June 2011

Operating the Electricity Transmission Networks in 2020

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Operating the Electricity Transmission Networks in 2020 June 2011 Update

Introduction

1. This document, an update to the Initial Consultation Report of June 2009, sets out National Grid's current analysis and views on operating the electricity networks in 2020. The initial consultation document that was published in June 2009 can be found on our website at http://www.nationalgrid.com/uk/Electricity/Operating+in+2020/

Industry Feedback

2. National Grid reviewed and reflected on the responses to the 2009 report and published the Follow Up Report to the initial consultation[1] in February 2010, which provided a summary of the feedback received on the consultation, together with an outline of how National Grid would proceed on the many points raised. In this 2011 report, feedback is requested on any views stated, and in addition to that, the usefulness of the content to refine our future reporting. To feed back comments on this consultation report please contact us at energy.operations@uk.ngrid.com

Roles and Responsibilities

3. The competitive gas and electricity markets in Great Britain have developed substantially in recent years and have successfully established separate roles and responsibilities for the various market participants. In summary, the provision of gas and electricity to meet consumer demands and contracting for capacity in networks is the responsibility of suppliers and shippers. National Grid has two main responsibilities: first, as the primary transporter, for ensuring there is adequate and reliable network capacity to meet anticipated transportation requirements; second, as system operator of the transmission networks, for the residual balancing activity in both gas and electricity. The structure of the markets and the monitoring of companies' conduct within it are the responsibility of Ofgem, whilst the Department for Energy and Climate Change (DECC) has a role in setting the regulatory framework for the market.

Legal Notice

4. National Grid operates the electricity transmission network through its subsidiary National Grid Electricity Transmission plc and the gas transmission network through its subsidiary National Grid Gas plc. For the purpose of this report "National Grid" is

[1] http://www.nationalgrid.com/uk/Electricity/Operating+in+2020

used to cover both licensed entities, whereas in practice our activities and sharing of information are governed by the respective licenses.

5. National Grid has prepared this consultation document in good faith, and has endeavoured to prepare this consultation document in a manner which is, as far as reasonably possible, objective, using National Grid's own knowledge and expertise together with reference to other reports published by third parties. While National Grid has not sought to mislead any person as to the contents of this consultation document, readers of this document should rely on their own information (and not on the information contained in this document) when determining their respective commercial positions. National Grid accepts no liability for any loss or damage incurred as a result of relying upon or using the information contained in this document.

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1 Foreword

1.1 This paper builds on the earlier work carried out under the *Operating the Electricity Transmission Networks in 2020*[2] consultation. The consultation identified a number of issues and associated challenges to operating the system by 2020, the majority of which arise as a result of a significant change in the GB generation mix. This paper considers further the issues pertaining to system balancing and builds on the issues identified in the previous consultation.

1.2 The underlying assumptions that formed the analysis described *Operating the Electricity Transmission Networks in 2020* are consistent with the 'Gone Green' Scenario described by the ENSG Vision of March 2009[3].

1.3 There are many potential scenarios that could materialise that would have different impacts on National Grid's role as National Electricity Transmission System Operator (NETSO). Therefore, many of the issues identified in this paper could be affected to a lesser or greater extent by other important influencing factors such as Electricity Market Reform (EMR) and future generation investment decisions.

1.4 In undertaking this assessment, the scenario provides a consistent basis for describing both the requirements for balancing services that will be necessary for National Grid as 'residual balancer' within the 'Gone Green' scenario context, whilst also identifying the potential size and future sources of service provision.

2 Executive Summary

2.1 The principal role of the National Electricity Transmission System Operator is to maintain the energy balance between generation and demand in an economic manner, whilst ensuring that this is achieved within the capability of the network. The ability to forecast system conditions and manage the risks inherent in operating a complex power network is vital to ensuring safe, secure and efficient system operation.

2.2 The operation of the Great Britain transmission system is fundamentally changing in the next 10 years, moving from a relatively predictable generation and demand base to one that includes a significant level of renewable generation with more variable output and demand that will become increasingly flexible, smart and price sensitive towards the end of the decade. Though they may not be a significant proportion of demand by 2020, new technologies such as electric vehicles, heat pumps and the

[2] http://www.nationalgrid.com/uk/Electricity/Operating+in+2020/Operating the Electricity Networks in 2020

[3] The ENSG home page is at http://www.ensg.gov.uk

introduction of smart meters across GB will gradually change the characteristics of demand, in an uncertain manner.

2.3 The design and operation of the transmission networks will change significantly not only as a result of the changing energy mix, but also as a result of the connection of offshore transmission assets and the connect and manage[4] regime.

2.4 The capability of the network must meet the requirements that will be placed upon it from the increased contribution of variable generation and demand profiles. The efficient development and design of the network will lead to a more complex control environment as more Quadrature Boosters (QBs), HVDC cables and compensation equipment are incorporated.

2.5 National Grid will play a leading role in shaping how our networks change and how they are operated, although it is important to note that 2020 is part of the journey towards the decarbonisation of the electricity industry and not the destination.

2.6 This consultation document provides an in depth assessment of the implications of these developments for operation of the balancing market and transmission networks and set out our view as to how these will change in the first stage of the transition between now and 2020. These views are summarised in the remainder of this Executive Summary.

Generation and Demand Assumptions (section 5)

2.7 The analysis undertaken in this document uses an updated view of National Grid's "Gone Green" scenario, which takes account of the electricity sector's contribution to meeting the targets set out in the UK renewable Energy Strategy.

Generation Type	**Capacity (GW)**	
	2010/11	**2020/21**
Coal	28.2	14.5
Coal (CCS)	0.0	0.6
Nuclear	10.8	11.2
Gas	31.9	34.7
Oil	3.4	0.0
Pumped Storage	2.7	2.7
Wind	3.8	26.8
Interconnectors	3.3	5.8
Hydro	1.1	1.1
Biomass	0.0	1.6
Marine	0.0	1.4
Total	**85.3**	**100.5**

[4] Connect & Manage was introduced by OFGEM to accelerate the connection of new generation based on the time taken to complete enabling works rather than waiting for wider reinforcements

2.8 In 2020, approximately 28% (26.7GW) of the transmission connected generation fleet[5] in Great Britain will consist of wind and other renewable technologies and they will play a significant role in meeting Great Britain's carbon reduction targets.

2.9 Assuming an average 30% load factor on wind, approximately 20% (70TWh) of average GB demand (320TWh) will be met through wind, compared to the current 3%.

2.10 The increase in intermittent renewable generation creates a greater envelope of uncertainty across all timescales and National Grid continually monitors the balance between demand and generation in order to assess whether there will be sufficient generation to meet demand and operating reserve requirements. The consequences of this increased level of uncertainty are considered further in this document.

2.11 The forecast of demand reflects the impact of the recession that occurred in 2008/2009, which National Grid believes resulted in a permanent loss in demand of approximately 2.5GW. Looking forward, the analysis takes into account economic growth and new demand from emerging technologies such as electric vehicles and heat pumps. This is offset by improvements in energy efficiency and an increase in embedded generation which reduces the growth in demand on the transmission networks. Peak demand is therefore assumed to be broadly similar to current demand levels out to 2020.

Operating Reserve Requirements and Costs (sections 6, and 11)

2.12 The change in the technology mix of the GB generation portfolio together with less stable demand profiles over the next 10 years will drive a significantly higher and more variable operating reserve requirement. This principally arises from the uncertainty and variability that result from the increased contribution from renewable and low carbon generation sources.

2.13 In the years leading up to 2020, the range of uncertainty in which National Grid operates will increase significantly as a larger proportion of generation scheduling becomes a function of dynamic weather systems. Whilst geographic dispersion of wind generation will smooth some of this volatility, the more predictable demand led scheduling of generation will gradually diminish. Therefore, it will be necessary to develop tools and processes that will assist in managing the risk around changes in the supply and demand balance and from a network perspective, fault resolution and congestion management across all operational timescales.

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[5] This assumes interconnector transfers at float

2.14 For example, National Grid expects to further improve forecast accuracy of wind generation. Based on analysis of current data from GB and Europe, it is currently assumed that wind output can deviate from forecast by 50%[6] over 4 hours however it is expected that this error could be reduced to around 30%[7] by 2020 through improved wind forecasting models.

