Each Scenario

From the variability investigation and calculations carried out in Chapter 3:, it is possible to estimate the energy storage requirements for each scenario required to maintain the supply-demand balance of the UK electricity network in the future fully renewable electricity network. The storage requirements can be calculated by running a cumulative total of the hourly import and export requirements over the year that have been used to investigate the interconnector capacity required in Chapter 4. The energy storage size is determined through an iterative process, whereby the 'store' is assumed to begin full with a capacity 'X' at the start of the year and is iteratively resolved to a storage 'Y' at the end of the year. When there is an import requirement (e.g. generation is less than demand) the 'store' starts to empty until there is an excess of generation (e.g. export requirement) when the 'store' starts to refill. In this way, it is possible to estimate the maximum energy storage requirement during the year that would be necessary to ensure demand is met at all times. This assessment is carried out for each of the scenarios discussed. It is important to note that this analysis considers that the cycle efficiency of the store is 100%. Whilst this is not feasible or realistic, this has been carried out to understand the ideal storage requirements required.

Further investigation considers the interplay of adding further renewable capacity, in the form of additional offshore wind capacity, onto the network and the effect this has on the amount of storage required. In this way, it is possible to discuss the financial pros and cons of different energy storage technologies and the benefits of installing additional offshore wind capacity.

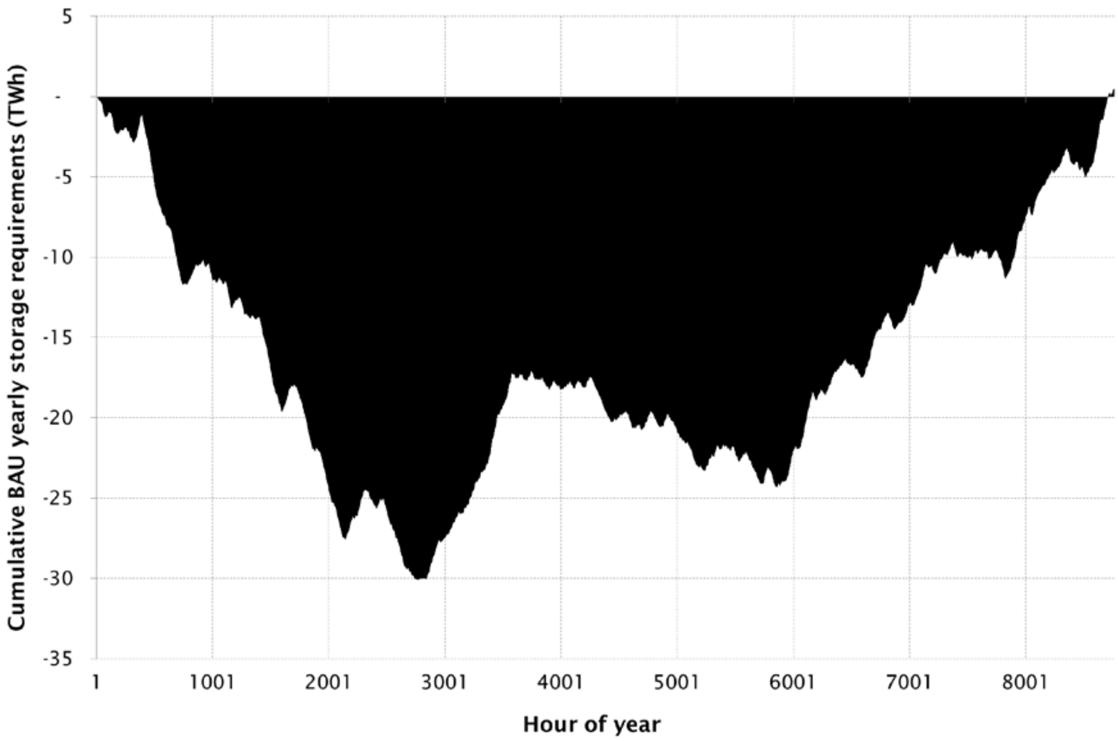
5.2.1 Ideal BAU scenario energy storage requirements

Firstly, the requirements for the BAU scenario are calculated. As introduced, the storage technology, which at this point is assumed to be an 'ideal' technology, begins the year full (hour 0) and reaches a low point before finalising the year at, or near, full (hour 8,760). This is dependent on the demand and generation profile modelled.

Figure 5-1 demonstrates that the lowest point, or the empty point of the 'store', is reached at a value of 30TWh at hour 2,769 for the BAU scenario, after which there is sufficient net generation over the remainder of the year to end the year full. The value calculated signifies the maximum storage capacity that the 'ideal' technology would need to have in order to ensure that demand is met during a period of cumulative low generation. In addition, from this analysis it can be further calculated that the ideal storage technology needs to be able to discharge for a maximum of 197 continuous hours and provide 30TWh of storage throughout the year. This is determined upon examination of the cumulative hourly supply-demand deficit over the year.

This profile is observed as the wind speeds in 2011 happened to be lower than average in the first quarter of the year, when demand was high, and higher than average in the last quarter of the year. Due to this, the store is in high demand during the first half of the year, after which there is sufficient generation from renewable sources to suffice the demand and also re-fill the store. This highlights the seasonal demand of the energy storage technology, which in turn is dependent on the specific weather profile.

Figure 5-1: Calculated annual electricity storage profile for the UK BAU scenario

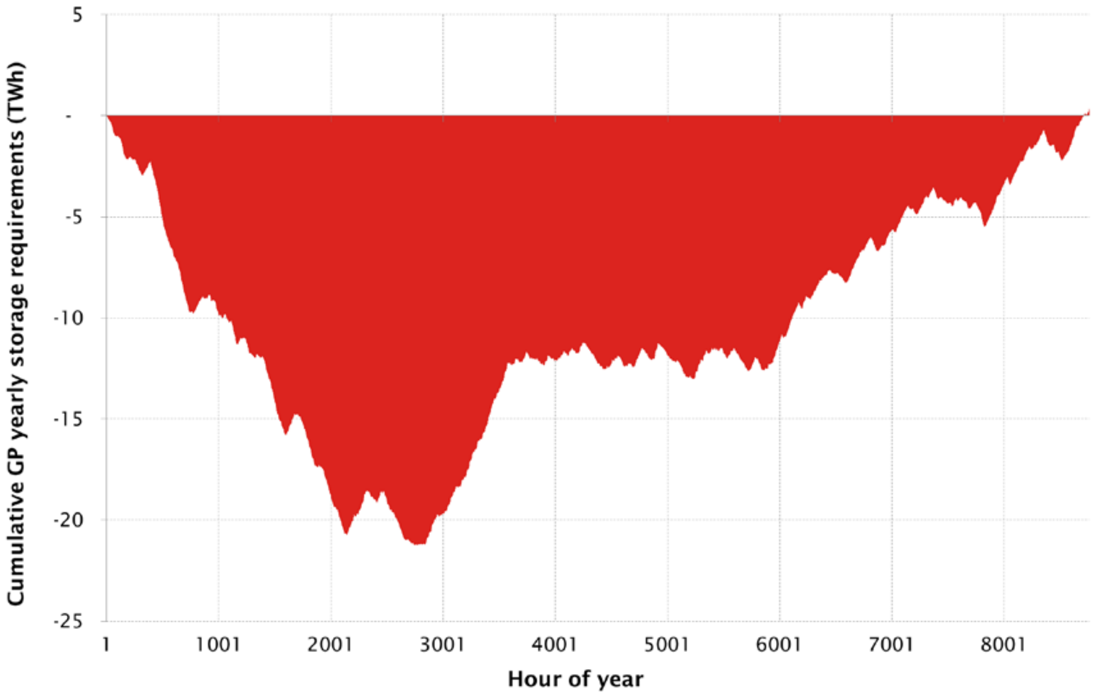


5.2.2 Ideal GP scenario energy storage requirements

This same approach is used for the GP scenario. In this case, it has been calculated that the overall demand for electricity is lower than it is for the BAU scenario. Therefore it is expected that the energy storage requirement is also lower.

Figure 5-2 illustrates that the lowest point, or the empty point of the ‘store’, is reached at a minimum of 21TWh at hour 2,745 for the GP scenario, after which there is sufficient net generation over the remainder of the year to recharge the ‘store’. It is also calculated that the ideal storage technology needs to be able to discharge for a maximum of 190 continuous hours and provide 21TWh of storage throughout the year in order to meet demand on the UK network.

Figure 5-2: Calculated annual electricity storage profile for the UK GP scenario

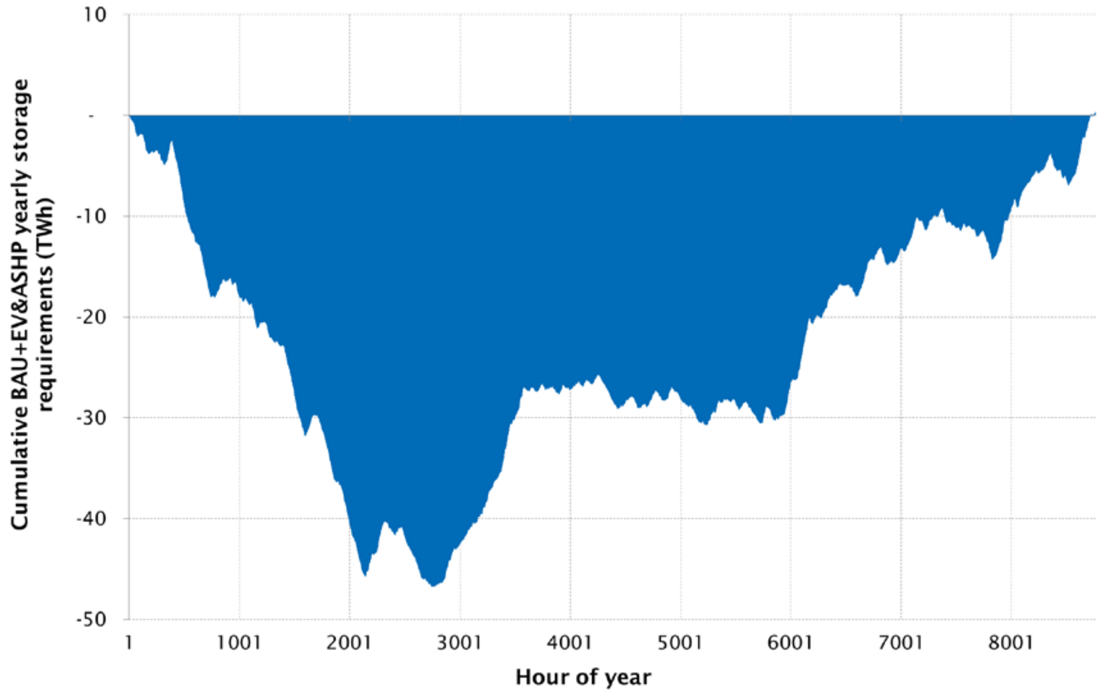


5.2.3 Ideal BAU+EV&ASHP scenario energy storage requirements

On the other hand, the BAU+EV&ASHP scenario has been shown to have the highest demand of the scenarios considered. In addition, the seasonal demand of heating demand present in this scenario exaggerates the storage requirements during the first quarter of the year.

Figure 5-3 shows that the lowest point, or the empty point of the 'store', is reached at 47TWh at hour 2,745 for the BAU+EV&ASHP scenario, after which there is sufficient net generation over the remainder of the year to recharge the 'store'. In this case it is calculated that the ideal storage technology needs to be able to discharge for a maximum of 216 continuous hours and provide 47TWh of storage throughout the year.

Figure 5-3: Calculated annual electricity storage profile for the UK BAU+EV&ASHP scenario

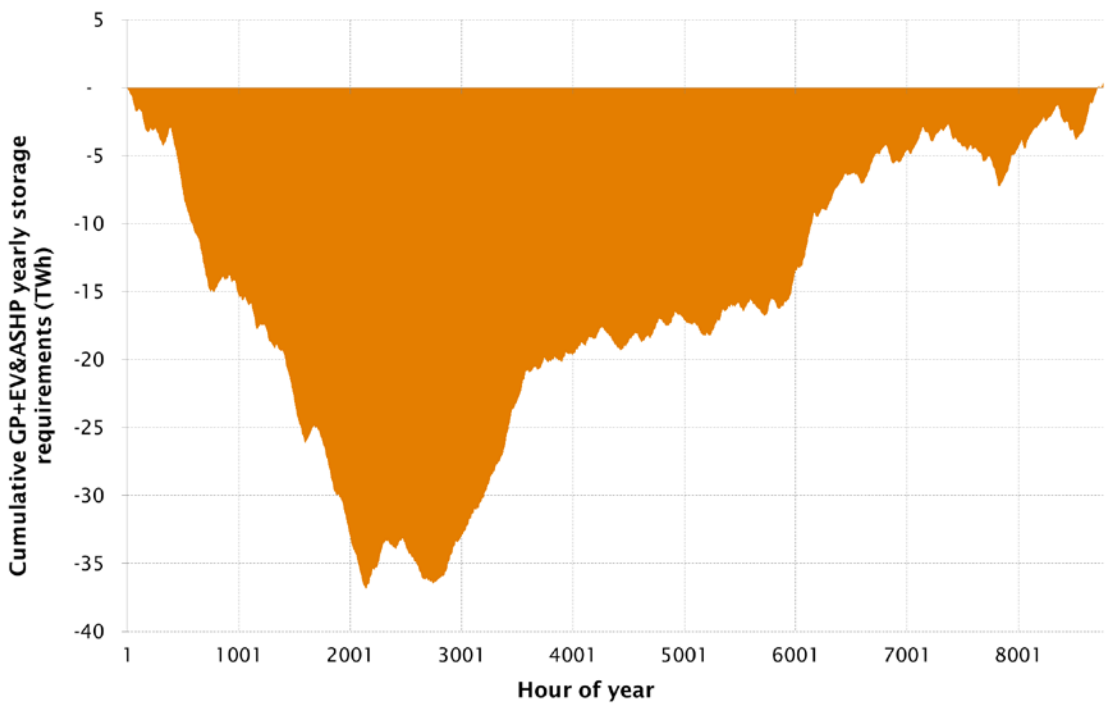


5.2.4 Ideal GP+EV&ASHP scenario energy storage requirements

Whilst this scenario includes a number of energy efficiency measures and a step change in user behaviour towards usage of electricity, the supply-demand deficit is comparable in scale to the BAU scenario due to the uptake in heating and transportation demands' for electricity.

Figure 5-4 highlights that the lowest point, or the empty point of the 'store', is reached at 37TWh at hour 2,141 for the GP+EV&ASHP scenario, after which there is sufficient net generation over the remainder of the year to recharge the 'store'. Therefore, in this case it is calculated that the ideal storage technology needs to be able to discharge for a maximum of 215 continuous hours and provide 37TWh of storage throughout the year.

Figure 5-4: Calculated annual electricity storage profile for the UK GP+EV&ASHP scenario



5.3 Investigation of Realistic Energy Storage Requirements

As has been discussed above, the profiles calculated are for an 'ideal' energy storage technology. However, in reality, the available energy storage technologies are not capable of providing these levels of storage. At present, only technologies such as pumped storage are capable of storing electricity for prolonged periods of time, which would be required to cope with the seasonal variation discussed previously. Nevertheless, the discharge duration of these technologies is limited by factors such as the size of the storage reservoir, which in the case of pumped storage is constrained by topography, and the cost. There is also the round trip efficiency of the technology which would need to be addressed.

It has been proposed to investigate the viability of three energy storage technologies in order to understand the potential costs and barriers they would face if adopted in the fully renewable UK electricity grid. The technologies chosen to take further for analysis are (i) pumped storage (PS), (ii) liquid air energy storage (LAES) and (iii) hydrogen (H2). The reasoning for the technologies chosen are given in the following Chapter.

5.3.1 Suitable energy storage technologies

This Chapter discussed the rationale behind and technological characteristics of the three proposed energy storage technologies. As discussed in Chapter 2, there is a wide range of energy storage technologies, based on storing energy kinetically, electrochemically, potentially or thermally. Chapter 2 also discusses the many applications that energy storage can provide to the electricity sector, from fast response voltage frequency control to long term storage of energy from renewable energy sources. In this case, the aim is to investigate the amount of energy storage capacity that would be necessary to ensure the hourly demand of electricity is supplied from a highly variable source of electricity.

Taking into account the assumptions and boundaries set out, it is possible to discount, at this point, a number of technologies due to their characteristics. Technologies such as flywheels, supercapacitors and batteries have been discounted as they tend to be best applied to short duration storage and fast response applications such as voltage frequency. It is to be noted that the technologies chosen need to be capable of storing large quantities of energy over prolonged period of time, but also be able to respond quickly to demand needs. Of the technologies introduced in Chapter 2 that meet the criteria set out above, there are four suitable technologies. However, in this thesis the viability of compressed air energy storage (CAES) has been discounted as this technology relies on the availability of geological formations in which to store the compressed air.

Each of the proposed energy storage technologies below have electrical, mechanical and state change inefficiencies. These efficiency losses need to be accounted for in the modelling of the technologies. It is proposed in this study that these losses are complemented by increasing the installed renewable capacity on the electricity network. As has been assumed when building the scenarios, it is proposed that offshore wind capacity is again scaled in each scenario to accommodate the losses from storing excess generation. These efficiencies will also be discussed below.

5.3.1.1 Pumped storage (PS)

Pumped storage is currently the only storage technology capable of operating at a commercial scale. As discussed in Chapter 2, the UK has up to 3GW of pumped storage capacity installed providing up to 27.6GWh of storage (Blamire, 2013). However, plans for expanding this capacity are limited as the majority of suitable sites have been developed and in the current market, it is not economically competitive with fossil fuelled ‘peaking’ plant which can provide the same services. On the other hand, studies have investigated the potential for future large scale installations in the UK. One such identifies a possible site in Scotland, Loch Morar, which if developed could provide a further 15GW of capacity and 1.3TWh of storage (Hunt, 2013). The issues with this however are the scale of this development and the impacts on the local ecosystem. This does highlight the potential in the future should energy storage be a prerequisite for the UK to divest itself of fossil fuels completely. For this reason, this technology has been selected as a potential large scale energy storage technology.

In terms of the efficiency of this technology, the roundtrip efficiency commonly used is 80% (Strbac et al., 2012). This will be taken into account with all calculations regarding PS.

5.3.1.2 Liquid air energy storage (LAES)

Liquid air energy storage (LAES) provides an innovative technology for storing excess electricity generated from renewables by cryogenically compressing air and then re-expanding this through a turbine to produce electricity with demand. Some of the key benefits of LAES are that cryogenic liquid production along with its distribution infrastructure and equipment supply chain are already mature, storage is at low pressure and there is no fuel combustion risk, plus for grid based storage there are no geographical constraints as with pumped hydro or large scale CAES. Additionally, it is stated that LAES is suitable for energy stores from 20MWh up to greater than 1GWh. A LAES facility of 500MW could be capable of storing 2GWh of renewable electricity (Brett, 2014). The energy density of LAES has also been shown to compare favourably to other low-carbon competitors.

This technology is not fully commercially available as of 2014. However, the company Highview Power Storage has a pilot plant in operation in Swindon, UK, which is connected to the distribution network and can provide 2.5MWh of storage from a 350kW system (Highview, 2014). This system was operational from July 2011 to November 2014, during which the plant underwent a full testing regime providing Short Term Operating Reserves (STOR) services.

LAES has been chosen as a suitable storage technology as this could be installed with relative ease across the network, being sited close to grid constraints for example. Additionally, the scalability of the technology and the existing supply chain in the UK for this technology makes this an attractive future proposition. In terms of the efficiency of this technology, round trip storage efficiency has been estimated at 60% (Brett, 2014), though this could increase to over 70% if the plant is used in combination other industrial process plants that have high waste heat or cooling.

