Operating the Electricity Transmission Networks in 2020

Initial Consultation

JUNE 2009

nationalgrid

Why has National Grid published this document?

National Grid operates the transmission networks across Great Britain under the terms of its Transmission Licence.

This licence stipulates that we should operate the transmission networks in an efficient, economic and co-ordinated manner.

In meeting this obligation we need to be aware of the technical characteristics and capabilities of electricity generation and demand.

We must also make assumptions regarding the future behaviour of energy market participants and how this will impact on the way the transmission networks can be operated. These assumptions are relevant to other stakeholders and many of them are relevant to any assessment of security of energy supply.

The location, type and size of generators connected to the transmission networks has started to change as have patterns of consumer demand. The pace and magnitude of this change will grow as emission and renewable energy targets are met. At National Grid we believe that we need to develop a plan in order to deliver these changes effectively.

This document has therefore been published at this time to set out and seek views on:

- Our assessment of the technical challenges presented to us in our role in operating the networks and as 'residual balancer';
- Our thoughts on how these challenges could be met; and
- Our assumptions regarding how energy market participants will respond to events in operational timescales.

About National Grid

National Grid owns and operates the high voltage electricity transmission system in England and Wales and, as Great Britain System Operator (GBSO), we operate the Scottish high voltage transmission system. National Grid also owns and operates the gas transmission system throughout Great Britain and through our low pressure gas distribution business we distribute gas in the heart of England to approximately eleven million offices, schools and homes. In addition National Grid owns and operates significant electricity and gas assets in the US, operating in the states of New England and New York.

In the UK, our primary duties under the Electricity and Gas Acts are to develop and maintain efficient networks and also facilitate competition in the generation and supply of electricity and the supply of gas. Our activities include the residual balancing in close to real time of the electricity and gas markets.

Through our subsidiaries, National Grid also owns and maintains around 18 million domestic and commercial meters, the electricity Interconnector between England and France, and a Liquid Natural Gas importation terminal at the Isle of Grain.

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1 Foreword

This consultation document describes and examines the likely issues relating to operating the electricity transmission networks in 2020. Our assessment is based on a vision for 2020 of an electricity transmission system which evolves to connect extensive renewable generation to achieve climate change objectives. This sustainability objective must be achieved whilst maintaining a diverse generation background and appropriate network standards in order to maintain security of supply and to do so affordably.

Since June 2008, we have worked with other energy companies, Government and Ofgem within the Electricity Networks Strategy Group (ENSG[1]). In March 2009, ENSG published its Vision of the network reinforcements required to meet the 2020 renewable energy target.

This ENSG Vision was based on an energy scenario developed by National Grid and tested within ENSG covering the UK's total energy demand across the electricity, heat and transport sectors. This scenario, known as 'Gone Green' set out the requirement to:

- connect circa 32 GW of renewable wind capacity; around 20 GW offshore and 10 GW onshore by 2020;
- account for an unprecedented churn in the generation fleet due to;
    - the closure of older, coal and oil fired generating plant because of the Large Combustion Plant Directive;
    - the retirement due to age of existing nuclear capacity; and
    - the expected connection of 12 GW of new gas-fired generation in the same timescales.

The purpose of this document is to complement the ENSG work and examine the issues of system operation against the same Gone Green scenario. The document outlines our initial views on the key issues we will face in our role as System Operator of the electricity transmission networks and provides an indication of the services we are likely to require as 'residual balancer', along with the potential providers of those services. We welcome comments on the views expressed in this document.

In undertaking our assessment, it has been necessary to make a set of underlying assumptions on the role of the market and likely market behaviour in maintaining security of supply and how this impacts on our role. We believe the information contained in this document on items such as Operating Margins (the difference between forecast demand and the available generation) and how wind is assumed to contribute to capacity for security of supply analysis, provides a useful platform for a wider debate on the market requirements associated with maintaining security of supply as we move towards 2020. In advance of those discussions we welcome any comments on the assumptions we have made in this document.

We believe the combination of the work undertaken for ENSG in identifying the electricity transmission network reinforcements required to meet the 2020 renewable target, this document identifying the system operation issues and the further work we recommend on assessing the market requirements associated with maintaining security of supply can make a significant contribution to the UK energy policy debate.

[1] The ENSG homepage is at: http://www.ensg.gov.uk/

2 Summary

Renewable energy and carbon emission reduction targets mean that the type and size of generation connected to the electricity transmission networks in Great Britain and Offshore will change.

Patterns of electricity demand will also change due to energy efficiency measures and the possible introduction of active and passive demand management.

We have used a scenario based approach to assess the challenges presented by this development to us in our future role as System Operator of the transmission networks in Great Britain and Offshore. The scenario we have focussed on is identical to that referenced by the Electricity Networks Strategy Group report of March 2009 which set out a strategy for transmission network investment to 2020.

The scenario helps us to quantify these challenges and establish the timescales over which they are likely to transpire. At this point we believe they can be addressed by building on our experience in operating transmission networks and by seeking out innovative solutions which allow more parties, including electricity consumers, to play a role in securing the nation's energy supply.

Our views are based on certain assumptions about how energy markets will behave and how this behaviour will in turn affect our ability to fulfil our responsibilities. We seek stakeholders' views on our assumptions and believe that this consultation exercise provides a useful springboard for further debate.

National Grid's Role

2.1 National Grid's role as the System Operator of the electricity transmission networks in Great Britain carries with it the responsibility for economic and efficient operation of the networks on behalf of electricity consumers.

2.2 In performing our System Operator role, we need to have tools in place to manage the networks which are effective in both technical and commercial terms. This means we need to make assumptions about how wholesale energy markets will perform as their behaviour sets the background for and the size of the operational challenge we face.

2.3 This role includes the position of 'residual balancer', the party responsible for managing the short term balance of electricity generation and demand within statutory technical limits. The term 'residual' is used as energy markets have been designed such that the bulk of the task of matching electricity generation and demand, including investing in new generating infrastructure where required, is performed by generators and suppliers as driven by market forces.

2.4 We believe it is valuable to set out our thinking on the operational challenge we will face, alongside the assumptions behind our thinking. We hope this consultation can provide context for future debate on efficient transmission network operation, wholesale energy market development and security of supply assessment.

Network Operation

2.5 Day to day operation of the transmission networks will become more complex because of the combination of:

- The impact of generation intermittency on the minute by minute national balance between electricity generation and demand;
- Changes in the way electricity is consumed and managed;
- A need to manage the networks more actively, itself triggered by:
    - The impact of generation intermittency on network flows;
    - New transmission access arrangements;
    - Interactions between transmission constraints and a growing requirement for operating reserve; and
- The general need to accommodate low load factor generation efficiently by sharing network capacity.

2.6 National Grid's job will change as we learn to deal with the fluctuations in electricity generated from renewable sources as well as the fluctuations in electricity demand we are already used to dealing with. We will have to deploy more sophisticated control solutions which make our networks even more 'smart' than they are today.

2.7 The regulated allowance for investment in our electricity system operator systems is approximately £9m for the year 2009/10. Development of the necessary new capability will require additional new investment at a level within this range over each year for the next 5 to10 years. We believe that this new investment would represent good value in the task of meeting emission and renewable energy targets and provide a platform for reducing the overall costs of electricity transmission borne by the consumer.

2.8 The energy industry will become more 'smart' with energy suppliers using tariffs to manage energy consumption and possibly to accommodate charging of electric cars. Distribution network operators may also look to get the most from their networks, by controlling small and perhaps domestic scale electricity generation for example. Both of these developments will change the pattern of electricity demand we see and give us more to do in operating the transmission networks.

2.9 Domestic and small scale electricity generation has a significant role in meeting emission and renewable energy targets and therefore plays a big part in the generation and demand scenario we have used in this report (which assumes, at 15GW in capacity, almost double today's levels). It is important to us that this type of generation can continue to operate when network disturbances occur, in the same way that larger scale generation does currently.

2.10 We have not needed to have visibility of the operating plans or characteristics of smaller generators in the past but beyond a certain scale it will be necessary to review the information provided to us.

2.11 Under a scenario with 29.5GW of transmission connected wind generation capacity, our Short Term Operating Reserve Requirement increases by 6.5GW in 2020 from today's levels of approximately 4GW. In today's prices, services of a value of some £418m per year are required to meet the Short Term Operating Reserve requirements for wind under this scenario.

2.12 These figures could decrease to nearer 4GW and £229m per year if wind forecasting performance improves to the levels we have assumed in the analysis presented within this document. The actual costs incurred in 2020 will be affected by market prices at the time.

2.13 We also see similar service costs of £88m per year triggered by the connection of larger generating units (up to 1,800MW) under our scenario. Connection of this type of unit is dependant on a change to the agreed criteria for connection to the transmission networks which is currently subject to consultation.

2.14 We will keep under review the contingency and emergency arrangements which both help to protect consumers from large scale electricity supply losses and would allow us recover should such extreme events occur. We will seek to replace the Black Start service providers expected to close over the next decade and seek to make the best use of new technology to complement or replace the emergency actions available to us currently.

New Technology and New Opportunities

2.15 We believe that the generation technologies which are new to Great Britain (wind, supercritical coal and the latest generation of nuclear power) will be or can be made capable of meeting our requirement for flexibility in operating the transmission networks. We seek industry views on whether this potential will be delivered.

2.16 There will also be new opportunities for large and small electricity consumers to provide Balancing Services to us. Energy storage, electric cars, smart metering and smart metering enabled control systems can all play a part. Fridges, washing machines and dishwashers could all contribute through co-ordinated demand management in the same way that generators do today.

2.17 We estimate that there are some 8GW of additional demand side services that could be available by 2020 to help meet our operating reserve requirements. Significant effort is required to realise the benefits available from these measures. We recognise that other parts of the energy industry will also be interested in them.

2.18 We have considered whether it would be helpful for us to quantify our longer term Balancing Services Requirements through a Ten Year Balancing Services Requirement statement designed to better inform potential providers. Market participants' are invited to express their views over the value of such a statement.

Managing Intermittency

2.19 Electricity generated from wind will displace the use of scarce fossil fuels, reducing carbon emissions in the process. It is important to remember that the wind is blowing somewhere across Great Britain most of the time and our scenario assumes a sufficient geographical dispersion of wind turbines, both onshore and offshore, to take advantage of this.

2.20 However, we have observed periods where the electricity generated from wind within the UK, Ireland and parts of Northern Europe has been very low. These can coincide with days of peak electricity demand when cold and still conditions persist.

2.21 As System Operator we need to balance supply and demand minute by minute and think it is prudent to plan for periods where the amount of electricity generated from wind is low at times of peak electricity demand. This does mean that other forms of generation are required at times when wind generation output is low, but we think that demand side measures have a growing role to play.

2.22 Interconnection between Great Britain and Northern Europe can also help. This has the effect of sharing intermittency across a wider area and reducing its impact. It is therefore important that we understand how European network operators and energy markets will act as this will affect the amount of electricity we can import if we need it. We have already engaged with our European counterparts to start this process.

Operating Margin

2.23 There is a great deal of uncertainty over how electricity operating margins (the difference between forecast demand and the available generation) will develop over the next decade. This is driven by uncertainty in underlying energy demand linked to economic activity, uncertainty over the rate of growth in small scale generation and uncertainty over the introduction and impact of energy efficiency measures. There is further uncertainty over the rate at which new generation can be constructed and how this can contribute once in operation.

2.24 National Grid makes its contribution to the management of future operating margins by providing information over various timescales in its Seven Year Statement (SYS) and Winter and Summer Outlook reports[2]. This information is intended in part to help energy market participants evaluate the need for investment in new electricity generation balanced against the prospects for electricity demand. We believe it is helpful at this stage to explore the issues around future operating margin assessment using our 'Gone Green' scenario in our familiar 'Winter Outlook' style.

2.25 Our analysis highlights that in order for stakeholders to assess the implications of future electricity operating margins they will need to come to a view on:

- The contribution of renewable generation;
- Flows across interconnectors;
- The required operating reserve;
- Energy consumers' reaction to price signals; and
- The value of specific measures which have the effect of reducing peak electricity demand compared to the value of additional electricity generating capacity.

[2] The SYS, Winter Outlook and Summer Outlook can be found at: http://www.nationalgrid.com/uk/Electricity/SYS/

Interactions with Energy Markets

2.26 We have based our thinking on an assumption that electricity market participants continue to take actions to minimise their exposure to 'imbalance' (the difference between the energy they have contracted to produce and/or consume and the energy actually produced or consumed, whether due to forecast error or plant 'failure').

2.27 We will continue to be reliant on this market participant action to operate the transmission networks efficiently, increasingly so as installed wind capacity increases. It is important though that market participants give us their views on whether the necessary operational capacity and flexibility will be available to us.

2.28 We expect there to be further debate over our assumption that markets will 'balance' and the mechanisms and obligations which allow security of supply objectives to be met.

3 Introduction

Purpose of Consultation

3.1 Targets for energy production from renewable sources and carbon emission reductions mean there will be significant changes in the:

- Location, type and size of generators connected to the electricity transmission systems in Great Britain and offshore; and
- Short and long term trends in consumers' demand for electricity.

3.2 This consultation document seeks to articulate the range of new technical challenges we will face in operating the transmission networks which are triggered by these changes in electricity generation and demand.

3.3 The document also explores how these challenges could be addressed and seeks views on:

- National Grid's assessment of the potential size and timescales of the challenges;
- How these challenges could be addressed using existing technologies and commercial arrangements; and
- The opportunity for new technologies to provide new services.

Scope of Consultation

3.4 This document focuses on the short term technical and operational issues which National Grid deals with currently under its licensed activity of System Operator for the electricity transmission networks in Great Britain, and in the near future, offshore.

3.5 We have used certain assumptions concerning energy market participants' behaviour as it affects operation of the transmission systems as a basis for our analysis and thinking. These are based on recent and historic experience.

3.6 We believe that it is useful at this stage for us to address these specific 'System Operator' issues whilst acknowledging that wider questions will persist over how energy markets can best be developed. This development may in turn impact on the assumptions we should be making about market participants' behaviour in the future.

3.7 In practical terms, this means that this document concentrates on:

- The 'Short Term Operating Reserve' required to manage uncertainties in the period approximately 4 hours ahead of real time;
- The way that electricity generation and demand can be balanced within this period; and
- The way that the electricity transmission networks can be configured and reconfigured in this period.

Objectives and Approach

3.8 Our views and analysis as presented in this consultation are guided by three key policy objectives:

- To enable the attainment of government climate change targets;

- To maintain current levels of security of supply in our residual balancing role;
- To minimise cost to consumers.

3.9 For the purposes of this consultation, we have used our 'Gone Green' scenario at 2020 to help quantify particular operational issues. This approach is consistent with that taken by the Electricity Networks Strategy Group chaired jointly by Ofgem and DECC.

3.10 As far as is possible, we have tried to articulate issues in a way which is relevant to the many other credible scenarios which may be used as a basis of analysis elsewhere.

Responding to This Consultation

3.11 We would welcome responses (in specific or general terms) to the questions raised within this document from all interested parties. We are particularly interested in the views of parties who have a stake in:

- Future energy demand volumes and patterns;
- Future generation development (scale and technology);
- Provision of Balancing Services; and
- New network and energy management technologies.

3.12 If you wish to respond to some or all of the questions raised in this document, please reply to us at Operating.2020@uk.ngrid.com by 14th August 2009.

3.13 Responses will be published on our website unless they are marked as confidential. These will be used as the basis of a report which National Grid will publish in autumn 2009, which will set out actions and next steps as well as providing an update on related areas of work.

4 Background

Our thinking as presented in this consultation document has been formulated in the context of government policy objectives, existing market mechanisms and our licence obligations as operator of the electricity transmission networks in Great Britain.

Further and related work is underway which we believe is relevant and we have therefore described this below.

Climate Change and Emissions Target Context

4.1 The UK Government is required to reduce greenhouse gas emissions by 80% by 2050 under the Climate Change Act. The draft UK Renewable Energy Strategy is aimed at supplying 15% of energy from renewable sources by 2020.

4.2 Prior to these dates, implementation of the Large Combustion Plant Directive will mean that 12GW of generating capacity in use today will need to stop generating before 2016. We may see further early generation closures driven by the proposed Industrial Emissions Directive.

4.3 Our 'Gone Green' generation background and demand forecasts have been validated against these targets as currently proposed. We have therefore accounted for the significant contributions from the heat and transport sectors, as well as advances in energy efficiency, when forming a view of the electricity sector's contribution within 'Gone Green'.

The 'Gone Green' Scenario

4.4 The analysis and discussion presented in this document is based on our 'Gone Green' scenario. We believe this scenario illustrates a set of plausible outcomes for 2020 and beyond which are useful in illustrating the challenges we face, even though other scenarios are equally plausible and consistent with the relevant policy objectives.

Generation Type	2009/10	2020/21
Coal	28.4	19.8
Nuclear	10.4	6.9
Gas	27.5	34.6
Oil	3.4	0
Pumped storage	2.7	2.7
Wind	2.4	29.4
Interconnectors	2.1	4.2
Hydro	1.0	1.1
Other	1.3	2.5
Total	**79.2**	**101.2**

Table 1: Total Transmission Contracted Generation Capacity in 'Gone Green'

4.5 Table 1 above illustrates the transmission contracted generation mix featured in our 'Gone Green' scenario in 2020. Table 2 shows the electrical energy output from all renewable sources (including 'embedded') within the scenario.

4.6 Within our 'Gone Green' electricity demand forecasts, we have included allowances for economic growth, growth in the number of electric vehicles and the electricity demand from applications such as heat pumps. This growth is partially offset by greater energy efficiency. The scenario also incorporates an increasing contribution from embedded generation which has the effect of reducing the growth in demand seen on the electricity transmission networks. Peak demand levels are therefore broadly similar to today's out to 2020 under this scenario.

4.7 Under 'Gone Green', we see 36% of the total electricity demand being met from renewable sources by 2020. This combined with our view of the heat and transport sectors results in the target of a 15% share of the EU 2020 target being met along with maintaining the 'flightpath' of emissions reduction to 2050.

Renewable Energy in 'Gone Green'	
Wind Capacity and Energy	19.4GW offshore, 12.9GW onshore, 98TWh of energy generated
Other Renewable Energy	49TWh (biomass 18, hydro 6, Tidal & Wave 6 & other 19 {incl CHP and solar PV})
Total Renewable Energy	147TWh
Renewable Energy Proportion %	36%

Table 2: Renewable Energy Contribution to Electricity Generation in 'Gone Green' at 2020

4.8 The electricity generation and demand background in 'Gone Green' is explored further in Section 5.

Electricity Market Arrangements

4.9 The electricity market arrangements within Great Britain are designed to promote trading of wholesale electricity between electricity generators, suppliers and traders at a bilaterally agreed price.

4.10 Electricity consumers commit to paying for their electricity through their agreement with an electricity supplier. Electricity suppliers then need to source enough electricity to meet the electrical energy their customers will consume, as the energy settlement and billing processes will allocate their customers' metered demand to their 'energy account'. They source this through bilateral trades with other suppliers and generators or from their own generation portfolio.

4.11 Electricity suppliers are incentivised to trade volumes of electricity to satisfy consumer demand because they know that any shortfall (or excess) will have to be met by other parties as co-ordinated by National Grid acting as the 'residual balancer' within its role as System Operator. The costs of National Grid's actions in doing this are reflected in a set of dual 'imbalance prices', where the 'imbalance' is the difference between what all parties have contracted to buy and the demand that consumers actually take in each half hourly period. This imbalance is normally small in comparison to the total electrical energy generated and consumed (at less than 3%).

4.12 The level of exposure that market participants have to these prices is dependent on the degree to which they have been able to balance their bilateral electricity contractual positions (ie did they buy enough, or too much in each half hour).

4.13 As the System Operator is likely to have to utilise the marginally priced services to resolve this residual imbalance, it should not be economically attractive for market participants to rely on this route to procure the majority of electricity required to meet their customers' needs. As such, imbalance price signals should encourage suppliers to balance their contract positions as accurately as possible and for generators to sell suppliers the energy they require in the forward and spot markets.

4.14 Thus a supplier is incentivised to buy its electricity up until the point where they perceive it is economically less efficient for them to do so than for the System Operator to meet the rest of demand on its behalf. This model aims to incentivise market participants to balance the vast majority of electricity required by customers and produced by generators.

National Grid's role as System Operator

4.15 National Grid's Transmission Licence contains a condition which states that it "shall co-ordinate and direct the flow of electricity onto and over the GB transmission system in an efficient, economic and co-ordinated manner".

4.16 This condition (C16-Procurement and Use of Balancing Services) governs the way that National Grid procures 'Balancing Services'. These are the services that both generation and demand can provide to us to help manage the networks and balance generation and demand in real-time.

4.17 These services are paid for through a charge on Transmission Users (the Balancing Services Use of System charge) and ultimately feed into electricity consumers' energy bills. Hence National Grid has been given a clear Licence obligation to procure these services efficiently. A full description of these services is given on the National Grid website under the heading Balancing Services[3] and summarised in Appendix D.

4.18 Overall, the Licence Condition establishes three important principles:

- To treat providers of Balancing Services equitably – Non-Discrimination;
- To act in accordance with set principles and criteria – Consistency; and
- To report and provide information on our actions – Transparency.

4.19 National Grid's reporting obligations recognise the need to differentiate between actions taken within the 'Balancing Mechanism' or 'BM' (the framework defined with the Balancing and Settlement Code which converts National Grid's actions into the components used to set the dual imbalance prices described above) and actions taken 'outside the BM'.

[3] Located at :http://www.nationalgrid.com/uk/Electricity/Balancing/

4.20 These actions taken 'outside the BM' include requests made of small and demand side Balancing Service providers as well as actions taking prior to the Balancing Mechanism window (which extends from 60 to 90 minutes ahead of real-time). Actions are necessary prior to the Balancing Mechanism window, at a point known as 'Gate Closure', because some services can only be delivered with more than 90 minutes notice, the most conspicuous example being the need to start up a coal or oil fired generator from a cold condition.

4.21 Actions taking 'outside the BM' are accounted for in imbalance prices through the 'Balancing Service Adjustment Data'. This is used to reflect the costs of actions 'outside the BM' within imbalance prices. This means that all of National Grid's balancing actions are accounted for in imbalance prices.

4.22 Because National Grid is free to develop new services and new ways of procuring them where it is economic and efficient to do so, the licence obliges us to report annually on the services we have procured. These reports as well as additional information are accessible on the National Grid website again under Balancing Services.