2.15 Currently, the level of uncertainty pertaining to generation and demand can be forecast to a high level of certainty. This stems from an ability to forecast demand to a high level of certainty through a deep understanding of historical and intrinsic behaviours, experiential learning and sophisticated modelling techniques. The ability to forecast patterns of generation comes through economic analysis, knowledge of long term generation performance and a relatively stable demand profile that can be met through controllable and predictable sources of generation.

2.16 It is important to note that the future generation mix may be less flexible as a result of technical as well as commercial considerations, and this will have an impact on system operation costs. The latter has been recently demonstrated when it was necessary to reduce wind output in Scotland, either as a result of insufficient demand or reduced transmission capacity during outages.

2.17 This is likely to initially become evident where the minimum output across inflexible thermal plant, synchronised thermal plant (running for operating reserve) and high renewable output exceeds demand.

Operating at minimum demands

2.18 During periods of minimum demand, renewable generation output is likely to reflect prevailing weather conditions rather than price signals. Whilst the coincidence of high wind output during minimum demand periods will be infrequent, it will become increasingly necessary to restrict the output from wind generation onto the system to ensure sufficient thermal capacity is synchronised to meet the technical requirements of operating reserve. Under this scenario it is estimated that it may be necessary to curtail wind output on about 38 days per year by 2020, although the coincidence of high wind days with low demand periods may only be 3 times per year.

2.19 The amount of reserve required may be reduced as forecasting abilities improve and some response holdings are allocated to wind, however the cost of constraining wind will become increasingly significant, assuming costs reflect foregone Renewable Obligation Certificates (ROC) revenues.

2.20 Alternatives to constraining wind include the use of storage technologies or time of use tariffs as they become more prevalent after 2020. The operational value of

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[6] Root Mean Square Error (RMSE) is ~17% for 1 standard deviation which using the empirical rule for a normal distribution means we would expect output to differ from forecast by 17%, 68% of the time. RMSE 50% is error for 3 standard deviations This provides 99.7% certainty in accordance with GB SQSS

[7] See note 6

these solutions therefore extends beyond contributing to potential shortfalls in meeting peak demands during low wind periods.

2.21 There are however, many operational aspects pertaining to larger renewable generation sources where further experience and understanding will need to be developed, for example, the effect of high wind cut-out across larger wind farms and subsequently, the impact on system frequency.

2.22 Inevitably, in managing a greater range of credible risk, there will be a subsequent increase in the cost of managing this uncertainty. For our scenario the overall forecast for managing the variability in wind output is around £286M by 2020, whilst the forecast for procuring the full operating reserve requirement would rise to be between £565M and £945M.

Reserve for Response (section 7)

2.23 An increase in the generation in-feed loss limit from 1320MW to 1800MW in April 2014 will increase the holding of reserve for response. The higher requirement initially reflects the connection of large clusters of offshore wind farms and subsequently includes the expected connection of larger 1800MW generating sets toward the end of this decade. This will mean that additional response has to be held to cater for a larger in-feed loss.

2.24 The additional cost of holding more reserve against this higher response requirement is expected to increase by £44M in 2015/16 and by £55M in 2020/21.

Operating Margins in Gone Green (section 8)

2.25 The monitoring of operating margins is important both in the context of ensuring National Grid is able to provide information to market participants in a timely manner and more importantly, to understand whether there will sufficient generation capacity to perform its balancing role.

2.26 The analysis provides a view of operating margins consistent with the Winter Outlook Report methodology that discounts the output of the GB generation fleet to reflect historic plant performance.

2.27 Two approaches[8] have been used in respect to forecasting the contribution of wind generation towards operating margins for the next 10 years. Since the previous consultation, forecast operating margins have slightly improved, although both methodologies demonstrate the importance of the contribution from wind generation to operating margins. A considerable narrowing of operating margin is expected after 2015, concurrent to plant closures associated with the Large Combustion Plant Directive (LCPD).

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[8] The first is consistent with National Grid's Winter Outlook methodology for thermal capacity, then applying average load factor for wind. The second applies Equivalent De-rated Capacity (EDC) methodology developed by Dr Chris Dent of Durham University

Thermal plant operating regimes (section 9)

2.28 The increased contribution from wind will reduce the load factor of thermal plant, particularly the more expensive marginal plant. Additionally the variable nature of wind means that thermal plant will have to operate in an increasingly flexible manner.

2.29 It is expected that the Combined Cycle Gas Turbines (CCGT) fleet can cope with the enhanced operating regimes but there will be a consequential operating and maintenance cost.

2.30 The analysis in this paper suggests that higher reserve requirements will moderate the impact of more renewable generation on thermal plant load factors, whilst the flexibility will fall on the higher merit thermal plant, which in this case tends to be CCGT.

2.31 An increase in starts of 26% is expected across the CCGT fleet, together with a 6% fall in load factor. Whilst a larger fall in load factor of approximately 12% on the most marginal plant will occur, the number of starts will reduce, as when it does run it tends to be for extended periods during low wind output.

Interconnectors (section 10)

2.32 Interconnector capacity is forecast to almost double from 3GW[9] to 5.7GW by 2020. The additional interconnectors will improve access to other European markets and the benefits thereof; but they will also bring additional complexity to the transmission network.

2.33 The analysis demonstrates an increasing contribution from interconnectors in meeting peak demand. Based on our scenario, from 2018, it is probable that imports to Great Britain across interconnectors will assist in meeting peak demand when the contribution from wind drops below 16% of capacity.

2.34 This increasing contribution from interconnectors reinforces the need for a transparent common European market to facilitate energy trading across borders. However it can also be expected that coincident high pressure weather patterns across Europe, leading to a widespread reduction in wind generation output, will occur and the market framework will need to identify contingencies for dealing with an overall deficit in generation capacity to meet demand.

2.35 Furthermore, as transmission system operators harmonise grid and balancing codes across Europe by 2014, it is expected that trading opportunities will increase.

2.36 Therefore it is expected that there will be an increase in the variability of flows over the interconnectors. However, some of the existing tools currently used by National Grid in balancing and congestion management to manage flows on the GB-France

[9] This does not include the intra GB Moyle interconnector from Scotland to Northern Ireland

(IFA[10]) interconnector, such as pre-gate trading, will no longer be available. In parallel, European Network and Balancing codes are being developed to harmonise congestion management and the allocation of capacity. These latter developments will provide the opportunity for closer co-operation between connected NETSOs for balancing and ancillary services.

2.37 The important contribution interconnectors will make towards the provision of adequate plant margins makes it an imperative that price signals in both wholesale markets and cash-out arrangements emerge in GB that will ensure imports through interconnectors occur; particularly as extended cold periods often correlate with lower wind output. Therefore, contrary to our historical approach, interconnectors will need to be included, as part of the margin calculations, i.e. recognising their contribution to security of supply.

2.38 National Grid believes that progression towards more day-ahead market coupling between national markets will provide the appropriate pricing signal in prompt or day-ahead timescales, although it is important to note that appropriate incentives for intra-day are maintained through the cash-out mechanism.

2.39 Furthermore it will be increasingly important that bi-lateral and multi-lateral agreements emerge between NETSOs to provide short term mitigation against variations in interconnector flows that may impact on the national transmission system.

Embedded Generation (section 13)

2.40 National Grid expects that there will be a significant increase in embedded generation, consisting of approximately 7GW of CHP and 8GW from other technologies such as photovoltaic (PV), energy from waste (EfW), biomass and anaerobic digestion (AD). The first year of operation under the Feed in Tariff Scheme (FITs) has seen an additional 50MW of photovoltaic generation commissioned. This level of trend growth would meet the National Grid Gone Green scenario of 1.5GW by 2020.

2.41 This higher level of embedded generation will have a significant bearing on the level of demand “seen” from the transmission network. National Grid will require improved visibility of metered output from embedded generation sources and a good understanding of intrinsic demand levels at the transmission/distribution networks interface (GSP) level in order to support super grid transformer outage placement and forecast total demand requirements.

[10] Interconnector France-Angleterre

Storage (section 14)

2.42 Storage could play a significant role, principally acting as wind or PV "sinks" to maximise the utilisation of low carbon energy, although there are significant hurdles around the economics of the current potential technologies.