For the purpose of this study, it is assumed that an efficiency of 60% is used as it is not possible to ensure that there will be the availability of waste heat/cooling where there would be a requirement for electricity storage.

5.3.1.3 Hydrogen (H2)

The final technology considered is hydrogen. Whilst this is not a storage technology, it is an energy vector that can be used to store excess electricity from renewable sources. The benefit of using hydrogen as an energy vector is its multiple potential uses: for generating electricity through a fuel cell, as a fuel for transportation or as a combustible fuel for heating applications. This gives hydrogen a high degree of flexibility. However, the focus in the present study is on the electricity storage benefits. For this, the main technologies required are an electrolyser, in order to convert excess electricity into hydrogen, a storage mechanism for the hydrogen and a fuel cell to reconvert the hydrogen into electricity. There are two main technologies available for storing hydrogen: one would be to use underground geological formations, such as depleted oil and gas fields or aquifers, or in man-made caverns in salt formations; a second more costly option is to store hydrogen in cylinders or tanks above ground.

It has also been discussed that hydrogen storage would be best suited to large-scale and long-term storage applications of 100s of GWh over periods of months (Crotogino et al., 2010). However, as of 2014 there are no commercially active hydrogen storage plants and are still technologically immature. In addition, the expected roundtrip efficiency for H2 is 45% due to the two-step nature of using electricity to produce hydrogen which is stored until it is converted back to electricity through a fuel cell or in direct combustion (Schoenung, 2011).

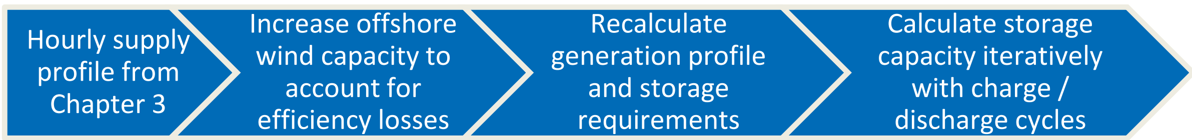
Due to the potential benefits and its expected capabilities to be able to provide large amounts of energy storage, H2 is included in this study to investigate the requirements in the fully renewable UK electricity scenario.

5.3.2 Calculation of energy storage requirements

All three energy storage technologies introduced above have been modelled to understand, under each of the four scenarios, the necessary installed capacity, potential technology storage needed and how much additional wind capacity would be required to account for any round trip losses as discussed above.

The energy storage requirements have been calculated iteratively by resolving the hourly demand and supply profiles calculated in Chapter 3:. However, contrary to the ideal storage previously calculated, the calculation below takes into account the extra offshore wind capacity required to substitute any efficiency losses. With the addition of extra renewable capacity, the energy storage requirements will differ from the requirements previously discussed.

Figure 5-5: Methodology for calculating energy storage capacity



These calculations have been carried out firstly by defining the required offshore wind capacity required, knowing that all other generation (from onshore wind, solar PV, hydro, geothermal, bioenergy and tidal) will remain constant. Once this capacity is known and scaled up from the generation profiles provided in Chapter 3, the new supply and demand profiles are calculated (see Figure 5-5). This is in turn analysed to obtain the specific energy storage capacity required in order to maintain the UK electricity supply. The results from these calculations are provided below.

5.3.2.1 PS calculation

As discussed, the round trip efficiency of PS is assumed to be 80% for this analysis and it is further assumed that offshore wind will deliver the additional energy required. When taking this into account, it is calculated that the additional offshore capacity is circa 104GW for the BAU scenario. The additional installed capacity will reduce the need for storage as there is more supply to meet the demand. In this case, the required installed PS capacity is calculated to be 45GW and capable of storing 9TWh of energy.

Similarly, considering the demand requirements for the other scenarios, the capacity of offshore wind capacity would be 50GW, 153GW and 99GW for the GP, BAU+EV&ASHP and GP+EV&ASHP respectively. This capacity of offshore wind capacity translates to a PS capacity of 57GW, 114GW and 114GW producing 12TWh, 22TWh and 22.5TWh of storage respectively.

5.3.2.2 LAES calculation

In the case of liquid air energy storage, the round trip efficiency is 60%. Therefore it is calculated that the offshore wind capacity required is 121GW for the BAU scenario, which in turn translates to a LAES capacity requirement of 11GW producing 2.3TWh of storage. Note that the storage requirement in this case is much lower than for PS even though the round trip efficiency is lower. This is due to the increase in offshore wind capacity that has been assumed to account for this efficiency loss. The net effect of this increase is that overall energy storage requirements will decrease.

Following this analysis for the other scenarios, the capacity of offshore wind capacity is calculated to be 58GW, 178GW and 115GW for the GP, BAU+EV&ASHP and GP+EV&ASHP respectively. This capacity of offshore wind capacity translates to a LAES capacity requirement of 35GW, 55GW and 70GW producing 7TWh, 11TWh and 14TWh of storage respectively.

As can be seen, there is a large capacity of variable generation supplying the grid and as a result, the overall requirement for storage will be lower when considering this technology.

5.3.2.3 H2 storage calculation

The round trip efficiency for H2 is 45% as excess electricity needs to be converted into hydrogen for storage and then re-converted into electricity through a fuel cell. Therefore it is calculated that the offshore wind capacity required is 134GW for the BAU scenario, which in turn translates to a H2 capacity requirement of 1GW producing 0.15TWh of storage. Again, this is due to the large increase in offshore wind capacity installed to account for the round trip efficiency reduction in H2.

The capacity of offshore wind capacity would be 64GW, 197GW and 128GW for the GP, BAU+EV&ASHP and GP+EV&ASHP respectively. This capacity of offshore wind capacity translates to a H2 capacity of 26GW, 5GW and 50GW producing 5TWh, 0.9TWh and 10TWh of storage respectively.

As is expected, due to the higher requirement for offshore wind capacity, there is a lower requirement for installed energy storage capacity.

5.3.3 Energy storage requirements summary

The energy storage requirements calculated above are summarised in Table 5-1. Note that the value provided in Table 5-1 is for the additional offshore wind capacity required. That is to say that if the BAU scenario is considered with LAES as the chosen energy storage solution, the offshore wind capacity required would be 86GW, which is the base offshore wind capacity in that scenario, plus 35GW of additional capacity to make a total of 121GW. This is what would be required alongside the 11GW of installed LAES capacity providing 2.3TWh of storage in order to ensure that demand is met throughout the year.

Table 5-1: Calculated energy storage characteristics, plus offshore wind capacity requirements, by scenario – Business as Usual (BAU), Green Plus (GP), BAU+EV&ASHP and GP+EV&ASHP – and by energy storage technology

Scenario	BAU	GP	BAU+EV&ASHP	GP+EV&ASHP
PS rated capacity (GW)	45	60	114	114
PS storage capacity (TWh)	9	12	22	23
PS offshore wind capacity (GW)	+18	+9	+26	+17
LAES rated capacity (GW)	11	35	55	70
LAES storage capacity (TWh)	2.3	7	11	14
LAES offshore wind capacity (GW)	+35	+17	+51	+33
H2 rated capacity (GW)	1	26	5	50
H2 storage capacity (TWh)	0.15	5	0.9	10
H2 offshore wind capacity (GW)	+48	+23	+70	+46

From this analysis it is possible to see the effect that a lower electrical efficiency has on the requirement for additional installed electricity generation capacity on the network. It is noted that whilst it is possible for additional generation to come from an alternative source, for consistency with previous assumptions made in the analysis it is assumed that offshore wind would be the most likely technology capable of providing the extra capacity required. Likewise, from the energy storage technology perspective, it is possible that electrical efficiencies for the three discussed can improve. Though this is only likely for LAES and H2 due to their technical immaturity.

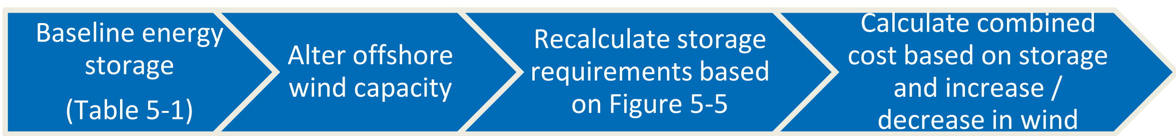
This analysis is developed further to understand the trade-off between the cost of installing the additional offshore wind capacity calculated under each scenario and the projected cost of the energy storage technology. With this it will be possible to provide some optimal combinations of energy storage capacity and offshore wind capacity.

5.4 Energy Storage Cost and Capacity Optimisation Analysis

Further investigation has been carried out to explore the optimal mix of storage and offshore wind capacity for each scenario in terms of installed capital cost. To maintain the same assumptions as Chapter 3, the capital cost estimate for offshore wind capacity used in this study is GBP 1.78 million/MW (Arup, 2011). It has been assumed that this cost will not decrease with economies of scale as there will be a substantial increase in the number of offshore turbines required that would need to be installed in less favourable locations. Some future cost projections for the capital cost of installing energy storage technologies have also been assumed. In this case, these are based on best estimates as costs are either commercially sensitive or for immature technologies. The cost estimate used in this analysis for PS installations is GBP 0.92 million/MW (Strbac et al., 2012). It has been found that estimates of likely costs for LAES installations are GBP 1.5 million/MW with a likely reduction to GBP 1.275 million/MW in the future (Arbon et al., 2013). It has been assumed that the lower cost estimate is achieved in this study as this technology is already being piloted for providing storage services on the UK electricity grid. In the case of hydrogen, there are multiple steps involved in generating hydrogen, then storing it in underground caverns or tanks above ground, and finally converting it back to electricity which makes these very variable. Due to the multi-stage nature of using hydrogen as an energy storage medium, cost estimates include the cost of an electrolyser to convert excess electricity into hydrogen, at an estimated GBP 0.207 million/MW, plus the fuel cell required to re-convert the stored hydrogen back into electricity, at a cost of GBP 0.305 million/MW. In addition, hydrogen will need to be stored, which in this analysis has been assumed to be in one of storage in underground caverns, at a cost of GBP 0.0002 million/MWh, or in tanks above ground, at GBP 0.0092 million/MWh (Schoenung, 2011). Both of these options for storing hydrogen will be considered to highlight their relative benefits.

This analysis considered variations in the quantity of installed offshore wind capacity and the related variation in energy storage capacity required to ensure demand is met at all times. This analysis then calculates an optimised combination of energy storage required plus wind capacity that gives the lowest capital costs solution taking into account the costs given. The results of these analyses are illustrated in the following Chapters following the methodology given in Figure 5-6.

Figure 5-6: Methodology used to optimise the energy storage costs for each scenario

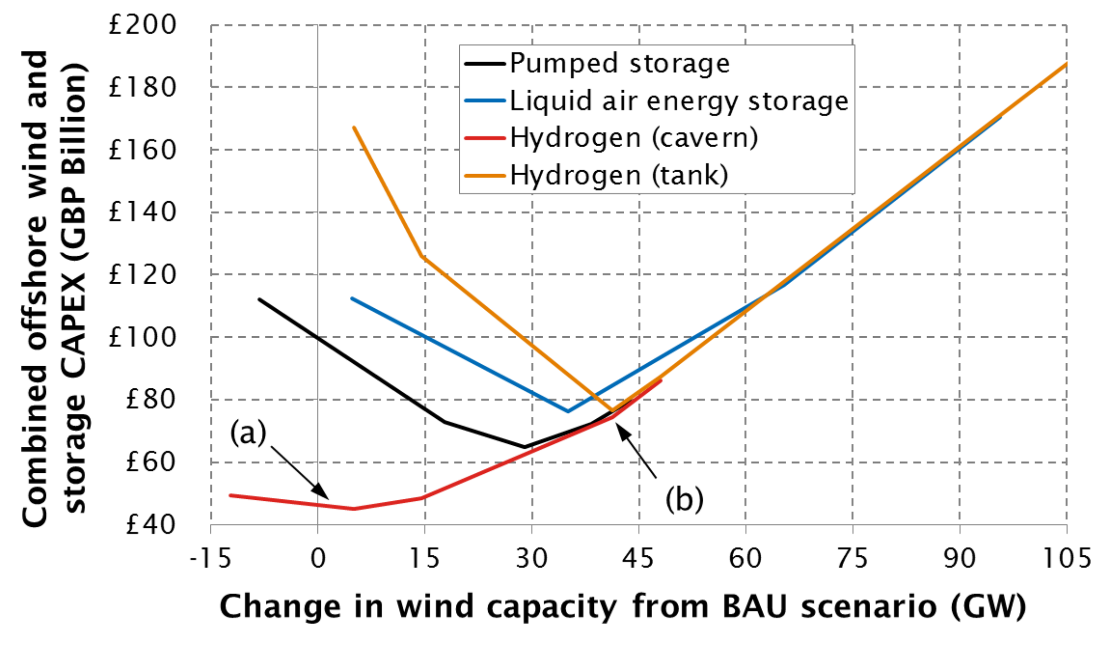


5.4.1 BAU energy storage cost analysis

For the BAU scenario, it has been calculated that the lowest capital cost solution to ensure a balanced grid could be achieved through H2. As discussed, hydrogen can be stored in underground caverns or in tanks above ground at different costs (though hydrogen storage underground is dependent on geological formations and is therefore geographically constrained). This lowest capital cost solution is achieved by installing an additional 5GW of offshore wind capacity. This is combined with 65GW of hydrogen capacity stored in caverns and would incur an additional cost of GBP 45 billion on top of the base scenario cost calculated in Chapter 3:. This is illustrated as point (a) in Figure 5-7. This has been calculated iteratively by determining the optimal storage capacity required and resolving for the additional wind capacity required to ensure demand is met throughout the year. This provides the most cost effective solution between energy storage and extra installed offshore wind capacity.

The same approach was taken with H2 stored in tanks, LAES and PS. It was found that the lowest cost solution for PS requires an additional installed wind capacity of 29GW at an additional cost of GBP 65 billion. Likewise for LAES, the lowest cost solution would require an additional offshore wind capacity of 35GW at an additional cost of GBP 76 billion. This is illustrated in Figure 5-7.

Figure 5-7: Calculated additional capital expenditure and offshore wind capacity required per energy storage technology to ensure demand is met in the BAU scenario, where (a) is the calculated optimal combination of energy storage (through storing hydrogen in caverns) and the required extra capacity from offshore wind generation required to ensure demand is met throughout the year; and (b) is the calculated cost for a more realistic scenario with 4GW of PS capacity on the network



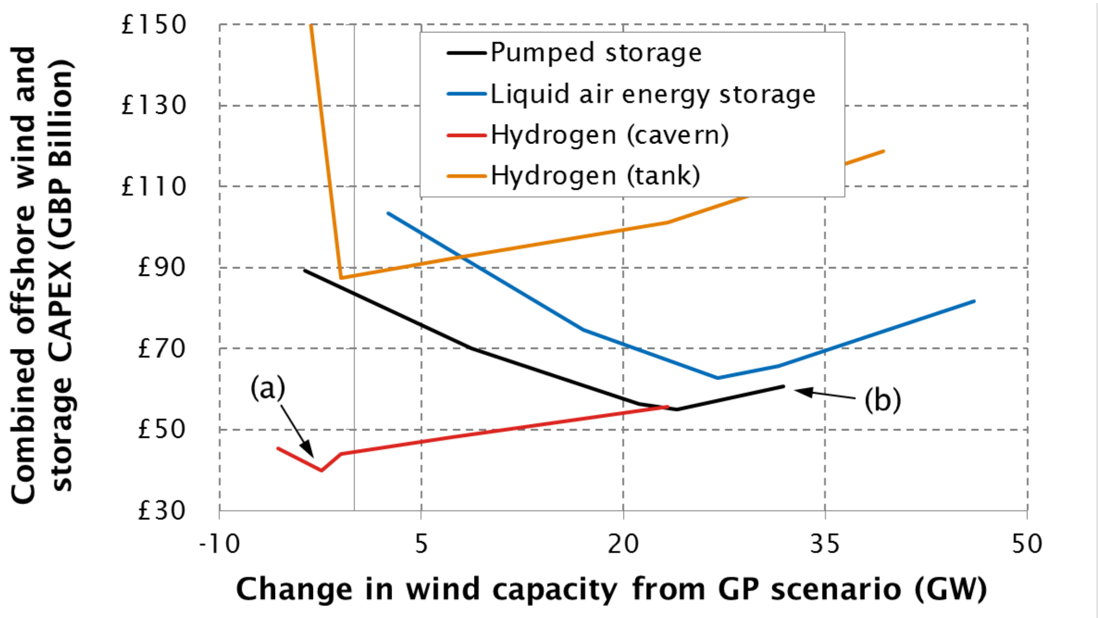
However, to put this into context, as of mid-2015 there was a total of 146GW of installed and operational energy storage capacity worldwide (Department of Energy, 2012), 142GW of which is pumped storage. In the context of the UK, pumped storage facilities are already in operation (for example the 1.8GW/9.1GWh capacity Dinorwig facility in North Wales (MacKay, 2009)). It has been discussed that in the UK there is only a potential for the total installed rated capacity to be increased to 4GW. In the BAU scenario, it has been calculated that this installed capacity would need to be able to store a combined capacity of 864GWh. This is based on the availability of a very large water reservoir being available to store enough water for a discharge duration of up to 212 hours, which is highly unlikely given the environmental effects this would have on the reservoir's and surroundings biodiversity. However, if this is taken to be the maximum capacity available for pumped storage in the UK for the BAU scenario, the calculated additional offshore wind capacity is calculated to be 38GW, which would incur a combined capital cost of GBP 72 billion for energy storage and wind capacity. This is shown as (b) in Figure 5-7.

5.4.2 GP energy storage analysis

The lowest capital cost solution for the GP scenario is achieved by installing an additional 1GW of offshore wind capacity. This is combined with 80GW of hydrogen capacity stored in caverns and would incur an additional cost of GBP 44 billion. This is illustrated as point (a) in Figure 5-8. As discussed above, the more feasible scenario would be to install an additional offshore wind capacity of 32GW and combining this with 4GW of pumped storage at an extra cost of GBP 61 billion (see (b) in Figure 5-8).

The sharp rise seen in the cost of hydrogen stored in tanks (orange line) is due to the high cost of the tanks, on a per MWh basis. When offshore wind is reduced and H2 stored in tanks is the sole balancing mechanism, the cost penalty in this case is high as illustrated in Figure 5-8.