Procurement of Balancing Services for Operating Reserve

4.23 In procuring Balancing Services, National Grid needs to make a number of decisions regarding the volume of services it procures and the timing of procurement. There is a trade off between the price reductions that can be achieved buying services over a longer period (and thus giving providers certainty over revenue) and the need to preserve competition in the long term.

4.24 We are also conscious of the need to avoid distorting wholesale market mechanisms. If we were to buy too large a volume of services, we risk sterilising capacity which could be used by wholesale markets more efficiently.

4.25 This need is an important consideration in procuring services in order to meet an 'operating reserve' requirement. By operating reserve, we mean the ability to adjust generation or demand to cater for both the difference in actual electricity demand compared to our forecast and the difference between planned generation output and actual generation output. Our operating reserve requirement is driven therefore by demand forecast errors and generation forecast errors.

4.26 We have developed a consistent process by which we buy operating reserve services, to meet a 'Short Term Operating Reserve Requirement' (STORR). This requirement is set at the level of reserve needed at four hours ahead to meet a Loss of Load Expectation equal to 1. This means that we undertake a statistical analysis of generation and demand forecast errors as measured over a four hour period and derive a requirement which caters for these forecast errors for all days of the year apart from 1. Hence this is described as satisfying a 1 in 365 requirement.

4.27 We seek to maintain operating reserve at this level and a well established system of information and warnings is in place to inform all interested parties if this requirement is unlikely to be met, which the industry has a good track record of responding to.

4.28 Where we meet some of our operating reserve requirement by buying it in advance, this is driven by an economic assessment which indicates that it is more efficient to do so.

Related Work

4.29 There is a great deal of interest in the issues that face the electricity networks over the next decades and many pieces of work which are relevant to or interact with those raised in this document. The following section outlines related pieces of work that National Grid is currently involved in.

Transmission Access and GB Queue Management

4.30 National Grid has been working, with the Transmission Owners in Scotland in particular, to advance the connection of new renewable generation projects in Scotland resulting in the advancement of some 450MW of generation to date.

4.31 The industry has also been engaged extensively in the development of new transmission access arrangements.

4.32 These two separate initiatives echo a general requirement on the transmission networks to deliver more. The extent to which this is delivered by traditional infrastructure enhancement or a reliance on short term and real time control actions will be critical in determining the complexity of system operation into the future.

Network Investment Scenarios

4.33 National Grid, Scottish Power Transmission and Scottish Hydro Electric, in co-operation with DECC, Ofgem and other industry stakeholders have formed the Electricity Network Strategy Group. The ENSG are considering a range of network reinforcements to support the connection of new generation in advance of firm commitment to connect.

4.34 This approach differs from the existing arrangements, where the Transmission companies reinforce on an 'invest and then connect' basis, where prospective connecting parties would need to provide some financial commitment. The aim is to undertake network investment in parallel with generation development, rather than sequentially as now.

4.35 The extent to which strategic investments are undertaken, will influence the level of complexity associated with accommodating additional generation in advance of wider network reinforcement required to meet SQSS standards.

Market Considerations

4.36 The characteristics of renewable and new generation technologies present challenges for the energy markets in a number of areas.

4.37 National Grid is participating in a multi-client study looking at the impact of intermittency on the wholesale electricity market. This study is based on applying 8 historical wind / demand years at an hourly resolution to future years with generation backgrounds that would lead to meeting 2020 renewable targets and 2050 CO_2 targets. There will be a number of useful outputs to this study however, from a network operation perspective these are concerned with:

- The ongoing and increased availability of flexible generation to provide balancing services and contribution to capacity margin;

- The level of dependency on and cycling of CCGTs and subsequently the impact on the Gas Network;
- The reserve challenge from supporting the increased wind and renewable challenge;
- The scope and value of more active demand management and storage; and
- The benefits that may accrue from greater interconnection.

SQSS Review

4.38 The Security and Quality of Supply Standard (SQSS) describes the planning standards for investment and standards for planning and operating the system real time.

4.39 The GB SQSS Fundamental Review[4] was proposed in November 2008, aiming to seek solutions to integrate new generation technologies such as wind and other renewable generation into the electricity networks. It recognises that there are a wide range of initiatives currently under consideration that could impact on the SQSS.

4.40 In addition the live SQSS 'Review of Infeed Loss Limits' (GSR007[5]), is considering the accommodation of infrequent infeed losses up to 1,800MW.

[4]More information is available at http://www.nationalgrid.com/uk/Electricity/Codes/gbsqsscode/fundamental/
[5] SQSS review GSR007 is listed at: http://www.nationalgrid.com/uk/Electricity/Codes/gbsqsscode/reviews/index.htm

5 Developments in Electricity Generation and Demand

There are numerous potential changes to the way electricity is generated and consumed within Great Britain over the next decades. It is important to quantify these changes within a credible timeline before assessing their impact, so we have used our 'Gone Green' scenario to prioritise our assessment of developments in generation and demand.

In this section we explore the extent to which generation and demand can be predicted or forecast and the technical flexibility which could be useful to us in operating the networks. We go on to assess how these characteristics and capabilities affect operation of the transmission networks in the subsequent sections of this document.

Electricity Generation

5.1 Our 'Gone Green' Scenario presents a picture of the electricity transmission networks with a significantly different profile of generation connected to it compared to today as illustrated in Figure 1.

5.2 In 2020 it shows generation from wind at a capacity of 29.5GW compared to 2.4GW in 2009/10, Gas fired generation capacity at 34.2GW compared to 27.5GW in 2009/10 and Coal fired generation capacity dropping from 28.4GW to 19.8GW in the same timescales.

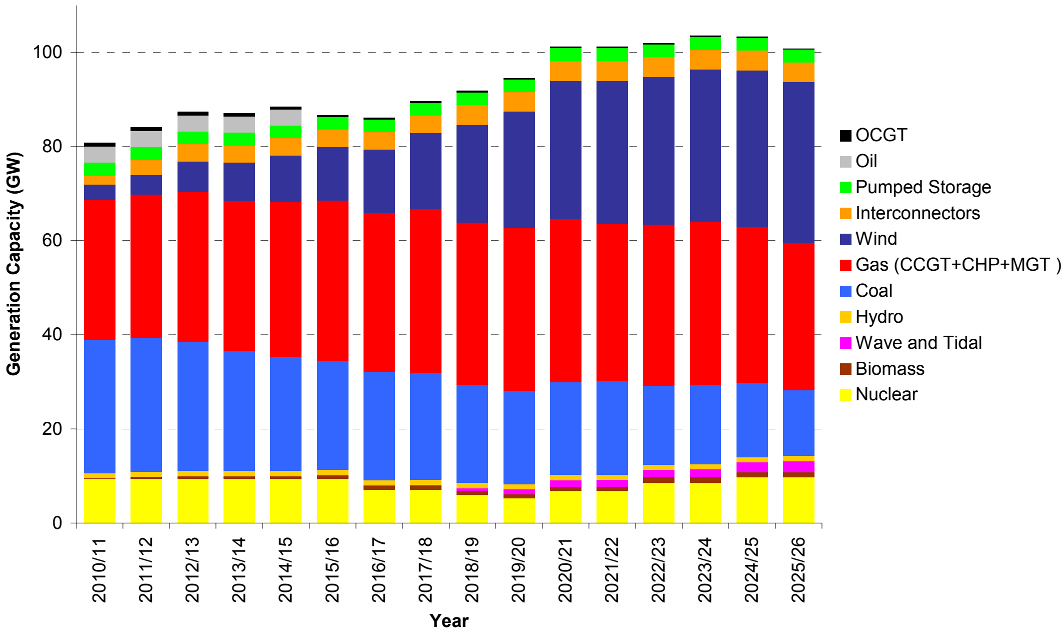

Figure 1: Generation capacity in 'Gone Green'

5.3 'Gone Green' assumes a Nuclear generation capacity of 6.9GW in 2020 compared to 10.5GW in 2009/10. The scenario anticipates the closure of existing nuclear stations and the start of a replacement programme in the latter part of the next decade. Interconnectors have a bigger role under 'Gone Green'. Some 'clean-coal' development is also assumed.

5.4 Growth in embedded generation, giving rise to some 15GW of embedded generation (including on-site CHP) in 2020 is also included in our 'Gone Green' generation mix. Note that Figure 1 shows transmission connected and larger scale embedded generation only.

5.5 A number of new or developing generation technologies emerge and become significant in this scenario. The following section discusses the impact that developments in generation could have on operation of the transmission networks from the aspects of flexibility and controllability and seeks views on the assumptions that National Grid should make regarding their operation.

Wind Generation

<u>Forecasting Output</u>

5.6 In order to develop an understanding of the characteristics of wind generation, it is first necessary to understand the characteristic of a wind turbine. A typical characteristic is highlighted below in Figure 2.

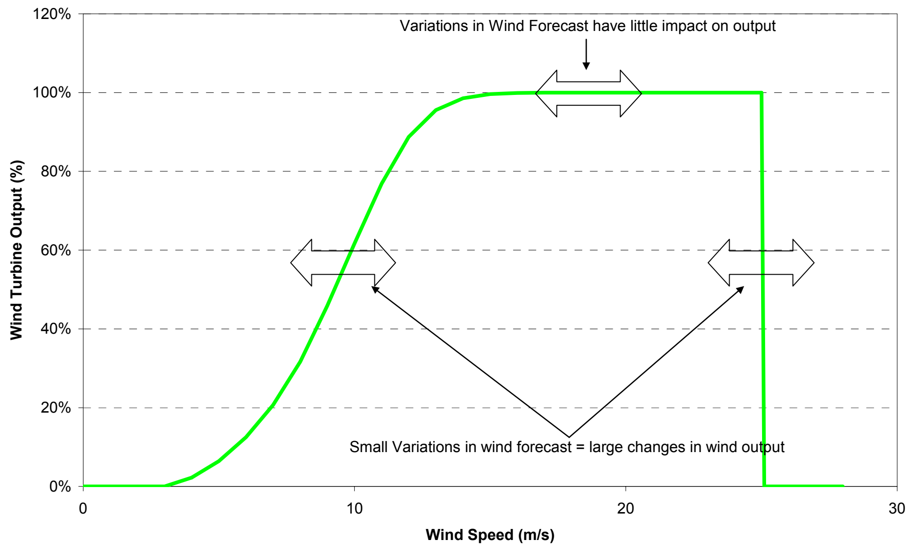

Figure 2: Typical wind turbine power curve

5.7 A typical wind turbine will generate electricity from around 4m/s (~9mph) and increase output with increasing levels of wind from this point. Full output from the wind turbine is obtained at around 15m/s (~34mph). Above 25m/s, a wind turbine will cut out. The wind turbine will restart again once wind speeds drop. Typically, after cut-out a wind turbine will restart after 3 minutes of wind speed being below 20m/s. Note that these thresholds are likely to be higher in turbines designed for operation offshore.

5.8 At various regions on the power curve, small variations in wind speed result in large changes in output which has implications for predicting the output from a wind farm. There is also a region where variations in wind speed have no impact on the output of the wind turbine. If a wind farm has many wind turbines, the effects are likely to be smoothed.

5.9 Our expectations of the output from wind generation can be informed by this power curve and information on wind speeds. In setting operational requirements we tend to rely on measured output, hence we go on to discuss our analysis of actual wind generation within Great Britain.

5.10 Using the metered output data available to us we have calculated an average load factor per month and per hour for wind generation which can be plotted for the whole year. This is shown below in Figure 3 where month is on the y-axis and hour of day is on the x-axis. The colour intensity indicates load factors with blue signifying load factors below 30% whereas yellow to red represent load factors above 30%.

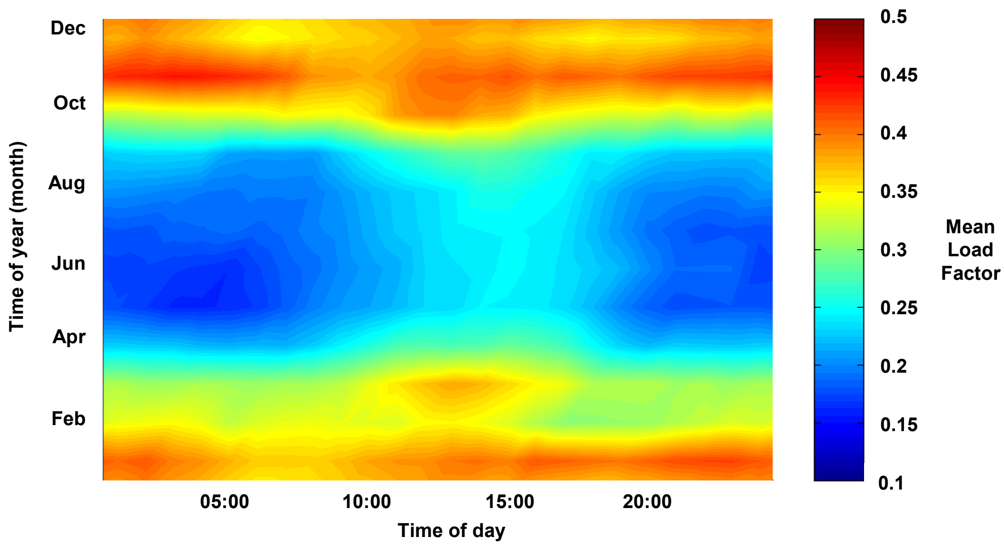

Figure 3: Recorded wind load factors 2008

5.11 From Figure 3 it is evident that winter load factors are higher than summer. The lowest average load factors are overnight in summer periods which corresponds to minimum demand conditions. Higher load factors are observed in the winter period which corresponds to high demands.

5.12 The main points we have derived from our data are:

- Average annual load factor is ~30%;
- Average winter load factor is ~35%; and
- Average summer load factor ~20%.

5.13 However, we also see a high degree of variation around these average load factors. Looking at the statistical distribution of our wind output data we have also observed that:

- Incidences of low wind output have occurred at all times of the year and across any hour in that day. By looking at the 5th percentile (the lowest 20th of measured values), we have seen that load factors of less than 1% are plausible at all times of year.
- High average load factors (>90%) occur at times across the winter.
- Across the summer period average load factors of 75% have been observed in the 95th percentile (the highest 20th of measure values).

Forecasting Variation in Output

5.14 In operating the transmission networks we need to assess the differences we may see between forecast generation output and the actual generation delivered, for all types of generator. We have therefore developed in-house generation output forecasting tools specifically for wind, and expect to continue our research and development in this area as well us introducing third party packages.

5.15 The way that wind output can vary throughout a day can be demonstrated by looking at what wind is doing now compared to 4 hours ahead of time (as used in 'persistence forecasting'). Similar to the style of the previous graph, Figure 4 shows 'root mean square errors' (a standard measure of the difference between predicted and observed values) at 4 hour ahead on the current metered wind fleet.

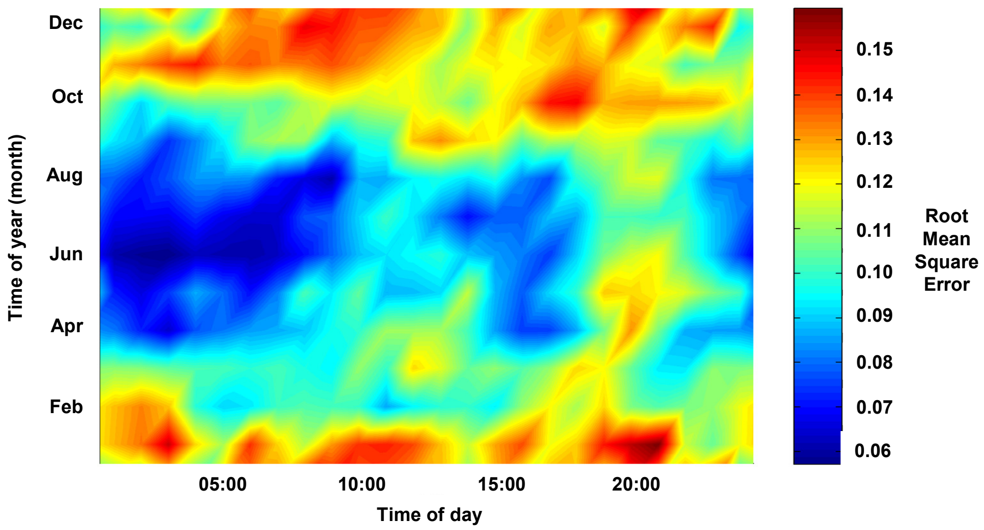

Figure 4: Persistence errors in forecasting wind

5.16 The pertinent points from the perspective of wind forecasting are:

- Wind forecasting errors are higher with higher wind outputs.
- There is evidence that errors are higher around dawn/dusk, coincident with demand changing rapidly or when the peak demand is recorded.

5.17 At National Grid we take into account persistence forecasting of wind along with forecasts from other tools to forecast wind generation output. The wind forecasting error for the metered fleet using these techniques is on average 10% rms of capacity. This parameter is important as it feeds into our calculations which determine the amount of reserve we require to cater for wind forecasting uncertainty.

5.18 It should be noted that our current dataset is from around 1.5 GW of wind farms that are predominantly located in Scotland. As dispersion in the metered wind fleet increases across Great Britain and we introduce new forecasting tools, it is anticipated that forecasting errors can reduce from current levels. Also, as we get the opportunity to analyse more metered output data, we should be able to quantify how forecasting errors vary under different wind conditions and different wind generation configurations.

Question 1. How do National Grid's observations align with your experience or modelling of wind generation?

Flexibility and Controllability

5.19 There are three main varieties of wind turbine generation technology either in operation or construction. The plain induction generator was the first variety to be installed in large numbers within Great Britain.

5.20 The Double Fed Induction Generator (DFIG) and full converter turbine have quickly become the choice for large utility scale wind farms as they offer increased flexibility, controllability, variable speed operation and better energy capture. These both employ power electronic converters to allow independent control of real and reactive power injected to the system.

5.21 The result is potentially highly flexible plant with a very controlled and stable frequency response capability. Our experience suggests these wind farms can have a minimum generation level of between 0 and 20% of their full output, provide up to 30% primary, secondary and high frequency response and have a response dead time of between approximately 0.5 and 1 second.

5.22 This technical ability is there for future use when high wind penetration makes it economically desirable. However, we have not seen this flexibility being offered within the Balancing Mechanism to date.

5.23 Future wind development could involve the use of permanent magnet and super-conducting generators. These specifically relate to further improvements in the mechanical and energy capture side of the turbines and are still likely to be connected to the grid via a full converter arrangement.

5.24 The use of power electronic conversion systems also has the effect of de-coupling the mechanical rotating components of the generator from the transmission system. This means that that they do not contribute the inertia that conventional rotating electrical machines do, and therefore do not help to decelerate any change in system frequency. More widespread use of this technology could therefore impact on the volume of frequency control services which National Grid will need to use.

Question 2. Are we correct in assuming that wind generation is controllable enough to assist in operating the networks?

Supercritical Coal

5.25 Supercritical Coal (forming part of a 'Clean Coal' installation) is a well developed generation technology which has been implemented internationally during the period when the development of generation across Great Britain has focussed on natural gas as the primary fuel. Our experience of supercritical coal is therefore limited but we have set out here our view of the technical flexibility of this technology.

5.26 The higher pressures of the supercritical boiler takes steam conditions beyond those possible in sub-critical boilers, increasing efficiency and reducing rates of carbon emission. Supercritical efficiency values are typically 45% compared to a best in class value of 38% for sub-critical boilers.

5.27 The technology is not new and it is utilised extensively across the world being commercially available in unit sizes of around 800MW (compared to the largest current UK coal-fired unit capacity of approximately 650MW).

5.28 Unlike conventional drum-type boilers there is no inherent energy storage within a supercritical boiler. The boiler is also a 'once-through' system giving a much longer steam generating path with no opportunity to re-circulate water or steam with insufficient energy.

5.29 This has meant that supercritical coal plant has been labelled as inflexible and non-responsive. This is not necessarily the case, with major manufacturers confirming that the GB Grid Code secondary frequency response capability requirement can be met and exceeded.

5.30 We therefore expect that any supercritical coal generators connected to the transmission system in Great Britain will be as flexible in response to balancing instructions (normally requiring a ramping capability of between 5 and 10 MW per minute) as the majority of the current coal fired fleet and will be capable of providing frequency response services.

5.31 However, the GB Grid Code frequency response requirement of 10% of capacity delivered within 10 seconds is seen as particularly challenging and will require development to standard designs if it is to be met.

Question 3. Should National Grid assume that Supercritical Coal generators will provide some flexibility in operation which will assist in operating the networks?

New Nuclear Generation

5.32 The Magnox, Advanced Gas Reactor and Pressurised Water Reactor nuclear power station designs implemented within Great Britain are traditionally regarded as inflexible in their mode of operation.

5.33 We have however observed the frequency response capability of the Pressurised Water Reactor design, and note the load following capability demonstrated by nuclear generators within Europe.

5.34 We believe that the inflexibility we are used to is largely driven by economic considerations but have assumed within our scenario planning that the nuclear generators will operate at as high an output as possible and are unlikely to offer flexibility unless significantly stronger price signals drive this behaviour.

Question 4. Should we assume that Nuclear generators will continue to concentrate on base-load operation?

Carbon Capture and Storage (CCS)

5.35 Carbon capture and storage technology could be applied to the supercritical coal and gas fired generations. In the case of coal, the process would operate post combustion. For gas, CO_2 could be captured both before and or after combustion.

5.36 No commercially available CCS plant exists at the scale required at the moment so it is difficult to quantify the impact that CCS could have on generator flexibility. It is possible that flexibility could be restricted by any throughput limits in CCS equipment but at this stage we see no reason to assume that unnecessary limitations could not be avoided if there was sufficient justification to do so.

Question 5. Is it likely that Carbon Capture plant will impose material restrictions on the operation of electricity generating plant?

Tidal Generation

5.37 Tidal Barrage and Tidal Stream technologies could be applied at a number of locations around the coast of Great Britain. A number of operating modes are possible (ebb generation, flow generation, pumping) including elements of energy storage. The degree of flexibility provided by this generation technology is limited in most designs.

5.38 However, generation output from tidal sources is likely to be highly predictable and hence should not have a detrimental impact on generation output forecasting.

5.39 Larger scale developments would have an impact on the operation of the transmission networks. When changes in tidal generation output did not match changes in consumer demand compensating balancing actions would be required either by the energy market or through System Operator action.

5.40 It should be noted that Severn Barrage development does not feature in our 'Gone Green' scenario by 2020. We intend to engage fully in the Severn Tidal Power consultation process, as initiated in the Phase one Consultation document of March 2009, in terms of transmission infrastructure requirements, and energy balancing and network control issues.