2.43 Certain storage technologies have the potential to complement CHP and PV generation, through the use of thermal stores and utility scale battery technologies. In addition, new technologies such as electric vehicles and heat pumps provide technically viable storage mediums.

2.44 Larger scale battery technologies[11] in particular do have the potential to provide other ancillary services such as fast reserve, voltage support etc. as well as more obvious applications of storing cheap energy for use over more expensive periods. As ~70% of the total energy supply cost results from the underlying cost of electricity, there should be significant value to suppliers in storage, however from an ancillary services perspective alone, they are not competitive against other alternatives.

2.45 The use of storage technologies aligned to PV generation and demand could play a significant role. In particular looking beyond 2020, the potential contribution or requirement for storage could be increasingly significant to Distribution Network Operators (DNOs), who may use storage to manage embedded generation.

2.46 There is considerable value in storage across the entire supply chain but perhaps insufficient for any discrete part. National Grid believes that suitable funding streams for using innovative storage technologies should be established so that they are developed and supported in the intervening years in order that all stakeholders can consider how such technologies could be applied making them viable in later years.

2.47 Whilst not considered within this paper, National Grid believes that large scale hydro such as pumped storage could provide the necessary system level flexibility and make a significant contribution to the security of supply. However it is difficult to identify how the economic investment would work within the current market framework.

[11] We do not consider vehicle to grid (V2G) services as economically viable in the near term due to additional costs that be incurred to make them export capable.

Demand Side Potential (section 15)

2.48 Over the longer term (post 2020) it is expected that the GB demand profile will gradually flatten as smart metering and time of use tariffs become more widespread. However, the current demand profile often contains high peaks of short duration and this is where it is envisaged that demand side could play a more immediate role.

2.49 A higher level of flexibility from thermal generation will be required to manage the greater level of uncertainty in generation output. It is National Grid's view that the demand side could play a significant role in providing some of this required flexibility and National Grid has actively promoted and been successful in the integration of demand side services over recent years under the Short Term Operating Reserve (STOR) framework. Indeed, during TRIAD periods, reduction in demand of between 0.5GW and 1.0GW are typically experienced. Looking forward, National Grid forecasts that a total of 2.0GW of demand response across the peak could be feasible by 2020.

2.50 From a system balancing perspective, it is more likely that the industrial and commercial sectors could provide reserve. For example, in larger premises, utilising thermal inertia through interruption of heating ventilation and air conditioning (HVAC) systems could provide significant demand reduction with minimal impact on the customer.

2.51 Likewise, from a supplier perspective there is significant demand at a domestic level that could be captured simply from domestic appliances, whilst towards the end of the decade, time and volume aggregation of electric vehicle demand and heat pumps could also be of consequence.

2.52 Importantly, in order to capture the potential of demand at a domestic level, a mandatory requirement to have the relevant equipment fitted to domestic appliances is needed. The cost of incorporating at manufacture is low, whereas the cost benefit of retro-fit is unlikely to be attractive to the end user.

Demand Side Services: Enablers and Operation (sections 16 and 17)

2.53 In sections 16 and 17 certain enablers are identified that could increase the potential sources of demand side response services. The operational relationships between NETSO, DNOs and other participants will necessarily have to be enhanced and a possible operational framework is outlined around which such services could be delivered. This subject is at an early stage of development and respondents' views on these ideas would be welcome.

Control of the Transmission Network and Enhanced SO Capability (sections 12 and 18)

2.54 The combination of increasing wind and embedded generation, together with a greater level of interconnection to Ireland and continental Europe will mean that at a national and regional level, the transmission network will be required to operate with more flexibility in order to cope with more variable transmission flows and voltage conditions.

2.55 The transmission system will have to operate in an increasingly flexible manner and will necessarily require more operating points and controls, for example to re-optimise power flows by tapping quad boosters more frequently or changing the flow across DC links integrated within the AC network.

2.56 The greater variability in generation will inevitably increase the number of energy balancing actions enacted by National Grid. In the first 2020 consultation[12] an estimate of a three fold increase in balancing actions was suggested and responses to the consultation generally agreed that the level of balancing activity will increase. Whilst balancing activity instructed by National Grid will be driven by the incentive on market participants to balance, it will be increasingly necessary to despatch generation and demand automatically.

2.57 In order to cope with these increased demands there will need to be a step change in operational systems capability beyond energy despatch. To ensure efficient operation of transmission, it will be necessary to be able to increase both the scope and frequency of network modelling capability, improve situational awareness of control engineers at the Electricity Network Control Centre (ENCC) and enable more automatic switching of circuit breakers and compensation equipment.

[12] Operating the Electricity Transmission Networks in 2020

Feedback

2.58 National Grid would welcome feedback on all of the areas that are considered in this paper. There are a number of areas where the level of certainty and knowledge warrants a greater number of questions, in particular through sections 9, 10 and 13 through to 17. These sections cover;

- Thermal plant regimes
- Interconnectors
- Embedded generation
- Energy storage developments
- Smart Grid and potential demand side services
- Enablers and operation of demand side service

Presented in sections 6 to 8 is a more factual view around the operational aspects of the transmission system, such as operating reserve, response requirements and operating margins. Section 11 considers the potential cost of meeting these requirements, whilst section 12 highlights some of the issues that will be faced in the operation of the transmission network in particular. Although there are fewer questions in these areas, National Grid would welcome your views via our mailbox at energy.operations@uk.ngrid.com

3 Aim

3.1 The aim of this paper is to further assess the likely requirements or changes to existing Balancing Services that may be required to operate the system in the future and provide supporting analysis to examine further some of the initial assumptions in order to consider potential issues or requirements outside of the peak periods.

3.2 Furthermore, this paper will detail the type of Balancing Services that will be required and what new ones may be available, in the future. National Grid anticipates that the complexity of operating the system will significantly increase from a NETSO perspective. Whilst some of the challenges of operating the transmission network are noted in this paper, the main focus is on the challenges of managing intermittent generation, in particular issues around reserve and response holdings and a more detailed view of likely plant regimes requirements across thermal generation.

4 Background

4.1 The *Operating the Electricity Transmission Networks in 2020* paper highlighted that there were numerous challenges faced by National Grid in its role as National Electricity Transmission System Operator and that the predominant focus for the level and provision of future balancing services revolved around:

- Intermittency from renewable generation
- Increasing levels of embedded generation including CHP and storage
- A greater number of interconnectors with more variable flows
- Increased penetration of demand side services

4.2 Intermittency of generation and increased uncertainty around persistence of wind generation will increase the level of operating margin required. Furthermore, from April 2014, additional reserve for response will be required due to increased holding requirements for the envisaged 1800MW generators, offshore connections and double circuit spurs.

4.3 Extrapolations based on the current wind penetration of 2.5GW were carried out in order to identify the potential rate of change in wind generation over a short period of time when wind capacity on the system is 30GW+. It was determined that a 50% change in wind output in 2020 could lead to 15GW change in output over a 2 hour period. In this update National Grid's current view of the future generation mix is provided in section 4 and an update to anticipated reserve requirements to accommodate a higher contribution from wind is included in section 5.0.

4.4 A majority of respondents to the previous consultation did express a view that existing incentives around reserve procurement through both generation and demand sources may not be sufficient to provide the required flexibility[13]. We have therefore attempted to parameterise the possible operating regimes of thermal plant, using a scheduling algorithm against a demand net wind[14] profile.

4.5 With the increased uncertainty that arises from a higher penetration of variable sources of generation to the GB generating fleet, an analysis of operating margins is provided in section 8 that illustrates the impact of daily variations in operating margin requirement.

4.6 The contribution of demand side services is uncertain. Whilst a number of respondents estimated 5% of demand was discretionary or deferrable, there is little or no evidence around the elasticity of demand. In section 15 we give further consideration to the possible demand profiles from domestic, electric vehicles and heat pumps and assess the potential they could make to balancing provisions.

4.7 As the number of HVDC interconnectors to GB increase, this will also bring the potential to exacerbate large variations in generation and demand within short notice timescales. However, there is the potential that they will bring an opportunity to provide response and reserve if the correct commercial frameworks are in place. Increased operational flexibility between neighbouring NETSOs will be required and in section 10, an outline of developments in European markets and their implications are discussed.