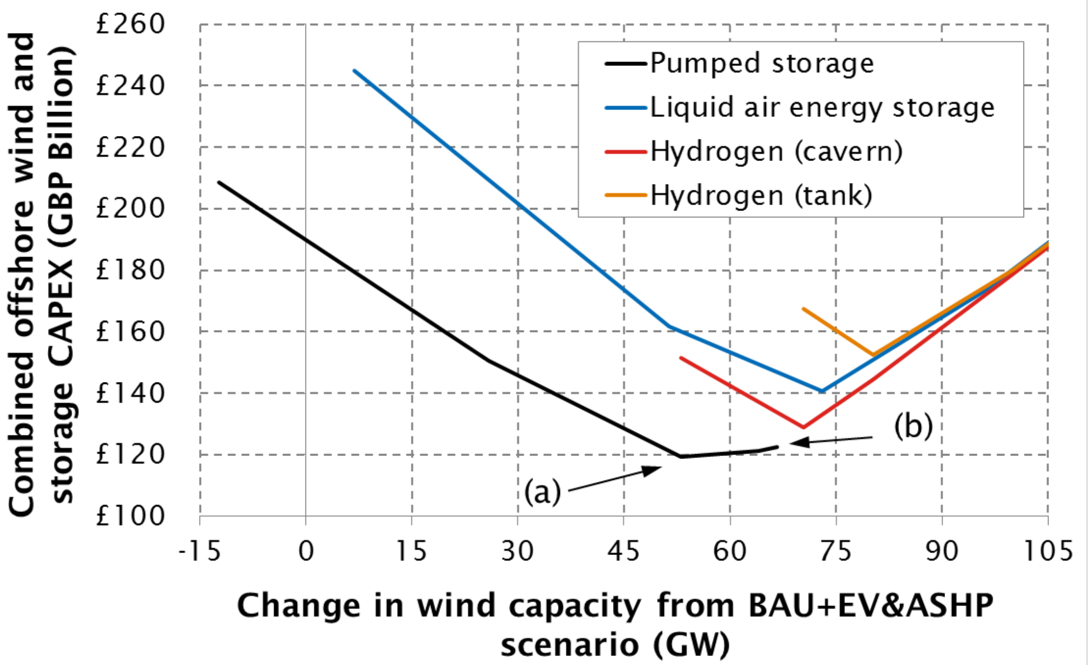
Figure 5-8: Calculated additional capital expenditure and offshore wind capacity required per energy storage technology to ensure demand is met in the GP scenario, where (a) is the calculated optimal combination of energy storage (through storing hydrogen in caverns) and the required extra capacity from offshore wind generation required to ensure demand is met throughout the year; and (b) is the calculated cost for a more realistic scenario with 4GW of PS capacity on the network



5.4.3 BAU+EV&ASHP energy storage analysis

In the case of the BAU+EV&ASHP scenario, Figure 5-9 indicates that the lowest capital cost could be achieved through PS. In this case, the optimal solution is achieved by increasing offshore wind capacity by 53GW and combining this with 27GW of pumped storage capacity at an additional cost of GBP 119 billion (see (a) in Figure 5-9). However, the availability of installing the required PS capacity in the UK is limited. Therefore, the more feasible scenario would be to increase the offshore wind capacity to 67GW and combining this with 4GW of pumped storage at an extra cost of GBP 123 billion (see (b) in Figure 5-9).

Figure 5-9: Calculated additional capital expenditure and offshore wind capacity required per energy storage technology to ensure demand is met in the BAU+EV&ASHP scenario, where (a) is the calculated optimal combination of energy storage (through pumped storage) and the required extra capacity from offshore wind generation required to ensure demand is met throughout the year; and (b) is the calculated cost for a more realistic scenario with 4GW of PS capacity on the network

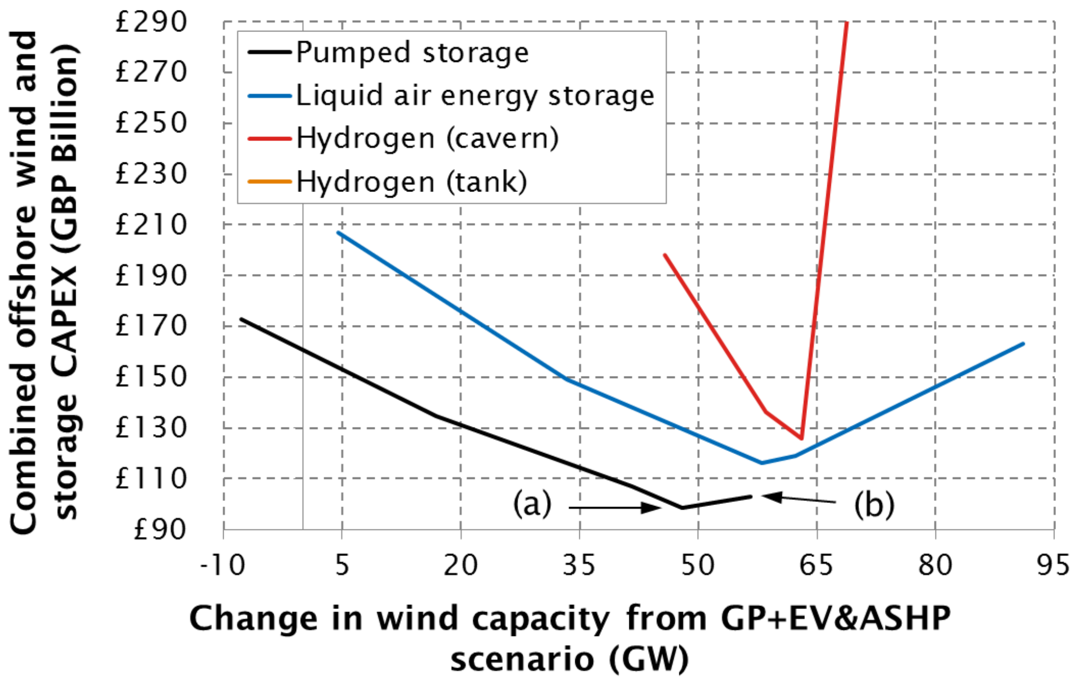


5.4.4 GP+EV&ASHP energy storage analysis

Lastly, Figure 5-10 indicates that in the GP+EV&ASHP scenario, the lowest capital cost could be achieved through PS again. In this case, the optimal solution is achieved by increasing offshore wind capacity by 48GW and combining this with 14GW of pumped storage capacity at an additional cost of GBP 99 billion (see (a) in Figure 5-10). However, as with the BAU+EV&ASHP scenario, the more feasible scenario would be to install an additional offshore wind capacity of 57GW and combining this with 4GW of pumped storage at an extra cost of GBP 103 billion (see (b) in (Figure 5-10).

It is of note that in this scenario, the cost of storing hydrogen in tanks is prohibitively high due to the high energy storage requirements. For this reason, it has not been illustrated in Figure 5-10.

Figure 5-10: Calculated additional capital expenditure and offshore wind capacity required per energy storage technology to ensure demand is met in the GP+EV&ASHP scenario, where (a) is the calculated optimal combination of energy storage (through pumped storage) and the required extra capacity from offshore wind generation required to ensure demand is met throughout the year; and (b) is the calculated cost for a more realistic scenario with 4GW of PS capacity on the network



5.4.5 Energy storage optimisation summary

It was found that in the BAU and GP scenarios the optimal solution would be using hydrogen storage in combination with storage in underground caverns. However, as discussed, this is not a mature technology and therefore it is proposed that the most feasible solution is either pumped storage or liquid air energy storage, although, based on existing cost projections for both technologies PS would be the best solution. On the other hand, for both BAU+EV&ASHP and GP+EV&ASHP scenarios, the optimal solutions were based on PS technology. In all scenarios, the storage of hydrogen in underground caverns is found to be a much cheaper solution than in tanks. This is due to the comparatively high cost per MWh of tank storage. It is important to remember that storage in underground caverns is heavily dependent on the availability of the required geological formations.

5.5 Discussions and Conclusions

This Chapter has investigated the feasibility of using large scale energy storage technologies to ensure the supply of electricity in the UK is met by a fully renewable electricity generation mix. It was discussed that an ‘ideal’ energy storage technology would need to be able to provide up to 30TWh of storage over 197 continuous hours for the BAU scenario. Likewise, for the GP, BAU+EV&ASHP and GP+EV&ASHP scenarios, ‘ideal’ storage requirements are up to 21TWh over 190 continuous hours, 47TWh over 216 continuous hours and 37TWh over 215 continuous hours respectively.

However, the analysis then considers three potential energy storage technologies: pumped storage (PS), liquid air energy storage (LAES) and hydrogen (H2). It is highlighted that these technologies have round trip inefficiencies, converting generated electricity into storage and then back into electricity when required. Therefore, there would need to be an additional installed electricity generation capacity to account for these losses, which is assumed to come from additional offshore wind capacity. The analysis then calculates the storage capacity required plus the additional renewable generation for each scenario. These results are summarised in Table 5-2.

Table 5-2: Calculated energy storage characteristics, plus offshore wind capacity requirements by scenario and by energy storage technology

Scenario	BAU	GP	BAU+EV&ASHP	GP+EV&ASHP
PS rated capacity (GW)	45	60	114	114
PS storage capacity (TWh)	9	12	22	23
PS offshore wind capacity (GW)	+18	+9	+26	+17
LAES rated capacity (GW)	11	35	55	70
LAES storage capacity (TWh)	2.3	7	11	14
LAES offshore wind capacity (GW)	+35	+17	+51	+33
H2 rated capacity (GW)	1	26	5	50
H2 storage capacity (TWh)	0.15	5	0.9	10
H2 offshore wind capacity (GW)	+48	+23	+70	+46

Further to this, this Chapter investigates the optimal combination of energy storage and additional offshore wind capacity on a capital cost basis for each scenario. It was found that in the case of the BAU and GP scenario the optimal solution would be using hydrogen storage in combination with storage in underground caverns. However, as discussed, this is not a mature technology and therefore it is proposed that the most feasible solution is either pumped storage or liquid air energy storage.

To put into context the amount of storage required for each of the optimal solutions discussed, comparative existing installations that are in operation in the UK as of 2013 are used. As discussed, it is has only been suggested that a maximum of 4GW of PS capacity is feasible in the

UK as the majority of suitable sites have been developed (Barton et al., 2013). However, it is important to note that the amount of storage required is, with the present sites, not feasible.

For comparison with LAES, the Isle of Grain liquefied natural gas (LNG) storage facility on the Thames estuary has been used. This facility has a storage capacity of 956,000m^3 (National Grid, 2009) and has been in operation for over 4 years. LAES is assumed to need a capacity of 39,000m^3 to store 1GWh of energy in liquefied air (Trompeteler, 2013). This therefore equates to needing 93 of the Isle of Grain facilities across the UK to ensure there is enough LAES storage.

In the case of H2 storage in caverns, there already is a hydrogen storage facility in the UK in Teesside that has three 150,000m^3 salt caverns that hold a storage capacity of 24.4GWh (Ozarslan, 2012). If we use this facility as a reference, there would need to be 559 equivalent caverns across the UK in the BAU scenario.

The findings above plus the findings of the comparisons based on the other scenario are summarised in Table 5-3, Table 5-4, Table 5-5 and Table 5-6 respectively.

Table 5-3: Calculated number of equivalent facilities required for each of the optimum combinations of energy storage and offshore wind for the BAU scenario and the estimated capital cost (GBP Billion)

BAU scenario	PS	LAES	H2 (cavern)
Storage rated capacity (GW)	4	11	65
Storage capacity (GWh)	864	2,272	13,645
Offshore wind capacity (GW)	+38	+35	+5
Combined offshore wind and storage cost (GBP Billion)	72	76	45
Equivalent n° facilities	-	93	559

Table 5-4: Calculated number of equivalent facilities required for each of the optimum combinations of energy storage and offshore wind for the GP scenario and the estimated capital cost (GBP Billion)

GP scenario	PS	LAES	H2 (cavern)
Storage rated capacity (GW)	4	12	80
Storage capacity (GWh)	864	2,269	17,308
Offshore wind capacity (GW)	+32	+27	-1
Combined offshore wind and storage cost (GBP Billion)	61	63	44
Equivalent n° facilities	-	93	559

Table 5-5: Calculated number of equivalent facilities required for each of the optimum combinations of energy storage and offshore wind for the BAU+EV&ASHP scenario and the estimated capital cost (GBP Billion)

BAU+EV&ASHP scenario	PS	LAES	H2 (cavern)
Storage rated capacity (GW)	4	8	5
Storage capacity (GWh)	864	1,638	920
Offshore wind capacity (GW)	+67	+73	70
Combined offshore wind and storage cost (GBP Billion)	123	141	129
Equivalent n° facilities	-	67	38

Table 5-6: Calculated number of equivalent facilities required for each of the optimum combinations of energy storage and offshore wind for the GP+EV&ASHP scenario and the estimated capital cost (GBP Billion)

GP+EV&ASHP scenario	PS	LAES	H2 (cavern)
Storage rated capacity (GW)	4	10	14
Storage capacity (GWh)	864	1,948	2,661
Offshore wind capacity (GW)	+57	+58	+63
Combined offshore wind and storage cost (GBP Billion)	103	116	126
Equivalent n° facilities	-	80	109

From this investigation it can be appreciated that the scale of the storage problem in the fully renewable UK electricity grid is challenging. The planning and construction required to provide enough storage tanks for LAES could be challenging. On the other hand, there is a precedent that installations of this scale are achievable and there is an abundant existing supply chain of the necessary equipment. In the case of H2 storage, the number of suitable sites to accommodate the large number of caverns for hydrogen storage is debatable as it relies on a set of specific geological formations. Additional insecurities at present with this solution is the limited penetration of hydrogen for use as an energy storage solution, which in turn highlights the immaturity of the technology necessary for this to be a viable solution at present.

However, the main barriers posed to these solutions are the economic aspects of each solution when competing in a heavily fossil fuelled centric electricity market and the need for more pilot schemes to prove the technological and commercial feasibility of the technologies. As a comparison, the recently approved new UK nuclear reactor, Hinkley Point C, is expected to cost up to GBP 24 billion for a 3.2GW capacity plant (Macalister, 2014), GBP 8 billion more than expected. As a result, this could have serious knock on effects to the consumer. Nonetheless, this could help pave the way to a secure fully renewable electricity grid.

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Chapter 6: Option 3 – Distributed Energy Storage

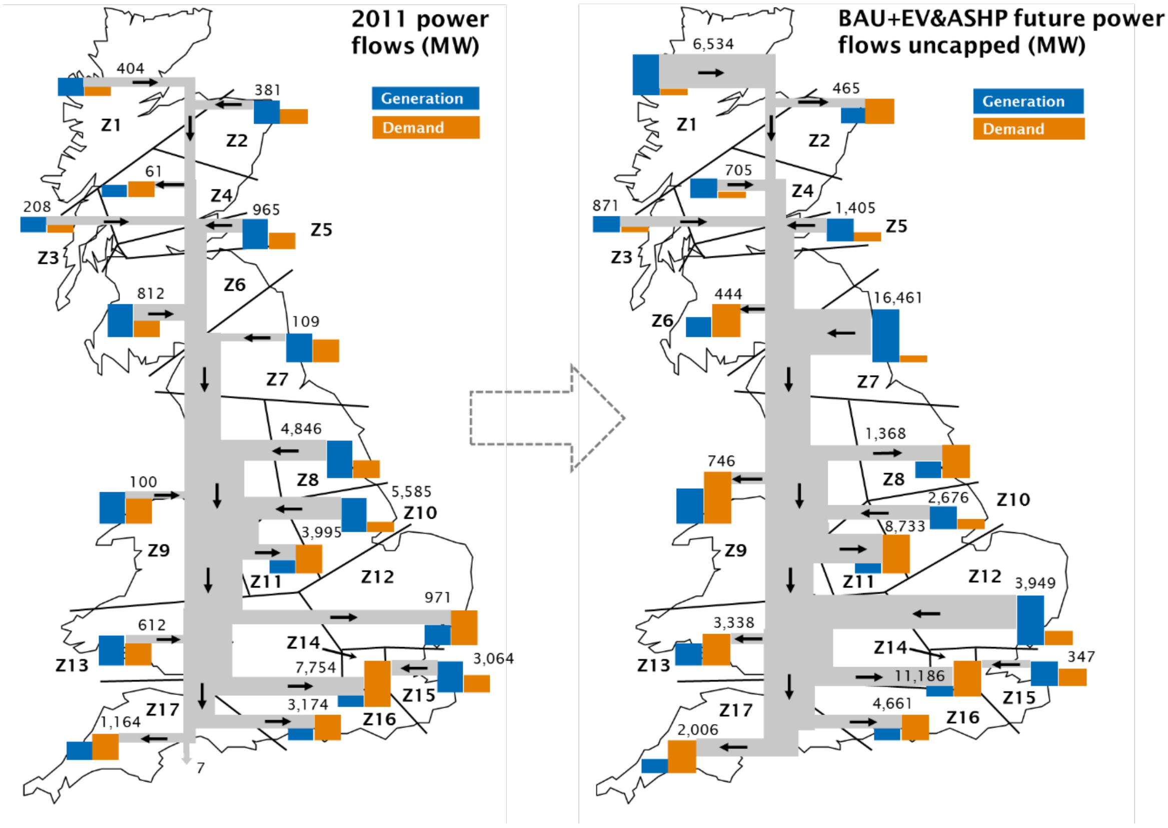
6.1 Introduction

A similar analysis as that carried out in Chapter 4.3 has been conducted to investigate the feasibility of using the potential energy storage capacity within the various network zones from electric vehicles and heat pumps. This analysis can only be carried out on the proposed BAU+EV&ASHP and GP+EV&ASHP scenarios.

Figure 6-1 illustrates the power flows around the UK network in 2011 and the calculated power flows for the calculated 2050 BAU+EV&ASHP scenario. The main flow of electricity in the UK is from North to South, with the main demand centres being the cities. It is apparent that in the future scenario, the overall flow of electricity is still from the North to the South however, the magnitude is much greater. It is also possible to appreciate the extent of increase in the gap between generation and demand in certain zones. Similarly with the GP+EV&ASHP scenario, the electricity flow is from North to South however the supply and demand in each zone are smaller due to the reduced overall scenario demand.

This analysis highlights where there may be issues on the existing electricity network in the future scenarios. Due to the large increase in the calculated capacity for offshore wind farms in the future scenarios there are larger generation flows in certain zones. It has been assumed that electricity generated from the proposed Round 3 offshore wind farms connects to the nearest existing electricity network point. For this reason, the amount of capacity connected to zones 1, 7 and 12 is much greater in the future scenarios than in 2011. This would imply that the transmission network would require upgrades in order to accommodate the increase in capacity. These bottlenecks on the electricity grid could potentially be ideal locations for targeted bulk energy storage installations as discussed in Chapter 5:, to ease network congestion and defer transmission upgrades. This Chapter discusses the potential storage available within the network zone and how much extra capacity from renewable sources can be integrated onto the network.

Figure 6-1: Average electricity power flows across the UK network in 2011 (National Grid, 2011a) and calculated for 2050 BAU+EV&ASHP scenario



6.2 Analysis of the Existing UK Electricity Grid Suitability

The electricity network capacity is closely monitored and administrated by National Grid. The National Electricity Transmission System (NETS) Seven Year Statement 2011 report has analysis on the available electricity network capacity within the zones and also sets out the proposed capacity upgrades to 2018 (National Grid, 2011a). The NETS statement enables an estimate of the effect of increases in installed capacity on the network. It is assumed that demand within each zone is scaled linearly to meet the assumed demand projections in the future. This exercise provides a view of the likely capacity upgrade necessary within each zone to be able to cope with the increased generation from renewable sources. Table 6-1 provides a summary of the BAU scenario electricity transfer required between each zone and the proposed upgrades from the NETS Statement (SYS capability). The calculated shortfall is the new transfer capacity that will be required. In some instances, it was found that the planned increases are sufficient to accommodate the increase in generation capacity, and hence are given a null value. However, for the instances where new capacity is required, the cost of such is estimated.

Due to the intricacies of electricity network connection and the commercially sensitive information, the cost of the upgrading the electricity network is given here as an indicative cost.

This is based on a value of GBP 44,394 per MW capacity of overhead line cables which has been calculated from information provided in Sterling et al. (2012). It is further assumed that all boundary upgrades are carried out by increasing the transfer capacity of existing infrastructure. This gives a guideline cost to increase the network capacity to account for the increase in renewable generation of GBP 2.2 billion.

This same process is carried out for the remaining scenarios. The total upgrade cost is calculated at GBP 700 million, GBP 3.8 billion and GBP 2 billion for the GP, BAU+EV&ASHP and the GP+EV&ASHP scenarios respectively.

It is of interest to investigate potential solutions that could defer or in fact eliminate the necessity to carry out this expensive network upgrading. The study now considers energy storage solutions on the local scale to understand what impact they could have to enable the integration of renewable generation on the network.