Question 6. Are there other aspects of tidal or marine technologies that we should consider further at this stage?

Gas Fired Generation

5.41 There is currently upwards of 25GW of gas fired generation capacity operating in combined cycle connected to the GB Transmission System. We have almost two decades of success in making use of the services offered by CCGT operators in operating the transmission networks.

5.42 The 'Gone Green' scenario features 34GW of gas fired generation capacity. This means that a larger amount of a flexible generation technology available to us today would be available to assist in operating the networks in 2020, but expected to run at a lower average load factor than now (note that 'Gone Green' does not included the impact of any post LCPD emissions limitations). The extension of our reliance on gas does however raise some specific issues which are of note but outside the scope of this consultation:

- A significant proportion of gas fired generation could be low merit and low load factor changing the underlying economics of this type of generation;
- Gas fired generation will also need to operate more flexibly in response to changing wind conditions which will in turn impact on:
    - CCGT operations and maintenance; and
    - Operation of the gas networks.

Question 7. Are there other restrictions we should consider in developing a view on gas fired generator flexibility?

Sub-Critical Coal and Oil

5.43 'Gone Green' incorporates the anticipated closure of some 12GW of Oil and Coal Fired generation which has opted out of the Large Combustion Plant Directive by 2016. The scenario then assumes that the remainder of the existing coal fleet (~18GW) operates until it is no longer economic for individual stations to do so. As well as a loss of capacity, these closures will remove some flexibility from the generation fleet which will need to be provided by other sources.

5.44 A consequential effect of the closure of these power stations is the closure of the associated auxiliary gas turbines which currently offer reserve services and Black Start capability which are discussed further later.

Electricity Demand

Trend

5.45 Our Gone Green scenario assumes that peak electricity demand remains at approximately 60GW up to 2020. There are a number of drivers behind the profile we have used.

5.46 The scenario assumes for example that the increased demand for electricity triggered by economic growth is offset by electrical energy efficiency measures by 2020. Further increases in electricity demand are triggered by the use of electricity in transport and in applications such as heat pumps. This, in turn, is largely offset by the anticipated growth in embedded generation (the smaller scale generation generally not visible to National Grid).

5.47 Clearly, a variety of forecasts can reasonably be adopted depending on the weight and volume given to the demand drivers outlined above. Economic growth is of particular interest at the moment. Specific demand efficiency measures may also have a further reducing impact on demand whilst any lag in investment in embedded generation would serve to increase the demand we see. For the purposes of this exercise however we have chosen to adopt a single demand scenario to ease the illustration of the effects we believe it is important to highlight.

Question 8. What is your view of future electricity demand growth and how would you quantify any uncertainty around this?

Demand Side Developments

5.48 There are three fundamental but emerging demand side technologies which require consideration when discussing electricity demand in 2020:

- Smart Metering: more sophisticated devices and communications infrastructure could aid commercial development of demand management technologies by providing tariff, billing and energy management services.

- Electric vehicles: these offer the opportunity to reduce emissions from the transport sector and might be key to meeting the 2050 greenhouse gas target.
- Embedded Generation: this includes the micro renewable and micro CHP technologies which are likely to become more prevalent and when viewed from a transmission perspective, tend to reduce the amount of electricity demand we see.

5.49 Taking a long-term perspective, these technologies will tend to flatten the daily demand profile as seen from the transmission system. In the case of electric vehicles, overnight demand could to rise in comparison with the daily demand peak. Demand side technologies might be expected to reduce overall daily consumption (by increasing price elasticity of demand) and also to shift load away from the peak. Embedded generation (particularly CHP) could also change electricity demand at peak.

5.50 'Smart', Electric Vehicles and Embedded generation are discussed further bellow.

Question 9. Are there other developments which will change the way that electricity will be consumed in 2020 that we should consider?

Smart Metering and Passive Demand Side Management: the 'Smart Meter'

5.51 A smart meter is a device for the domestic environment that can measure and display real time energy utilisation and costs, and can record energy consumption in, for example, half-hourly intervals. A ‘minimum package’ of smart meter will comprise a convenient method to display information in a prominent location such as in the kitchen. More sophisticated solutions include displays integrated with the television, personal computer or mobile phone amongst other devices.

5.52 When armed with real-time information on energy price and usage, consumers might become more involved in their energy purchase decisions. Rather than running a washing machine during the day during a ‘high price period’, the consumer might choose instead to run the washing machine overnight (and on a more energy efficient programme). This may lead to some reduction in household aggregate electricity demand as well as a change in shape of the demand profile.

5.53 The extent to which consumers can shift load is limited to those appliances whose demand for energy can be conveniently decoupled from the moment of use. Heating of hot water and night storage heating are both examples in which electrical energy is converted to, and stored as heat.

5.54 Power stations which service peak demand will tend to be more expensive, less efficient and more polluting than those stations which service baseload and are more greatly utilised. Moreover, by helping to manage peak demand, the existing transmission and distribution infrastructure can be used as efficiently as possible.

Smart Metering and Active Demand Side Management: the 'Smart Home'

5.55 It may be possible to deliver greater energy savings than those achieved by manual consumer intervention by automating appliances’ response to price signals. Clothes washing, air conditioning and heating could be set to avoid peak hours in a day or the appliance to run overnight - dependent upon the consumer's preference.

5.56 This simple model does not require an external 'controlling mind'. Appliances can make decisions on their energy usage based solely on a price signal derived from the smart meter or internet.

5.57 Balancing Services, such as frequency response can also be delivered without recourse to a 'command and control' function. For example, a frequency-sensitive load management circuit can be installed within appliances (such as refrigerators) during manufacture. We discuss this further in Section 8. However, we believe that the Balancing Services provided by this technology would be more valuable if integrated within the dynamic world of the smart grid, described below.

Smart Metering and the 'Smart Grid'

5.58 The term 'Smart Grid' is often applied across our industry. The transmission networks are currently equipped with real time measurement and intelligent, automatic control systems and hence to a greater extent can already be described as 'smart'.

5.59 The addition of a two way communication facility to appliances, meters, distributed generation and associated network technologies could together provided new benefits. 'Gone Green' describes a world in which Distribution Network Operators (DNOs) face an increasing demand for network capacity, particularly from heat pumps and electric vehicles. Active load management affords the opportunity to balance new investment in networks against managing existing capacity in real time. Consequently, the smart metering infrastructure and the IS systems which sit behind it, could be important tools in active network management in distribution and transmission.

5.60 We believe that Suppliers, DNOs new 'aggregator' players and National Grid as System Operator will take an interest in and value the services that active demand and generation management can bring.

Question 10. Do you share our view that distribution companies, suppliers, aggregators and ourselves will all value and compete for demand side services?

Electric Vehicles (EVs)

5.61 Professor Julia King, in her report[6] on low carbon transport, sets out the challenge for the transport sector if the UK is to meet its 2050 greenhouse gas reduction target. Our 'Gone Green' scenario recognises the efforts of Government to promote electric vehicles and includes projections for electric vehicles in 2020.

Charging electric vehicles: Environmental Considerations (EVs)

5.62 Electric vehicles, if charged overnight today, might derive their energy from either coal fired or gas fired plant. By 2020 however, in 'Gone Green', the overnight marginal plant is likely to be gas-fired combined cycle plant. In the summer, low overnight demand coupled with favourable windy conditions, might result in the marginal plant being renewable wind.

[6]Reports available at: http://www.hm-treasury.gov.uk/king_review_index.htm

5.63 It is generally accepted that the 'well to wheels' carbon emissions of an electric vehicle fuelled ultimately by a transmission-connected combined cycle gas turbine will emit less carbon dioxide than one fuelled from petrol or diesel. This is partly because the charging and energy conversion process in an EV charged from the domestic mains is more efficient than oil refining and internal combustion. However, natural gas is also a less carbon intensive fuel than petrol/diesel and will emit less carbon per unit of energy converted.

Electric Vehicles in 'Gone Green'

5.64 Whilst 'pure' plug-in electric vehicles are comparatively rare, the hybrid electric vehicle (HEV) (without a plug-in facility) is more common. We view these vehicles as a precursor[7] to plug-in hybrid electric vehicles (PHEVs) which would be able to charge from a mains electricity socket overnight and be capable of running for some distance on an electric charge only. We also see greater interest in the pure electric vehicle (EV).

5.65 Our assessment of vehicle demand appropriate to 'Gone Green' was guided by a recent report published by BERR and Cenex[8]. This comprehensive report described about 1.5 million vehicles in the UK for a 'high' scenario. We have adopted this number of vehicles for 'Gone Green', but take a more pessimistic view on energy efficiency than the authors, and have accounted for a fleet equivalent to a demand 6 TWh annually.

Question 11. Are our assumptions around the number of electric vehicles in 2020 reasonable?

The role of Smart Metering/Grid in Electrified Transport

5.66 For electric vehicles to succeed to mass-market levels *and* enjoy the greatest environmental and economic benefits, the charging process must be co-ordinated such that charging is targeted at periods when electricity prices are low. A failure to do this would increase peak electricity demands unnecessarily, triggering a requirement for more generation and network infrastructure.

5.67 A 13 Amp domestic mains socket can provide 3 kW of power, and would take around 7 hours to charge a 22 kWh battery. On the assumption that an electric vehicle can travel 3 miles on one kWh of charge, an overnight charge would provide a 60 mile range. If the car were to travel 12,000 miles per year, that would be an average of 34 miles per day (although the average daily commute in Britain is less than this). So the 22kWh battery would be about half full before charging each night.

5.68 The resulting overnight charging profile might resemble that shown in simple terms in Figure 5 below.

5.69 However, without an appropriate price signal and/or co-ordination consumers would be ambivalent as to the time of day to charge. Vehicles could be plugged in and charge at full power when the driver returns from work – just at the time that the UK is experiencing peak demand. Moreover, the vehicle

[7] See for example: http://www.dailymail.co.uk/sciencetech/article-1054211/The-new-greener-Prius-plug-power-socket.html

[8] Report available under the heading 'Related Documents' at: http://www.berr.gov.uk/whatwedo/sectors/automotive/electrificationoftransport/presentations/page48841.html

will generally be charged from the least fuel efficient and most marginal (and expensive) plant.

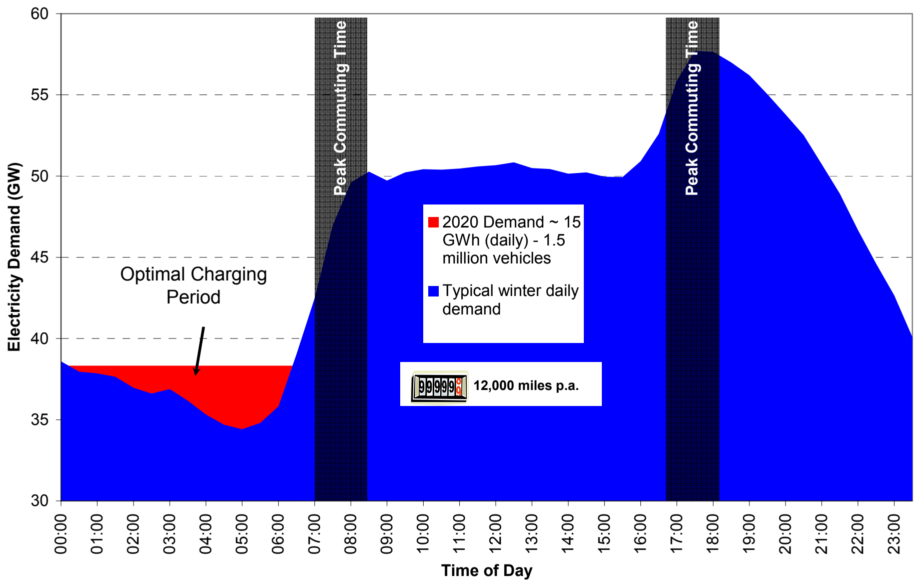

Figure 5: Matching vehicle charging to the current electricity demand profile

5.70 In 2020, the optimal time for charging electric vehicles may be as much related to the times at which wind generation is at its maximum as the underlying demand profile. Tidal generation could also have a similar effect.

5.71 National Grid as System Operator is also likely to value the capability to adjust charging schedules as a Balancing Service. This means that we need to look beyond the fixed 'time of use' tariffs of the simplest smart metering solutions towards more sophisticated solutions for Electric Vehicles.

Question 12. Is it valid to assume that electric vehicle charging will be co-ordinated via a smart grid or something similar and will react to price signals?

Development of Embedded Generation

5.72 Our Gone Green scenario looks across ‘electricity’, ‘heat’ and ‘transport’. This approach informs our view on the renewable electricity capacity that is required, based on the renewable contribution that can be expected from the other sectors. The scenario does not depend solely upon transmission connected renewable solutions, but recognises the role of embedded generation in meeting climate change objectives.

5.73 Gone Green assumes an increase of 6GW in embedded generation capacity between 2009/10 and 2020/21 to almost 15GW. Some 45% of this capacity is assumed to be Combined Heat and Power plant. The remaining proportion (totalling some 8GW) we have assumed comprises generation from renewable sources: wind, solar, tidal, biomass and hydro-power.

5.74 In terms of micro renewables, we assume a very aggressive penetration rate of domestic roof-mounted solar photovoltaic panels. This high rate was informed by experience in Germany and leads to around 3.5 GW of solar renewable energy by 2020. Other studies, which have examined the possible penetration of Solar PV against assumptions on financial support are less bullish. For example, Element Energy[9] proposed that solar PV could reach about two thirds of this capacity if supported by a combination of feed-in tariffs, soft loans and zero-carbon homes legislation.

5.75 We have made no formal distinction in our modelling between domestic and larger scale CHP applications. Our view at this stage is that of the 7 GW of CHP assumed in 'Gone Green', the majority is likely to consist of district heating schemes rather than the mass penetration of micro CHP.

5.76 Our more conservative view on micro CHP is based on our longer term energy modelling. Micro CHP promotes greater energy efficiency in the short term because a micro CHP device is likely to emit marginally less carbon than the 'equivalent model' of an 'A' rated boiler combined with the equivalent electrical output. In the longer term, however, carbon emissions from the micro CHP unit are unlikely to be sequestrated (via a carbon capture and storage facility). Consequently, every unit of micro CHP electrical output might eventually be at the expense of a unit of 'carbon sequestrated', nuclear or renewable electricity delivered via the networks. These issues are less of a concern for larger scale CHP installations.

5.77 Embedded generation is further considered in Section 7 in the context of operating the system.

Question 13. Do you foresee a greater or lesser role from embedded and distributed generation than we have assumed?

The Demand Side – A comparison with other scenario work (LENS)

5.78 A detailed comparison with other scenario work is beyond the scope of this document. However, Ofgem's work on Long Term Energy Scenarios (LENS) is worth highlighting, given the exposure that this work has had within the industry.

5.79 LENS identified a number of scenarios including 'Big Transmission and Distribution', 'Energy service Companies', 'Microgrids', 'Multi Purpose Networks' and 'Distribution System Operators'. The scenarios differ markedly in their assumptions on both generation and demand.

5.80 Gone Green has some of the characteristics of 'Big T&D' in that it supports renewable, transmission-connected wind capacity. However, it also has many similarities with the other scenarios which allude to significant microgeneration, 'smart control' and electric vehicles within their narrative.

5.81 We see the transmission system's role as providing a 'secure backbone' which can support the growth and innovation in smaller demand and generation technologies. Consequently, 'Gone Green' should be considered as a conflation of the LENS scenarios, rather than a mapping to one single picture of the future.

[9] Report available at:http://www.berr.gov.uk/energy/sources/sustainable/microgeneration/research/page38208.html

6 Reserve and Operating Margin

The reserve required to cater for short term electricity generation and demand forecast errors will change as the type of generation connected to the transmission networks changes. We have quantified this effect within the bounds of our 'Gone Green' scenario.

We go on to highlight our recent operational experience and its implications for operating margins into the future. Finally, we investigate the issues to be dealt with when operating at periods of low demand, again using our 'Gone Green' scenario as a background.

Operating Reserve Requirement in 'Gone Green'

6.1 In this section, the Short Term Operating Reserve Requirement (STORR) described in Section 3 is examined in greater detail. For the purposes of this forward looking analysis, we have calculated STORR using the statistical process described in Appendix A. The requirement is expressed in terms of the reserve capacity (measured in MW) required at four hours ahead of real-time.

6.2 The process uses parameters we have derived from historic data to quantify demand forecasting performance, changes in conventional generation availability and wind output forecast performance. We then evaluate a reserve requirement which satisfies our '1 in 365' criteria.

6.3 Currently, our standard wind forecasting error at 4 hours ahead is around 10% (rms)[10] of wind generation capacity. We believe that with better forecasting and more geographic dispersion this standard error could improve to around 6% (rms) of capacity at 4 hours ahead. However with the commissioning of large off-shore wind farms, it is possible that wind forecast errors may start increasing again due to the large concentrations of wind farms in a geographically small area and this has been assumed in this study.

Question 14. Is our anticipated improvement in wind forecasting performance at 4 hours ahead achievable?

6.4 In this analysis, it is assumed that current levels of reserve providers are available and contracted. For example, the current level of static response providers are maintained which minimises the reserve for response requirement. Our analysis also assumes that demand forecast error and generator unavailability remain at current levels.

6.5 The level of STORR is dependent on day of the week, season and time of the day. For example, we generally hold more STORR on a Monday due to greater uncertainty over the demand estimate on the first day of the week and the higher likelihood of unplanned generation loss from units that have been desynchronised over the weekend. An overview of STORR on a Monday

[10] Using the empirical rule for a normal distribution this means that we expect actual output to differ from forecast output within a range of +/- 10% of wind capacity 68% of the time, +/-20% 95% of the time and +/- 30% 99.7% of the time.

winter peak demands for average and no wind is illustrated below in Figure 6 as derived for our 'Gone Green' scenario.

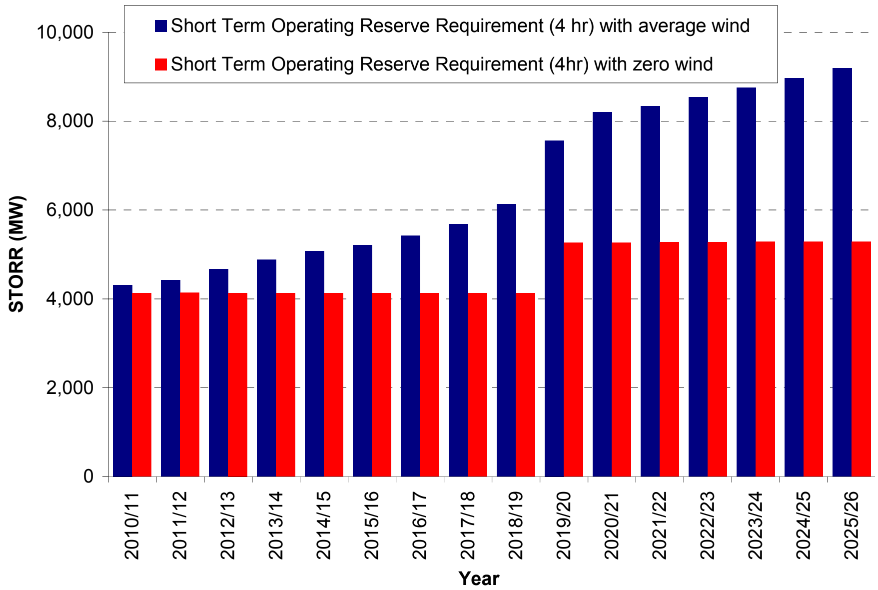

Figure 6: 'Gone Green' view on future STORR

6.6 With no wind, STORR is a function of conventional generation losses and demand forecast errors. If the next generation of large nuclear sets connects, this would increase STORR as more reserve for response is required to cover the frequency containment requirement with an increased largest loss (from 1,260MW to 1,800MW).

6.7 It can be seen that as wind generation capacity increases, STORR will increase year on year from current levels. It is possible to separate out the additional reserve for wind out of total STORR and this is shown in Figure 7 . A central view of additional STORR for wind is plotted and compared with the level of reserve that would need to be held if a wind forecasting error of 10% did not improve going into the future.

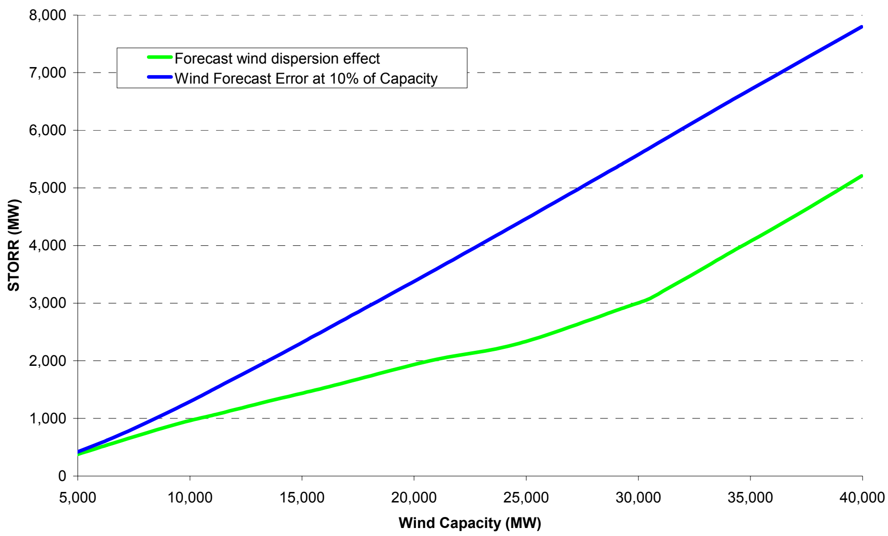

Figure 7: 'Gone Green' additional average STORR for wind

6.8 As wind generation increases, so does geographic dispersion of the wind farms and we believe that this combined with ongoing improvements in wind forecasting will allow us to minimise the reserve requirements for wind going forward. There is considerable uncertainty in predicting this future requirement but as we increase our operational experience of wind, we do expect our assumptions and forecasts to be updated accordingly.

6.9 It should be noted that the above is the average additional contribution and during periods of high wind, it is anticipated that this requirement will increase due to the characteristics of a wind turbine (at very high wind speeds a wind turbine will shut down in order to protect itself).

6.10 In the future, it is possible that reserve requirements will be significantly different day on day and even across a day depending on the wind forecast. This will have implications for future procurement of Balancing Services and control room operations.

Question 15. Do you have any views on our projected Short Term Operating Reserve requirement under 'Gone Green'?