4.8 An increase in embedded generation will require a greater level of transparency to the NETSO, or alternatively, DNOs may take an increasingly active role in managing system operations. In section 17, consideration is given to how the operational relationships may have to develop to accommodate more embedded generation and demand side services.

4.9 It was noted and agreed by respondents' to the consultation[15] that more automated control will be required as the number of balancing actions increases as a consequence. In section 18 an overview describing the nature of future control tools is provided.

4.10 For this report National Grid has not considered how Electricity Market Reform will impact on the operation of the balancing and operation of the transmission network. However National Grid is mindful of the proposals put forward by DECC in their consultation document issued in December 2010.

[13] Based on responses to Q30 in Follow Up Report

[14] By netting off forecast wind generation from underlying demand, the output profile regime of thermal plant can be determined

[15] A summary of responses to the *Operating the Electricity Transmission Networks in 2020* were published in February 2010 *Operating the Electricity Transmission Networks in 2020 Follow Up Report*

4.11 If implemented, the proposals outlined in the consultation have the potential to significantly impact the actions National Grid take when operating the National Electricity Transmission System in the medium and longer term.

4.12 The focus of this update revolves around Balancing Services and in particular across the following areas;

Reserve Management

- The level and associated flexibility of reserve requirements to manage the variability and uncertainty of wind output.
- The potential impact on system operation of wind cut-out, which can happen when wind speeds are in excess of technical limits.
- An analysis of potential thermal plant cycling as wind penetration increases over the coming decade.

Embedded Generation

- Consideration to how CHP and storage may participate in balancing the system.
- Consideration to how National Grid or other third parties can encourage participation of embedded generation and demand to Balancing Services.

Smart Grids and Smart Metering

- Consideration of balancing services and what could be available as a result of grid improvements and the roll out of smart meter technology and how these may be captured.
- Consideration of how market participants' may interact and co-operate for demand side balancing services.

Interconnectors

- An overview on the current ENTSO-E developments, with respect to potential market arrangement or regimes on Interconnectors.
- An analysis of how changes to commercial arrangements on interconnectors may impact on system balancing.

5 Generation and Demand in the Gone Green Scenario

5.1 The analysis and discussion presented in this document is based on our "Gone Green" scenario. National Grid believes 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	Capacity (GW)	
	2010/11	2020/21
Coal	28.2	14.5
Coal (CCS)	0.0	0.6
Nuclear	10.8	11.2
Gas	31.9	34.7
Oil	3.4	0.0
Pumped Storage	2.7	2.7
Wind	3.8	26.8
Interconnectors	3.3	5.8
Hydro	1.1	1.1
Biomass	0.0	1.6
Marine	0.0	1.4
Total	**85.3**	**100.5**

Table 1: Total Transmission connected Capacity in "Gone Green"

5.2 Table 1 above illustrates the transmission contracted generation mix featured in our updated November 2010 "Gone Green" scenario for 2020.

5.3 Within our demand forecasts under the 'Gone Green' scenario, are included allowances for economic growth, growth in the number of electric vehicles and heat pumps. The growth is broadly offset by improvements in energy efficiency and an increase in embedded generation, which has the effect of reducing the growth in demand seen on the transmission network.

5.4 However, there is forecast a small increase in the peak ACS demand of approximately 2.3%, from ~56GW in 2010/11 to ~57.3GW in 2020/21.

6 Reserve Requirements (Operating Reserve)

6.1 The NETSO is obliged to ensure that sufficient generation or flexible demand is available at all times to manage uncertainties around generation output and demand fluctuation.

6.2 This is set at a level such that there is a less than 0.3% (or 1 in 365) chance of being unable to maintain security of supply from approximately 4 hours ahead of real time. It includes regulating reserve, reserve for response and STOR[18] and is referred to in combination as operating reserve.

6.3 Operating reserve has previously been known as the STORR (Short Term Operating Reserve Requirement). To address the potential confusion with the STOR product, STORR will now be known as operating reserve.

6.4 The level of reserve requirement (operating reserve) will increase towards 2020. Operating reserve constitutes an appropriate balance between synchronised and static providers that can increase output at short notice to ameliorate demand forecast error and generation shortfalls. This is derived from a statistical analysis of generation output losses across conventional plant and demand forecast error.

6.5 It was noted in the initial consultation[19] that there was a necessary increase in operating reserve towards 2020 for two reasons. First, the anticipated connection of larger generation assets will increase the normal in-feed loss risk from 1000MW to 1320MW and the largest credible in-feed loss risk from 1320MW to 1800MW. Second, as wind capacity increases as a proportion of the GB generation fleet, it is necessary to accommodate the additional variability from wind output within operating reserve.

6.6 The first significant sharp increase in operating reserve occurs in 2014. This step change was expected to occur in 2018, in line with the expectation that the first 1800MW generator will connect during this period.

6.7 The SQSS review group proposed in September 2010[20] that an amendment should be made to the GSR007 proposals and that the requirement should be accelerated forward to 2014. This will allow new generation to connect to transmission spurs that in combination with existing generation would normally result in the need to wait for transmission reinforcement.

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[18] Short Term Operating Reserve
[19] Operating the Electricity Transmission Networks in 2020
[20] http://www.nationalgrid.com/NR/rdonlyres/FFD822C4-FD40-400B-A7E0-DF27DC42289B/43403/IndustryOpenLetterInfeedLoss.pdf

6.8 Bringing the higher in-feed limit forward will offset the cost of reinforcement[21] and accelerate the connection of low carbon generation. The detail of the response requirement is discussed further in section 7.

6.9 Figure 1 shows required levels of operating reserve against three different scenarios of wind load factor 0%, 30% and 100%, for each year until 2025.

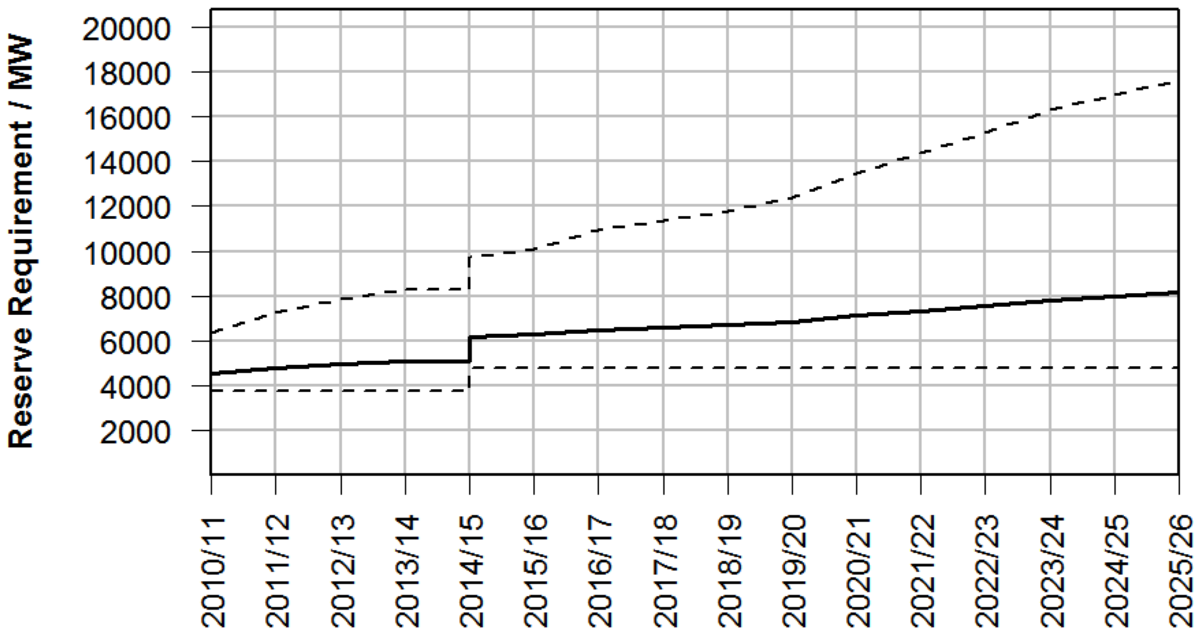

Figure 1: Operating Reserve Requirement Gone Green

6.10 The most significant driver to increasing operating reserve is the increasing level of wind capacity. Therefore on days where wind is expected to contribute a high proportion of the total GB generation output, more operating reserve is required to manage the risk of a change in wind output from 4 hours ahead. Conversely, a lower level of operating reserve is required on days of low wind output as demand is met from more conventional sources of generation.