Table 6-1: Investigation of the network transfer capacity in the BAU scenario and the amount of investment required to meet it. Note, negative future transfer values denote import requirement (Source: adapted from (National Grid, 2011a, Sterling et al., 2012))

Boundary	Future transfer (MW)	SYS capability (MW)	New transfer capacity (MW)	Cost (GBP million)
1	5,386	2,300	3,086	137
2	5,060	3,400	1,660	74
3	668	500	168	7
4	6,361	3,650	2,711	120
5	7,182	5,350	1,832	81
6	7,568	8,050	-	-
7	19,620	6,600	13,020	578
8	17,814	11,035	6,779	301
9	13,529	10,985	2,544	113
10	- 5,229	6,167	-	-
11	18,694	9,556	9,138	406
12	- 7,679	4,804	2,875	128
13	- 1,585	3,264	-	-
14	- 8,667	9,849	-	-
15	690	6,121	-	-
16	21,170	16,909	4,261	189
17	- 6,760	5,706	1,054	47
Total investment required for BAU scenario				**2,181**

6.3 Distributed Energy Storage

As discussed, four future electricity demand scenarios have been developed of which two of these include electrification of heating and transportation: the BAU+EV&ASHP and GP+EV&ASHP

scenarios. It is proposed to investigate the suitability and scale of electricity storage that the uptake of electrification can provide to the future UK electricity network. It is assumed that these systems will be connected to the low voltage distribution network (Segurado et al., 2011). For this it is assumed that the necessary transmission and distribution systems within each zone are sufficient to enable the transfer of electricity from the generator (connected to the transmission network) to the electric vehicles and ASHPs, from now on referred to as 'store', and vice versa. The 'store' refers to the amount of electricity storage in the battery of an electrified vehicle and the thermal store within the thermal mass of the domestic property. It is further assumed that all the vehicles are plugged into the electricity network and that the grid operator has full control over the energy stored within the battery. The use of vehicles and their availability to provide storage to the electricity network are not discussed here.

6.3.1 Domestic heating

For this study it has been assumed that there is a mass uptake of domestic heat pumps to supply all space heating. This can be supplied by a number of heat pump technologies, however in this case it has been assumed that the technology used is air source heat pumps (ASHP) with a coefficient of performance (COP) of 3.5 as detailed in Cabrol and Rowley (2012). As well as supplying space heating, it has also been assumed that ASHP can supply a portion of domestic hot water demand.

As has been detailed in Chapter 3, a total heating demand in the region of 187TWh per year has been calculated. As it is proposed that all this demand be supplied by ASHP, the total electricity demand is 53TWh per annum due to the COP of this technology. It has also been calculated that the amount of electricity demand for hot water is in the region of 16TWh per year in the UK.

This gives a total figure of 69TWh per year of electricity demand for heating and hot water. For this discussion, it has been assumed that the grid operator has full control of this demand during the winter months (October to March) to be able to use this to balance supply and demand from renewable sources throughout the year. For example, a dwelling's heating system could be forced on or off for a period of up to 30 minutes to provide balancing. To be able to calculate the amount of thermal storage available in each zone, the annual demand per household calculated in Chapter 3 has been used in combination with the housing census data as shown in Table 6-2.

6.3.2 Electric vehicles

As detailed in Chapter 3, a potential second source of energy storage is within the batteries contained inside electric vehicles. It has been calculated that by 2050, there is the potential for 7 million vehicles on the roads to be electric, 70% of which are plug-in hybrid vehicles (PHEV) and 30% are pure battery electric vehicles (Crossley and Beviz, 2010) and the total amount of electricity demand from EV is in the order of 34TWh per annum in the UK if all vehicles are plugged in and charging.

This electricity demand can also be considered as a potential store as, with the right control systems in place, the grid operator could call upon these reserves to balance shortfalls and excesses in renewable generation. This also has a benefit as vehicles are likely to be geographically dispersed, following a similar pattern to the spread of households. However, due to the current limitations in battery technology impinging on the range that these vehicles are able to travel, it is proposed that EV are mainly located in urban areas. For this reason, the spread of EV has been calculated based on the ratio of households in each zone over the total in the UK thereby giving a scale that ranges from 0.2% in areas of Scotland to 14.8% in Zone 9. This trend can be appreciated in Table 6-2.

6.3.3 Total distributed energy storage potential in the UK

The amount of 'storage' that can be provided through the uptake of ASHP to supply heating and hot water and the potential collective battery store in EV in the UK has been calculated. Table 6-2 shows the distribution of this storage across the zones of the UK network based on housing census data. The total combined amount of distributed 'storage' in the UK is in the region of 103TWh per year. From the analysis in Chapter 5 it has been calculated that for the BAU+EV&ASHP scenario, the ideal bulk energy storage technology capable of a maximum storage capacity of 46.8TWh is required in order to sustain a balance supply and demand profile throughout the year. In the case of the GP+EV&ASHP scenario, this maximum capacity has been calculated as 36.8TWh. If all the potential distributed storage can be used, there would be sufficient storage capacity on the electricity network to balance the supply and demand.

However, as has been introduced, the EV and ASHP 'store' is distributed around the UK in line with the housing stock distribution and the renewable generation capacity is located in specific locations around the electricity network. Of interest are the pinch points in zones 1, 7 and 12 as these are where supply is far greater than demand. It is of note that zones 11 and 14 have the reverse, in that demand far outweighs supply due to these zones. Whilst this is where there is greatest possibility to accommodate the excess renewable generation, the grid infrastructure would have to be upgraded extensively to ensure that it would be able to be transferred there from the landing points of the offshore wind farms (which are zones 1, 7 and 12). Therefore these are discounted in this study.

Table 6-2: Zonal distribution of storage from domestic heat pumps and electric vehicles

Zone	2011 households	Future households	Spread of EV	EV store (TWh)	ASHP store (TWh)
1	188,173	246,338	50,947	0.2	0.5
2	220,520	288,683	59,705	0.3	0.6
3	46,679	61,108	12,638	0.1	0.1
4	236,109	309,091	63,926	0.3	0.6
5	352,714	461,739	95,496	0.5	0.9
6	1,444,301	1,890,739	391,040	1.9	3.9
7	1,351,900	1,769,777	366,023	1.8	3.6
8	2,224,100	2,911,577	602,168	2.9	6
9	3,832,300	5,016,876	1,037,584	5.1	10.3
10	1,681,800	2,201,650	455,342	2.2	4.5
11	1,557,400	2,038,797	421,661	2.1	4.2
12	2,016,600	2,639,938	545,988	2.7	5.4
13	2,784,700	3,645,460	753,949	3.7	7.5
14	3,266,200	4,275,793	884,314	4.3	8.7
15	1,430,500	1,872,672	387,304	1.9	3.8
16	1,945,000	2,546,206	526,603	2.6	5.2
17	1,275,400	1,669,630	345,311	1.7	3.4
	25,854,396	**33,846,075**	**7,000,000**	**34**	**69**

It is useful to understand the amount of demand, and hence storage, available within each zone as this will be used as the basis for further investigation into the potential for these technologies to be able to absorb excess generation from renewable sources. This will be discussed in the next Chapter.

6.4 Analysis of Constrained Zones and Effect of Distributed Energy Storage

Here the total maximum technical capability of storage within each zone to absorb renewable generation will be investigated. To do this, it is proposed that the worst pinch points on the network are investigated in greater detail. These are created where there is a large amount of generation from renewables, in most cases from offshore wind, which needs to be distributed to where there is a demand or where there is a large demand from densely populated areas and not enough generation.

From the analysis carried out in Chapter 6.1 on the generation and demand flows on the future network, it has been identified that the worst pinch points created are, in order of severity, at the boundaries of zones 7, 1 and 12. These have been chosen as there is the largest imbalance between electricity generated, which is driven by the increase in generation from offshore wind farms connecting to the network in these zones, and the demand within these zones. There are two notable zones which have a reverse effect, which is that demand is much higher than generation. This is the case with zones 11 and 14, which are the zones encompassing Birmingham in the Midlands and Greater London. For the discussion in this chapter, these have not been considered as the focus is on assessing the maximum potential storage available in zones where there is a large increase in generation and the grid would have to be upgraded substantially in order to ensure the generation could be re-distributed to these zones. It is noted that there is a large storage potential within these zones as they are major urban areas which have a high housing density and a larger proportion of EV. These zones could be used to minimise peak transmission capacity requirements as long as the grid infrastructure is suitable.

The analysis investigates the amount of installed capacity and the respective generation from the different renewable sources that would be within the zone over the course of the year. This was compared to the demand from within the zone, which is driven by the forecasted increase introduced earlier. From this, the amount of excess generation can be determined. From the investigation carried out into the zonal 'store' from the electrification of domestic heating and transportation, it is possible to determine how much of the excess generation can be absorbed within the zone assuming all of this potential 'store' can be utilised (Figure 6-2).

Figure 6-2: Methodology for estimating the zonal energy storage capacity

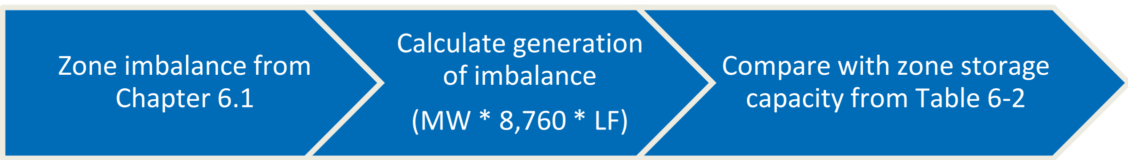


Table 6-3 shows the results for the BAU scenario with associated EV and ASHP. It can be seen that in the case of Zone 7, only 8% of the imbalance generation can be absorbed. This is driven by the large capacity of offshore wind expected to be developed in the waters east of this zone. The result for Zone 1 is similar in scale (3% excess generation absorbed); however in this case, there is a smaller demand and amount of 'storage' within the zone due to a lower population. On the other hand, the results for Zone 12 show that a significant proportion of the generation (65%) can be absorbed within the zone. This is due to the high population within this zone.

Table 6-3: Analysis of storage availability within zones and amount of generation that could be absorbed in the BAU plus electric vehicles (EV) and air source heat pumps (ASHP) scenario

BAU+EV&ASHP	Zone 7	Zone 1	Zone 12
Peak imbalance between generation and demand (MW)	16,461	6,534	3,949
Annual generation imbalance (TWh)	70.5	21.5	12
Storage within zone (TWh)	5	0.7	8
Excess generation absorbed (%)	8%	3%	65%
Storage within neighbouring zones (TWh)	30	2	39.5
Excess generation absorbed including neighbouring zones (%)	50%	13%	+100%

The effects of considering the neighbouring zones have also been investigated. This would have the net effect of being able to distribute the excess generation across a larger portion of the population. However, it is important to note that in this case, there would need to be investment made to increase the line capacity between neighbouring zones to account for this. It is now possible to see how the excess generation from Zone 7 can be distributed between Zones 6, 8 and 9 also (as depicted in Figure 6-1). With this extra storage capacity, up to 50% of the excess generation can be absorbed. In the case of Zone 1, due to the location on the network, only a relatively modest amount of generation can be absorbed within Zones 2, 3 and 4 (13%). Whereas for Zone 12, the location on the network is favourable as there is a larger proportion of population, which means that all of the excess generation can be absorbed.

The same analysis has been carried out for the GP with EV and ASHP scenario. Table 6-4 gives a summary of the findings. In this case, the amount of generation in each zone is lower than the previous scenario but also the demand. This means that there is still a measure of excess generation that needs to be absorbed. In this scenario, Zone 7 along with its neighbouring zones can absorb up to 71% of the excess generation. In Zone 12, it would be possible to absorb all the excess generation within the constraints of its own zone. This would be the best possible case for distributed storage from ASHP and EV to be able to ensure the supply and demand of renewables is feasible.

Table 6-4: Analysis of storage availability within zones and amount of generation that could be absorbed in the GP plus electric vehicles (EV) and air source heat pumps (ASHP) scenario

GP+EV&ASHP	Zone 7	Zone 1	Zone 12
Peak imbalance between generation and demand (MW)	11,615	5,272	1,961
Annual generation imbalance (TWh)	50	17.5	5.9
Storage within zone (TWh)	5	0.7	8
Excess generation absorbed (%)	11%	4%	+100%
Storage within neighbouring zones (TWh)	30	2	39.5
Excess generation absorbed including neighbouring zones (%)	71%	16%	+100%

It has been shown that in most cases, there is not enough storage within each zone to be able to accommodate the proposed levels of renewables required to ensure all the electricity demands are met. It would require the addition of neighbouring zones within the boundary, or indeed across boundaries, to be able to absorb greater amounts of generation. However this would require additional investment to increase the network capacity to be able to cope with the increases in power flows.

Further steps necessary would be to calculate a likely estimated cost of HV and LV cables for each case to ensure that the electricity network within each zone can cope with the additional renewable generation. There also needs to be an investigation into the capability of the distribution network in accommodating the amount of generation discussed here and the costs and/or feasibility of control systems to be able to regulate these flows. Another aspect which is not considered is the business model for the grid operator being able to control the amount of storage within the battery of an EV, affecting the personal usage of the vehicle, or controlling temperatures within households. However, it is expected that flexible control of electrical loads and two-way flow of electricity will become prevalent in the future network, especially in the GP based scenarios where household smart metering and options for time-of-use tariffs will be employed.

6.5 Discussion and Conclusions

From this analysis it is seen that with sufficient uptake of electrification of domestic heating and transportation a significant level of renewable electricity generation can be accommodated onto the existing network. When considering the BAU+EV&ASHP scenario, the amount absorbed ranges from 3% to 65% when considering Zones 1, 7 and 12 in isolation. This rises to 13% to 100% when considering the amount of storage potential in their neighbouring zones. Likewise in the GP+EV&ASHP scenario, it was found that between 4% and 100% of the excess generation can be absorbed within the zones, which rises to 16% to 100% when considering the neighbouring zones. However, it is important to note that a proportion of the network would need to be upgraded to allow for bi-directional electricity flows on a large scale as well as the mass roll out of smart control systems to be able to regulate this.

It was found that, depending on the location within the electricity network and the future scenario discussed, anywhere from 3% to 100% of excess generation could potentially be absorbed into the local network by controlling the amount of storage contained within batteries in vehicles plugged into the electricity network and electrified domestic heating.

It is likely that any future electricity scenario that has 100% of its electricity generated from renewable energy sources will employ a combination of methods and technologies to account for the variability of this supply. Distributed storage will play a major role alongside larger scale storage and increased interconnection with neighbouring networks. Demand side management will have, and already does have in the case of the industrial and commercial energy sectors, an important role to play in the domestic energy sector.

Further work needs to be carried out to investigate the compatibility of domestic heating requirements and electric vehicle usage with the variability of electricity supply on the network. The energy services associated with these devices that are being proposed must be provided reliably on a daily basis and the limitations of the energy 'store' to be available when there is a surplus or deficit of generation. There is a seasonal variation to the heating demand in the UK which could have an adverse effect on the amount of storage available. The colder temperatures during winter months also have an effect on the amount of energy available in the battery of a vehicle, found to be reduced by an average of 57% based on external temperature in the U.S. (AAA, 2014), meaning that there would potentially be less storage capacity available to the grid. During the winter months, electricity demand is higher due to the increased need for artificial lighting and electric space heating. The modelled scenarios have defined the required capacity based on this higher demand during the winter. However, due to the relative unpredictability of wind resources, the effects of there being a low resource are heightened. There is however a clear seasonal link present between higher availability of wind generation and an increased demand for household heating. Another concern relating to the amount of storage that is available from vehicles plugged into the network is the number of vehicles connected at any one time. In addition, another consideration to take into account is the amount of battery energy that will be available due to the owner needing to use the vehicle.

Clearly these issues need to be addressed for this technological solution to be feasible. There is a large volume of research and technical trials being carried out that are investigating this feasibility and how these systems can interact with each other to ensure a secure and stable network.

Chapter 7: Option 4 – Hybrid Interconnector and Energy Storage Solution

7.1 Introduction

The aim of this Chapter is to pull together the learnings discussed in Chapter 4 and Chapter 5 in order to create a more realistic future solution to accommodate the supply and demand issues created from a fully renewable UK electricity grid.

The output from this analysis has been generated in a similar way to the calculation of the optimum energy storage for each scenario discussed in Chapter 5.4. However, the variables used in this situation are interconnector capacity, calculated in Chapter 4.2, and energy storage capacity.

7.2 Hybrid interconnector and energy storage calculations

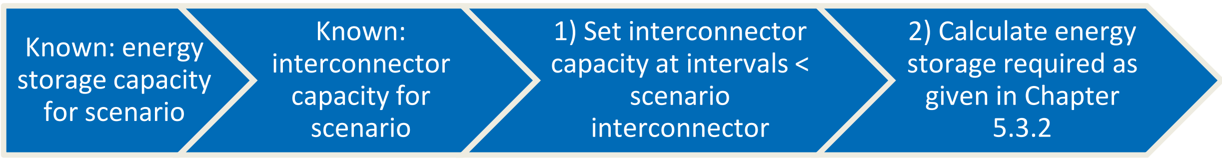
As has been introduced, this analysis pulls together the findings from the analysis carried out on the interconnector requirements and the optimum energy storage solutions for each scenario. For the three chosen energy storage technologies (pumped storage, liquid air storage and hydrogen stored in caverns), the optimum capacity of interconnector has been calculated through stepped trial and error to provide the lowest CAPEX for the scenario. The analysis starts from the known energy storage costs and interconnector costs that have been calculated for each scenario (see Table 7-1).

Table 7-1: Summary of energy storage and interconnector capacity and cost for the BAU and GP scenario

Scenario	Capacity (MW)	CAPEX (GBP Bn)
BAU pumped storage	14,193	64.7
BAU liquid air energy storage	10,718	76.2
BAU hydrogen (cavern) storage	65,287	44.8
BAU interconnector	59,855	57.8
GP pumped storage	13,438	55.1
GP liquid air energy storage	11,516	62.8
GP hydrogen (cavern) storage	80,128	39.8
GP interconnector	40,124	38.7

For each scenario, there are two known points which are: the capacity of the energy storage solution and interconnector which are required to ensure the demand is met year round. Therefore the analysis has been carried out using these two fixed points. From this starting point, it is possible to change one of the variables in order to calculate the capacity for the other. The methodology used for this is given in Figure 7-1.

Figure 7-1: Methodology used to calculate capacity of hybrid scenario



As has been done in Chapter 4 and Chapter 5, the estimated CAPEX for each solution can be calculated using the cost data available. It is important to note that the CAPEX cost given here is only for the solution proposed and does not include the full cost of the scenario which would be the cost of the required renewable energy capacity. Additionally, these CAPEX costs do not include any learning rates for future improvements in energy storage technologies.

This analysis is also extended to the electrification scenarios, BAU+ASHP&EV and GP+ASHP&EV, using the energy storage costs and interconnector costs that have been calculated for these scenarios. These are illustrated in Table 7-2.