Reserve Costs in 'Gone Green'

6.11 In order to assess the costs of operating reserve, we must convert our 'MW' requirement in to a volume of reserve energy then derive a cost based on price assumptions. We have used our published model[11] to calculate STORR costs under 'Gone Green'.

Reserve Volume Assumptions

6.12 National Grid ensures that the Short Term Operating Reserve Requirement is met by first assessing generator operating plans against a forecast of electricity demand. Where there is not sufficient generating capacity readily available in the required timescales over and above forecast demand to meet our reserve requirements, we need to take actions to make up the deficit using either generation or demand side Balancing Services.

6.13 The volumes we need to procure vary from year to year depending on market and system conditions. A range of just over 2TWh up to nearly 4TWh has been seen in recent years.

6.14 We need to make an assumption about how much of this residual action is required in order to forecast future costs. The volume required is dependant on system and market conditions, therefore we base our forecasts on historic data with a weighting applied such that more attention is paid to periods which better represent possible future conditions.

6.15 For this analysis, we have put a weighting on previous years experience as shown below in Table 3. We then use these volumes (totalling 2.95TWh) as a baseline for our forecast under the 'Gone Green' scenario.

[11] The model is available under the heading Margin Forecast Summary, 8th Dec 08 at: http://www.nationalgrid.com/uk/Electricity/soincentives/AnalystArea/

Year/Source	2005/ 06	2006/ 07	2007/ 08	2008/ 09*	2009/ 10*	Weighted Average	Proportion of Total (%)
Relative Weighting	*0.5*	*0.5*	*2.0*	*0.5*	*0.5*		
Coal	1.08	0.85	0.82	1.44	1.39	1.01	34
Gas	0.95	0.49	0.92	1.11	1.09	0.91	31
OCGT	0.09	0.07	0.05	0.10	0.10	0.07	2
Oil	0.10	0.07	0.07	0.11	0.11	0.08	3
Hydro	0.05	0.04	0.03	0.06	0.06	0.04	2
Pumped Storage	0.23	0.22	0.28	0.37	0.36	0.29	10
UK Trades	0.32	0.21	0.23	0.38	0.37	0.28	9
French Trades	0.13	0.15	0.16	0.23	0.22	0.17	6
SO to SO	0.05	0.05	0.10	0.10	0.10	0.09	3
Total (TWh)	**3.00**	**2.15**	**2.68**	**3.91**	**3.80**	**2.95**	

* Forecast

Table 3: Historic reserve volumes and weight applied

Cost of Contracted Services

6.16 To maintain operating margin and get access to coal and oil generators that have not run for a period of time, National Grid is required to bring the generator to a state of readiness using the 'BM StartUP' Balancing Service. These costs are forecast to be around £23m for 2009/10. This cost is assumed constant going forward and is adjusted according to the volume of reserve from these generators. For example, when oil plant closes, we assume there will be an equivalent reduction in BM StartUp costs.

6.17 The Short Term Operating Reserve service (STOR)[12] is currently the dominant Balancing Service for reserve with over 2.5GW of reserve procured in any year from Balancing Mechanism and non-Balancing Mechanism participants. STOR option fees are based on window periods based on an economic analysis of historic reserve spend. Table 4 indicates current forecast BM StartUp and STOR costs.

Service	Forecast Cost (£m)
BM StartUp	23
BM STOR Utilisation	14
Non-BM STOR Utilisation	9
BM STOR Option Fees	56
Non-BM STOR Option Fees	14
Total	**116**

Table 4: Forecast STOR & BM Start Up costs for 2009/10

6.18 It is anticipated in this analysis that STOR windows will be broadened as the overall reserve requirement increases. A 10% increase in hours in 2016, and a further 10% increase 2020 are therefore assumed with a corresponding increase in utilisation. The effect of these changes is set out in further detail

[12] Described briefly in Appendix D and also at : http://www.nationalgrid.com/uk/Electricity/Balancing/services/rserveservices/STOR/

in the table in Appendix C. It is also assumed that there is no net change in provider volume.

Forecast under 'Gone Green'

6.19 To produce a forecast of costs under 'Gone Green' we first calculated the overall STORR requirement in line with installed wind generation capacity as shown above. This was then translated into an annual volume, based on the volume of 2.95TWh given in Table 3.

6.20 This volume was in turn adjusted for each year according to the additional STORR required for wind and for the additional reserve required to cater for the connection of larger generating units (assumed to occur in 2019 in the 'Gone Green' scenario). Please note that this analysis does not include the estimated additional cost of some £105m per year associated with additional frequency response holding for larger units identified in the GB SQSS review of Infeed Loss limits (GSR007[13]) cost benefit analysis.

		2010/11		**2016/17**		**2020/21**		**2025/26**	
STORR under Gone Green (Mondays, Winter Peak)									
Average Wind Conditions (MW)		4,310		5,421		8,200		9,187	
Low Wind Conditions (MW)		4,128		4,123		5,267		5,286	
Annual net STORR Volume (TWh)		3.13		4.57		7.37		8.37	
Wind Generation Background									
Available Wind (MW)		2,964		12,280		26,129		30,301	
Wind Forecast Error (% of capacity) at 4h		10.0		7.3		6.0		6.4	
STORR Volume for Wind (TWh)		0.19		1.32		2.98		3.96	
Largest Infeed Loss (MW)		1,260		1,260		1,800		1,800	
STORR Volume for larger loss (TWh)		0		0		1.14		1.16	
'On the Day' Reserve Volumes and Costs									
	*Offer Price (£/MWh)**	TWh	£m	TWh	£m	TWh	£m	TWh	£m
Coal	102	*1.07*	42.2	*1.30*	51.3	*1.77*	69.7	*1.33*	52.4
Gas	136	*0.97*	70.7	*1.65*	120.7	*2.69*	195.8	*3.75*	273.5
OCGT	200	*0.08*	10.5	*0.05*	7.4	*0.08*	10.9	*0.06*	8.4
Oil	295	*0.09*	28.9						
Hydro	175	*0.05*	5.3	*0.07*	7.7	*0.11*	12.0	*0.13*	14.2
Pumped Storage	175	*0.31*	34.7	*0.45*	50.6	*0.73*	81.6	*0.83*	92.7
UK Trade	61	*0.29*	-0.6	*0.43*	-0.8	*0.69*	-1.3	*0.79*	-1.5
Interconnector Trade	98	*0.18*	6.3	*0.40*	13.9	*0.86*	29.9	*0.98*	65.7
Interconnector SO to SO	90	*0.10*	2.6	*0.21*	5.7	*0.45*	12.3	*0.51*	13.9
Total Volume and Cost		***3.13***	**200.6**	***4.57***	**256.5**	***7.37***	**410.9**	***8.37***	**519.3**
Contracted Service Cost (£m)		110.8		120.3		155.2		171.0	
Total STORR Cost (£m)		**311.4**		**376.8**		**566.1**		**690.3**	
Wind STORR Cost (£m)		**18.4**		**108.8**		**228.7**		**326.9**	
Largest Infeed Loss Cost (£m)		**0**		**0**		**87.9**		**95.4**	

* Offer Price is referenced against an Energy Balancing Psuedo Price of 63 £/MWh to derive a cost

Table 5: Reserve volume increases in the 'Gone Green' Scenario

[13] SQSS review GSR007 is listed at: http://www.nationalgrid.com/uk/Electricity/Codes/gbsqsscode/reviews/index.htm

6.21 An overview of the increase in reserve volumes and costs at specific years out to 2025 is shown above in Table 5 with further detail in Appendix C. For the year 2020/21, this shows a cost of £229m attributable to STORR for wind and a cost of £88m attributable to STORR for larger generating units.

6.22 As LCPD opted out oil plant closes, we have assumed that its margin volumes will be replaced by conventional coal or CCGT generation. Oil plant has a low SEL/MEL ratio (the ratio of minimum sustainable output to maximum capability, with a low value indicating a large flexible operating range) and short run times compared to coal / CCGT plant. Therefore in the analysis an adjustment has been made to compensate for the loss of oil generation, assuming it will be replaced by CCGT plant. This has the effect of adding 0.3TWh to our STORR volume requirement from 2016 onwards.

6.23 We have used the prices published as part of our incentive scheme discussions (incentive year 2009/10) for the purposes of this analysis. Therefore all future reserve costs are at current prices in order to allow comparison of year on year volume changes. In practice prices will change from these levels but there is no market forward curve for power and gas prices for the period under consideration which can be used to guide price assumptions.

6.24 There is considerable uncertainty around the prices the market will offer us for Balancing Services into the future. In this analysis, the prices have been fixed at 2009/10 forecast values. Operational experience indicates volatility in these prices when operating margin surpluses reduce. For example, in this analysis, the oil plant is assumed at a price of £395MWh. However, we have observed prices on these unit at +£900MWh when operating surpluses approach levels where a system warming is imminent.

6.25 There are two additional assumptions of note in our analysis. These are:

- That future European legislation on cross border balancing will not impact our current trading strategy on interconnectors.
- Our trading team is able to trade for energy and margin.

Sensitivity to Wind Forecasting Error

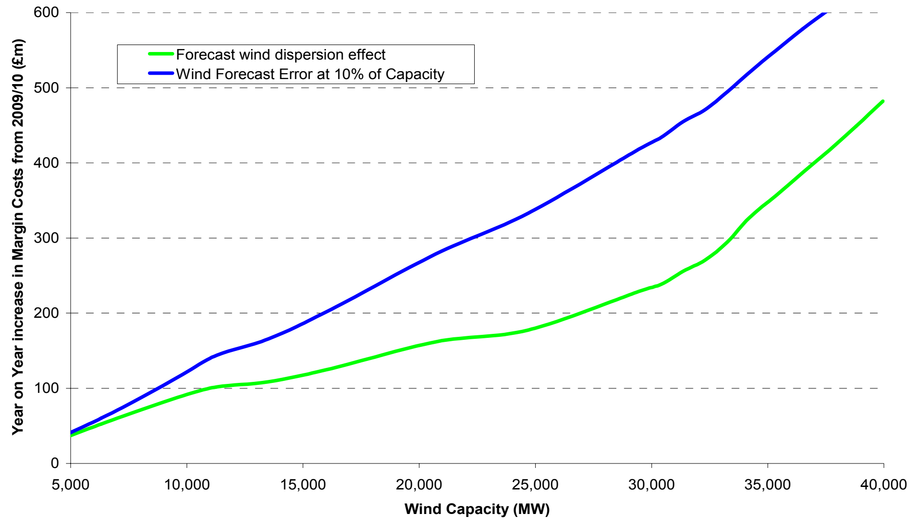

Figure 8: Incremental reserve costs versus wind generation capacity

6.26 Reserve requirements are very much influenced by the assumed level of wind forecast errors. Figure 8 compares a standard error of 10% against a reducing error due to dispersion and wind forecast improvements.

6.27 It is evident that increased geographic dispersion effects and wind forecasting improvements could significantly reduce reserve costs going forward. As indicated previously, there is a lot of uncertainty around how accurately the wind generation fleet output can be predicted. In the 'Gone Green' scenario there are a number of large offshore wind farms which may start to reduce any dispersion effects in the future.

Question 16. Do you have any views on our projected volumes, prices and costs for STORR under 'Gone Green'?

Periods of Low Wind

Historic Wind Speeds at Peak Demand

6.28 Accurate electricity demand prediction requires a wide range of historic weather information at various locations across the country. National Grid has records of historical demand and weather conditions going back over 20 years.

6.29 Currently there are 13 weather stations in our source database. A map of the locations is shown in Figure 9.

6.30 There are a number of points to highlight in the wind data that is presented in this section and used in Figure 10 below:

- The wind speed data is from weather stations close to demand centres. These are not necessarily located where the current and future wind farms are located. For wind forecasting purposes, National Grid takes data from additional weather stations which are closer to wind farms. However, the records from these sites are not as extensive.
- The data presented is not adjusted for hub height.
- Over the years certain weather stations will have moved location whilst some have been added (there were additions with BETTA).

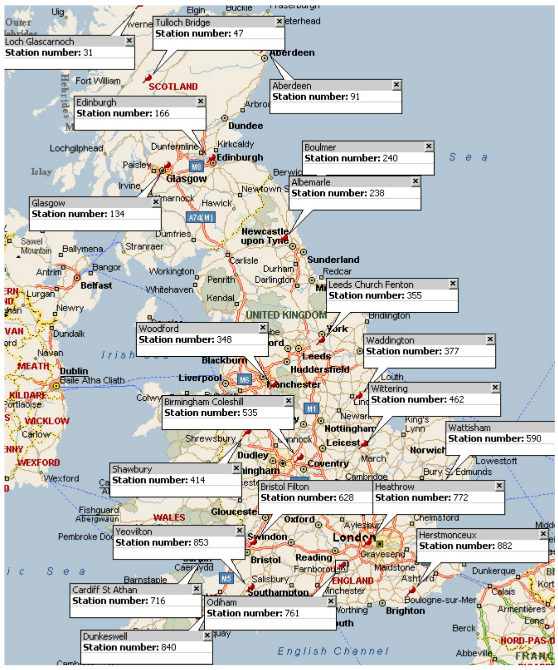

Figure 9: Weather Station Locations

6.31 However, it is considered that the data does give an indication of weather patterns experienced at times of winter peak demand across GB. Figure 10 shows average winds, recorded in GB, across the top five winter peak demands.

6.32 Generally a wind turbine will not generate until wind speed is above 4 metres per second. From the data in Figure 10, it is evident that even when taking into account hub height adjustment, there is a possibility of low wind generation output across GB at times of winter peak demand.

6.33 The weather characteristics that result in these conditions are generally high pressure systems which result in below average temperatures and low winds. These high pressure weather systems can be large enough to also encompass Ireland and Western Europe and can persist for a number of days in a row.

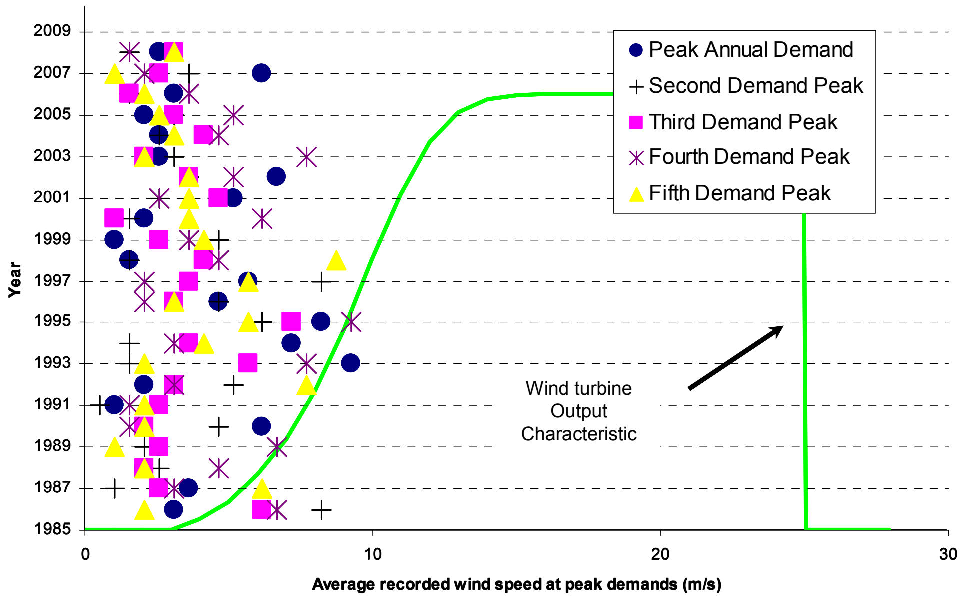

Figure 10: Measured Wind Speeds at times of Winter Peak Demands

Recent Operational Experience

6.34 The issue of high pressure weather systems at times of peak demands is illustrated by conditions on Tuesday 6th January 2009, the day of peak electricity demand for financial year 2008/09. The weather forecast received by National Grid at the start of this week predicted temperatures across the region of below normal for the time of the year, with low wind speeds except in Scotland where they were forecast to be moderate.

6.35 Figure 11 shows the metered wind output recorded across this week. The wind is displayed at percentage of metered capacity. Across this week the metered capacity available is 1209MW.

6.36 On Monday 5th January GB peak demand was around 58GW. Across the peak half hour the recorded output from the metered wind fleet was around 6% of capacity. As the Monday peak demand declined, wind generation increased output overnight up to 40%. On Tuesday 6th January wind output declined from overnight levels. Demand reached the peak for the year at 59.2GW. Across this period, the output from the wind fleet falls and a 16% output is recorded across this half hour.

6.37 Similar weather conditions persisted in Wednesday 7th January 2009 but the demand did not quite reach the levels of the previous day. Peak demand was recorded at around 59GW with the wind fleet output at around 12% of full capacity. The weather then started to change and more wind was experienced for the reminder of the week with very high outputs recorded across the weekend.

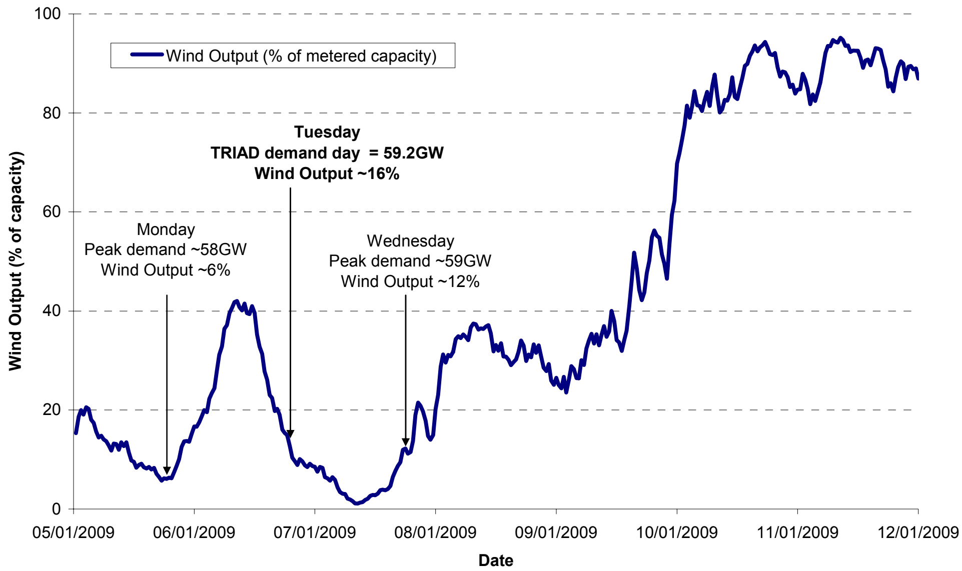

Figure 11: Wind output at peak electricity demand for 2008/09

Implications of Low Wind Periods for Operating Margin Analysis

6.38 The calculation of future wind output assumptions is influenced by the levels of wind generation connecting, where it connects (on-shore or off-shore), how geographically dispersed the wind fleet is and the characteristics of individual wind turbines.

6.39 We have already presented our view of metered wind generation data which shows an average load factor of 35% in winter. In taking a view of the generation available to meet peak electricity demands, we need to have much more certainty than that represented by averages (which represent a value achieved 50% of the time). For the purposes of operating margin analysis, we therefore need to assume a contribution of less than the average of 35%.

6.40 We will need to analyse wind output at times of peak demands as more wind generation connects to establish the correct 'capacity credit' number (the proportion of installed capacity assumed available at times of peak demand) which is consistent with our reserve criteria (where the Loss of Load Expectation is equivalent to 1 in 365 days).

6.41 Government sponsored research[14] into wind output at times of peak demand reports preliminary conclusions that “the probability of having low wind output at times of peak demand is considerable. There is a 10% probability that wind output will be below about 20% of installed capacity at times of peak demand in winter and a 5% probability of output being below about 15%”. Whilst

[14] SKM's report "Growth Scenarios For UK Renewables Generation And Implications For Future Developments And Operation Of Electricity Networks" (BERR Publication URN 08/1021) is available on the BERR website at: http://www.berr.gov.uk/files/file46772.pdf

there is no direct mapping between this assessment and our '1 in 365' assessment, we believe that a 5% probability (1 in 20) is a reasonable reference point for assessing a 'capacity credit'.

6.42 We also need to take account of the way our operating reserve requirement varies with anticipated wind output and how this affects any 'capacity credit'.

6.43 We cannot at this stage state the precise levels of operating reserve required to cater for wind forecasting error at low wind output for the portfolio of wind turbines we might see in 2020, but we can say that for wind generation operating at an average of 15% capacity across the fleet, we will carry some operating reserve specifically for to cater for it. The need to carry operating reserve means the effective 'capacity credit' for wind output of 15% of capacity will therefore be less than 15%.

6.44 National Grid's view at this stage is that for 2020, a wind generation output assumption of up to 15% of capacity at times of peak demand is reasonable. However, taking the issues explored above and our recent operational experience together, we believe that it is essential to look carefully at the implications of infrequent 'low wind' events within Great Britain.

6.45 We therefore explore the implications of low wind output in our following operating margin assessment.

Question 17. Is National Grid's current view that 'low wind' events across Great Britain need to be considered when evaluating electricity operating margins reasonable?

Operating Margin in 'Gone Green'

Approach

6.46 Our analysis of future operating margins is based on the approach adopted for Winter and Summer Outlook reports which is normally applied to a 6 to 9 month ahead view of operating margins.

6.47 Under this approach we derive a generation requirement which is the sum of forecast Average Cold Spell (ACS)[15] demand and STORR (a Short Term Operating Reserve Requirement).

6.48 At times of winter peak demand we observe around 0.8 to1.3GW of demand management as consumers responded to peak conditions. In our operating margin analysis we therefore assume 1GW of demand side response in our demand forecasts. We also take account of generation and demand side Balancing Service providers when looking at STORR. In summary then, our generation requirement incorporates the effects of the demand response to price signals and the contribution that small generation and demand side providers make to reserve.

6.49 We then compare this generation requirement to the generation we think will be available, which means that we scale expected generation capacity in accordance with our historic experience of generator availability.

[15] Annual Average Cold Spell (ACS) Conditions are a particular combination of weather elements which gives rise to a level of peak demand within a Financial Year which has a 50% chance of being exceeded as a result of weather variation alone.

6.50 We feel it useful to present forward looking analysis in this form (which interested parties are familiar with) but recognise that different approaches could be more appropriate for any routine operating margin assessment over the timescales we have covered in this report.

Assumptions

6.51 The forecast peak demand under 'Gone Green' rests at around today's levels of 60GW. This forecast is based on a combination of the observed trend in peak demands in recent years, the growth in embedded generation in distribution networks, more efficient use of energy and likely slower economic growth over the near term.