[21] The reinforcement would not be required after transition to the higher in-feed loss limit in 2019

6.11 In our previous consultation[22], it was explained that we had experienced changes in wind output of 50% over 2 hours[23] against our current relatively low levels of wind penetration. Similar changes in output have been seen in continental Europe where there is a higher level of penetration with greater dispersion. It is necessary to ensure in the event of a loss of wind output, sufficient reserve is available in appropriate timescales to cover such an eventuality.

Recent Operational Experience of wind output

6.12 It is useful to again demonstrate through recent operational experience, why the higher level of operating reserve is required.

6.13 Figures 2, 3 & 4 demonstrate three scenarios, as to why the increased level of reserve is required if maintaining current GB SQSS. These graphs show wind forecast error from 4 hours ahead for three weeks across the year. This is an important time horizon as all unit commitment decisions towards operating reserve have to be made at this point.

6.14 Each graph shows that the forecast aligns with actual generation for a majority of the week. However, within each week there is one day where the error is significant.

6.15 It is apparent from Figure 2, that in this instance the forecast profile for 26-February was consistent with the actual output, but the magnitude or level of output was over forecast by between approximately 30% and 80% over the 26th February 2010.

[22] Operating the Electricity Transmission Networks in 2020 7.3
[23] These changes could be increased output as well as decreased outputs

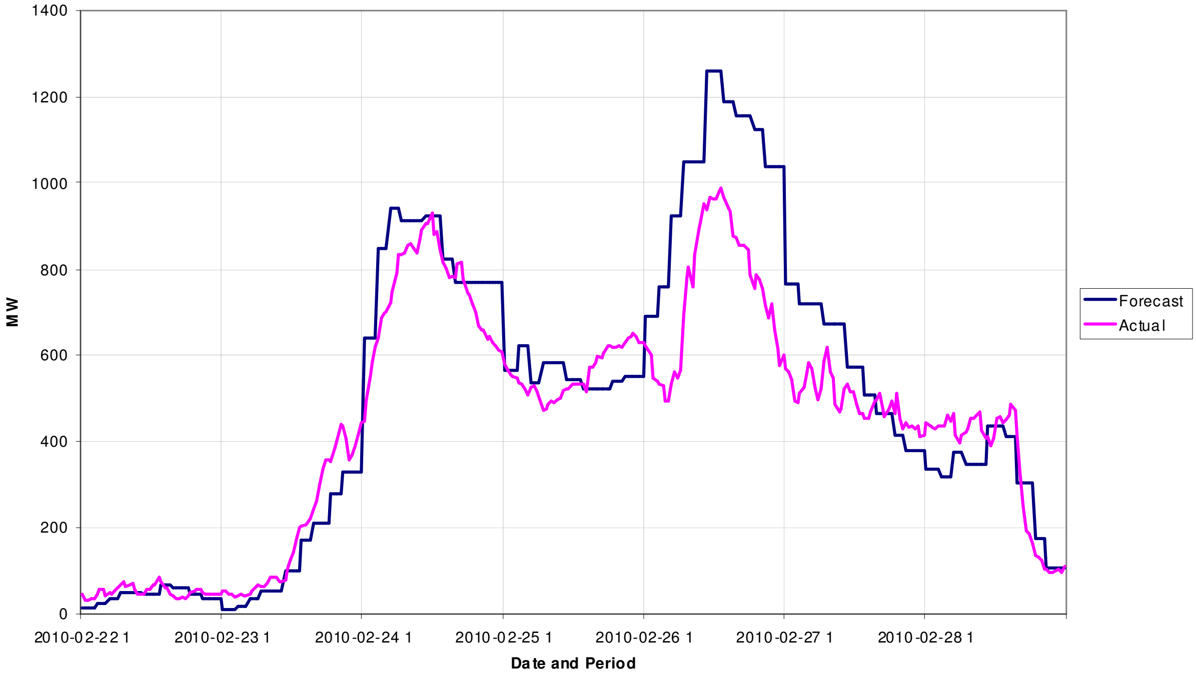

Figure 2: 26-February-2010 (week 22-February-2010 to 28-February 2010)

6.16 In Figure 3, a shortfall in wind output is apparent, with an approximate 50% shortfall over a short period, against the forecast wind output on 19-July-2010

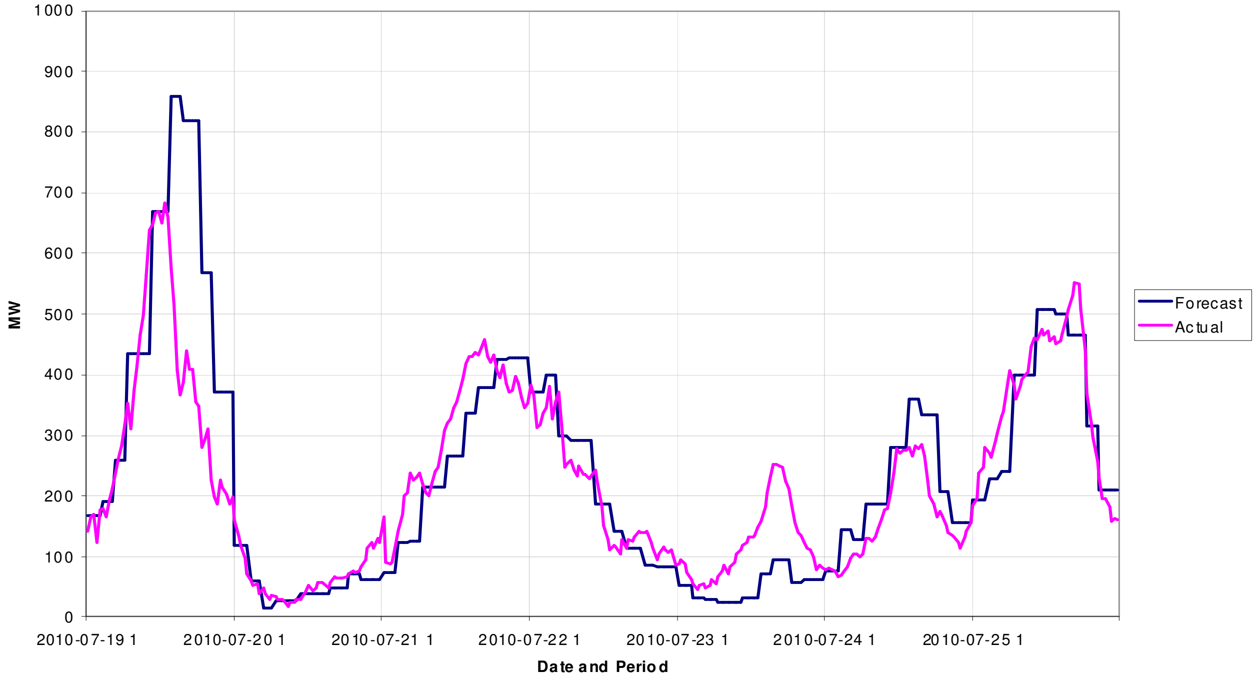

Figure 3: 19-July-2010 (week 19-July-2010 to 25-July-2010)