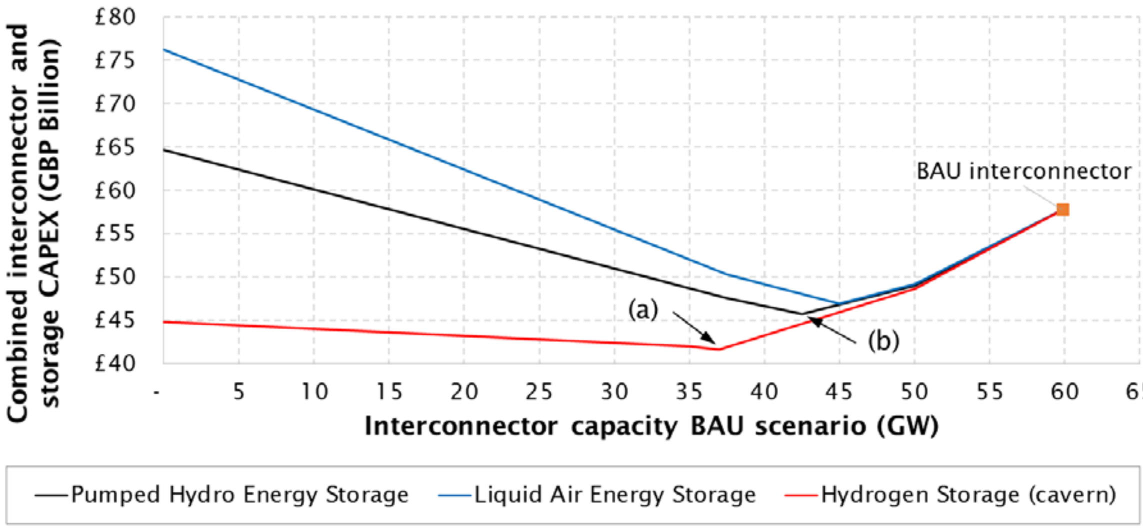
Table 7-2: Summary of energy storage and interconnector capacity and cost for the BAU+ASHP&EV and GP+ASHP&EV scenario

Scenario	Capacity (MW)	CAPEX (GBP Bn)
BAU+ASHP&EV pumped storage	27,036	119.3
BAU+ASHP&EV liquid air energy storage	8,315	140.8
BAU+ASHP&EV hydrogen (cavern) storage	4,669	128.9
BAU+ASHP&EV interconnector	82,585	79.8
GP+ASHP&EV pumped storage	14,201	98.6
GP+ASHP&EV liquid air energy storage	9,890	116.1
GP+ASHP&EV hydrogen (cavern) storage	13,509	125.9
GP+ASHP&EV interconnector	61,823	59.7

7.2.1 BAU scenario hybrid solution

When the BAU scenario is considered, the starting point is the calculated energy storage solutions and interconnector capacity. The zero value of interconnector is the optimum energy storage capacity (see Chapter 5) and the maximum interconnector capacity value (illustrated as orange square in Figure 7-2) is the minimum interconnector capacity required (import) without energy storage to ensure the demand is met (see Chapter 4). The findings of this analysis are illustrated in Figure 7-2.

Figure 7-2: BAU hybrid solution highlighting an 'optimum' solution (a) and a 'realistic' solution (b)



The analysis has been carried out taking into account pumped storage, liquid air energy storage and hydrogen (cavern) storage. As discussed in Chapter 5, these three technologies are capable of providing long term storage and as such have been proposed as potential technological solutions to ensure demand is met year round. However, there is an inherent uncertainty in the level of risk with these technologies due to their maturity. As such, it is assumed that hydrogen, and especially using cavern storage, has the highest risk and pumped storage the lowest. Figure 7-2 illustrates three curves, relating to each of the technologies. There are also two highlighted optimum combinations of energy storage and interconnector capacity. Option (a) is the lowest CAPEX combination and relates to a 37GW interconnector plus 11GW of hydrogen storage (cavern) at a combined CAPEX of GBP 42 billion. However, as discussed, this solution has a high level of risk and immaturity. Therefore, a more realistic solution is provided which uses pumped storage. Option (b) on the plot relates to a 42.5GW interconnector plus 5GW of pumped hydro at a CAPEX of GBP 46 billion. The two solutions given represent an investment in the region of 2.6% to 2.8% of the 2012 UK GDP respectively. Table 7-3 summarises the calculations and inputs for the analysis carried out on the BAU scenario.

Table 7-3: Summary of inputs and calculations of the hybrid BAU solution

Scenario	Interconnector capacity (MW)	Energy storage capacity (MW)	Interconnector cost (GBP Bn)	Energy storage cost (GBP Bn)	Combined CAPEX (GBP Bn)	% of 2012 UK GDP
BAU pumped storage	-	14,193	-	64.7	64.7	4.0%
37.5GW + pumped storage	37,500	12,422	36.2	11.3	47.5	2.9%
42.5GW + pumped storage	42,500	5,205	41	4.7	45.8	2.8%
50GW + pumped storage	50,000	823	48.2	0.7	49	3.0%
BAU liquid air energy storage	-	10,718	-	76.2	76.2	4.7%
37.5GW + liquid air energy storage	37,500	11,042	36.2	14.1	50.2	3.1%
45GW + liquid air energy storage	45,000	2,722	43.4	3.4	46.9	2.9%
50GW + liquid air energy storage	50,000	731	48.2	0.9	49.2	3.0%
BAU hydrogen (cavern) storage	-	65,287	-	44.8	44.8	2.8%
35GW + hydrogen (cavern) storage	35,000	15,027	33.7	8.2	42.1	2.6%
37GW + hydrogen (cavern) storage	37,000	10,856	35.7	5.9	41.7	2.6%
50GW + hydrogen (cavern) storage	50,000	663	48.2	0.3	48.6	3.0%
BAU interconnector only	59,855	-	57.8	-	57.8	3.6%

7.2.2 GP scenario hybrid solution

As with the BAU scenario, Figure 7-3 illustrates the findings of the analysis carried out on the GP scenario. In this case, the optimum solution (a) is for a 24GW interconnector plus 8.5GW of hydrogen storage (cavern) at a CAPEX of GBP 28 billion. However, the realistic solution (b) would be a 27.5GW interconnector plus 4GW of pumped hydro at a CAPEX of GBP 30.5 billion. These two solutions represent an investment in the region of 1.7% to 1.9% of the 2012 UK GDP respectively. Table 7-4 summarises the calculations and inputs for the analysis carried out on the GP scenario.

Figure 7-3: GP hybrid solution highlighting an 'optimum' solution (a) and a 'realistic' solution (b)

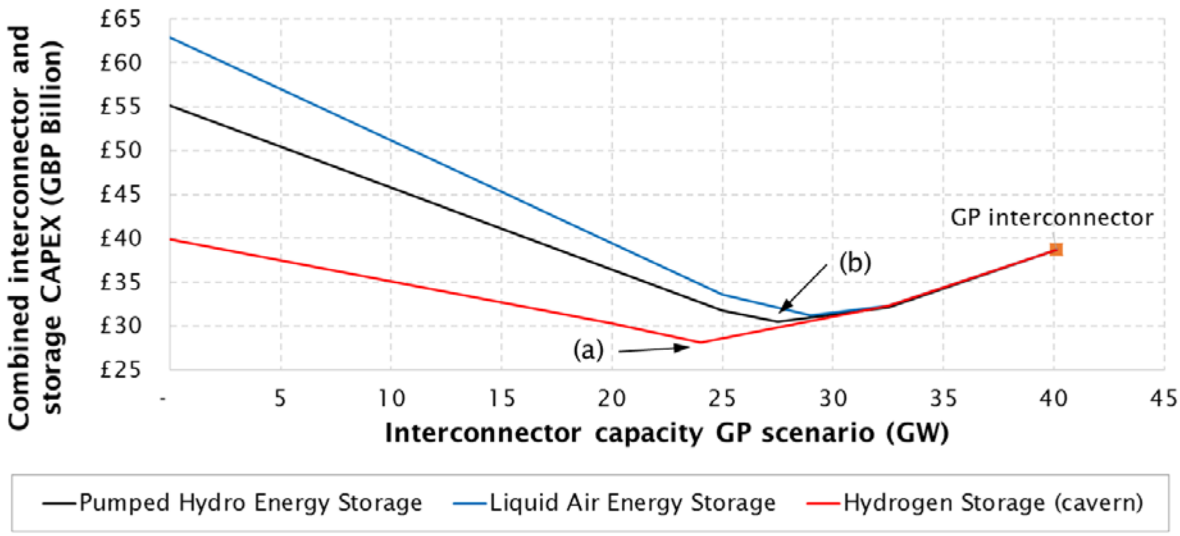


Table 7-4: Summary of inputs and calculations of the hybrid GP solution

Scenario	Interconnector capacity (MW)	Energy storage capacity (MW)	Interconnector cost (GBP Bn)	Energy storage cost (GBP Bn)	Combined CAPEX (GBP Bn)	% of 2012 UK GDP
GP pumped storage	-	13,438	-	55.1	55.1	3.4%
25GW + pumped storage	25,000	8,354	24.1	7.6	31.7	2.0%
27.5GW + pumped storage	27,500	4,355	26.5	3.9	30.5	1.9%
32.5GW + pumped storage	32,500	860	31.3	0.7	32.1	2.0%
GP liquid air energy storage	-	11,516	-	62.8	62.8	3.9%
25GW + liquid air energy storage	25,000	7,425	24.1	9.4	33.6	2.1%
29GW + liquid air energy storage	29,000	2,498	28	3.1	31.1	1.9%
32.5GW + liquid air energy storage	32,500	765	31.3	0.9	32.3	2.0%
GP hydrogen (cavern) storage	-	80.1	-	39.8	39.8	2.5%
20GW + hydrogen (cavern) storage	20,000	20,336	19.3	10.9	30.3	1.9%
24GW + hydrogen (cavern) storage	24,000	8,506	23.1	4.9	28.1	1.7%
32.5GW + hydrogen (cavern) storage	32,500	693	31.3	0.9	32.3	2.0%
GP interconnector only	40,124	-	38.7	-	38.7	2.4%

7.2.3 BAU+ASHP&EV scenario hybrid solution

As with the BAU scenario, Figure 7-4 illustrates the findings of the analysis carried out on the BAU+ASHP&EV scenario. In this case, the optimum solution (a) is for a 55GW interconnector plus 13.3GW of hydrogen storage (cavern) at a CAPEX of GBP 60 billion. However, the realistic solution (b) would be a 62.5GW interconnector plus 5GW of pumped hydro at a CAPEX of GBP 65.1 billion. These two solutions represent an investment in the region of 3.7% to 4% of the 2012 UK GDP respectively. Table 7-5 summarises the calculations and inputs for the analysis carried out on the GP scenario.

Figure 7-4: BAU+ASHP&EV hybrid solution highlighting an 'optimum' solution (a) and a 'realistic' solution (b)

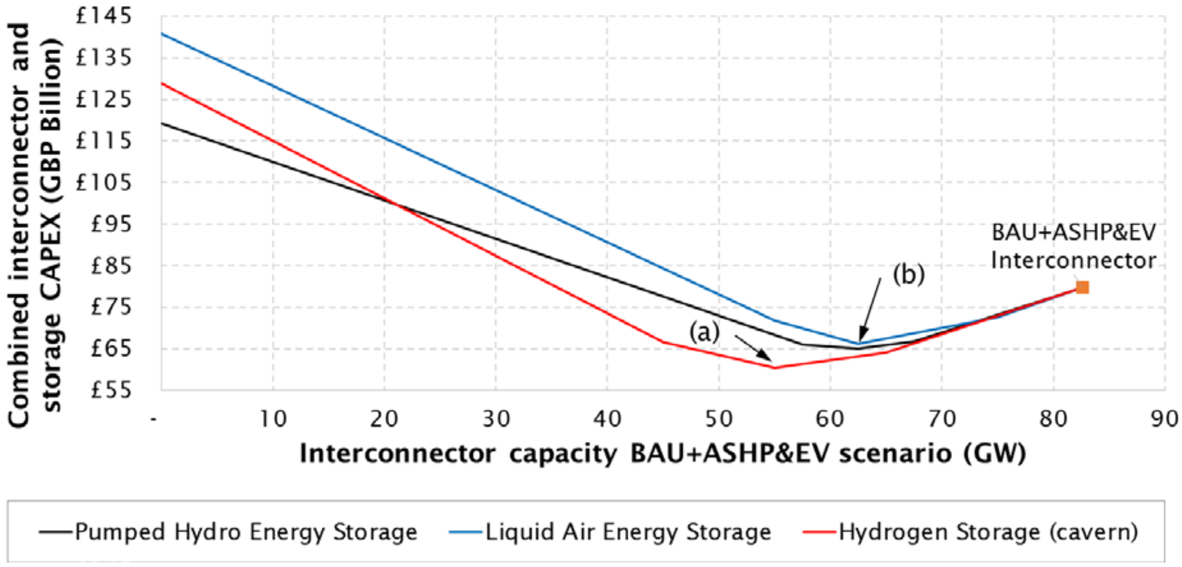


Table 7-5: Summary of inputs and calculations of the hybrid BAU+ASHP&EV solution

Scenario	Interconnector capacity (MW)	Energy storage capacity (MW)	Interconnector cost (GBP Bn)	Energy storage cost (GBP Bn)	Combined CAPEX (GBP Bn)	% of 2012 UK GDP
BAU+ASHP&EV pumped storage	-	27,036	-	119.3	119.3	7.4%
57.5GW + pumped storage	57,500	11,571	55.5	10.6	66.1	4.1%
62.5GW + pumped storage	62,500	5,203	60.4	4.8	65.1	4.0%
67.5GW + pumped storage	67,500	1,806	65.2	1.7	66.8	4.1%
BAU+ASHP&EV liquid air energy storage	-	8,315	-	140.8	140.8	8.7%
55GW + liquid air energy storage	55,000	14,716	53.1	18.8	71.9	4.4%
62.5GW + liquid air energy storage	62,500	4,625	60.4	5.9	66.3	4.1%
75GW + liquid air energy storage	75,000	200	72.4	0.3	72.7	4.5%
BAU+ASHP&EV hydrogen (cavern) storage	-	4,669	-	128.9	128.9	8.0%
45GW + hydrogen (cavern) storage	45,000	42,069	43.5	23.2	66.6	4.1%
55GW + hydrogen (cavern) storage	55,000	13,337	53.1	7.3	60.5	3.7%
65GW + hydrogen (cavern) storage	65,000	2,590	62.8	1.4	64.2	4.0%
BAU+ASHP&EV interconnector only	82,585	-	79.8	-	79.8	4.9%

7.2.4 GP+EV&ASHP scenario hybrid solution

As with the BAU scenario, Figure 7-5 illustrates the findings of the analysis carried out on the GP scenario. In this case, the optimum solution (a) is for a 42.5GW interconnector plus 7.8GW of hydrogen storage (cavern) at a CAPEX of GBP 46.7 billion. However, the realistic solution (b) would be a 45GW interconnector plus 5.8GW of pumped hydro at a CAPEX of GBP 48.8 billion. These two solutions represent an investment in the region of 2.9% to 3% of the 2012 UK GDP respectively. Table 7-6 summarises the calculations and inputs for the analysis carried out on the GP scenario.

Figure 7-5: GP+ASHP&EV hybrid solution highlighting an 'optimum' solution (a) and a 'realistic' solution (b)

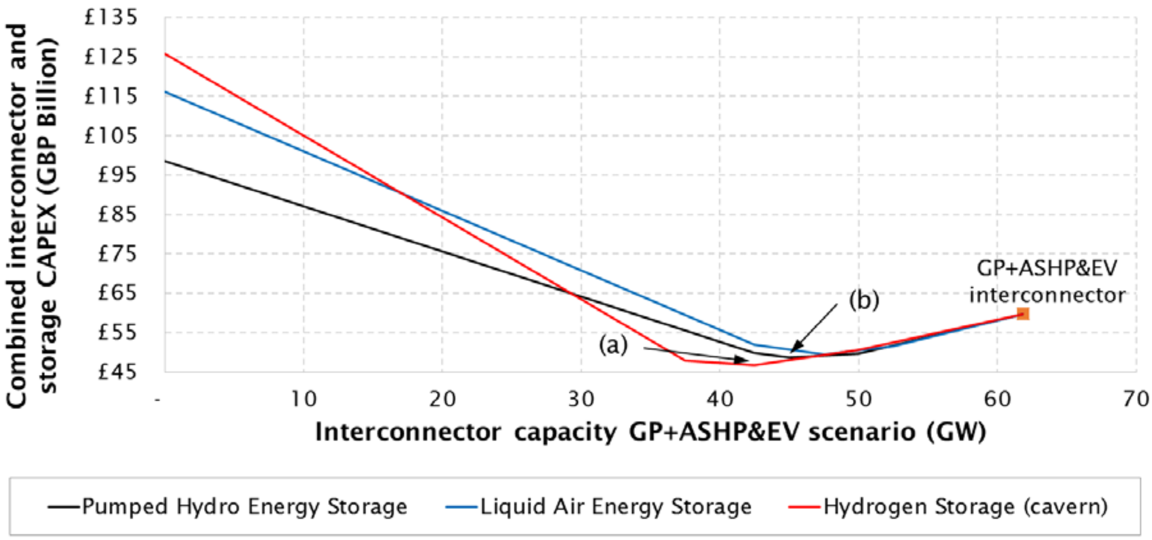


Table 7-6: Summary of inputs and calculations of the hybrid GP+ASHP&EV solution

Scenario	Interconnector capacity (MW)	Energy storage capacity (MW)	Interconnector cost (GBP Bn)	Energy storage cost (GBP Bn)	Combined CAPEX (GBP Bn)	% of 2012 UK GDP
GP+ASHP&EV pumped storage	-	14,201	-	98.6	98.6	6.1%
42.5GW + pumped storage	42,500	9,712	41.0	8.9	49.9	3.1%
45GW + pumped storage	45,000	5,792	43.5	5.3	48.8	3.0%
50GW + pumped storage	50,000	1,526	48.3	1.4	49.7	3.1%
GP+ASHP&EV liquid air energy storage	-	9,890	-	116.1	116.1	7.2%
42.5GW + liquid air energy storage	42,500	8,633	41.0	11.0	52.0	3.2%
47.5GW + liquid air energy storage	47,500	2,833	45.9	3.6	49.5	3.1%
52.5GW + liquid air energy storage	52,500	627	50.7	0.8	51.5	3.2%
GP+ASHP&EV hydrogen (cavern) storage	-	13,509	-	125.9	125.9	7.8%
37.5GW + hydrogen (cavern) storage	37,500	19,548	36.2	11.6	47.8	3.0%
42.5GW + hydrogen (cavern) storage	42,500	7,823	41.0	5.6	46.7	2.9%
50GW + hydrogen (cavern) storage	50,000	1,229	48.3	2.2	50.5	3.1%
GP+ASHP&EV interconnector only	61,823	-	59.7	-	59.7	3.7%

7.3 Discussion and conclusions

This Chapter considers the combination of interconnector and energy storage capacity required to ensure that demand is met throughout the year in a fully renewable UK electricity grid. This analysis draws on the conclusions and findings of Chapter 4 and Chapter 5 and provides a hybrid of the two technological solutions.

As such, this analysis indicates that a combination of energy storage and interconnector would be suitable to ensure demand is met throughout the year. It also shows that a hybrid solution would be a lower CAPEX option than installing either one of the solutions separately. However, in this analysis it is assumed that each energy storage technology has the same characteristics and has been modelled to have the same response time. Hence a mixture of energy storage technologies with interconnectors would not provide any advantageous solutions. Any optimal solution would be based solely on availability of the plant to provide capacity and based on the market mechanism in which they were operating; the main driver in which case would be the cost per MW or MWh. Therefore this analysis focuses on understanding the optimum combination of interconnector capacity and explicit energy storage technology.

In the case of the BAU scenario, the optimal solution with hydrogen (cavern) storage and interconnector is calculated to cost GBP 41.7 billion, whereas a more realistic solution using pumped storage is calculated to cost GBP 45.8 billion. Likewise, the GP scenario optimal solution is also hydrogen (cavern) storage and interconnector at a cost of GBP 28 billion, with the realistic solution using pumped storage costing GBP 30.5 billion.

Similarly when considering the electrified scenarios, the optimal solution for the BAU+ASHP&EV is hydrogen (cavern) storage and interconnector calculated to cost GBP 60.5 billion, whereas the realistic solution using pumped storage is calculated to cost GBP 65.1 billion; for the GP+ASHP&EV the optimal hydrogen (cavern) storage and interconnector is calculated to cost GBP 46.7 billion whereas the pumped storage solution is calculated to cost GBP 48.8 billion. This is summarised in Table 7-7.