6.52 The demand figures we use in this scenario are referred to as restricted demand (as they incorporate the effect of price driven demand suppression) and include generating station load and exclude interconnector exports.

6.53 In our annual Winter Consultation report, we make assumptions on interconnector flows based on price spreads between markets. For example we normally assume a 300MW export to Northern Ireland via the Moyle Interconnector and a 2,000MW import from France over the peak period. Looking to the future with a lack of forward price curves, it is difficult to forecast future interconnector flows and hence sensitivities around Interconnector flows are presented.

6.54 Analysis of Operating Margins requires a view of our reserve requirement as described above. In this analysis, average levels are quoted along with a low wind level.

6.55 It should also be noted that the STORR levels quoted anticipate that the majority of STORR will be held on reserve providers that are available at various timescales e.g. demand side providers, STOR, OCGTs, CCGTs etc. Contingency reserve requirements remain at current levels in this analysis. It is assumed that the market takes into account the day-to-day variability of wind generation, and adjusts/self-balances at the 4 hour ahead stage.

Generation Type	Availability (%)
Nuclear	80
Coal	85
Oil	95
CCGT/CHP/MGT	90
OCGT	95
Pumped Storage	95
Onshore Wind	95

Generation Type	Availability (%)
Offshore Wind	85
Biomass	90
Wave	90
Tidal	90
Hydro	60
Interconnectors	100
New Nuclear	95

Table 6: Generator Availability Assumptions across the Winter Period

6.56 Future plant availabilities are based on historic availability levels and are identical to those reported in our Winter Outlook reports. For plant that we have no experience of (offshore wind and new nuclear), we have made assumptions. Our availability assumptions are set out by fuel type in Table 6 above and as applied by year in Appendix B.

6.57 Wind is split between offshore and onshore. We are assuming that offshore wind will have a lower availability than onshore due to physical restrictions on repairs and maintenance particularly during winter periods.

6.58 New nuclear plant is assumed to have a higher availability than the current fleet which has seen a decline in availability in recent years. We have yet to observe any noticeable decline in availability in other types of conventional plant as they age.

Question 18. Are our generator availability assumptions reasonable for application to analysis of future operating margins?

Assessment

6.59 Figure 12 shows our view of electricity operating margins out to 2025 under the 'Gone Green' scenario. This illustrates operating margins with average wind (black line) and with at full wind capacity (green line). In both cases, interconnectors are assumed at net float.

6.60 In this view surpluses increase until the LCPD opted out plant starts to close. After 2015, surpluses decline sharply and wind output has a greater influence.

6.61 With average wind and interconnectors at float, demand is met in full with a small operating margin shortfall between 2016 and 2019. Under this scenario it would be anticipated that we would maintain operating margins using interconnector capacity or additional reserve providers.

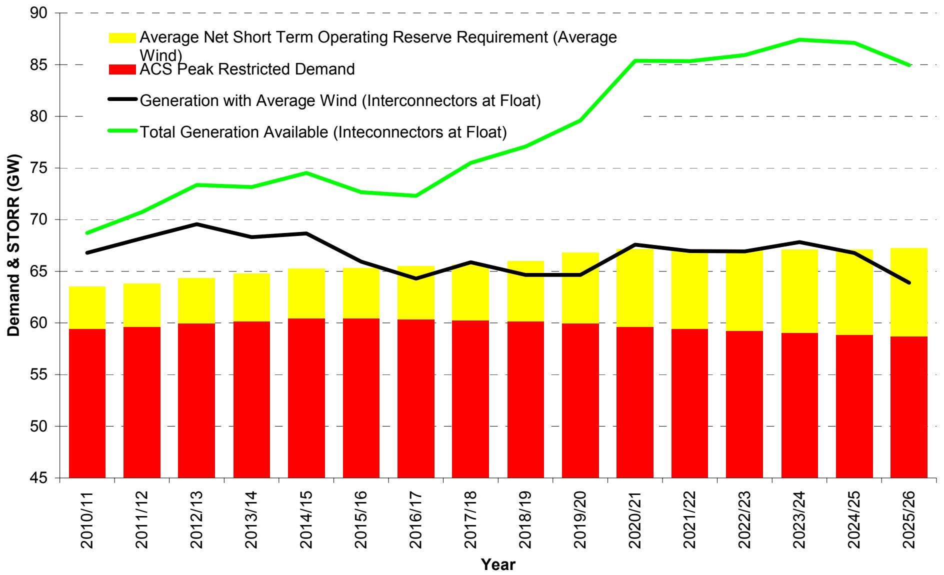

Figure 12: Operating Margins in 'Gone Green'

6.62 In Figure 13 we show the impact of assuming no net contribution from wind under different interconnector flow assumptions. This figure shows the lower STORR under 'low wind' conditions (as we are no longer required to carry STORR for wind forecast errors). With low wind output and full imports from interconnectors (blue line) operating margins are generally maintained under this scenario until post 2015 where the wind output and interconnector flow assumptions become more important.

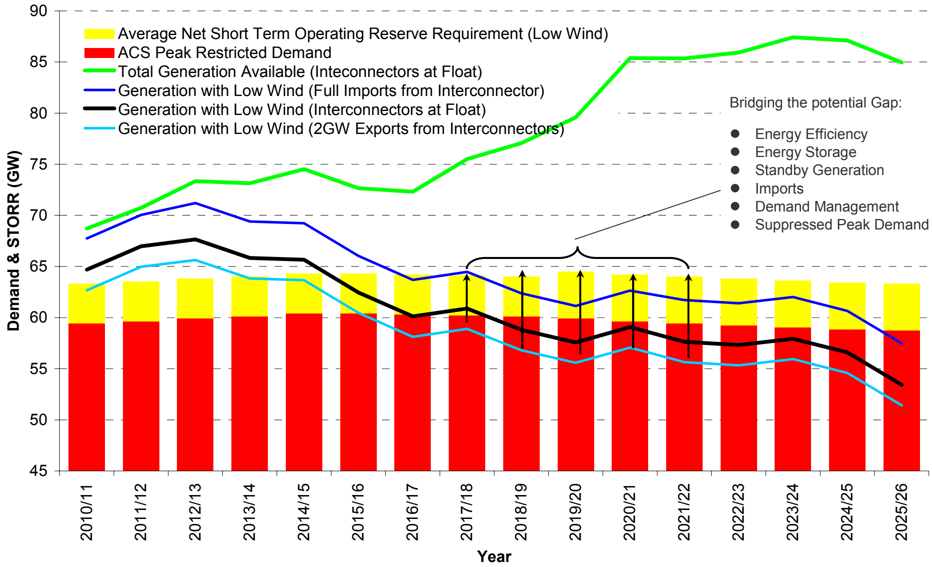

Figure 13: Influence of Wind assumptions on Operating Margins

6.63 This highlights two key points:

- Interconnector flow assumptions, and hence a knowledge of market and system conditions in Europe are key to any operating margin assessment;
- If we assume that a 'low wind' scenario is credible at winter peak, under this 'Gone Green' scenario, action would need to be taken on a number of fronts including:
    - Identification of further sources of reserve which National Grid would have access to, including demand side providers, storage, standby generation (OCGTs or large reciprocating engines) or interconnectors; or
    - Measures to reduce peak demand, whether through energy efficiency or by giving consumers an incentive to avoid discretionary energy consumption at times of peak demand.

6.64 If these actions were not taken under the 'Gone Green' scenario then there would be an increased risk (greater than 1 in 365 on days where STORR is not met) that involuntary demand control measures would be required.

6.65 It should also be noted that conventional fossil fuelled generation could be used to bridge any operating margin gap but this could mean that emission and renewable energy targets would not be met. More innovative solutions would ensure the relevant policy objectives of meeting targets, managing costs and maintaining security of supply are met.

6.66 We expect that Interconnectors will be capable of exporting or importing power over the winter and expect the direction of power transfer to be determined by relative market prices as we have observed over recent history. As new Interconnectors commission, National Grid expects to have operational agreements with new System Operators to contribute to its Balancing Service portfolio.

6.67 We also see a benefit in better provision and sharing of information from market participants and system operators across Northern Europe. This will help in assessing the contribution interconnectors can make to security of energy supply in individual systems.

6.68 It is also worth noting at this point the uncertainty around future peak electricity demand forecasts. In the past these have been strongly correlated with economic growth. The rate of future economic growth within Great Britain is particularly uncertain at the present time and its impact is illustrated by the reduction of 1.1GW in our forecast of electricity demand in summer 2009. There are further challenges in predicting the rate at which embedded generation will be constructed (effectively reducing the demand met by the transmission networks) and accounting for the impact of specific energy efficiency measures.

Question 19. We would welcome comments from market participants on how they expect to manage periods of low wind generation output and whether this is an important consideration for them.

Question 20. Are we correct to highlight the importance of wider European issues in electricity operating margin analysis?

Question 21. Are there further technical solutions for maintaining operating margins which we have not mentioned here?

Question 22. Do you think National Grid's view of future operating margins is useful and do you have views on how this should be presented?

Operating at Minimum Demands in 'Gone Green'

Background and Assumptions

6.69 Minimum electricity demand in Great Britain system occurs across weekends and in particular across bank holiday weekends at around 04:30 in the morning. During these periods generating companies need to decide whether to shut generators down or whether to run them at a minimum technically sustainable level to follow the demand patterns.

6.70 National Grid is also concerned with ensuring not only that generation output matches consumer demand but also that there is enough flexible generation and demand available to cater for both generation and demand losses. The need to cater for a demand loss is termed a 'negative reserve' requirement. Typically this requirement is around 1,600MW but it can increase in proportion to the maximum demand loss on the system and changes with system conditions. For this analysis, the requirement is set at approximately 2,600MW from 2020 onwards in cases where interconnectors are exporting.

6.71 Calculating the growth (or decline) in summer minimum demand in the future is uncertain. Embedded generation growth, general progress in energy efficiency and load shifting as well as specific developments such as electric vehicles and will impact on minimum demand levels.

6.72 For the purposes of this analysis it is assumed that demands remain constant (consistent with our assumptions regarding peak demand), with demand defined as the off-take from the transmission system (excluding generating station load), with all interconnectors assumed at float and with pumped storage in pumping mode.

	MW
Demand	
Background Demand	22,000
Pumping Load	2,058
Total	**24,058**
Negative Reserve	
Negative Regulating Reserve	900
Negative Response Reserve	700 to 1,700
Total Negative Reserve Requirement	**1,600 to 2,600**

Table 7: Minimum demand background assumptions

6.73 Generation availabilities are lower in summer compared to winter as generators take the opportunity to perform maintenance. In assessing minimum demand periods, the availability assumptions applied to the nuclear fleet and CHP / CCGT plant (whose main output is heat / steam with electricity generation as a secondary product) are critical. The availability of pumped storage is also critical as this in effect increases the demand on the system. Availabilities assumed for this study are shown below in Table 8.

Generation Type	Availability
Nuclear	60%
CHP and 'Must Run' Gas	75%
Pumped Storage	75%

Table 8: Generation availability assumptions for minimum demand assessment

6.74 The study assumes that other categories of generation which may be equipped with carbon capture plant can shutdown overnight for minimum demands.

6.75 For this study, average wind/wave/tidal output and high wind/wave/tidal output is examined and compared against demand to determine if generation exceeds demand.

6.76 It should be noted that wind generation is assumed to be flexible and available to be curtailed subject to its bid price. Our current operational experience is that wind farms do not actively engage in the Balancing Mechanism but we would expect some operators in the future to submit prices which are related to the lost income from Renewable Obligation Certificates (ROCs).

Question 23. Are our assumptions regarding the level of electricity demand during the minimum demand periods reasonable?

Question 24. Are our generation availability assumptions for minimum demand periods reasonable?

Question 25. Is our central assumption regarding wind generation bid prices related to ROCs reasonable?

Assessment

6.77 Average output from wind, wave and tidal generation across summer overnight periods is assumed to be 20%. Figure 14 indicates the expected output from generation based on the availabilities in Table 7, average output from renewables and interconnectors all assumed at float.

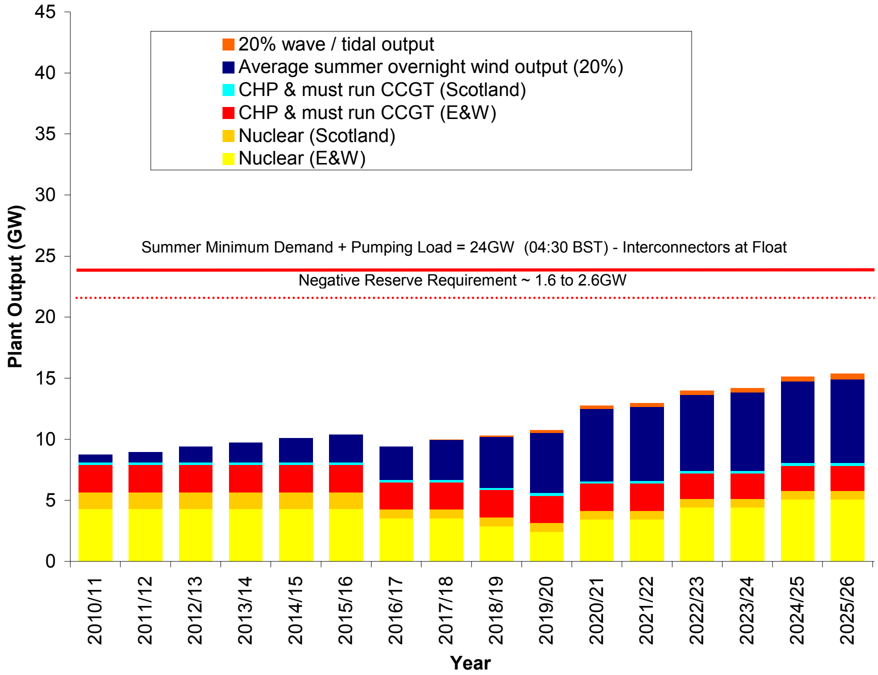

Figure 14: Average renewable generation output at summer minimum under 'Gone Green'

6.78 Under this view, there is sufficient headroom from the minimum demand levels. From 2010 to 2019, the increasing renewable generation is generally offset with a declining nuclear fleet. Post 2020 this changes and negative reserve margins will decrease.

6.79 As described in Section 4, operational experience of the metered wind fleet indicates that high wind output of up to 75% can be experienced 5% of the time across the summer. Based on these parameters, we can anticipate that across any summer period for 5% of the time (6 nights), we will see renewable output at levels shown below in Figure 15.

6.80 Under the high renewable generation output scenario depicted in Figure 15, action would be required in order to maintain negative reserve margins. Prior to 2020 under 'Gone Green', this would occur where 75% renewable generation output coincided with the lowest demands of the year. We would expect this to happen less than 6 nights per year. After 2020 under 'Gone Green' the volume of actions required suggests risk would appear to be present throughout the summer period (6 nights a year or more).

6.81 This situation can be managed in a number of ways:

- Interconnector exports of up to at least 4GW are possible by 2020;
- Demand may increase as prices drop or go negative (e.g. smart meters, electric vehicle charging); and
- Short term storage such as batteries could take advantage of excess spill and prices.

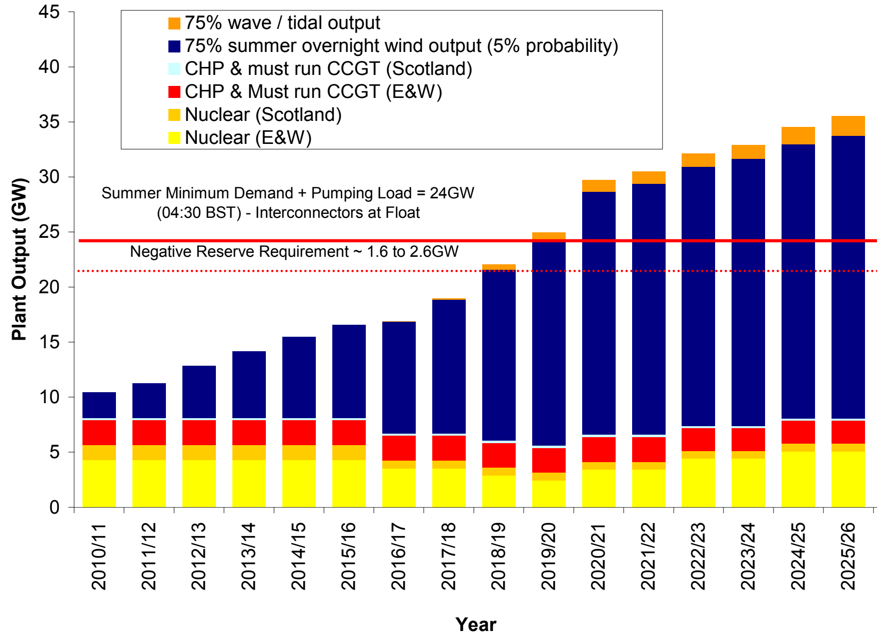

Figure 15: High renewable generation output under 'Gone Green' at summer minimum

6.82 However if we assume that National Grid needs to on occasion take action for about 4 to 6 hours overnight we can estimate a Balancing Services cost associated with curtailment action at minimum demands. Our estimates are based on the assumption that:

- Wind farms can provide all the dynamic response required (about 1.3GW of secondary response required translates to around 2.4GW of de-loaded wind generation);
- Wind farms look to recover lost ROCs (Renewable Obligation Certificates) payments for any reduction in output with an average bid price of -£100 MWh with a -£50MWh equivalent response holding price;
- Interconnectors are used by market participants to export excess generation;
- Our negative reserve requirement increases to approximately 2,600MW to cater for the loss of an exporting interconnector; and
- We need to curtail wind for 4 hours on average a night until 2025 whereas after 6 hours curtailment is required.

6.83 Our analysis also takes account of 500MW of electric vehicle charging demand in 2020 and 1,500MW in 2025. This is less than the charging demand illustrated in Section 5 Figure 5 as we have assumed charging activity will be reduced by the end of the overnight period.

6.84 Using the assumptions listed above, Table 9 gives an indication of the excess capacity that could be planning to generate and the associated total costs per night of managing via pulling back wind. Costs to pull back wind and place on response are estimated at around £1.6m per occasion in 2020 and rising thereafter to £5m per occasion in 2025 under our 'Gone Green' scenario. As more wind farms connect and dispersion increases, the probability of above average wind speeds and costs will become clearer.

6.85 Costs could be significantly higher if it is not possible to allocate frequency response to wind generation. Where it is necessary to curtail wind generation, costs will be dependant on the availability of viable bids.

6.86 This analysis looks at the overall transmission network balance and negative reserve requirement under 'Gone Green'. In practice we expect to experience localised negative reserve issues where wind generation output is high, and therefore exports across certain transmission boundaries are high, during the summer transmission system maintenance period. We will look to quantify this effect over shorter timescales than those covered by 'Gone Green', where we would have a better view of minimum demands, actual generation behaviour and the transmission infrastructure available to us.

	2020/21	**2025/26**
Balancing Action Required		
Generation (see Table 8)		
Nuclear (GW)	4.1	5.8
CHP & must run CCGT (GW	2.4	2.3
Renewables at 75% output (GW)	22.1	25.7
Total Generation (GW)	28.7	33.7
Demand(see Table 7)		
Demand (GW)	24.1	24.1
Electric Vehicle Demand (GW)	0.5	1.5
Total Demand (GW)	24.6	25.6
Energy Excess (GW)	4.1	8.2
Negative Reserve Requirement (GW)	2.6	2.6
Total Balancing Action Required (GW)	**6.7**	**10.7**
Balancing Actions		
Wind part loaded on Response (Dynamic) GW	2.4	2.4
Interconnector Flow (GW)	4.1	4.2
Additional Pull back (GW)	0.2	4.2
Total Balancing Actions (GW)	6.7	10.7
Cost to pull back wind (£m per occasion)*	**1.6**	**5.0**

*at -100£/MWh bid price vs a balancing price of 10£/MWh plus -50£/MWh equivalent response bid price where responsive

Table 9: Costs of managing summer minimums under 'Gone Green'

Question 26. Is it reasonable to assume that minimum demand periods will be managed using Interconnectors and Wind Generation in preference to the curtailment of Nuclear Generation?

7 Operating the Networks

The changes we expect to see over the next decade present a number of challenges to the energy markets.

There are however a number of important and in some cases more onerous challenges which are specific to National Grid as operator of the transmission networks. The scale of these will be dependant on the type of networks which we operate and are therefore critically affected by network investment decisions. We have therefore articulated these issues in general terms which reflect our current view.

Real-Time Energy Balancing

Background

7.1 The transmission system in Great Britain operates as an island with High Voltage Direct Current (HVDC) interconnections to Europe and Northern Ireland. Annual peak demand is around 60GW with the minimum level at approximately 25GW.

7.2 The interconnections provide a means to both import and export power. However, because HVDC technology is used, Great Britain is not synchronised to the rest of Europe and hence the electricity system within Great Britain operates at its own Alternating Current (AC) frequency. This frequency is the ultimate measure of whether generation and demand are in balance at any one instant: if there is a deficit of energy, frequency goes down and vice versa.

7.3 National Grid is responsible for controlling frequency within the statutory limits of 50.5Hz and 49.5Hz by controlling the flow of electricity onto and over the transmission networks. Control is managed within operational limits of 50 +/- 0.2Hz and variations within this range occur over short timescales (over periods of seconds and minutes rather than hours). Control is achieved by instructing generation and demand relative to an FPN (Final Physical Notification) to meet the forecast demand for each minute within the next few minutes to the next hour and a half (the Balancing Mechanism window).

7.4 The total generation output is 'instructed' under normal operation to be within 50MW of the predicted demand level at any minute in the balancing window period. In isolation, an instruction to change generation or demand by 100MW will typically move the frequency by up to 0.07Hz. This degree of sensitivity to an 'imbalance' means that electrical generation and demand need to be closely matched at all times in order for frequency to remain within the limits set out above.

7.5 Automatic frequency response from synchronised generation is instructed ahead of time on a proportion of the generation to meet a minimum dynamic response holding. This helps to slow down changes to the system frequency caused by the second by second variations in the generation and demand balance. Further frequency response is instructed to cater for large sudden imbalances, typically caused by the loss of a large generating unit.

7.6 The majority of National Grid's minute by minute instructions take the form of 'Bid Offer Acceptances' (BOAs) within the Balancing Mechanism. As described in Section 3, the costs of these actions, which are paid for at the submitted bid or offer price, feed into imbalance prices which serve as an incentive on market participants to limit the imbalance which National Grid has to deal with. This incentive means that the number of balancing actions required is reasonably predictable and National Grid has scaled its operating model to suit.