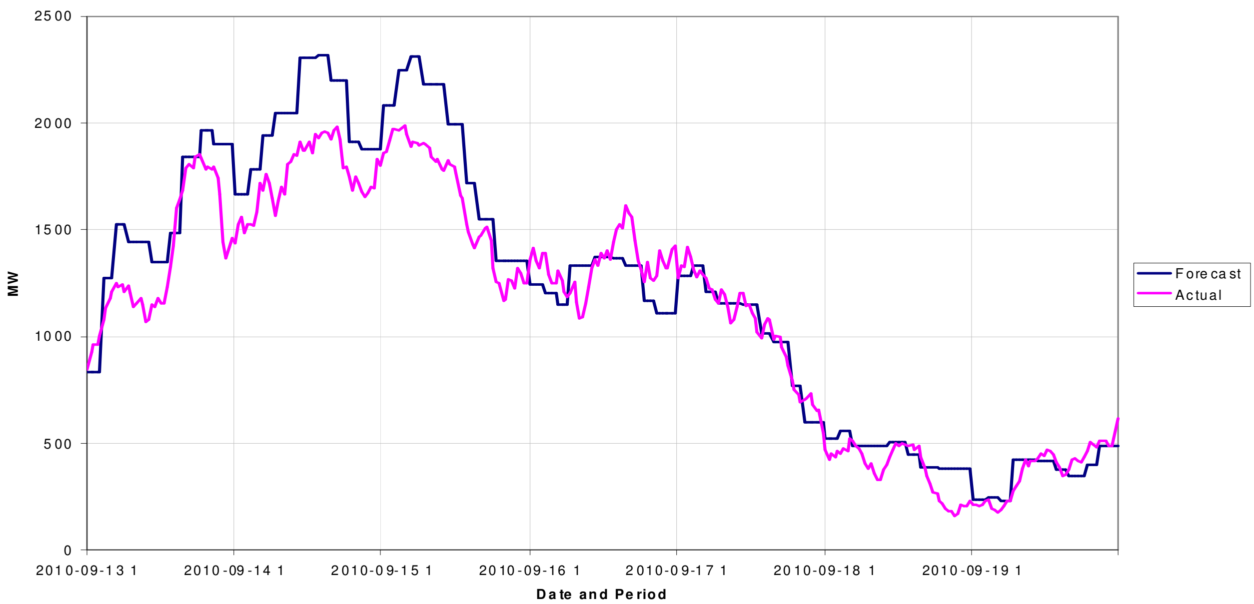

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Figure 4: 15-September 2010 (week 13-September 2010 to 19-September 2010)

6.17 In Figure 4, it appears that the forecast profile is generally in line with actual output across the week, but with a consistent error across a two day period. It should be noted that both actual and forecast wind output is high across the two days were the error is most significant. This may be a result of higher wind speeds leading to turbine cut outs on protection.

Wind Cut-Out

6.18 An additional operational challenge that will increasingly present itself in the future is that which can be termed wind cut-out. This occurs when wind speeds are sufficiently high that wind turbines automatically shut down to maintain structural integrity.

6.19 The speed at which this happens will vary depending on the location and size of wind turbine, although on-shore turbines tend to cut out at wind speeds of ~25m/s.

6.20 National Grid has recently witnessed such an event, when wind speeds in Scotland were sufficiently high to create this phenomenon. National Grid does not currently have the wind speed data for all wind farm locations; however, Figure 5 illustrates the effect witnessed on 3-February 2011.

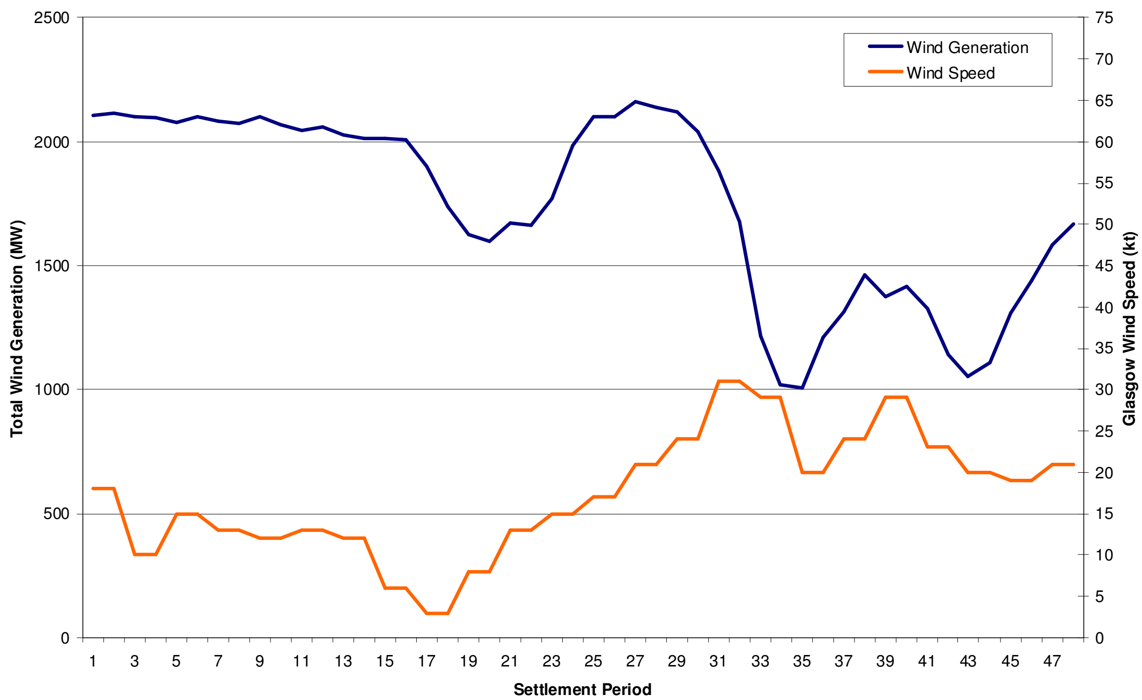


Figure 5: Wind Generation and Wind speed (Glasgow) 3rd February 2011

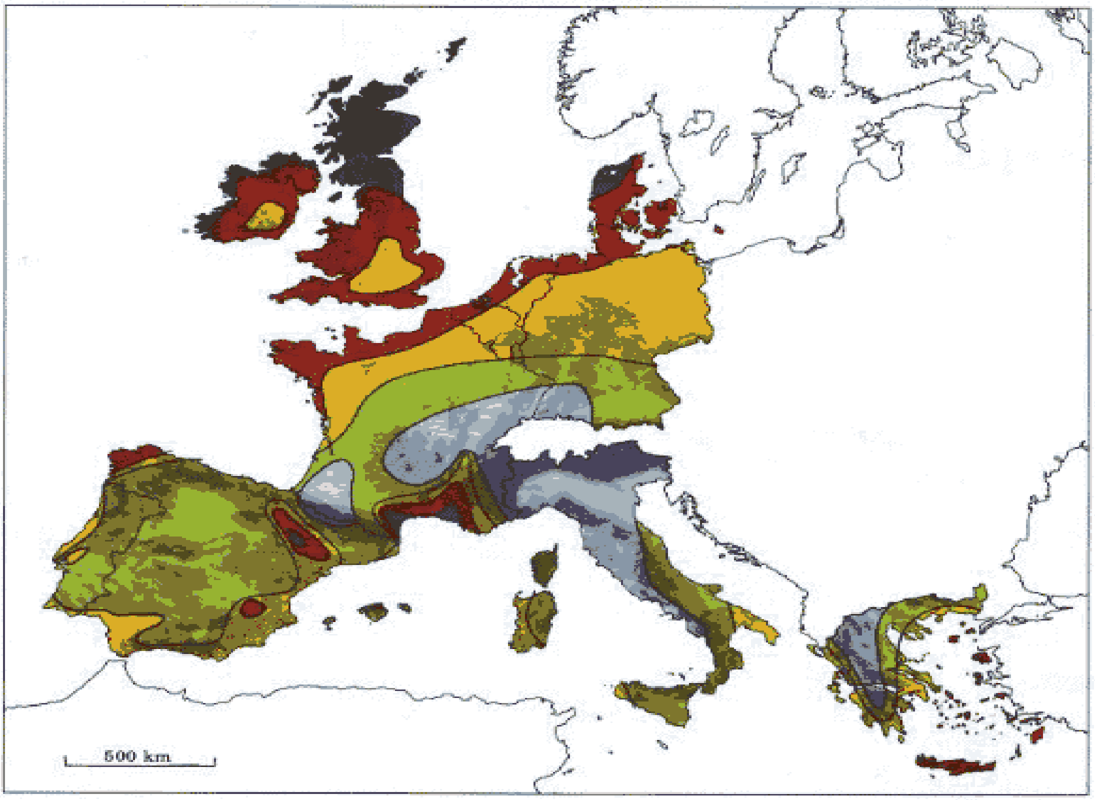
6.21 The effect of cut out can have a significant impact, not only due to the resultant loss in expected generation but also the speed and additional uncertainty that can arise when production starts again as wind speed drops. In the example shown above, a significant decrease in generation occurred when wind speed exceeded 25m/s, which resulted in a reduction of ~50% of the wind production over the course of an hour. As wind speed dropped below 20m/s, output was restored before a further loss a short period afterwards.