Table 7-7: Summary of optimal and realistic hybrid interconnector/energy storage solutions

Scenario	Technology	Interconnector capacity (MW)	Energy storage capacity (MW)	Combined CAPEX (GBP Bn)	% of 2012 UK GDP
BAU	Hydrogen (cavern) storage	37,000	10,856	41.7	2.6%
	Pumped storage	42,500	5,205	45.8	2.8%
GP	Hydrogen (cavern) storage	24,000	8,506	28.1	1.7%
	Pumped storage	27,500	4,355	30.5	1.9%
BAU+ASHP&EV	Hydrogen (cavern) storage	55,000	13,337	60.5	3.7%
	Pumped storage	62,500	5,203	65.1	4.0%
GP+ASHP&EV	Hydrogen (cavern) storage	42,500	7,823	46.7	2.9%
	Pumped storage	45,000	5,792	48.8	3.0%

A level of confidence analysis has been carried out on the analysis above. This has been calculated based on a confidence level of 95%. It is determined that the combined interconnector and pumped storage cost in the BAU scenario is likely to be between GBP 41.8 billion and GBP 49.8 billion, with a margin of error of GBP 4 billion. Likewise, for the combined interconnector and hydrogen (cavern) storage cost in the BAU scenario is likely to be between GBP 32 billion and GBP 51.4 billion, with a margin of error of GBP 9.7 billion. This is illustrated, alongside the liquid air energy storage hybrid solution, in Figure 7-6.

Likewise, for the GP scenario it is determined that the combined interconnector and pumped storage cost is likely to be between GBP 28.4 billion and GBP 32.7 billion, with a margin of error of GBP 2.1 billion. Likewise, for the combined interconnector and hydrogen (cavern) storage cost in the GP scenario is likely to be between GBP 22.9 billion and GBP 33.3 billion, with a margin of error of GBP 5.2 billion. This is illustrated, alongside the liquid air energy storage hybrid solution, in Figure 7-7.

Figure 7-6: Combined cost of the BAU scenario optimal hybrid solutions with 95% confidence levels

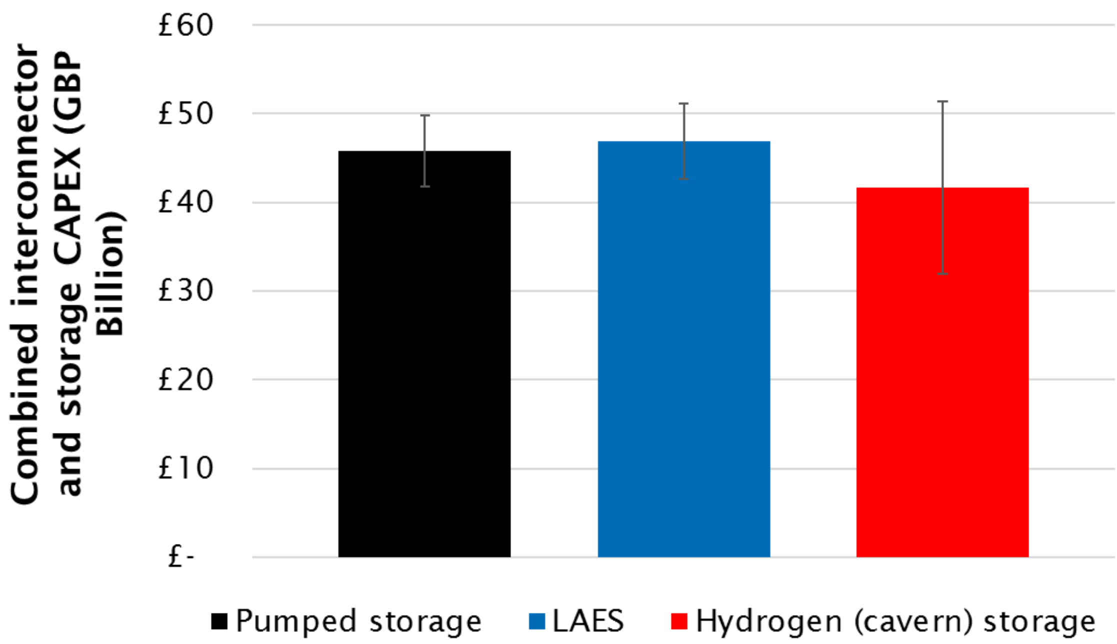
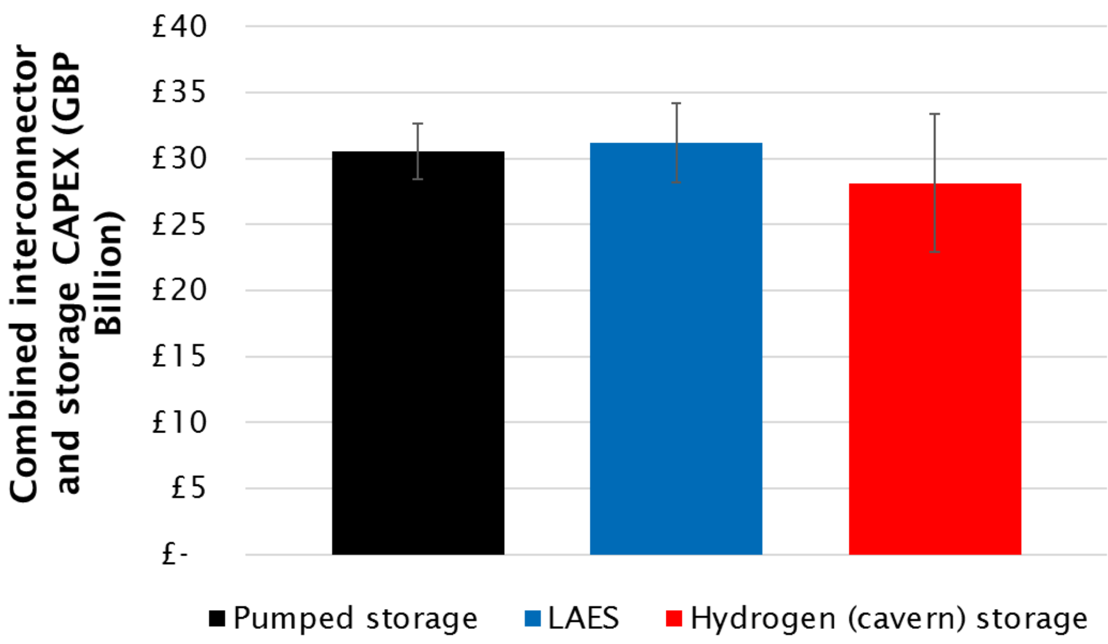


Figure 7-7: Combined cost of the GP scenario optimal hybrid solutions with 95% confidence levels



This analysis was also extended to the electrified scenarios with ASHP and EV. For the BAU+ASHP&EV scenario, it is determined that the combined interconnector and pumped storage cost is likely to be between GBP 63 billion and GBP 67.3 billion, with a margin of error of GBP 2.1 billion. Likewise, for the combined interconnector and hydrogen (cavern) storage cost in the BAU+ASHP&EV scenario is likely to be between GBP 52.7 billion and GBP 68.2 billion, with a margin of error of GBP 7.7 billion. Whereas, the GP+ASHP&EV scenario it is determined that the combined interconnector and pumped storage cost is likely to be between GBP 47.2 billion and GBP 50.3 billion, with a margin of error of GBP 1.5 billion. For the combined interconnector and hydrogen (cavern) storage cost in the GP+ASHP&EV scenario, it is likely to be between GBP 41.7 billion and GBP 51.6 billion, with a margin of error of GBP 4.9 billion. These scenarios are illustrated, alongside the liquid air energy storage hybrid solutions, in Figure 7-8 and Figure 7-9 respectively.

Figure 7-8: Combined cost of the GP+ASHP&EV scenario optimal hybrid solutions with 95% confidence levels

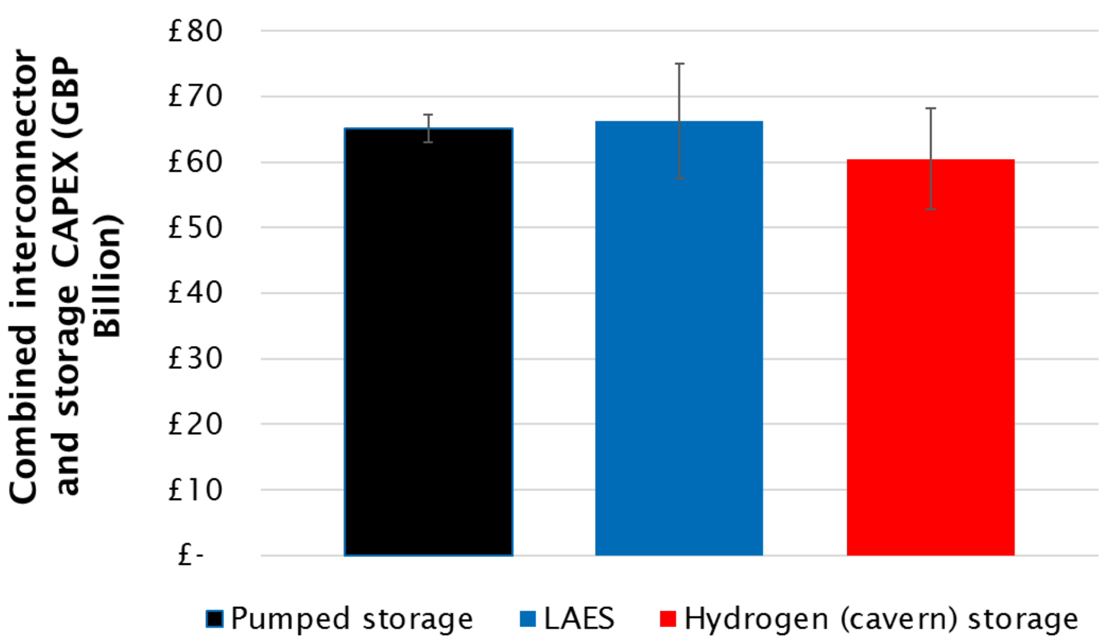
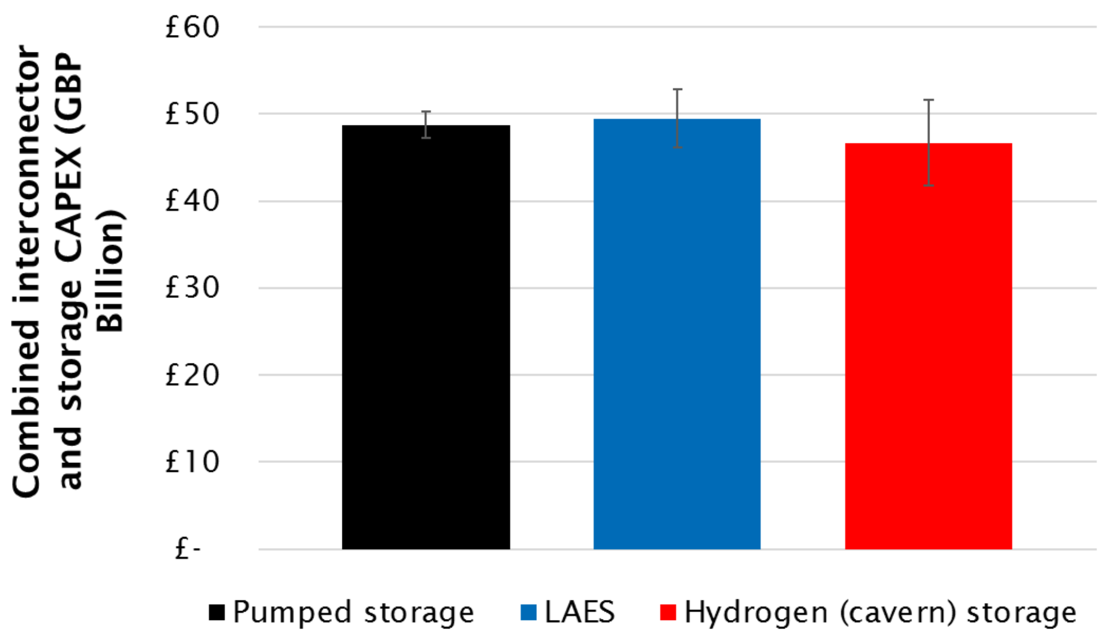


Figure 7-9: Combined cost of the GP+ASHP&EV scenario optimal hybrid solutions with 95% confidence levels



When considering the preferred future solution, this would need to involve multiple energy storage technologies across a range of capacities in order to be able to provide ancillary services to the electricity network as well as providing storage for excess renewable electricity. A careful assessment of the storage technology and the required service needs to be undertaken in order to be able to provide the most optimal solution in these scenarios.

However, this analysis indicates that a technological solution to the supply and demand imbalance inherent in a fully renewable UK electricity grid is possible and at a moderate CAPEX. This shows the way that technology needs to be developed in order to meet the decarbonisation targets and realise the advantages of a renewable electricity grid in the UK.

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Chapter 8: Results, Discussions and Conclusions

This thesis has introduced the origins of energy use and the dependency that humans have on energy in day to day life. The theories behind sustainable development and how these issues need to be taken into account in any future planning to avoid detrimental effects to our planet that will affect future generations have also been introduced in Chapter 1.1.2. The science of climate change and the differences in consensus over the origins, effects on our lives and what needs to be done to avoid emissions of greenhouse gases (GHG) have been discussed in Chapter 1.1.3. An investigation into the current levels of GHG emissions that the UK emits by sector in Chapter 1.1.5 identified that the main single contributor to these emissions is the energy supply sector.

Chapter 2.2 then introduces the current electricity grid in the UK and how it is governed under the British Electricity Trading and Transmission Arrangements (BETTA). The UK electricity demand profiles have been presented in Chapter 2.2.3 and the variations in demand requirements throughout the year were illustrated. How the generation mix in 2011 supplied the demand was also described in Chapter 2.2.4, highlighting the contribution that generation from renewable energy sources (RES) made to this. The transmission and distribution network that is currently in place in the UK to ensure that electricity is transmitted from source of generation to the end user was described in Chapter 2.2.2. The potential future demand increase from the uptake of electric vehicles and increase in use of electricity for heating, and the planned upgrades to the electricity generation and network have also been investigated in Chapter 2.2.5.

The potential sources of electricity generation from RES and their benefits have been described in Chapter 2.3. The technologies that have been described include generation from wind energy, hydropower, bioenergy, solar energy, marine energy and geothermal. The potential renewable resource availability in the UK has also been presented throughout Chapter 2.3.3. It was found that if all practicable RES are exploited, the total amount of electricity generated would be sufficient to supply the UK energy demand. This illustrates the energetic position in which the UK is located in terms of the amount of electricity that can be harnessed if exploited fully. If the lower estimate for electricity generation from renewable energy is achievable, it has been calculated that this is still over twice the electricity demand in 2013.

A new electricity network model has been presented in Chapter 2.4, distributed generation. This model ensures that variability of supply from RES does not pose detrimental effects to the electricity network and enables the integration of a number of different generation sources and tools that enable the reliable supply of electricity. The various advantages and challenges of such a model have been set out in Chapter 2.4.2 and 2.4.3. An added benefit of the distributed generation model is the potential to create a pan-European network that would enable the exploitation of a vast resource of RES, though this would entail significant financial investment. The technological advances that have made electricity transmission over great distances have been discussed. The benefits of using HVDC technology to interconnect various electricity networks have been highlighted in Chapter 2.5.2 and the expected costs to implement this are given in Chapter 2.5.1. The feasibility of using interconnection technology to integrate a massive penetration of renewable electricity onto an electricity network has been investigated in Chapter 2.5.3.

A key enabler to the integration of RES onto the electricity grids are energy storage systems or ESS. The thesis discusses the benefits that ESS can provide to the electricity network as well as the potential barriers that need to be addressed in Chapters 2.6.1 and 2.6.2. The various ESS technologies and their suitability to providing benefits to the grid have been discussed in Chapter 2.6.3. It was found that the majority of ESS technologies need extensive development and field testing before they are considered to be in a 'grid-ready' state. Once this has been achieved, ESS technologies will be well placed to provide multiple benefits to the grid and enable the mass integration of RES onto the grid, helping in the de-carbonisation of the energy supply sector in order to meet the current GHG reduction targets. Details of different technology costs along with the needs from the electricity network and the solutions that energy storage can provide have been investigated. The assumption going forward with energy storage is that the technologies to be considered will need to be able to cope with large amounts of electricity and also be able to store this electricity over extended periods of time.

The aim of the thesis is to investigate an optimal combination of energy storage, both central and distributed, and grid interconnection with Europe on a cost basis to ensure that supply and demand is balanced in a fully renewable UK grid.

8.1 Summary of Scenarios and Analyses

This thesis sets out the electricity demand scenarios that are used to investigate the future fully renewable electricity grid in Chapter 3.3. The two main scenarios are a Business as Usual (BAU) scenario which assumes electricity demand increases with a growth rate of 1% per annum in line with existing growth, and the Green Plus (GP) scenario which assumes the rate of demand increase is reduced to 0.25% per annum and represents a scenario in which there is an increase in consumer awareness of energy consumption and environmental issues.

It then sets out two technological advances that are likely to see an increased uptake in the future: electrification of transportation and heating in Chapter 3.2. It discusses the projections for uptake of plug-in electric vehicles in the UK and the increase in demand due to their charging requirements in Chapter 3.2.1. For the purpose of this thesis, it has been assumed that electric vehicles that plug into the electricity grid will feature in the fully renewable electricity grid. It has been calculated that a total of 5%, of the projected vehicle park of 40 million vehicles in the UK, are battery electric vehicles (BEV) and 12.5% are plug-in hybrid vehicles (PHEV). Based on an assumed battery charging and discharging efficiency of 80% and a vehicle utilisation of 50 weeks per year, with four full charge/discharge cycles per week the total calculated amount of electricity demand from the electrification of vehicles is in the order of 34TWh per annum.

There is also a calculation on the increase of demand due to the uptake of heat pumps for domestic heating and hot water demand in Chapter3.2.2. It is noted that whilst demand for transportation is assumed to be constant over the course of the year, the electrical demand for heating is assumed to be prevalent over the winter months, from October through to March. It has been assumed that in the future UK beyond 2050, the ASHP demand can be regulated so that the grid operator can control the demand and be able to use this to balance supply and demand from renewable sources throughout the year. However, this will only be available on the demand from ASHP and therefore the amount of demand that can be controlled has been calculated to be 69TWh/year, which is the full calculated heating demand of 53TWh/year plus 16TWh/year which is the calculated portion that ASHP will be able to provide for hot water demand.

The Chapter then introduces the supply necessary to meet the required electricity demand. The calculations and assumptions made to estimate the amount of capacity and generation from a mix of renewable technologies have been given along with the estimated cost to install the required capacity in the future.

The demand profiles are then discussed in detail in Chapter 3.3.2. The BAU scenario and GP scenario have been developed based on actual 2011 hourly demand data and linearly scaled up to meet the future proposed levels. In addition, the effects of electrification of transportation and heating discussed previously have been added to these two scenarios to create a further two scenarios for discussion: BAU+EV&ASHP and GP+EV&ASHP. The different scenarios have been presented and compared to illustrate the differences in installed capacity and cost.

These capacities have been calculated as the minimum installed mix required to meet the yearly electricity demand for each scenario and do not, at this stage, consider the hourly variation of generation and demand (Table 8-1).

It can be seen that the most expensive scenario is the business as usual combined with the uptake of air source heat pumps and electric vehicles. This is to be expected though as this scenario carries the highest electricity demand and hence the highest installed capacity. In addition, the baseline scenario proposed by Gardner (2011) is provided for comparison.