7.7 Figure 16 below shows that for the last three years the number of BOAs issued is typically 30,000 per month, an average of 40 per hour.

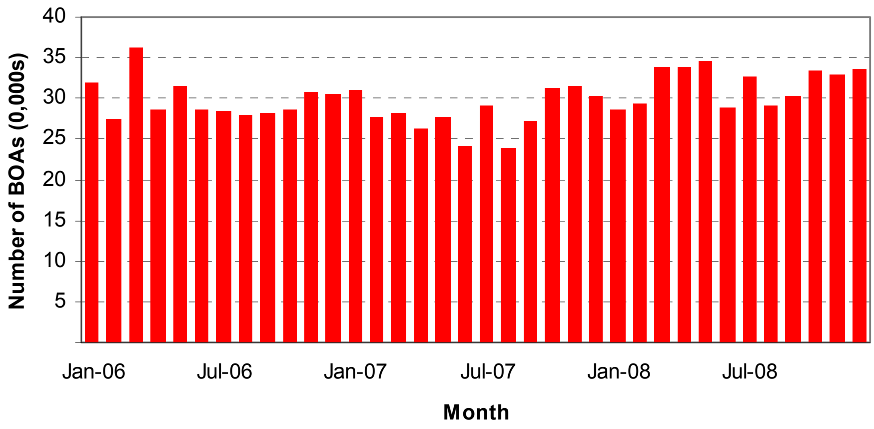

Figure 16: Number of Bid Offer Acceptances Issued

7.8 Figure 17 below shows the gross energy volume of all BOAs issued by month for the last three years. It can be seen that total balancing energy volumes are typically 0.9TWhr per month representing approximately 2.5% of total electrical energy transmitted.

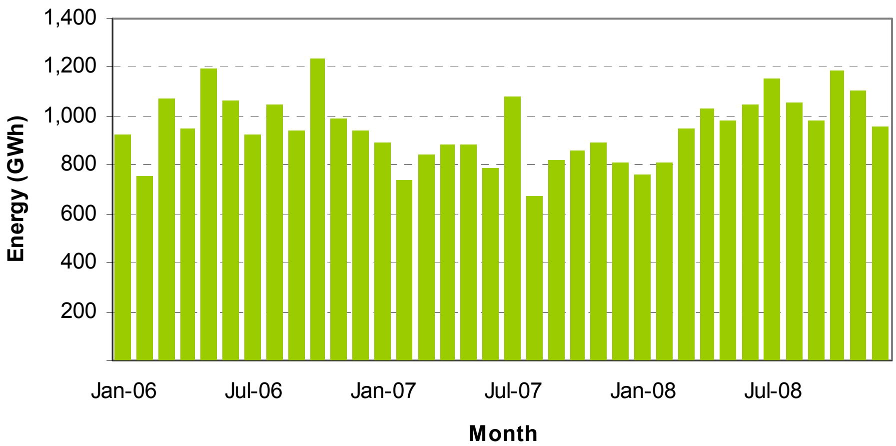

Figure 17: Energy Traded Through Bid Offer Acceptances

7.9 The average duration of any BOA, including any ramp up or down, is shown below at 36 minutes. Note that this analysis excludes the BOAs issued to pumped storage plant which has significantly different dynamic parameters to other generators. The average duration of all BOAs reduces to 30 minutes when the BOA issued to pumped storage plant is included.

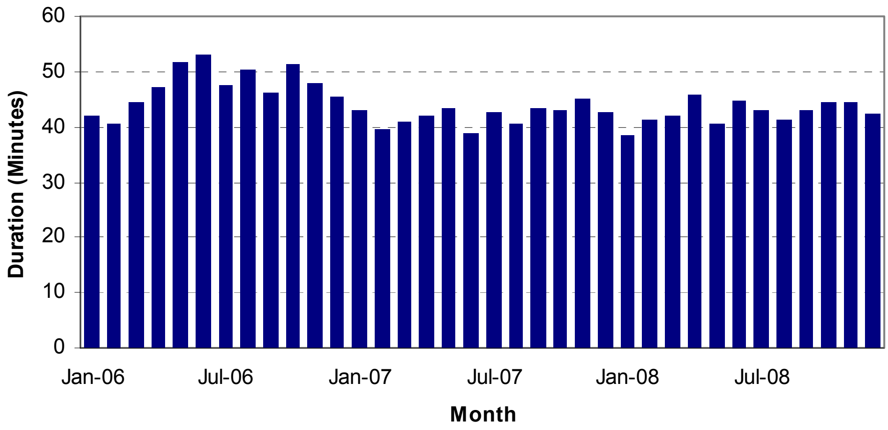

Figure 18: Average BOA Duration

7.10 The energy balancing activity is undertaken by a team of control room engineers. A BOA is issued electronically by our control engineers via data links (the Electronic Despatch Logger - EDL) to a control point (traditionally a control room within a power station) and is subsequently accepted and then acted upon by the power station engineer. The current process for issuing a BOA is therefore constrained by the time needed to review despatch advice, create and issue any one BOA and the time needed to accept and act upon a BOA at the receiving control point.

7.11 National Grid is in the process of replacing its energy balancing systems and consulted on its plans in October 2008[16]. This exercise covered 'Phase 1' development, focussing on replacement of the current systems. A further consultation is planned in 2010 on 'Phase 2'. The system developed and implemented in Phase 2 will need to have the capabilities required to meet the challenges faced in operating the networks in 2020.

Energy Balancing in 2020

7.12 In order to assess real-time energy balancing activity into the future, it is necessary to address three questions;

- Will market participants' imbalance differ significantly from that experienced currently?
- Can peak activity periods be managed efficiently?
- Will sufficient flexible generation or demand by available?

<u>Imbalance</u>

7.13 Market participants' imbalance (the difference between their contracted position and their actual positions) is a critical driver of activity in National Grid's control room. Intuitively, the larger the volume of imbalance that National Grid has to resolve, the more activity that is involved.

7.14 The Net Imbalance Volume (NIV) represents the sum of all of the system and energy balancing actions for the Settlement Period (including pre-Gate Closure actions reported in BSAD), netted off to give the energy imbalance or 'length' of the overall system. There is considerable variation in the length of

[16] The "BM System Replacement" consultation report is available at http://www.nationalgrid.com/NR/rdonlyres/B961884A-EC28-4771-A40F-02F254B00A18/28752/bmrepconsultationv10.pdf

the system across all time scales. Table 10 below shows the annual variation in average NIV and its Standard Deviation.

Calendar Year	Average NIV (MW)	Standard Deviation (MW)
2006	-433	451
2007	-165	421
2008	-394	486
2009 (to April)	-479	403

Table 10: Net Imbalance Volume 2006 to 2009

Future NIV under 'Gone Green'

7.15 For the purposes of this analysis we have assumed that electricity Cash Out rules remain unchanged and market participants trade/manage their positions right up to gate closure.

7.16 Based on the information in Table 10, we have developed a view of future NIV under our 'Gone Green' scenario based on a weighted average of NIV over the last 3 years of 404 MW (long) and a Standard Deviation of 456MW.

7.17 We have also assumed that:

- Market participants contract 95% of their wind portfolio output across all time scales (i.e. they spill 5% on average);
- There is an rms error of 5% of wind for volatility in NIV at gate closure to real-time for National Grid to manage; and
- The average annual load factor for the wind fleet is 30%.

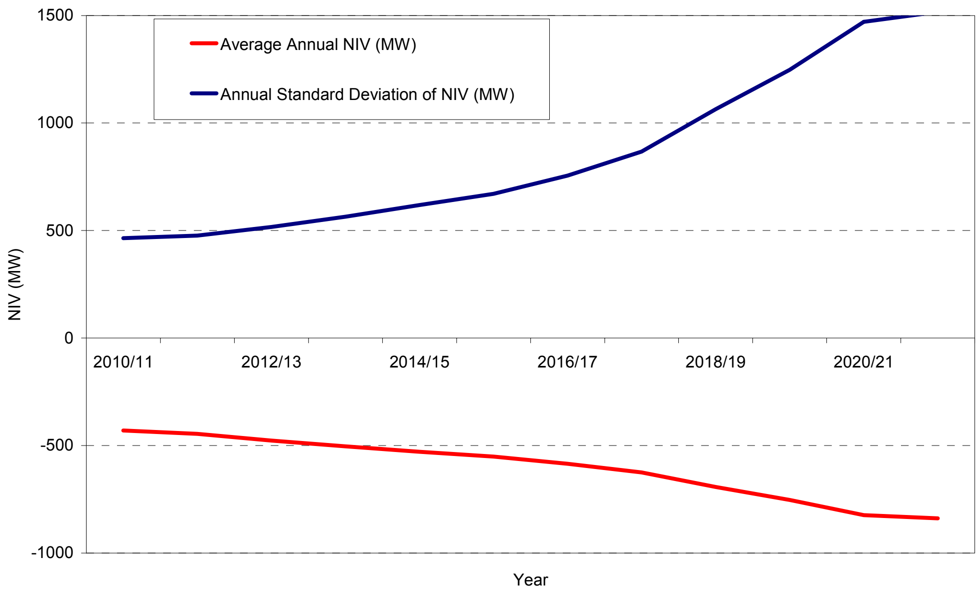

Figure 19: Future NIV under 'Gone Green'

7.18 There are a number of points to note from the view presented in Figure 19:

- Average NIV almost doubles by 2020 (i.e. about twice as long as currently); and
- The Standard Deviation (volatility) shows a three fold increase.

7.19 In general as the volume of generation from wind increases we expect the system to get longer on average. However, this may not be uniform across the day as we expect market participants to focus their attention on periods of peak prices.

<u>Impact on Energy Balancing</u>

7.20 We have observed a strong correlation between the standard deviation of NIV and the number of instructions we issue. Based on this correlation and our view of future NIV in Figure 19 we can come to a view of how many instructions will be required.

7.21 It is possible to project forward the increase in instructions sent out as presented in Figure 20.

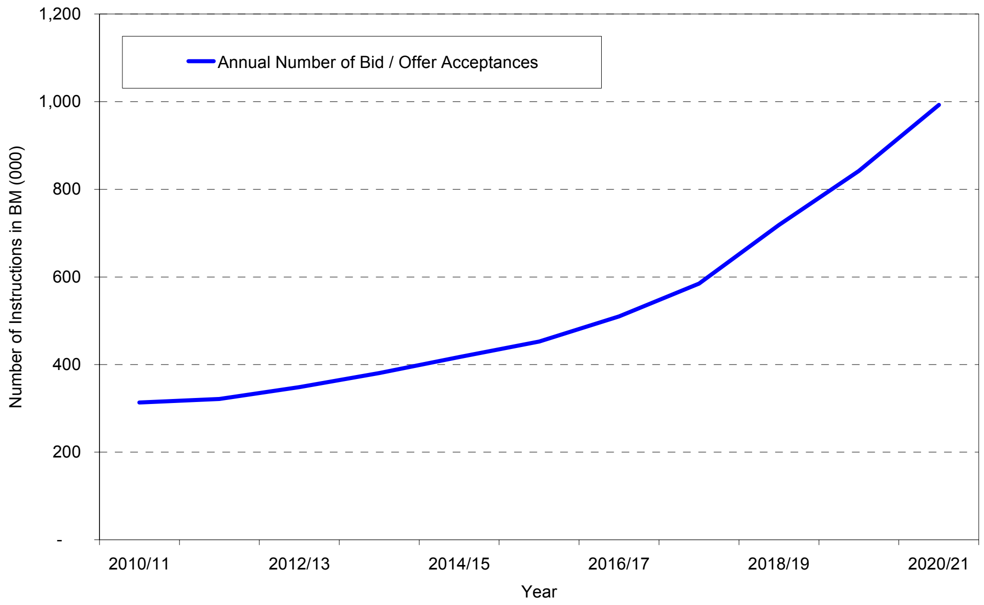

Figure 20: Future number of Bid Offer Acceptances under 'Gone Green'

7.22 The main points to note from this analysis are:

- Number of instructions issued will show a modest increase over the next few years and then will accelerate; and
- We could see three times the number of instructions issued in 2020 compared to 2010.

7.23 The analysis suggests that National Grid's operational systems need to be developed to accommodate new levels of activity, whether in terms of instructions issued or to facilitate other solutions. This suggests to us that our next generation of energy balancing systems need to be able to issue Bid Offer Acceptances or take equivalent action without the level of manual intervention required at the present time.

Question 27. Do you agree with National Grid's view of increased balancing activity in the future due to variation in market length?

Ramping

7.24 One of the most onerous periods for electricity energy balancing is the morning pick up in demand, which starts just before 06:00 on week day mornings with most of the morning demand established by 08:00. Across this period the increase in demand can be 14,000MW at a rate of 80-100MW/minute.

7.25 The increase in demand is met by self-despatched generation ramping to meet half hourly energy profiles. National Grid's role in these periods is to ensure that generation and demand side service providers can be instructed to meet the actual minute by minute demand. In general terms, the faster the rate of change of demand, the more effort is needed to manage this process.

7.26 This period is occasionally made more challenging by generation failures or late synchronisations and interconnectors moving from import to export (a swing of 3,000MW on the interconnector to France is not unusual over an hour or less). Pumped storage plant also transitions from pumping to generating in this period, subject to the self despatch ramp rate limits set out in the Grid Code.

7.27 Another factor to be considered in the period such as the morning pick-up is that a large amount of generation is already ramping at its maximum rate (typically 10-15MW/min) and so is unable to be instructed to increase output.

7.28 This risk period is managed by small increases in operating reserve where the demand increase is at its most rapid.

7.29 The peak periods of energy balancing activity for National Grid in 2020 are likely to be at similar times as today. By taking the demand changes we see today and superimposing the effect of variations in wind generation we can assess a worst case position.

7.30 Experience to date with modest levels of wind penetration (some 1.2GW of transmission connected wind capacity) has shown output changing by up to 750MW in 6 hours (eg.250MW to 1,000MW) and by 300MW in 2 hours (eg. 600MW down to 300MW) which can represent a 50% change in output in 2 hours. Looking at our 'Gone Green' scenario in 2020, a 50% change in output would represent a maximum change in output in the order of 15GW over 2 hours.

7.31 To quantify this effect further, we have analysed current demand patterns and extrapolated our wind generation data to look at the maximum rate of change that we could be exposed to. Table 11 shows the number of occasions we could expect to see ramp rates of up to 11GW/h in 2020. This analysis does not account for dispersion effects which we would expect to reduce overall ramp rates but does suggest a significant increase in ramping activity.

	Current Demand Ramp Rate exceeds *x*GW/h on:	**Projected Demand + 30GW of wind Ramp Rate exceeds *x*GW/h on:**
7GW/h	32 occasions pa	63 occasions pa
8GW/h	7 occasions pa	22 occasions pa
9GW/h	1 occasion pa	8 occasions pa
10GW/h	0 occasions pa	3 occasions pa
11GW/h	0 occasions pa	1 occasion pa

Table 11: Potential Ramp Rates in 2020

7.32 We therefore conclude that the coincidence of wind generation output changes and demand changes will trigger increased real-time balancing activity. This supports the conclusion we have drawn from our NIV analysis which suggest that our operational systems will have to be developed to automate the issue of balancing instructions.

7.33 The need to deal with increased ramp rates also suggests a need to reduce the time between issue of instruction and delivery of the required response. The Automated Generator Control (AGC) facilities we see in use in other countries would help achieve this.

Question 28. Do you agree with National Grid's view that ramping effects will impact on operation of the networks?

Question 29. Do you believe that a new approach is required in the development of System Operator to generation or demand control point interfaces for 2020?

Generator Flexibility

7.34 Taking November 2008 as a representative month, National Grid issued 34,000 BOAs. 15,500 (45%) of these were issued to coal fired generators, 11,500 (33%) to gas and 900 (2.5%) to oil fuelled plant. Of the remainder of the instructions in this month 5,400 (16%) were to Pumped Storage, 300 (~1%) were to OCGTs and 400 (~1%) to other hydro plant.

7.35 Our 'Gone Green' scenario features an expansion in gas fuelled generation capacity to 34GW by 2020 whilst retaining some 20GW of coal fired capacity as well as Pumped Storage capacity at current levels. Given the high percentage of BOAs issued to this type of generation currently (94% in November 2008), there is no indication under this scenario that sufficient technical flexibility will not be available to us in 2020.

7.36 However, under certain conditions and particularly during periods of low demand as described in Section 5 it is likely that National Grid will need to take specific actions to retain the necessary flexibility.

7.37 These actions would involve curtailment of generation which planned to run, in some cases to be replaced by generation which can operate more flexibly, and the use of interconnectors to either reduce imports or increase exports to neighbouring systems. The potential costs of these actions are explored in the previous section under 'Operating at Minimum Demands in 'Gone Green''

7.38 We recognise the need to manage the costs we incur in this area and would highlight our expectation that flexibility will be offered in response to economic and price signals, given that this flexibility is not a mandatory requirement under current arrangements.

7.39 Our view of credible summer minimum conditions with wind generation operating at 75% of capacity as presented in Section 5 also suggests a need for wind, nuclear or CHP plant to offer some degree of flexibility. Given that the operational requirement for flexibility is over and above that required to follow the electricity demand profile we believe it will continue to be essential that operators of these forms of generation are capable of responding to real-time direction whether through the Balancing Mechanism or some other Balancing Service.

Question 30. Are there any specific factors which suggest that adequate flexibility will not be available to National Grid for use in operating the networks in 2020?

Network Management

Operating a Reliable and Secure Transmission System in 2020

7.40 National Grid manages real-time operation of the transmission networks across Great Britain[17] in accordance with the Grid Code and Security and Quality of Supply Standard. These endeavour to set out the way in which the networks should be both designed and operated such that an acceptable balance is maintained between the reliability in supply delivered to end consumers and the costs that consumers bear.

7.41 Security standards mean that National Grid not only has to ensure that the networks are operating within the voltage limits and power ratings (for example) applicable at any one moment but also that it has to ensure that unacceptable conditions do not occur in the event of a fault.

7.42 In order to this, National Grid must

- Plan operation of the network in accordance with the forecast generation and demand;
- Determine the events which could trigger unacceptable operating conditions;
- Determine pre-fault actions which must be taken to avoid the risk of unacceptable conditions, either by re-configuring the network or altering generation or demand patterns using Balancing Services; and
- Determine post-fault actions to be used if an event occurs, which could be used to return equipment to its continuous rating.

7.43 Security assessments using network models are carried out at many phases across planning timescales from years and months ahead, down to day ahead and then within day. Each of these represents a complex engineering study, requiring skilled interpretation and analysis.

7.44 These assessments need to make use of a forecast generation output and demand pattern in order to work out the impact on the transmission networks. At present they are focussed on key 'cardinal points' on the demand curve which are easily determined to represent the most onerous conditions of the day.

7.45 Clearly, in a scenario involving a significant amount of renewable generation such as 'Gone Green', the scope for variation in generation output is much greater than it is today. The means that the most onerous operational conditions will not necessarily occur at times of peak demand, but could be driven by changes in flows from wind generation.

7.46 In order to make sure the transmission networks are operated within standards under all the conditions presented by variable generation output (for any given level of transmission network capacity), National Grid can either:

[17] National Grid operates the transmission networks in Scotland through an interface with Scottish Power's and Scottish Hydro-Electric's control rooms. Similar arrangements may apply to the new offshore networks.

- Adopt a more conservative approach (essentially paying for Balancing Services which guarantee the networks are secure for a wide range of possible conditions); or
- Develop systems which can perform regular automated security assessments in timescales which allow necessary action to be taken.

7.47 At the present time we do not believe it would be acceptable to adopt a more conservative approach as this would impose more constraints on the transmission networks and their users. We therefore anticipate developing our systems such that multiple forward looking security assessments can be conducted in timescales which allow Balancing Services to be invoked or networks to be re-configured to resolve security issues.

Getting More from the Transmission System

7.48 The ability of a transmission system to transfer power is dictated by both the maximum steady state power transfer capability of the network and the way in which faults can be managed.

7.49 Bulk transfer capability can be enhanced by:

- Thermal modelling and monitoring of selected priority circuits for precise calculation of short term ratings in real time;
- Automatic inter-tripping to resolve post-fault problems quickly without manual intervention;
- Control of flows using devices like Quadrature Boosters (QBs - also referred to as 'phase shifters'); and
- Control of voltage using Static Var Compensators (SVCs).

7.50 The future transmission network is expected to include more technology with HVDC circuits (on and off shore) and series compensation in addition to more shunt compensation and inter-tripping schemes.

7.51 The resilience of and co-ordination between the control systems for controllable transmission devices such as QBs and SVCs becomes more critical as we stretch the operating envelope of the transmission systems.

7.52 Traditionally theses devices have a strong element of local control with co-ordination between devices carried out by a control room engineer. Development will need to be undertaken to provide new advice and control tools to co-ordinate the optimal pre and post fault settings on controllable devices.

Voltage control

7.53 Voltage management is a key process in secure operation of the power system.

7.54 The system voltage varies across the network and fluctuates at each point on the network during the day. It is important that steady state voltages are maintained within operational ranges and reactive power reserves are maintained for post fault support of the network voltage in line with the SQSS. Without careful management of the reactive reserves the system could be at risk post fault to voltage collapse which will cause widespread or complete system shut down.

7.55 Voltage management is undertaken using a number of actions. These include despatching generation to target reactive power output and adjusting the output of the reactive compensation plant which forms part of the transmission networks.

7.56 Voltage profiles vary with changes in active power flows. Therefore, the variations in generation output we would see under our 'Gone Green' scenario would not only increase the activity levels in our energy balancing, but will also mean significantly more work is required in order to achieve acceptable voltage control.

7.57 We therefore see three actions essential to maintaining voltage control performance on the transmission networks:

- Continued provision of reactive power by generators (synchronous and non synchronous) in line with Grid Code requirements;
- Continued investment in voltage control equipment; and
- Where required, the introduction of wider area automatic voltage control schemes which can respond either directly or indirectly to changes in flows through the networks.

Question 31. The combined challenge of:

a) ensuring the networks are operated safely and securely against a background of generation variability; whilst

b) getting more from existing infrastructure;

suggests to us that control, communication and information systems have a greater part to play in controlling flows across the transmission networks.

Are there alternative approaches which should be considered?