6.22 The challenge of volume uncertainty has already been discussed, however a rapid loss of generation faster than that demonstrated in this example could also lead to a higher response requirement. In particular, in the event of variable or gusting winds, the system will have to be able to remain secure for variable changes over a short time period in addition to the impact on regulating reserve.

6.23 As the larger offshore wind generation is connected to the transmission system, the potential impact of this effect may be exacerbated by large volumes of Maws concentrated in a comparatively small geographical area, thus dampening or eliminating the operational benefit of dispersion.

6.24 At this point in time, it is difficult to ascertain the frequency of this event occurring. However, by looking at the wind resource around GB it is clear that the probability of wind cut out is greater in GB than other neighbouring systems.

6.25 Understanding the potential speed or rate of change in wind output is important as it will determine how national Grid allocates operating reserve to meet different services. This is discussed in more detail in section 7.0.



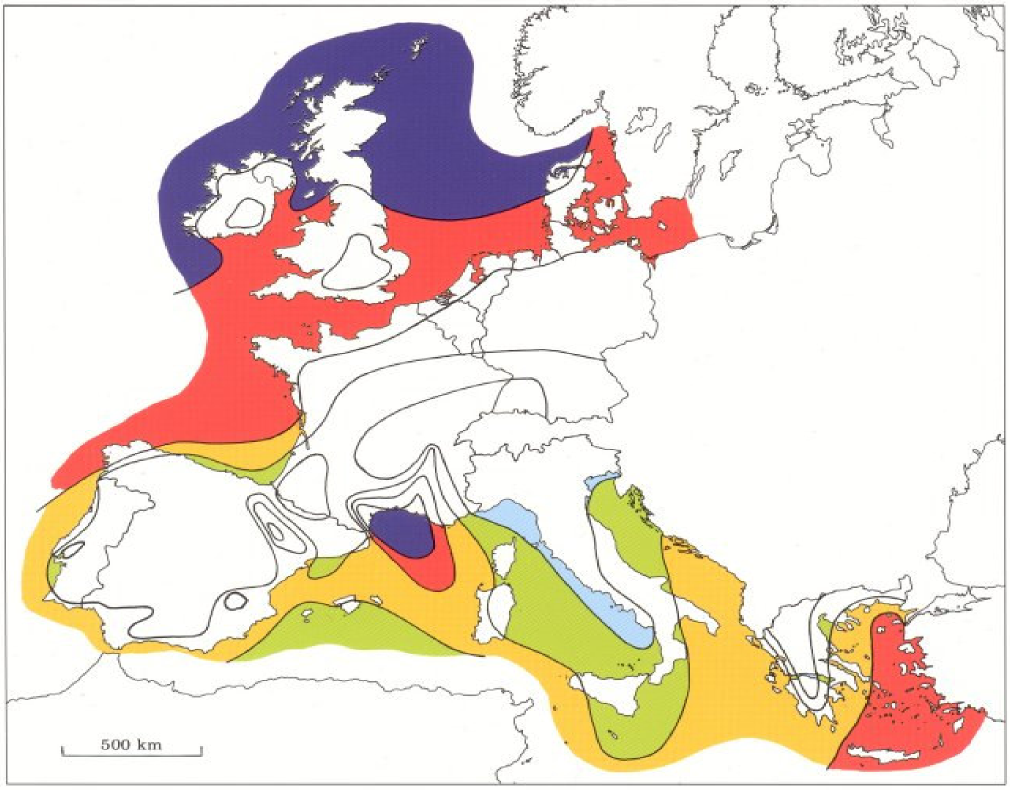
Wind resources[1] at 50 metres above ground level for five different topographic conditions										
	Sheltered terrain[2]		Open plain[3]		At a sea coast[4]		Open sea[5]		Hills and ridges[6]	
	$m\,s^{-1}$	Wm^{-2}	$m\,s^{-1}$	Wm^{-2}	$m\,s^{-1}$	Wm^{-2}	$m\,s^{-1}$	Wm^{-2}	$m\,s^{-1}$	Wm^{-2}
	> 6.0	> 250	> 7.5	> 500	> 8.5	> 700	> 9.0	> 800	> 11.5	> 1800
	5.0-6.0	150-250	6.5-7.5	300-500	7.0-8.5	400-700	8.0-9.0	600-800	10.0-11.5	1200-1800
	4.5-5.0	100-150	5.5-6.5	200-300	6.0-7.0	250-400	7.0-8.0	400-600	8.5-10.0	700-1200
	3.5-4.5	50-100	4.5-5.5	100-200	5.0-6.0	150-250	5.5-7.0	200-400	7.0- 8.5	400- 700
	< 3.5	< 50	< 4.5	< 100	< 5.0	< 150	< 5.5	< 200	< 7.0	< 400

Figure 6: Onshore Wind Resource in Western Europe[24]

6.26 In Figure 6 the darker the colour, the higher density of wind resource. It is clear that GB has a denser wind resource than most of Western Europe, with Scotland having the most dense wind resource along with the west coast of Ireland and NW Denmark.

6.27 Similarly, Figure 7 shows the wind resource over open sea. This again clearly shows that the coastal waters around GB have the most dense wind resource.

[24] From the European Wind Atlas – Copyright ©1989 by Risø National Laboratory, RosKilde,Denmark



Wind resources over open sea (more than 10 km offshore) for five standard heights										
	10 m		25 m		50 m		100 m		200 m	
	$\mathrm{m\,s^{-1}}$	$\mathrm{Wm^{-2}}$	$\mathrm{m\,s^{-1}}$	$\mathrm{Wm^{-2}}$	$\mathrm{m\,s^{-1}}$	$\mathrm{Wm^{-2}}$	$\mathrm{m\,s^{-1}}$	$\mathrm{Wm^{-2}}$	$\mathrm{m\,s^{-1}}$	$\mathrm{Wm^{-2}}$
	> 8.0	> 600	> 8.5	> 700	> 9.0	> 800	> 10.0	> 1100	> 11.0	> 1500
	7.0-8.0	350-600	7.5-8.5	450-700	8.0-9.0	600-800	8.5-10.0	650-1100	9.5-11.0	900-1500
	6.0-7.0	250-300	6.5-7.5	300-450	7.0-8.0	400-600	7.5- 8.5	450- 650	8.0- 9.5	600- 900
	4.5-6.0	100-250	5.0-6.5	150-300	5.5-7.0	200-400	6.0- 7.5	250- 450	6.5- 8.0	300- 600
	< 4.5	< 100	< 5.0	< 150	< 5.5	< 200	< 6.0	< 250	< 6.5	< 300

Figure 7: Offshore Wind Resource for Western Europe [25]

6.28 This can only provide an indication and it would be useful to identify the operating characteristics of existing offshore wind. The country with the most offshore wind capacity until recently was Denmark. National Grid has identified the frequency of wind cut out events in Denmark and numerous events have been identified.

Q1. Do you agree that cut out will be an issue for GB or will wind (onshore and offshore) turbine technology compensate for the GB wind resource density?

Q2. Will wind turbines within a comparatively small geographical area behave in a consistent manner?

[25] Copyright ©1989 by Risø National Laboratory, RosKilde,Denmark

6.29 The issues addressed in this section highlight the fact that it is not only the average reserve requirement that is going to increase over the next decade, but the nature of the variability of renewable output means that the uncertainty of the requirement will vary greatly. Therefore the flexibility of reserve provision will also need to be greater.

Reserve Level Setting

6.30 National Grid currently assumes that wind output can decrease by 50% over 4 hours, decreasing to around 30% by 2020. National Grid believes that the forecast wind error will be 10% RMS of wind capacity. Therefore, in order to secure for a 99.7% confidence or 1 in 365 criteria, in 2020 there will be a need to carry operating reserves equivalent to 30%[26] of the forecast wind output four hours ahead of real time.