Table 8-1: Summary of renewable capacity and generation requirements, and estimated CAPEX cost for each scenario

Technology	Gardner (2011) (GW/TWh)	BAU (GW/TWh)	GP (GW/TWh)	BAU + EV & ASHP (GW/TWh)	GP+ EV & ASHP (GW/TWh)
Onshore wind	30/80	30/65	30/65	30/65	30/65
Offshore wind	82/310	86/288	41/138	127/425	82/275
Solar PV	18/15	34/37	34/37	34/37	34/37
Tidal	2/7	2/7	2/7	2/7	2/7
Bioenergy	12/95	14/95	14/95	14/95	14/95
Hydro	4/13	2/13	2/13	2/13	2/13
Geothermal	5/35	5/35	5/35	5/35	5/35
Total	153/555	173/540	128/390	214/677	169/527
Estimated scenario CAPEX (GBP Bn)	249	280	200	353	273

As discussed in Chapter 3.3.3, it has been assumed that offshore wind supplies any additional generation capacity required to cope with rises in demand. This assumption was taken as this technology proves the least challenging in terms of planning. The next steps included comparing the hourly demand profiles and hourly generation profiles for each scenario to investigate the mismatch and the variability between supply and demand in the proposed future scenarios.

Going forward, the variability calculated for each scenario is further investigated to provide technological solutions to balance the supply and demand to ensure that demand is met throughout the year across the UK.

8.2 Discussion of Results

This thesis has introduced potential renewable energy mixes for the UK that meet proposed annual proposed electricity demands set out in this study in Chapter 3.3. The estimated capital costs for these scenarios range from £200 billion to £353 billion. However, when considering the hourly demand and generation profiles, the issue of generation variability becomes apparent due to the variable sources such as wind and solar PV. Analysis carried out in Chapter 3.4 found that the level of available dispatchable generation in the UK (hydro, bioenergy and geothermal) in these scenarios is insufficient to meet demand when there is only a small contribution from wind due to high pressure systems (anticyclones) across the whole of the UK. A range of technological solutions to balance the generation and demand of UK electricity grid have been discussed.

Firstly, the interconnector capacity required to ensure that the electricity supply and demand is balanced throughout the year has been investigated in Chapter 4.2. The analysis here assumes that the interconnector is able to balance the active and reactive power in the system, like a slack bus. In the first instance, it is found that the excess generation is greater than the shortfall during the year. For this reason, it is possible to look at two levels for the interconnectors: full export capacity and capped capacity at import requirement. This approach enables the financial reasoning behind installing interconnectors to accommodate all the import and export requirements or solely for the import requirements to be explored.

In all the scenarios investigated, it is found that the maximum import requirement is during the winter months at the beginning of the year whereas the maximum export requirement is during the summer months. This is to be expected as during the winter months demand is higher and in this instance (the studied year of 2011) the amount of renewable generation available was low. During summer, the reverse occurs whereby demand is now low and output from renewables is comparatively high. In this case, generation from wind is lower during the summer but the imbalance between supply and demand is greater as demand is low.

In order to ensure that supply and demand are met, the absolute minimum capacity of interconnector required under these conditions is the import requirement, since any quantity of generation above this is surplus to the running of the electricity network. The estimated costs for installing the import capacity required for each scenario was found to be GBP 58 billion for the BAU scenario, GBP 39 billion for the GP scenario, GBP 80 billion for the BAU+EV&ASHP scenario and finally GBP 60 billion for the GP+EV&ASHP scenario. This is equivalent to 3.6%, 2.4%, 4.9% and 3.7% of the UK's GDP level in 2012.

The second part of the analysis considers the financial reasons behind increasing the interconnector capacity to accommodate and export some of the excess generation throughout the year. In this case, it is demonstrated in Chapter 4.4 that the costs per MWh of excess electricity ranges from GBP 2,800 to GBP 7,600/MWh which makes this financially unappealing. On the other hand, it is shown that the excess electricity could be sold to commercial users at wholesale price to obtain revenue in the range of GBP 1.1 million to GBP 12.5 million. This excess electricity could then be converted to heat or hydrogen for use in the heating or transportation sectors.

This technological solution is highly dependent on the European electricity network being capable of accommodating these levels of import and export throughout the year. An investigation of the data for 2011 suggests that the maximum yearly average consumption across the European grid was 62GW, with a maximum to minimum monthly consumption range in France of 72GW to 44GW respectively (entso-e, 2014). This suggests that if the European grid maintains its current levels of demand and generation, this would not be a feasible solution. Realistically, due to the high costs and the high dependence on the neighbouring grids which are unlikely to be capable of providing the necessary capacity to balance the supply and demand profiles, interconnection is only expected to provide up to a further 7.5GW in the near future (Brown, 2014).

An alternative solution investigated in Chapter 5.2 is large scale energy storage considering pumped storage (PS), liquid air energy storage (LAES) or hydrogen (H2) as potential solutions to ensure the supply of electricity in the UK is met by a fully renewable electricity generation mix. It was discussed that an ‘ideal’ energy storage technology would need to be able to provide up to 30TWh of storage over 197 continuous hours for the BAU scenario. Likewise, for the GP, BAU+EV&ASHP and GP+EV&ASHP scenarios, ‘ideal’ UK wide storage requirements are up to 21TWh over 190 continuous hours, 47TWh over 216 continuous hours and 37TWh over 215 continuous hours respectively.

However, the analysis then considers three potential energy storage technologies: pumped storage (PS), liquid air energy storage (LAES) and hydrogen (H2). It is highlighted in Chapter 5.3.1 that these technologies have round trip inefficiencies, converting generated electricity into storage and then back into electricity when required. Therefore, there would need to be an additional installed electricity generation capacity to account for these losses, which is assumed to come from additional offshore wind capacity. The analysis then calculates the storage capacity required plus the additional renewable generation for each scenario and is presented in Chapter 5.3.2. These results are summarised in Table 8-2.

Table 8-2: Calculated energy storage characteristics, plus offshore wind capacity requirements by scenario and by energy storage technology

Scenario	BAU	GP	BAU+EV&ASHP	GP+EV&ASHP
PS rated capacity (GW)	45	60	114	114
PS storage capacity (TWh)	9	12	22	23
PS offshore wind capacity (GW)	+18	+9	+26	+17
LAES rated capacity (GW)	11	35	55	70
LAES storage capacity (TWh)	2.3	7	11	14
LAES offshore wind capacity (GW)	+35	+17	+51	+33
H2 rated capacity (GW)	1	26	5	50
H2 storage capacity (TWh)	0.15	5	0.9	10
H2 offshore wind capacity (GW)	+48	+23	+70	+46

Further to this, Chapter 5.4 optimises the combination of energy storage and additional offshore wind capacity on a capital cost basis for each scenario. It was found that in the case of the BAU and GP scenario the optimal solution would be using hydrogen storage in combination with storage in underground caverns. However, it is discussed that this is not a mature technology and therefore it is proposed that the most feasible solution is pumped storage as this is a proven technology which is in use on the electricity grids at present. The third solution investigated using liquid air energy storage is still relatively immature, however pilot projects are underway using these on the electricity grid as storage solutions.

From this investigation it can be appreciated that the scale of the storage problem in the fully renewable UK electricity grid is challenging. The planning and construction requirement to provide enough storage tanks for LAES could be challenging. On the other hand, there is a precedent that installations of this scale are achievable and there is an abundant existing supply chain of the necessary equipment. In the case of H2 storage, the number of suitable sites to accommodate the large number of caverns for hydrogen storage is debatable as it relies on a set of specific geological formations. Additional insecurities at present with this solution is the limited penetration of hydrogen for use as an energy storage solution, which in turn highlights the immaturity of the technology necessary for this to be a viable solution at present.

However, the main barriers currently posed to these solutions are the economic aspects of each solution when competing in a heavily fossil fuelled centric electricity market and the current need for more pilot schemes to prove the technological and commercial feasibility of the technologies.

In addition, the study investigates the potential of storing excess renewable electricity within batteries in electric vehicles and in the thermal mass of domestic properties through air source heat pumps in Chapter 6.3. From analysis it is seen that with sufficient uptake of electrification of domestic heating and transportation a significant level of renewable electricity generation can be accommodated onto the existing network. However, it is important to note that a proportion of the network would need to be upgraded to allow for bi-directional electricity flows on a large scale as well as the mass roll out of smart control systems to be able to regulate this.

It was found in Chapter 6.4 that, depending on the location within the electricity network and the future scenario discussed, anywhere from 3% to 100% of excess generation could potentially be absorbed into the local network by controlling the amount of storage contained within batteries in vehicles plugged into the electricity network and electrified domestic heating.

Chapter 7 considered the combination of interconnector and energy storage capacity required to ensure that demand is met throughout the year in a fully renewable UK electricity grid. This analysis draws on the conclusions and findings of Chapter 4 and Chapter 5 and provides a hybrid of the two technological solutions.

As such, this analysis indicates that a combination of energy storage and interconnector would be suitable to ensure demand is met throughout the year. It also shows that a hybrid solution would be a lower CAPEX option than installing either one of the solutions separately. In the case of the BAU scenario, the optimal solution with hydrogen (cavern) storage and interconnector is calculated to cost GBP 41.7 billion, whereas a more realistic solution using pumped storage is calculated to cost GBP 45.8 billion. Likewise, the GP scenario optimal solution is also hydrogen (cavern) storage and interconnector at a cost of GBP 28 billion, with the realistic solution using pumped storage costing GBP 30.5 billion.

Similarly when considering the electrified scenarios, the optimal solution for the BAU+ASHP&EV is hydrogen (cavern) storage and interconnector calculated to cost GBP 60.5 billion whereas the realistic solution using pumped storage is calculated to cost GBP 65.1 billion; for the GP+ASHP&EV the optimal hydrogen (cavern) storage and interconnector is calculated to cost GBP 46.7 billion whereas the pumped storage solution is calculated to cost GBP 48.8 billion.

When considering the preferred future solution, this would need to involve multiple energy storage technologies across a range of capacities in order to be able to provide ancillary services to the electricity network as well as providing storage for excess renewable electricity. A careful assessment of the storage technology and the required service needs to be undertaken in order to be able to provide the most optimal solution in these scenarios.

However, this analysis indicates that a technological solution to the supply and demand imbalance inherent in a fully renewable UK electricity grid is possible and at a moderate CAPEX. This shows the way that technology needs to be developed in order to meet the decarbonisation targets and realise the advantages of a renewable electricity grid in the UK.

It is likely that any future electricity scenario that has 100% of its electricity generated from renewable energy sources will employ a combination of methods and technologies to account for the variability of this supply. Distributed storage will play a major role alongside larger scale storage and increased interconnection with neighbouring networks. Demand side management will have, and does have as in the industrial and commercial energy sectors, an important role to play in the domestic energy sector.

Further work needs to be carried out to investigate the compatibility of domestic heating requirements and electric vehicle usage with the variability of electricity supply on the network. The energy services associated with these devices that are being proposed must be provided reliably on a daily basis and the limitations of the energy 'store' to be available when there is a surplus or deficit of generation. There is a seasonal variation to the heating demand in the UK which could have an adverse effect on the amount of storage available. The colder temperatures during winter months also have an effect on the amount of energy available in the battery of an electric vehicle, found to be reduced by an average of 57% based on external temperature in the U.S. (AAA, 2014), meaning that there would potentially be less storage capacity available to the grid. During the winter months, electricity demand is higher due to the increased need for artificial lighting and electric space heating. The modelled scenarios have defined the required capacity based on this higher demand during the winter. However, due to the relative unpredictability of wind resources, the effects of there being a low resource are heightened. There is however a clear seasonal link present between higher availability of wind generation and an increased demand for household heating. Another concern relating to the amount of storage that is available from vehicles plugged into the network is the number of vehicles connected at any one time. In addition, another consideration to take into account is the amount of battery energy that will be available due to the owner needing to use the vehicle.

Clearly these issues need to be addressed for this technological solution to be feasible. There is a large volume of research and technical trials being carried out to investigate the feasibility and how these systems can interact with each other to ensure a secure and stable network.

In reality, a mix of interconnection and energy storage technologies is required to ensure the future highly variable electricity grid is viable. Further detailed investigations are required to fully understand the likely combinations as this is a complex question. The trade-offs to be investigated centre around the location of interconnectors and energy storage: hydrogen storage in salt caverns is constrained to the North-West of England and would require network upgrading to transmit the electricity, whereas interconnectors can be installed where required closer to the load centres. In addition, consumer behaviour towards electricity usage will help reduce the amount of balancing required. However, one of the most important factors to the viability of the fully renewable electricity grid is the market structure and the governing energy policy. Furthermore, investment in key network upgrades and renewable capacity is needed now in order to safeguard the future electricity grid.

8.3 Future Work

The aim of this study is to take a snapshot view of a future UK electricity grid where all electricity generation comes from renewable energy sources. The object of this is to understand the supply and demand issues that this could pose and test the feasibility of technological solutions to ensure that demand is met throughout the year. One of the main constraints of this study is the consideration of the UK electricity network in its current state and also that all the renewable capacity installed would connect directly to the HV transmission network. Having provided the requirements and identified the needs in this potential future, further work would need to consider the interactions between this renewable capacity and the electricity network, and an overhaul in the way the electricity network is structured, which is to be assumed given that this future scenario leads itself to a decentralised network. Additionally, consideration was not made to changes in consumer behaviour beyond a slight increase in concerns for environmental issues leading to better energy efficiencies and a reduction in demand in the GP scenario. It could be envisaged that if such a future scenario in the UK is adopted, there would also be a major shift in consumer behaviour and therefore a change in the electricity demand requirements.

Some more technical issues that have not been addressed include the need to replace the inherent system inertia from synchronous conventional thermal plant generators. This provides an effective way of stabilising the electrical frequency of the system, providing voltage control and also fault current needed to increase the system strength with the loss of a large generator. It has been mentioned that many of these services can be delivered through energy storage systems, though the combination of storage required to be able to provide demand and supply balancing and the services mentioned is an area which requires enquiry. Furthermore, it would be beneficial to investigate the amount of ‘sterile’ storage, the amount of storage that is not available for balancing services, which would be required in this scenario. ‘Sterile’ storage is required due to the inaccuracies in forecasting to a high degree of accuracy the electricity demand and potential effects of the weather on supply. There will need to be a portion of energy storage capacity that would need to remain in reserve to cover any such eventualities which could impact on the economics of this solution.

On the economics of energy storage, it is important to consider the high fixed costs of the technology. In an economic analysis of energy storage technologies in a renewable electricity system, it would be valuable to investigate the cycling of the technology as using storage over long periods would reduce the amount of cycles that the store would undertake; therefore, the cost of such a solution would be very high and this would have an adverse impact on the cost of electricity to the consumer.

It is highlighted that the interconnector solution assumes that the EU electricity network would be able to supply any shortfall in generation from renewables and, vice-versa, be able to use any excess generation. This poses some serious considerations: would it be politically acceptable to depend to this degree on neighbouring electricity networks and would the UK be capable of reciprocating the services? Another consideration to take into account is the required extensions and/or upgrade to the UK electricity network in order to cope with the high capacity transfers. This would add a significant cost to the transmission option.

As outlined, the aim with this study is to consider the UK electricity network as a whole in a fully renewable scenario. It highlights the potential issues that would arise with a mismatch in supply from renewables and demand and poses potential technological solutions that could be established to ensure security of supply.

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Appendices

Appendix A: UK Electricity Supply Map 2012 (DECC, 2012f)

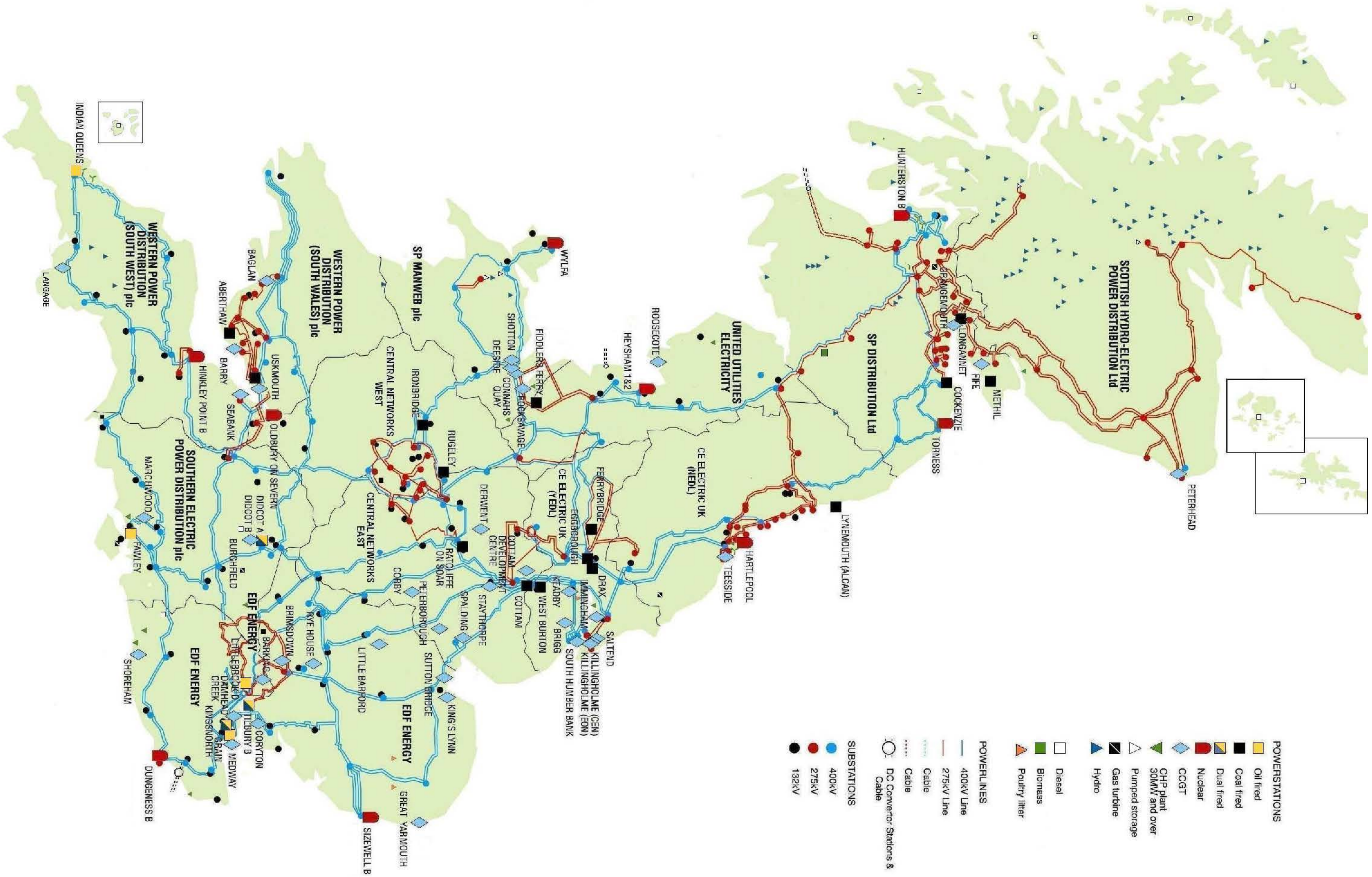
Appendix B: UK Power Flow Diagram 2012/13 (National Grid, 2013c)

Appendix C: Sample of UK Renewables Obligation Generators 2013 database (REF, 2013)