Embedded Generation

7.58 Embedded Generation (by which we mean in this context any generation not visible to us as the operator of the transmission systems) has a significant contribution to make in meeting carbon emission reductions and renewable energy targets as illustrated by the embedded generation growth in our 'Gone Green' scenario.

7.59 In developing the arrangements for embedded generation and making any assessment of the economic and environmental benefits it provides it is important to consider the three areas of impact that embedded or distributed generation has on operation of the transmission networks:

- Our demand forecasts are based on a correlation between measurable parameters (eg temperature), time of day and metered demand. Variations not visible to us increase our demand forecast error and therefore necessitate higher reserve levels at a higher cost.
- Any mismatch between the resilience of embedded generation compared to large scale generation might exacerbate a transmission system disturbance, particularly a large frequency deviation as experienced on the 27th May 2008[18].

[18] A full report entitled "Report into System Events of 27 May 2008" is available at http://www.nationalgrid.com/uk/Electricity/Codes/gridcode/associateddocs/

- In the absence of accurate metered data, forecasting the local impact of embedded generation (in terms of flows onto and fault level infeeds on distribution networks), can result in sub-optimal running arrangements at the boundary with the distribution system, potentially triggering unnecessary network investment in the future.

7.60 National Grid currently has no metering or visibility of most of the existing embedded medium and small scale generators. These historically have had minimal impact upon our ability to forecast transmission demand.

7.61 However, in very recent years we have observed the impact embedded wind farms are now having on local demand. High wind days would have previously resulted in higher demand to be met due to the cooling effect of the wind, whereas now higher wind speeds result in a reduction in demand observed on the transmission system as embedded wind output increases.

7.62 Where this demand is in a potentially constrained part of the system, the impact becomes one of network management as well as energy balancing, as in real time we see higher exports due to the lower than predicted demand.

7.63 As increasing levels of embedded generation are installed there will also be greater uncertainty in the way the overall system reacts to changes in frequency. Sufficient data will be required to allow suitable modelling of the overall system to calculate the necessary response holding to meet our statutory frequency control obligations.

7.64 There may be some overall economic benefit in aligning the frequency performance obligations between the Grid Code and the Distribution frameworks for some embedded generation to reduce their contribution to system disturbances. There will need to be a balance between the potential costs to generators to meet any aligned obligations and the cost to consumers for holding additional response if obligations remain as they are. The overall penetration level of embedded generation will need to be taken in to account in establishing this balance.

7.65 The Grid Code and Distribution Code (Small Embedded Generation Frequency Obligations) Working Group, established following the 27th May 2008 frequency excursion investigation, is due to report by December 2009. The resilience of embedded generation and the issue of alignment of frequency obligations is included in the terms of reference for the Working Group. We believe it is also appropriate to seek views in this consultation.

7.66 We also see a need to keep information provision from distributed generation under review, as requested by Ofgem in the correspondence from the Director General of Ofgem, Alistair Buchanan CBE, on 29th January 2009[19]. Current work is focussed on low cost information gathering using internet based solutions. The development of Smart Metering could add further value in the long term.

Question 32. What criteria should National Grid use in developing any requirements for information regarding embedded generators? Are there other ways of obtaining this information?

[19] A copy of this correspondence at available at: http://www.ofgem.gov.uk/Markets/WhlMkts/CompandEff/InvestigReport/Documents1/Frequency%20deviation%2027%20May%202008.PDF

Black Start

7.67 National Grid has an obligation under the Grid Code to ensure that the transmission networks can be re-energised in the event of a total or partial shutdown. No such event has been experienced in Great Britain since privatisation of the electricity industry in 1990 (the last partial shutdown was during the 'hurricane' of 1987) but widespread incidents have occurred in Italy and the North East of the United States.

7.68 This obligation is met by contracting with generating stations to be able to re-start from shutdown, ensuring transmission equipment can be operated in the absence of external supplies and by agreeing contingency procedures with generators and network operators.

7.69 Contracts for Black Start services are defined as "Part 2 System Ancillary Services". These are services that generators have to provide subject to agreement of terms with National Grid.

7.70 Our contracting strategy is based on a restoration plan which covers 6 major restoration zones across the GB Transmission System. These zones are aligned to distribution network boundaries thereby ensuring a relatively even share of duties during restoration.

7.71 Also, having 6 restoration zones means the energisation of the GB Transmission System, as a whole, is achieved at a relatively uniform rate and ensures the majority of the large non-Black Start stations have supplies restored in a timely fashion. To aid restoration times the Black Start stations need to be available to energise the first part of the GB Transmission System within approximately 2 hours.

7.72 Taking into account generator outages, running regimes and the risks of failure during start-up we typically contract for three stations within each zone. A particular zone may warrant either more or less Black Start stations depending upon the type of Black Start stations, distribution network boundaries, and non-black Start generation demographics.

7.73 Amongst the current fleet of 23 Black Start stations there are 5 stations that opted out of the LCPD and are expected to close. We are therefore seeking alternative providers at the earliest possible opportunity.

Future Provision

7.74 We are currently investigating the feasibility of providing Black Start services from technologies not included in our current portfolio including:

- Wind ;
- Supercritical Coal;
- HVDC Interconnectors (capability is dependant on the choice of DC conversion equipment); and
- Storage technologies (capability is dependant on scale).

7.75 We believe it is necessary to investigate these alternative options at this stage in order to maintain our portfolio of Black Start providers towards the end of the next decade.

Question 33. Are there additional options that National Grid should consider to maintain a Black Start capability?

8 Balancing Services

National Grid buys the services needed to assist in the operation of the Transmission System in accordance with the conditions laid out in Transmission Licence Condition C16. The biggest proportion of these services has traditionally been provided by large generators. Smaller scale and demand side providers have however played an increasing role in the past two decades.

The analysis in Section 6 of this document highlights our expected growth in the volume of reserve services required. We now explore where we could get these services from.

Balancing Services Requirement in 2020

8.1 National Grid procures a wide range of Balancing Services from various sources. These can be generation or demand sites, BM (Balancing Mechanism) or Non–BM providers, as long as technical and commercial service requirements are met.

8.2 Figure 21 below shows the service volume that National Grid currently procures for a typical winter to help cover STORR (Short Term Operating Reserve Requirement) compared against the 2020 'Gone Green' scenario requirement. This illustrates the significant potential increasing requirement for Balancing Services to provide reserve.

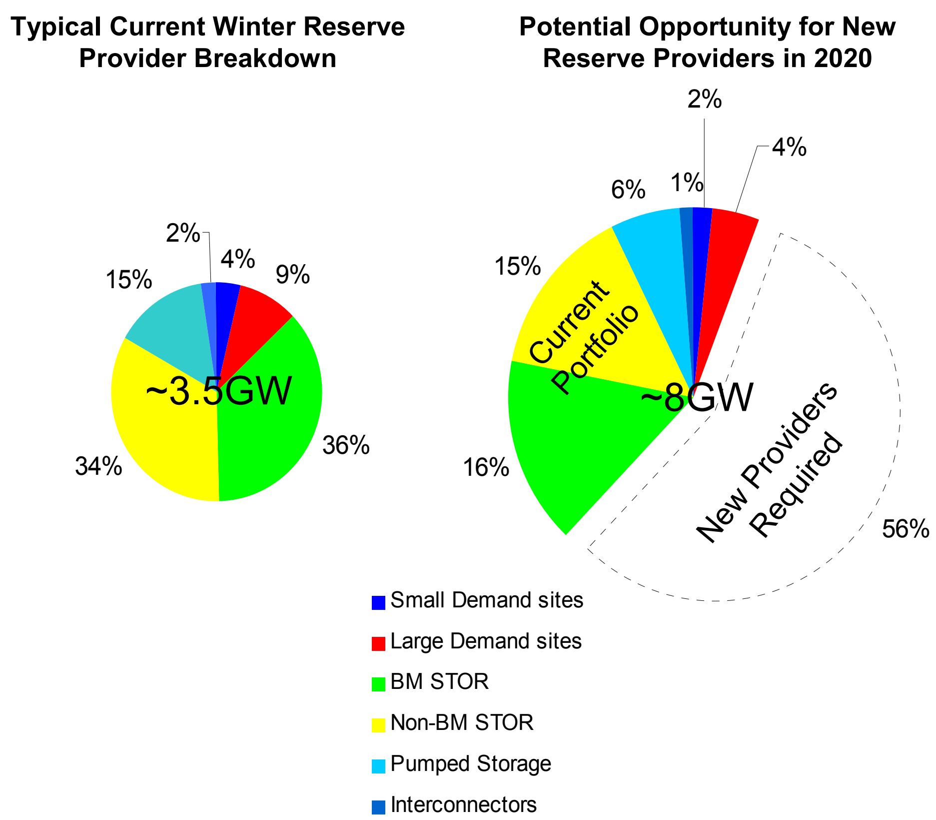

Figure 21: Requirement for new Reserve Providers

Future Service Providers

8.3 National Grid expects that it will need to procure an increasing volume of Balancing Services to meet reserve requirements. As some of the traditional service providers such as LCPD opted out generating plant close, we foresee demand side services, interconnectors and storage technologies playing a more prominent role.

8.4 We provide below our current view of the Balancing Services potential from these sources alongside generation sources, with an emphasis on the provision of reserve and frequency response services.

Interconnectors

8.5 HVDC Interconnectors use power electronics to control the flows across them and hence the imports and exports to the respective transmission networks at either end of the Interconnector. As such, they are technically capable of providing flexibility to both the wider energy market and to transmission companies.

8.6 Two HVDC interconnectors, one to France and one to the all Irish market are currently capable of providing Balancing Services to National Grid. These include automatic response to Low and High Frequency events, Intertripping in response to a transmission fault, Constraint Management and Balancing, Reactive Power and Emergency Assistance.

8.7 There are several projects in progress for new interconnectors which we expect to be able to provide Balancing Services, also potentially including Black Start capabilities. We have already highlighted our assumption that interconnectors will be able to make a significant contribution in the future.

Question 34. Are we correct in assuming that new interconnectors will be able to meet some of our Balancing Services requirement?

Demand Side Service Providers

8.8 We have developed a number of demand side Balancing Services successfully by introducing contract forms which allow parties that are not involved in the Balancing Mechanism to provide services to us.

8.9 Each provider must meet minimum technical criteria in respect of minimum size, response time and measurability of service. These criteria ensure that an effective service is procured on non-discriminatory terms at a scale appropriate to the transmission networks. It is important, for example, that service delivery can be measured and verified in a way that gives adequate confidence in delivery in real-time operation, which can be challenging for small providers.

8.10 Without these criteria National Grid risks paying for a service which is either not delivered or not useful and hence not economic and efficient.

8.11 In the current financial year, we have contracted with all providers which meet our technical criteria. This, along with the increase in the volume of reserve we expect to procure, suggests that there is scope to expand the provision of services from demand side participants.

8.12 We are therefore pursuing new demand side options. We will also keep under review our technical criteria and the need for systems which facilitate delivery of services.

Dynamic Demand

8.13 Dynamic Demand is the term currently used to refer to electrical appliances which are fitted with control circuitry capable of monitoring mains electricity supply frequency and adjusting the appliance's power consumption accordingly.

8.14 When a large number of appliances are given a similar characteristic, the small scale service can be aggregated into one which is useful in balancing the transmission system through the provision of frequency response. The technology is suited to devices like refrigerators, which can adjust their operating cycle but maintain conditions (in this case temperature) within a required range.

8.15 Installation of these devices to domestic appliances is most likely to be done at the time of manufacture so as to offer the most cost effective way of mass dispersal. With larger demand loads (industrial refrigeration for example) it may be possible to apply the technology retrospectively.

8.16 Initial estimations for the potential provision of frequency response services from domestic refrigeration range from 728MW to 1174MW. This is based on 40 million refrigeration appliances being pooled together[20] which we see as an upper estimate of service potential. Our own estimate is slightly lower (approximately 500 MW) largely because we have factored in future appliance efficiency savings in our model.

8.17 Other domestic appliances and air conditioning could be fitted with this circuitry. It is possible however that the provision of a valuable frequency response might, to some extent, be exclusive of providing other demand side services (such as load shifting). This is because the frequency response characteristic could not be relied upon if the appliance has ‘time shifted’ away from its expected window of operation. One potential example is a refrigerator fitted with a ‘price sensitive’ smart device being programmed to avoid operation in the peak half hour of a day. This would mean that for this half hour, the expected demand side response was not available.

8.18 National Grid places value on obtaining access to the demand reduction on a timely basis and, most importantly, being certain that the demand reduction can be delivered. It would be helpful, therefore if domestic appliances could ‘report back’ their status to some extent. We speculate that the development pathways of smart grid technology and pre-programmed dynamic frequency response must eventually come together. For a small increase in data traffic, appliances could be set to a different ‘mode’ and provide different variations of Balancing Services.

8.19 The potential of the simple 'Dynamic Demand' service is however significant at the present time and we are supporting its development. We will seek to address a number of questions which we have regarding a full scale long term roll-out of the technology during these trials. This includes the measurability and controllability of the service over the lifetime of appliances.

[20] Figures derived from the report titled "The potential from dynamic demand" which is available at: http://www.berr.gov.uk/files/file49040.pdf

8.20 We are conscious for example that if larger generating units connect to the transmission system our frequency control service requirement may change in emphasis to static provision (provided at a set frequency on a number of occasions per year) rather than dynamic provision and that this may be more suitable for domestic appliances.

Electric Vehicles

8.21 Service providers (or aggregators) could provide a range of Balancing Services by modifying the charging characteristics of the vehicle fleet. A simple Balancing Service might be based on parts of the vehicle fleet commencing or ceasing charging in response to a signal from the System Operator or a service aggregator.

8.22 Electric vehicle batteries are currently expensive and the value to the consumer of providing any services must exceed both the cost of battery depreciation and any loss in vehicle utility (such as reduced range). Battery technologies are discussed further below.

8.23 The value which an electric vehicle can capture through Balancing Services is hard to estimate, given the range and mix of services, the value of these services to the, and uncertainty over the capability of the electric vehicle charging technologies. We do not at this stage regard Balancing Services revenue as a significant purchase incentive for electric vehicles in its own right but intend to work with partners better to understand the capability of electric vehicle technology to provide balancing and other energy services.

Question 35. What is your view on the potential of electric vehicles to provide balancing and other energy services?

Potential for New Demand Management Services

8.24 We have performed some simple modelling of domestic appliances and light industrial loads to understand the potential for new demand reduction services, in MW (power) terms, from the range of loads and appliances in the market. This is both to inform our view and stimulate external debate on the potential for providing balancing and other services to us, energy suppliers and Distribution Network Operators.

8.25 We have drawn upon data collected by the Market Transformation Programme[21] (MTP) and our own 'Gone Green' scenario analysis. We have used the MTP's projections on energy usage by appliance and industrial load in 2020. For each appliance/load, we made broad assumptions to derive some indication of the potential for modulating the power in response to the requirements of a system operator, supplier or distribution company.

8.26 For example, a refrigerator can draw about 100 Watts of power. However, if the compressor is only on for 20% of the time, then, for a population of refrigerators, only 20% of the power is available for 'switching off'.

8.27 MTP has developed a number of scenarios in their work describing the energy requirement for future domestic appliances. The scenario which we have chosen and which we feel is more sympathetic with the underlying drivers of Gone Green is called "Earliest Best Practice" (EBP) which factors in

[21] Website: http://www.mtprog.com/

significant energy saving innovations (which in turn impacts on the potential for demand management).

8.28 The output for the model is shown graphically in Figure 22 below. Wet appliances comprise washing machines, washer dryers and dishwashers. Domestic refrigeration includes refrigerators, freezers and combined units. Industrial refrigeration includes the range of devices from process chillers and cold cellar air conditioning to refrigerated vending machines. Finally air conditioning contains package and other air conditioning appliances.

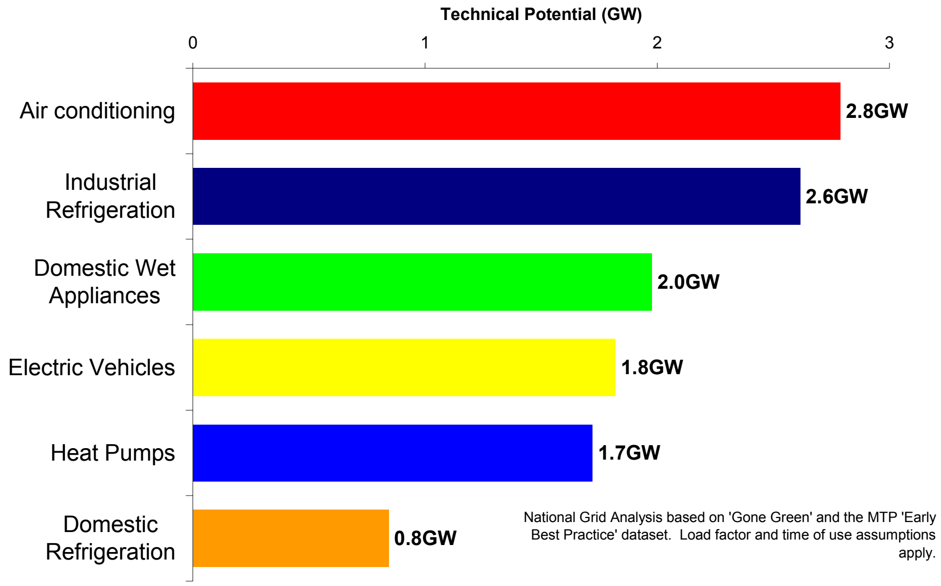

Figure 22: Indicative Potential for Demand Management from Specific Domestic and Light Industrial sectors in 2020

8.29 There are three points that this analysis brings out:

- Almost 33% (in this model) of the demand side potential lies in the new technologies of electric vehicles and heat pumps facilitated by domestic 'smart' control systems.
- Domestic refrigeration and wet appliances together form about 25% of the potential, again facilitated by domestic 'smart' control systems.
- Industrial refrigeration and air conditioning represent about 50% of the potential in this simple model, a proportion of which could be accessed through existing energy management infrastructure.

8.30 The GW power value expressed in the diagram represents the instantaneous power demand which might be manipulated if a signal were sent the full range of appliances in the year 2020. A straight forward arithmetic sum of the ‘slices’ is not reflective of the potential at any one point in time. This is because electric vehicles for example will charge mainly at night and industrial air conditioning might also be expected to be on mostly during the day in the warmer parts of the year.

8.31 In this simple model, the technical potential for new demand side services in 2020 sums up to 11 GW. Assuming 75% of this can be accessed as a useable service, this translates into a technical potential of 8GW, given investment in the necessary infrastructure and willingness to change behaviours. The useable service volume is likely to be less than this, depending on how long any demand management action can be or needs to be sustained for.

8.32 We recognise that energy suppliers and other network operators will also value this capability and may be better placed to take advantage of it in some cases.

Large Industrial Providers

8.33 Currently National Grid has agreements with large industrial users who have the ability to temporarily switch off their load at our request or using a low frequency relay. Predominantly these sites have favoured the provision of frequency response services.

8.34 We are keen to expand the volume of services from large installations. However a significant expansion would be dependant on large scale energy users choosing to locate in Great Britain.

Question 36. How much of the electricity demand in Great Britain do you think could be regarded as discretionary or deferrable and hence available for use as a Balancing Service or other energy service?

Question 37. What specific actions should National Grid take to facilitate Balancing Services from demand-side providers while maintaining the required quality and volume of service?

Storage Technologies

8.35 Several different storage technologies currently exist in varying states of commercial readiness. The underlying value of storage is determined by the price differential between peak and off peak power prices, the ability to 'cycle' the technology and the potential revenues available from Balancing Services.

8.36 Table 12 lists the most advanced storage technologies and some of their key parameters at the present time.

Technology	Average Efficiency	Largest Current Capacity	Life (Years)	Cycle Life	Development Status
Pumped Storage	65-80%	> 2 GW	>50	>10,000	Commercial
CAES (Compressed Air Energy Storage)	75%	300MW	>30	Not Available	Commercial
Flywheel	85-90%	20 MW	20	Not Available	Demo & Commercial
Supercapacitor	90-99%	1 MW	10	>100,000	Demo & Commercial
Zinc Bromide Battery	70%	0.5 MW	>20	2,000 @ 100% DOD	Demo
Sodium Sulphur Battery	75-80%	10 MW	12-15	2,500 @ 100% DOD	Demo & Commercial
Nickel Cadmium Battery	60-65%	46 MW	15	>1,000	Demo & Commercial
Lithium Ion Battery	86-93%	1 MW	7	16,000 @ 100% DOD	Demo & Commercial
Lead Acid Battery	70-80%	20 MW	5-10	1,200 @ 80% DOD	Commercial

Table 12: Comparison of Energy Storage Technologies

Pumped Storage

8.37 Currently pumped storage is the most widespread and mature electrical energy storage technology within the GB market. Generating capacity stands at 2.7GW with pumping capacity of a similar level giving a significant potential regulating range of greater than 4GW.

8.38 We are not aware of any immediate plans for new pumped storage stations within Great Britain and have assumed that the current facilities will continue in operation.

CAES (Compressed Air Energy Storage)

8.39 This technology uses electricity to power a generator which drives compressors that force air into a storage reservoir at high pressure. During peak demand periods the air is withdrawn, heated in gas or oil fired combustors and expanded through turbines to drive a generator.

8.40 Like water based storage, development of large scale CAES is limited geographically by the requirement for an appropriate features such as salt cavities.

8.41 Further developments of the technology include a wind turbine air compressor which instead of producing electricity directly pumps air into the CAES facility.

Battery Technology

8.42 Many different battery technologies are currently being developed or used on a commercial basis. The table below illustrates the main advantages and disadvantages of the most prominent existing technologies.

Type	Technology	Advantages	Disadvantages
Zinc Bromide flow battery (ZnBr)	Electrochemical reaction between two salt solutions	Capable of sustaining a long discharge period	Poor at delivering reactive power
Sodium Sulphur battery (NaS)	Positive sulphur electrode and Negative Sodium electrode separated by alumina conductive ceramic	Demonstrated at a utility scale	Scaling of NaS systems is more expensive than scaling of flow batteries
Nickel Cadmium battery (NiCd)	Nickel hydroxide positive electrode separated from a cadmium negative electrode	Mature technology that can be scaled into a relatively large system	Technology suffers from a memory effect and must be periodically exercised. Cadmium is also highly toxic
Lithium Ion (Li-ion)	Amongst newest rechargeable technology, being improved continuously	High energy density, development focussing on electric vehicles. Large R&D investment in technology	Large scale application still limited
Lead Acid (PbA)	Mature technology, oldest rechargeable battery in existence	Relatively inexpensive compared to other batteries	Short life cycle, lowest energy density

Table 13: Comparison of Battery Technologies

Flywheel

8.43 A flywheel energy storage system draws power from the grid and stores the energy in a high density rotating flywheel. When the energy is required the motor driving the flywheel acts as a generator. As the flywheel continues to rotate the generator delivers power back to the grid.