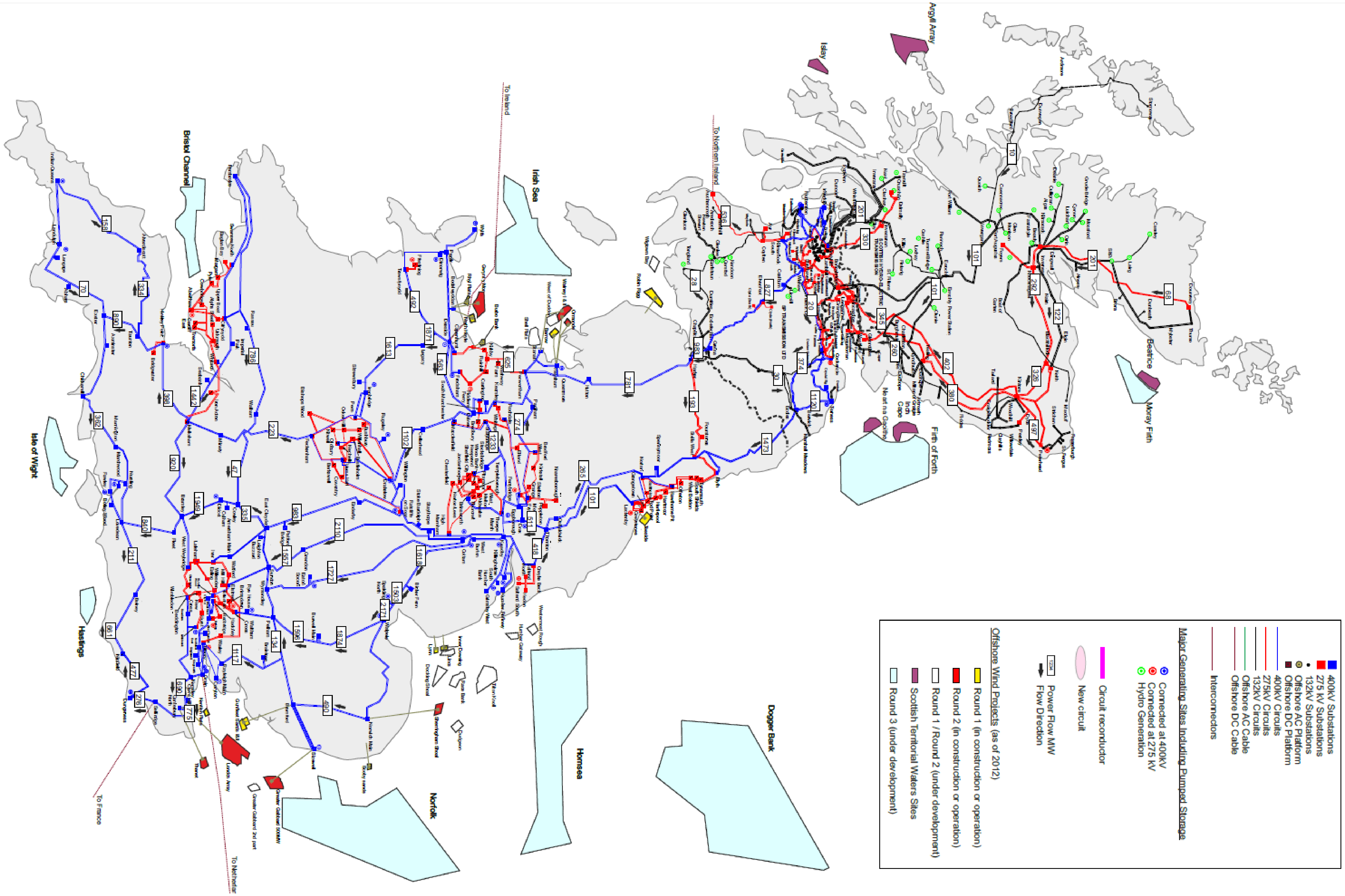
Appendix D: UK offshore wind projects under development (The Crown Estate, 2012)

Appendix E: UK Demand Profiles 2002-2012 (NationalGrid, 2013d)

Appendix A UK Electricity Supply Map 2012 (DECC, 2012f)



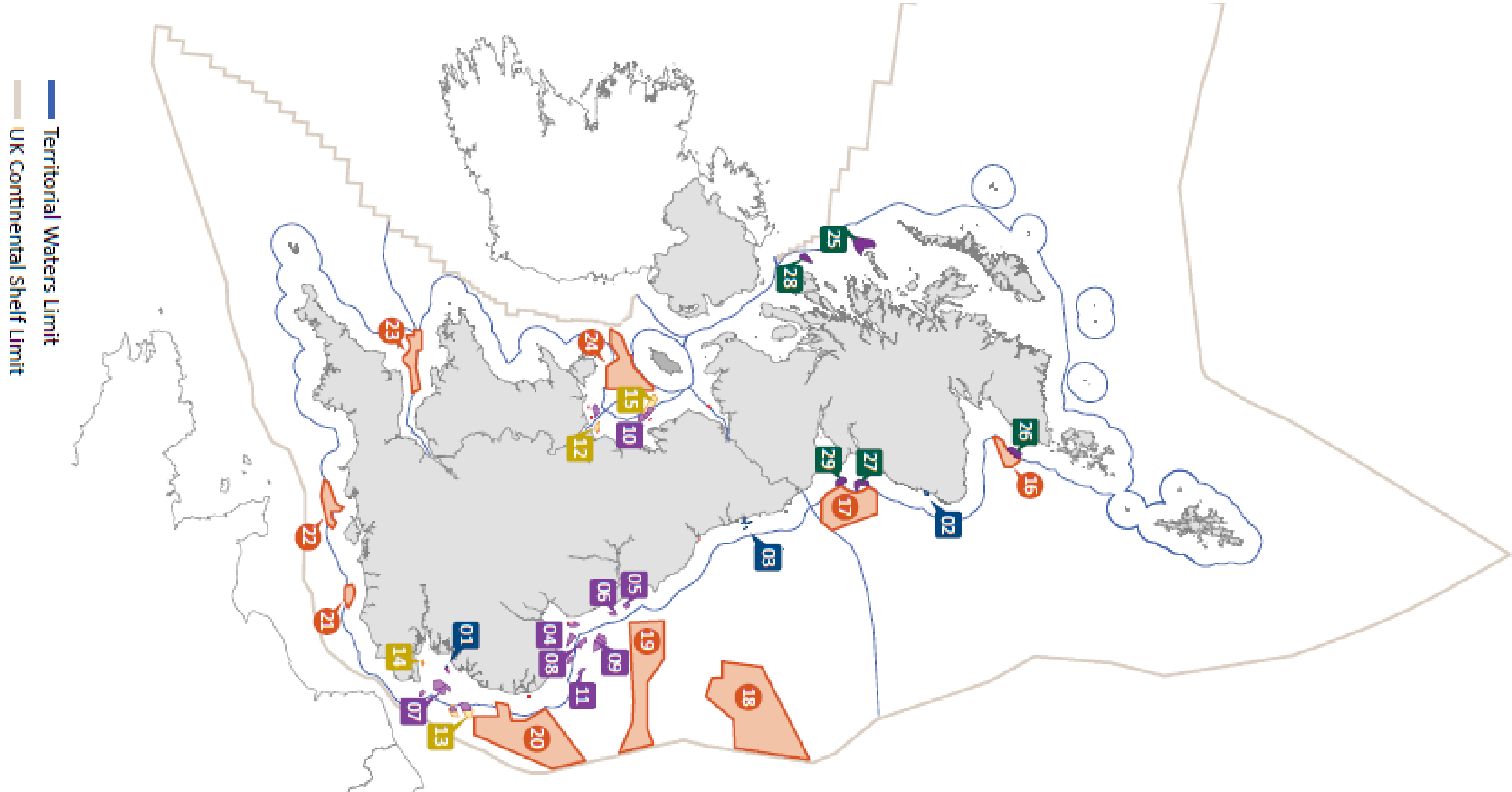
Appendix B UK Power Flow Diagram 2012/13 (National Grid, 2013c)



Appendix C Sample of UK Renewables Obligation Generators 2013 database (REF, 2013)

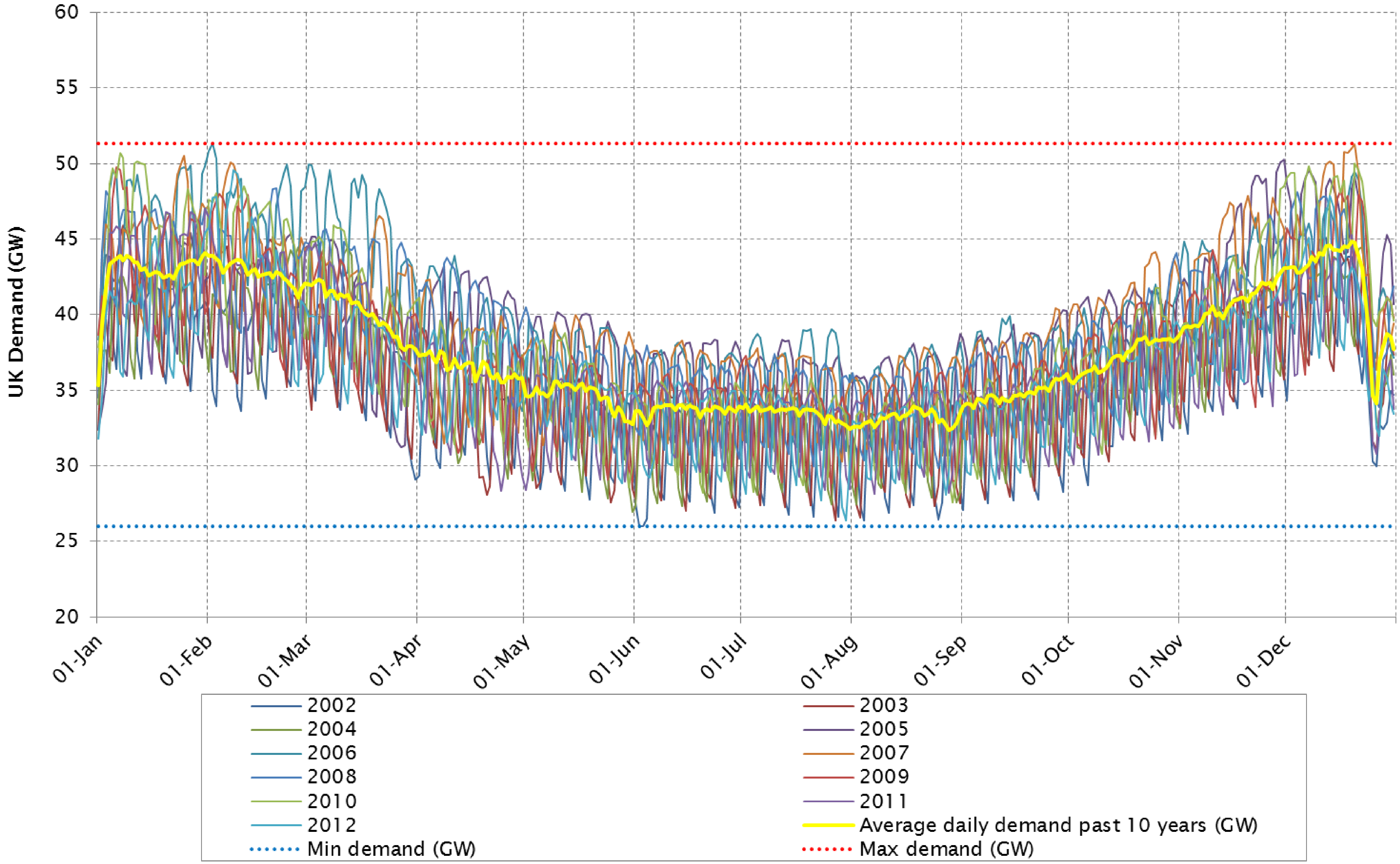
RID	Generator Name	Count	Installed Capacity (kW)	Technology Group	Technology Sub-group	Ch	Accreditation Da	Rolling LF	Annual LF	Latest_ROC Da	Latest MWh p	Latest ROCs p.
R00083RAEN	Drax Power Station (RB) - A,C,E	England	2,000,000	Biomass	Biomass co-firing		01/03/2003	4.80%	11.00%	Sep-12	1,934,000	1,005,410
R00015RPEN	Thanet Offshore Wind Farm	England	300,000	Wind	Off-shore wind		02/07/2010	30.30%	28.70%	Sep-12	755,894	1,511,790
R00080RAEN	Tilbury Dedicated Biomass Power Station - A,C,E	England	1,127,000	Biomass	Dedicated biomass		01/08/2002			Feb-12	573,048	859,529
R00089SQSC	Whitelee Windfarm	Scotland	322,000	Wind	On-shore wind		14/12/2007	21.90%	28.70%	Sep-12	812,032	812,032
R00014RPEN	Greater Gabbard	England	500,000	Wind	Off-shore wind		23/02/2011			Sep-12	841,373	1,682,750
R00019RPEN	Walney Offshore Wind Phase I	England	183,600	Wind	Off-shore wind		07/02/2011	40.20%	38.90%	Sep-12	626,820	1,253,640
R00011RPEN	Inner Dowsing Offshore Wind Farm	England	90,000	Wind	Off-shore wind		20/04/2008	34.10%	30.30%	Sep-12	258,560	387,820
R00010RPEN	Lynn Offshore Wind Farm	England	90,000	Wind	Off-shore wind		28/03/2008	33.10%	35.90%	Sep-12	306,093	459,117
R00007RAEN	Thetford Power Station (RA) - A B	England	41,500	Biomass	Dedicated biomass		01/04/2002	66.30%	60.80%	Sep-12	221,542	332,297
R00008RPEN	Burbo Offshore Windfarm - A (31/01/07)	England	90,000	Wind	Off-shore wind		01/07/2007	33.10%	34.70%	Sep-12	274,416	411,604
R00103SQSC	Crystal Rig II Wind Farm	Scotland	135,365	Wind	On-shore wind		16/12/2009	29.90%	33.00%	Sep-12	399,823	399,823
R00125RAEN	Ferrybridge C Power Station - A,C,E	England	1,960,000	Biomass	Biomass co-firing		01/04/2002	1.40%	0.50%	Sep-12	87,022	43,511
R00012RPEN	Gunfleet Sands I	England	108,000	Wind	Off-shore wind		24/07/2009	33.60%	35.10%	Sep-12	333,389	500,059
R00006RPEN	Kentish Flats Ltd - A,C	England	90,000	Wind	Off-shore wind		01/08/2005	30.30%	33.70%	Sep-12	266,198	266,198
R00007RPEN	Barrow Offshore Windfarm - A	England	90,000	Wind	Off-shore wind		01/01/2006	33.60%	41.60%	Sep-12	328,928	328,928
R00005SASC	Stevens Croft - A, B, C, D, E, (01/06/07)	Scotland	46,000	Biomass	Dedicated biomass	Y	01/06/2007	59.00%	66.60%	Sep-12	294,633	585,650
R00063SQSC	Hadyard Hill Windfarm - A,C	Scotland	119,600	Wind	On-shore wind		01/11/2005	24.70%	27.00%	Sep-12	283,518	283,518
R00020RPEN	Ormonde Wind Farm	England	150,000	Wind	Off-shore wind		18/08/2011	29.50%	31.20%	Sep-12	410,796	821,593
R00011RAEN	Elean Business Park	England	40,000	Biomass	Dedicated biomass		01/04/2002	65.00%	60.80%	Sep-12	213,569	330,444
R00003SPSC	Robin Rigg Offshore Wind Farm (East)	Scotland	89,239	Wind	Off-shore wind		20/04/2010	33.00%	34.70%	Sep-12	274,140	548,279
R00002SPSC	Robin Rigg Offshore Wind Farm (West)	Scotland	89,239	Wind	Off-shore wind		18/07/2009	34.00%	38.10%	Sep-12	301,258	451,865
R00023RPEN	Walney Offshore Wind Phase II	England	183,600	Wind	Off-shore wind		25/08/2011			Sep-12	388,094	776,189
R00060SQSC	Black Law Windfarm - A,C	Scotland	124,200	Wind	On-shore wind		01/03/2005	22.10%	22.50%	Sep-12	245,724	245,724
R00005RPWA	Rhyl Flats Wind farm	Wales	90,000	Wind	Off-shore wind		15/07/2009	31.80%	40.30%	Sep-12	318,571	477,832
R00062SQSC	Farr Wind farm ltd - A	Scotland	92,000	Wind	On-shore wind		01/10/2005	28.10%	27.20%	Sep-12	219,818	219,818
R00165SQSC	Clyde Windfarm (South)	Scotland	127,400	Wind	On-shore wind		01/07/2011	27.10%	27.70%	Sep-12	312,804	312,804
R00106RAEN	Fiddler's Ferry Power Station - A,C,E	England	1,995,000	Biomass	Biomass co-firing		01/04/2002	1.20%	0.50%	Jun-12	72,398	37,232
R00150SQSC	Arecleoch	Scotland	120,000	Wind	On-shore wind		19/11/2010	28.20%	31.00%	Sep-12	326,710	326,710
R00016SESC	Kinlochleven Hydro Power Station, G	Scotland	19,500	Hydro	Hydro		01/04/2002	95.00%	94.60%	Sep-12	161,952	161,952
R00004RPWA	North Hoyle Offshore Wind Farm - A	Wales	60,000	Wind	Off-shore wind		01/11/2003	33.60%	36.70%	Sep-12	193,410	193,410
R00006SASC	Caledonian CHP1	Scotland	25,850	Biomass	Dedicated biomass	Y	30/04/2009	78.20%	79.90%	Sep-12	182,726	365,453
R00037RAEN	Wilton 10 Biomass Gen station (RA) - A	England	17,450	Biomass	Dedicated biomass	Y	10/08/2009	61.30%	66.90%	Jul-12	170,504	273,760
R00013RPEN	Gunfleet Sands II	England	64,800	Wind	Off-shore wind		24/07/2009	34.70%	35.10%	Sep-12	199,483	299,209
R00066SQSC	Pauls Hill Wind Farm - A,C,E	Scotland	64,400	Wind	On-shore wind		01/11/2005	31.40%	34.00%	Sep-12	192,312	192,312
R00005RPEN	Scroby Sands Wind Farm	England	60,000	Wind	Off-shore wind		01/05/2004	28.80%	33.70%	Sep-12	177,612	177,612

Appendix D UK offshore wind projects under development (The Crown Estate, 2012)



No	Project name	Developer	Indicative Capacity (MW)
Demo sites			
01	Gunfleet Sands 3	Dong	12
02	Aberdeen Bay European Offshore Wind Deployment Centre	Vattenfall Wind Power UK, and Aberdeen Renewable Energy Group (AREG)	Up to 100MW
03	Blyth offshore wind demons-tration site	New and Renewable Energy Centre (NAREC)	Up to 100MW
Round 2 sites			
04	Docking Shoal	Centrica	540
05	Westermost Rough	Dong	240
06	Humber Gateway	E.On	219
07	London Array 2	Dong, E.On	370
08	Race Bank	Centrica	620
09	Triton Knoll	RWE	900-1200
10	West of Duddon Sands	Iberdrola, Dong	389
11	Dudgeon	Warwick	560
Round 1 and 2 extension sites			
12	Burbo Bank Extension	Dong	234
13	Galloper Extension	SSE, RWE	504
14	Kentish Flats 2 Extension	Vattenfall	51
15	Walney Extension	Dong	750
Round 3 zones			
16	Moray Firth	EDP Renovaveis, Repsol	1300-1500
17	Firth of Forth	SSE, Fluor	3465
18	Dogger Bank	RWE, SSE, Statkraft, Statoil	9000-12800
19	Hornsea	Mainstream, Siemens, Dong	4000
20	East Anglia	Iberdrola, Vattenfall	7200
21	Rampion	E.On	665
22	Navitus Bay	Eneco, EDF	900-1200
23	Atlantic Array	RWE	1500
24	Irish Sea	Centrica, Dong	4185
Scottish territorial waters sites			
25	Argyll Array	Iberdrola	1800
26	Beatrice	SSE, Repsol	1000
27	Inch Cape	EDP Renovaveis, Repsol	905
28	Islay	SSE	690
29	Neart na Gaoithe	Mainstream	450

Appendix E UK Demand Profiles 2002-2012 (NationalGrid, 2013d)



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