8.44 This technology is currently most suited to providing frequency response and acting as back up power for critical loads. It may also be useful in the future in providing inertia as the number of generation facilities connected via power electronics increases.

Supercapacitor

8.45 Supercapacitor technology stores energy electrostatically for the release of power over a very short time period. A supercapacitor polarizes an electrolytic solution enabling it to store energy electrostatically. No chemical reaction takes place. This system has the advantage of being highly reversible so that the device can be charged and discharged hundreds of thousand of times. As it does not rely on slow chemical reactions, discharge can be far more rapid.

Question 38. Are there further aspects of storage or other storage technologies we should consider when looking forward to 2020?

Generation

8.46 The final source of future Balancing Services we discuss is from further conventional electricity generation. The most likely source of additional reserve services would seem to be from plant in the form of Open Cycle Gas Turbines (OCGTs), CCGTs operating (potentially in open cycle mode) or from large reciprocating engines.

8.47 The carbon emissions for each unit of energy produced by these forms of generation could be high compared to other generation. However, our requirement for reserve is quantified in terms of capacity and not in running hours (ie low load factor generation can contribute). Therefore their lower capital cost could mean that OCGTs are a viable source of Balancing Services and of flexibility to the energy market.

8.48 Appropriately sized OCGTs could also contribute to Black Start requirements as well as providing other network services.

Question 39. What are the prospects for the provision of Balancing Services from new OCGTs or other 'Back-Up' generation?

Applicability of Technologies to Different Balancing Services

8.49 Table 14 summarises our view of the Balancing Services that can be provided or enabled by the technologies described above.

	Frequency Response	Fast Reserve	Fast Start	STOR	Energy Balancing	Reactive Power	Black Start
Pumped Storage	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Compressed air storage	Yes	No	No	Yes	Yes	Yes	Yes
Flywheel	Yes	Yes	No	No	No	Yes	No
Supercapacitor	Yes	No	No	No	No	No	No

	Frequency Response	Fast Reserve	Fast Start	STOR	Energy Balancing	Reactive Power	Black Start
Battery Technologies[22]	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Dynamic Demand	Yes	No	No	No	No	No	No
Smart Metering	Yes	Yes	Yes	Yes	No	No	No
Electric Vehicles	Yes	Yes	Yes	Yes	No	No	No
Large Industrial sites	Yes	Yes	Yes	Yes	No	Yes	No
Interconnectors	Yes	Yes	Yes	Yes	Yes	Yes	Yes
OCGT Generation	Yes	Yes	Yes	Yes	Yes	Yes	Yes

Table 14: Mapping of Technology to Balancing Service Capability

Question 40. Is our mapping of technology to Balancing Services reasonable?

Meeting the Future Requirement

8.50 Our expectation that our reserve requirement will grow in a period where the generation fleet within Great Britain is changing significantly has led us to consider developing a statement of our long term Balancing Services requirement.

8.51 This could cover a period of 5 to10 years ahead and would highlight the volume of reserve services that National Grid considers it will need to procure. We think that this would be useful to potential providers of Balancing Services and energy market stakeholders.

Question 41. Is a statement of National Grid's view of its long term Balancing Services requirement useful to industry stakeholders?

Question 42. What period should a long term Balancing Services Requirement statement cover?

8.52 We also intend to keep our technical and commercial service criteria under review to ensure that required volume and quality of service is available to us and develop a suite of services which:

- Continue to offer specific solutions to National Grid's need for services that can help re-establish response holding, provide regulating reserve and cope with plant loss and demand forecast errors.
- Allow National Grid to signal to the market what capabilites are valued most.
- Accommodate a range of operational characteristics:
  - Differing size of service provision;
  - Differing response times to instructions; and
  - Differing duration of service provision.
- Create a more transparent and standardised contractual basis where possible.

[22] Not all battery technologies can provide the whole suite of services.

- Procure services on a flexible basis where sufficient alternative capacity is available.

8.53 We recognise that some new technologies could see National Grid as the sole or largest customer of their technology in Great Britain. This contrasts considerably to the historical provision of services by generators which view revenue from Balancing Services as a supplementary income stream rather than the principal one. Developers may hence ask for some form of commitment on revenue streams from National Grid to initiate the commercialisation of the services.

8.54 We also recognise that new and existing technologies can provide services which could be useful to energy suppliers. It may not be appropriate for potential providers to invest in order to meet our specific technical requirements if their capabilities could deliver value to the wider energy market.

Question 43. What changes to the current reserve products would better encourage the provision of reserve services?

Question 44. What actions would ensure that procurement of reserve services does not impact adversely on the efficient operation of the wholesale energy markets?

<<END>>

Appendix A Derivation of Reserve Levels

The process we use for deriving the Short Term Reserve Requirements we discuss in this document is outlined below. The reserve levels we use in real time vary with time of day, day of week and season and take account of energy market conditions and specific contingencies. However, the principles we describe below are still applicable.

Define URE, DFE and WFE as follows:

$$URE_{4ha} = \sum_{PN_{4ha}>0} MEL_{4ha} - \sum_{FPN>0} MEL_{RT}$$

$$DFE_{4ha} = Demand_{Actual} - Demand\_Forecast_{4ha}$$

$$WFE_{4ha} = Wind\_Generation\_Forecast_{4ha} - Wind\_Genereration\_Meter$$

Terms are described as follows, all in MW:

> URE = Upward Reserve Error (conceptually the amount of conventional plant failure)
> DFE = Demand Forecast Error.
> WFE = Wind Forecast Error
> MEL = maximum export limit (an 'on-the-day' measure of capacity)
> PN = physical notification
> FPN = the final PN
> 4ha is “4 hours ahead”
> RT is “real-time”

We combine URE, DFE and WFE to give us a measure of the forecast errors we need to cater for. A reserve level is chosen so that we are confident that in a given half-hour we have enough reserve to cater for forecast errors on all but 1 day a year (a 1 in 365 probability).

We then add on a level of Reserve for Response in order to part load units and put them on frequency response. Reserve for Response is a function of demand and the largest loss on the system.

From observation at Winter Peak demand, typical means and standard deviations are:

> DFE is normally distributed with mean=0MW, std=450MW
> URE has mean 600MW, std=600MW
> WFE has mean of zero and standard errors that depend on level of dispersion.

Appendix B Generation Assumptions

Generation Capacity in 'Gone Green' Scenario

	2010/ 11	2011/ 12	2012/ 13	2013/ 14	2014/ 15	2015/ 16	2016/ 17	2017/ 18	2018/ 19	2019/ 20	2020/ 21	2021/ 22	2022/ 23	2023/ 24	2024/ 25	2025/ 26
Wind	3.2	4.2	6.3	8.1	9.8	11.3	13.5	16.2	20.7	24.7	29.4	30.4	31.4	32.3	33.3	34.2
Wave and Tidal	0	0	0	0	0	0	0.1	0.2	0.6	1.1	1.4	1.5	1.6	1.7	2.1	2.4
Biomass	0.1	0.4	0.6	0.6	0.6	0.8	0.8	0.8	0.8	0.8	0.8	0.8	1.1	1.1	1.1	1.1
Gas (CCGT+CHP+MGT)	29.7	30.5	32	32	32.9	34.2	33.7	34.8	34.6	34.6	34.6	33.5	34.2	34.8	33.1	31.3
OCGT	0.8	0.8	0.8	0.7	0.6	0.4	0.4	0.4	0.4	0.3	0.3	0.3	0.3	0.3	0.3	0.2
Coal	28.4	28.4	27.4	25.4	24.3	23.1	23.1	22.7	20.8	19.8	19.8	19.8	16.8	16.8	15.8	13.9
Hydro	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
Pumped Storage	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7
Oil	3.4	3.4	3.4	3.4	3.4	0	0	0	0	0	0	0	0	0	0	0
Nuclear	9.4	9.4	9.4	9.4	9.4	9.4	7.1	7.1	6	5.3	6.9	6.9	8.6	8.6	9.7	9.7
Interconnectors	2	3.2	3.7	3.7	3.7	3.7	3.7	3.7	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2
Total Generation Capacity	**80.8**	**84.1**	**87.4**	**87.1**	**88.5**	**86.7**	**86.2**	**89.7**	**91.9**	**94.6**	**101.2**	**101.2**	**102**	**103.6**	**103.4**	**100.8**

Generation assumed available at winter peak (applying Table 6 availabilities)

	2010/ 11	2011/ 12	2012/ 13	2013/ 14	2014/ 15	2015/ 16	2016/ 17	2017/ 18	2018/ 19	2019/ 20	2020/ 21	2021/ 22	2022/ 23	2023/ 24	2024/ 25	2025/ 26
ACS peak restricted demand (GW)	59.4	59.6	59.9	60.1	60.4	60.4	60.3	60.2	60.1	59.9	59.6	59.4	59.2	59	58.8	58.7
Demand + Net Average STORR (GW)	63.5	63.8	64.3	64.8	65.3	65.4	65.6	65.8	66.2	67.1	67.5	67.4	67.4	67.3	67.3	67.3
Assumed Generation Availability at Winter Peak (GW)																
Wind	3	3.9	5.9	7.4	9	10.3	12.3	14.6	18.6	22	26.1	27	27.8	28.6	29.5	30.3
Wave and Tidal	0	0	0	0	0	0	0	0.1	0.5	1	1.3	1.4	1.4	1.5	1.9	2.2
Biomass	0.1	0.4	0.5	0.5	0.5	0.7	0.7	0.7	0.7	0.7	0.7	0.7	1	1	1	1
Gas (CCGT+CHP+MGT)	26.7	27.5	28.9	28.9	29.6	30.8	30.3	31.4	31.1	31.1	31.1	30.2	30.8	31.4	29.8	28.2
OCGT	0.7	0.7	0.7	0.6	0.6	0.4	0.4	0.4	0.4	0.3	0.3	0.3	0.2	0.2	0.2	0.2
Coal	24.1	24.1	23.3	21.6	20.7	19.6	19.6	19.3	17.7	16.9	16.9	16.9	14.3	14.3	13.5	11.8
Hydro	0.6	0.6	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
Pumped Storage	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6
Oil	3.3	3.3	3.3	3.3	3.3	0	0	0	0	0	0	0	0	0	0	0
Nuclear	7.6	7.6	7.6	7.6	7.6	7.6	5.7	5.7	4.8	4.3	5.7	5.7	7.1	7.1	8	8
Generation assumed available (I/C at Float)	**68.7**	**70.7**	**73.4**	**73.2**	**74.5**	**72.7**	**72.3**	**75.5**	**77.1**	**79.6**	**85.4**	**85.4**	**85.9**	**87.4**	**87.1**	**85**

Appendix C STORR costs

			2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26
Requirement (TWh)		Base STORR Volume	2.95	2.95	2.95	2.95	2.95	2.95	2.95	2.95	2.95	2.95	2.95	2.95	2.95	2.95	2.95	2.95
		Wind STORR Volume	0.19	0.29	0.55	0.76	0.96	1.10	1.32	1.57	2.03	2.34	2.98	3.11	3.32	3.53	3.74	3.96
		Larger Infeed Loss STORR Volume							0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30
		Loss of Flexible STORR Volume										1.14	1.14	1.15	1.15	1.15	1.16	1.16
		Annual NET STORR Volume	3.13	3.23	3.49	3.71	3.90	4.04	4.57	4.82	5.28	6.73	7.37	7.51	7.72	7.93	8.15	8.37
Offer Price (£/MWh)	Coal	Offer Price	102	102	102	102	102	102	102	102	102	102	102	102	102	102	102	102
		Multiplier	2.06	2.06	2.06	2.06	2.06	2.06	2.06	2.06	2.06	2.06	2.06	2.06	2.06	2.06	2.06	2.06
		Baseload Power Price	49.7	49.7	49.7	49.7	49.7	49.7	49.7	49.7	49.7	49.7	49.7	49.7	49.7	49.7	49.7	49.7
	Gas	Offer Price	136	136	136	136	136	136	136	136	136	136	136	136	136	136	136	136
		Multiplier	3.25	3.25	3.25	3.25	3.25	3.25	3.25	3.25	3.25	3.25	3.25	3.25	3.25	3.25	3.25	3.25
		Fwd Fuel price expressed in £/MWh	41.79	41.79	41.79	41.79	41.79	41.79	41.79	41.79	41.79	41.79	41.79	41.79	41.79	41.79	41.79	41.79
	OCGT	Fixed Value	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200
	Oil	Fixed Value	395	395	395	395	395	395	395	395	395	395	395	395	395	395	395	395
	Hydro	Fixed Value	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175
	Pumped Storage	Fixed Value	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175
	UK Trade	Peak Power Price	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61
	Interconnector Trade	Trade Price	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98
	Interconnector SOSO	Fixed Value	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90
	Energy Balancing Price	Pseudo Price (£/MWh)	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63
Volume (TWh)	COAL		1.07	1.10	1.15	1.11	1.12	1.15	1.30	1.35	1.34	1.61	1.77	1.80	1.53	1.58	1.51	1.33
	GAS		0.97	0.95	1.02	1.14	1.27	1.35	1.65	1.56	1.84	2.45	2.69	2.74	3.14	3.23	3.43	3.75
	OCGT		0.08	0.08	0.09	0.08	0.08	0.05	0.05	0.06	0.06	0.07	0.08	0.07	0.06	0.06	0.07	0.06
	OIL		0.09	0.09	0.10	0.10	0.11	0.11										
	HYDRO		0.05	0.05	0.05	0.06	0.06	0.06	0.07	0.07	0.08	0.10	0.11	0.11	0.12	0.12	0.12	0.13
	PUMPED STORAGE		0.31	0.32	0.35	0.37	0.39	0.40	0.45	0.48	0.52	0.66	0.73	0.74	0.76	0.78	0.80	0.83
	UK TRADE		0.29	0.30	0.33	0.35	0.37	0.38	0.43	0.45	0.50	0.63	0.69	0.71	0.73	0.75	0.77	0.79
	Interconnector Trade		0.18	0.22	0.27	0.32	0.34	0.35	0.40	0.56	0.62	0.79	0.86	0.88	0.90	0.93	0.95	0.98
	Interconnector SOSO		0.10	0.12	0.14	0.17	0.18	0.19	0.21	0.30	0.32	0.41	0.45	0.46	0.47	0.49	0.50	0.51
	Total		3.13	3.23	3.49	3.71	3.90	4.04	4.57	4.82	5.28	6.73	7.37	7.51	7.72	7.93	8.15	8.37
Cost (£m)	COAL	£m	42.2	43.5	45.2	44.0	44.1	45.4	51.3	53.2	52.7	63.6	69.7	71.0	60.5	62.2	59.5	52.4
	GAS	£m	70.7	69.4	74.5	83.5	92.4	98.6	120.7	113.5	134.5	178.5	195.8	200.0	229.1	235.4	250.0	273.5
	OCGT	£m	10.5	10.8	11.7	10.8	10.8	6.6	7.4	7.8	8.6	9.9	10.9	10.0	8.6	8.8	9.0	8.4
	OIL	£m	28.9	29.8	32.2	34.2	36.0	37.3									0.0	0.0
	HYDRO	£m	5.3	5.5	5.9	6.3	6.6	6.8	7.7	8.2	8.9	11.4	12.0	12.2	13.1	13.4	13.8	14.2
	PUMPED STORAGE	£m	34.7	35.8	38.7	41.1	43.2	44.8	50.6	53.4	58.5	74.5	81.6	83.1	85.4	87.8	90.2	92.7
	UK TRADE	£m	-0.6	-0.6	-0.6	-0.7	-0.7	-0.7	-0.8	-0.9	-0.9	-1.2	-1.3	-1.3	-1.4	-1.4	-1.5	-1.5
	Interconnector Trade	£m	6.3	7.7	9.5	11.3	11.9	12.3	13.9	19.5	21.4	27.3	29.9	30.4	31.3	32.1	48.5	65.7
	Interconnector SOSO	£m	2.6	3.1	3.9	4.6	4.9	5.0	5.7	8.0	8.8	11.2	12.3	12.5	12.8	13.2	13.6	13.9
	BM StartUP		17.8	18.4	19.4	19.6	20.1	20.7	12.9	13.3	13.2	16.0	17.5	17.8	15.2	15.6	14.9	13.1
	BM STOR Utilisation		13.6	13.9	14.5	15.2	16.0	16.8	18.0	19.7	22.6	25.4	31.6	32.3	33.1	33.8	34.6	38.5
	NBM STOR Utilisation		9.1	9.3	9.7	10.2	10.7	11.2	12.1	13.2	15.2	17.0	21.1	21.6	22.1	22.6	23.1	25.8
	BM STOR Option Fees		56.2	56.2	56.2	56.2	56.2	56.2	61.8	61.8	61.8	61.8	68.0	68.0	68.0	68.0	68.0	74.8
	NBM STOR Option Fees		14.1	14.1	14.1	14.1	14.1	14.1	15.5	15.5	15.5	15.5	17.1	17.1	17.1	17.1	17.1	18.8
	Total (£m)		311	317	335	350	366	375	377	386	421	511	566	575	595	609	641	690
		Base STORR costs (£m)	293.0	288.9	282.5	278.3	276.3	273.3	242.9	235.9	234.7	223.6	226.2	225.5	227.1	226.1	231.7	242.9
		Wind STORR costs (£m)	18.4	28.0	52.5	72.1	89.9	101.8	108.7	126.1	161.9	177.7	228.7	238.2	255.6	270.7	294.4	326.9
		Larger Infeed Loss STORR costs (£m)										86.5	87.9	87.8	88.7	88.5	90.9	95.4
		Loss of Flexible Plant STORR costs (£m)							25.1	24.4	24.2	23.1	23.3	23.3	23.4	23.3	23.9	25.1

Appendix D Description of Balancing Services

Frequency Response

National grid has a licence obligation to control frequency, i.e. ±1% of nominal system frequency (50.00Hz) save in abnormal or exceptional circumstances. Therefore National Grid must ensure that sufficient generation and or demand is held in automatic readiness to manage all credible circumstances that might result in a frequency variation. This is either provided on a Dynamic or Non Dynamic basis. In the former, loads automatically regulate themselves in response to second by second changes on the system frequency. In the latter, the service is triggered at a defined frequency deviation.

Three separate services are currently procured to manage frequency: Mandatory Frequency Response, Firm Frequency Response (FFR) and Frequency Control by Demand Management (FCDM).

Reserve Services

National Grid needs the ability to source extra power either in the form of increased generation or demand turndown, in order to deal with unforeseen demand increase and generation unavailability. The current range of ancillary services is made up of products that require differing response times so that operating reserve levels can be maintained. Starting with the quickest response time these services are listed below.

Fast Reserve

The service looks to provide the rapid delivery of active power via increased generation or reduced demand within two minutes of instruction. Once instructed the provider needs to be able to sustain output for a minimum of 15 minutes. The minimum size of instruction is 50MW for a single unit.

Fast Start

Currently provided by generation BMUs the service is for units to start rapidly, from a standstill condition, and automatically deliver power within five minutes from a low frequency relay or within seven minutes of a manual instruction. Output should be maintained for a minimum of four hours or until a cease instruction is given. Procurement is through bilateral contracts.

Demand Management

This is a service for the provision of reserve in contingency timescales, via a reduction of active power from demand sites. The provider must be able to deliver across two consecutive settlement periods and deliver a demand reduction of at least 25MW from one or more sites. Again procurement is through bilateral contracts.

Short Term Operating Reserve (STOR)

The STOR service can be provided by either generation or demand assets irrespective of whether they are a Balancing Mechanism Unit (BMU) unit or not. The minimum volume required is 3MW and can be provided from either a single site or an aggregation of sites. Delivery needs to be within four hours or less of instruction and should be able, if needed, to maintain MW level for at least two hours. Procurement is via a competitive tender process with services being provided on either a committed or flexible basis.

BM Start-Up

This product is procured to make sure that National Grid has on the day access to additional generation BMUs that would not otherwise be available in Balancing Mechanism timescales. The product is required to maintain contingent generation reserves in excess of forecast demand and to meet on the day demand plus reserve requirements. Procurement is conducted through bilateral commercial services agreements. Two elements exist to the product. The BM Start-Up product is for the provision of ‘energy readiness’ capabilities that can be converted into energy utilisation if required. The second part of the product is Hot Standby. This is a contractual agreement to hold a generator in a ‘state of readiness’ once a start up request has been made.

Reactive Power

National Grid requires reactive power services to help manage system voltage through the production or absorption of reactive power. The service is procured either through the mandatory provision of the service or through the enhanced reactive power services. The former is only provided by Generation BMUs where as the latter may be provided by both BMUs and Non BMUs and by generation or demand sites. The obligatory service is procured via either market agreements or default payment arrangements. For the enhanced service a tender round is run every six months.

Black Start

Black Start is the procedure to recover from a total or partial shutdown of the transmission system. In general most power stations need an electrical supply to start up. However under emergency conditions Black start stations would receive this supply from small onsite auxiliary generation. Procurement from generation BMU’s usually takes place via National Grid expressing interest to a new provider during their connections agreement. However National Grid may also express interest in determining the feasibility of retro-fitting the capability.

Intertrips

Intertrips are procured to automatically disconnect generation or demand when a specific event occurs so as to relieve post fault localised network overloads, maintain system stability and manage system voltage. There are two types of intertrip service that are currently procured: commercial intertrips and system to generator operational intertrips. Both types may be specified at the time of connection agreement with the former also negotiated on an ad-hoc basis.

System Operator (SO) to System Operator (SO) Services

These services are provided on a mutual basis with other transmission system operators that are connected to the GB Transmission system through interconnectors. The agreements set out a framework that allows System Operators to alter interconnector flows after the interconnector gate closure time. The SO to SO service covers two balancing services, Constraint management and Balancing

(CM&B) and Emergency Assistance. CM&B service provides a commercial means for each SO to vary the scheduled transfer limit in either direction for a pre determined price. This facility provides the SOs with the ability to procure any residual capacity to satisfy system requirements. Emergency assistance is used as a last resort when the SO is suffering from a shortfall of generation. The service is important in maintaining security of supply.

Maximum Generation

The maximum generation service allows access to capacity which is outside the generator's normal operating range and is only enacted in times of severe system stress. Currently the service is only provided by BMU specific generators.

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