6.31 This level of reserve requirement does not take account of how the market participants may manage the variability within their portfolios i.e. it assumes no self balancing in the four hours ahead of real time.

6.32 How the market manages variability in terms of temporal and volume aspects will be important to the eventual level of operating reserve requirement. This is discussed further in section 9.0, though in the context of market participants' balancing, it will be pertinent to consider how the efficient allocation of reserves can be achieved with the higher levels of uncertainty.

6.33 Currently the reserve requirements are derived on consideration of basic reserve, reserve for response and reserve for wind. In section 10 and 11, consideration is given to how potential changes in trading and balancing arrangements on interconnectors may impact on operating reserve requirements.

6.34 Table 2 also contains the operating reserve levels for average wind (30% load factor) as described earlier in Figure 1. The forecast reflects the assumption that wind variability will be dampened in the early part of the decade as geographic dispersion increases and wind forecasting performance improves. However as the larger offshore wind farms commence operations it is assumed that the increased concentration of turbines will reverse some of the beneficial effect of geographic dispersion.

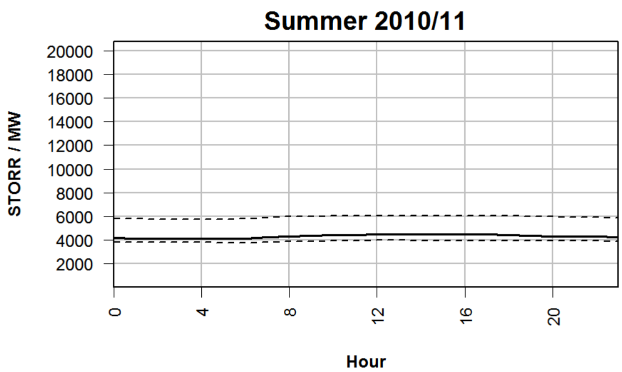
[26] This assumes that wind dispersion reduces the potential reduction in wind output from current levels and that forecasting capability improves

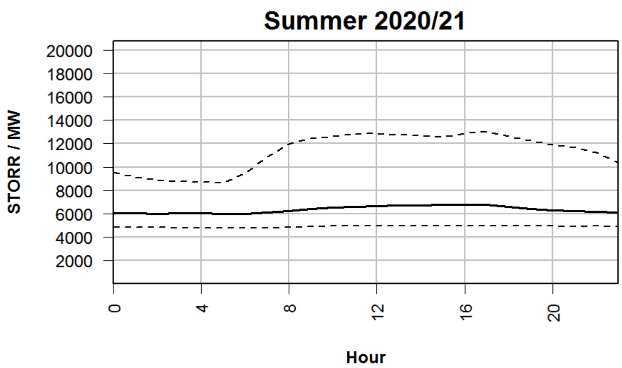
Year	Installed Capacity / MW					ACS Demand MW	Wind Forecast Error (rmse	Operating Reserve Requirement MW
	Wind	Nuclear	Coal	Gas	Other			
2011/12	5,795	9,444	28,166	29,364	9,383	55,900	47.79%	4777
2012/13	7,677	9,444	28,166	29,799	9,431	56,100	45.57%	4938
2013/14	9,086	9,444	22,428	31,034	9,946	55,900	43.36%	5054
2014/15	10,681	9,444	22,060	32,234	10,176	56,700	41.14%	6163
2015/16	12,198	9,444	20,120	35,231	7,796	56,800	38.93%	6267
2016/17	14,888	9,444	20,970	34,331	8,346	57,000	36.71%	6483
2017/18	17,378	9,444	21,720	33,437	8,746	57,200	34.50%	6587
2018/19	19,928	8,363	21,720	33,912	9,196	57,700	32.29%	6684
2019/20	22,258	10,033	21,679	32,706	9,645	57,900	30.00%	6832
2020/21	24,599	11,233	17,745	31,918	9,939	57,600	30.00%	7111
2021/22	26,799	10,548	17,745	31,918	9,999	57,200	30.00%	7335
2022/23	28,130	11,748	17,745	31,918	10,264	57,100	30.50%	7545
2023/24	28,955	13,418	14,461	33,158	10,280	57,100	31.00%	7803
2024/25	29,530	11,008	14,461	32,366	10,380	57,000	31.50%	7968
2025/26	30,605	12,658	14,461	32,999	10,770	57,000	32.00%	8134

Table 2: Average Operating Reserve levels with average wind (30% load factor)

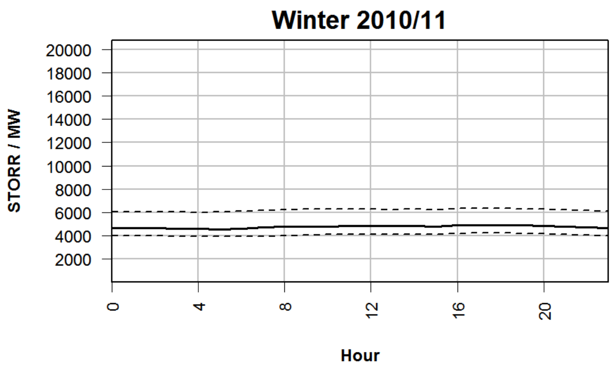
6.35 The average operating reserve requirement increases by 53% from 4777MW to 7335MW, between 2010/11 and 2020/21.

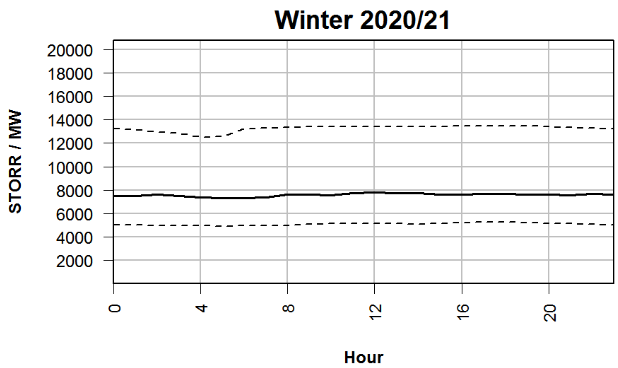
6.36 Figures 8 to11 show the diurnal and seasonal current operating reserve profiles and those for 2020/21. The absolute change in operating reserve across both seasons from the current year to 2020 is evident. However by 2020, there is a lower overnight requirement as compared to the daytime, during the summer.





Figures 8&9: Diurnal operating reserve profiles Summer 2010/11 and Summer 2020/21





Figures 10&11: Diurnal operating reserve profiles Winter 2010/11 and Winter 2020/21

6.37 In 2020/21, during periods of low demand and high wind output, National Grid may have to constrain wind output to accommodate plant minimum levels. This is principally due to two operational issues;

- Demand must be larger than the total output from wind and thermal generation
- The total amount of generation output available from non-wind sources at 4 hours or less, in addition to wind output, must also be larger than the sum of demand and operating reserve.

6.38 Currently during the overnight periods in the summer National Grid often takes action to reduce the amount of generation on the system. This typically arises as a consequence of generators running through minimum demand periods to avoid 2-

shifting and or lower demand outturns. This situation has to be managed to avoid breaching the first operational issue.

6.39 The second requirement must also be met, because as wind output increases, operating reserve also increases to cover the risk of a short term[27] change in wind output. Any shortfall in wind generation must be met by part loaded and or static, short notice thermal generation. This can be antagonistic to the first requirement and can only be met though curtailing wind output. In doing this, operating reserve is reduced as less reserve is carried for the intermittency risk, thus assisting in meeting the first operational issue.

6.40 It is less likely that the wind fleet will be generating near full output at times of minimum demand (i.e. summer minimum). Likewise, at times of high demand it is expected to give a lower credit to the contribution of wind generation during periods of peak demand that are driven by extended cold spells.

6.41 This is demonstrated by Figures 12 and 13 which show output and associated load factor by time of day and month. In particular, it is pertinent to note that during the periods that the GB experienced extended cold periods with snow, in December 2009, February 2010 and December 2010, the contribution from wind was low.

6.42 For a period of one month between October 2010 and November 2010 load factors were consistent. During periods like this, it would be expected that reserve costs would increase to cover the potential variability in wind output.

[27] Within 4 hours

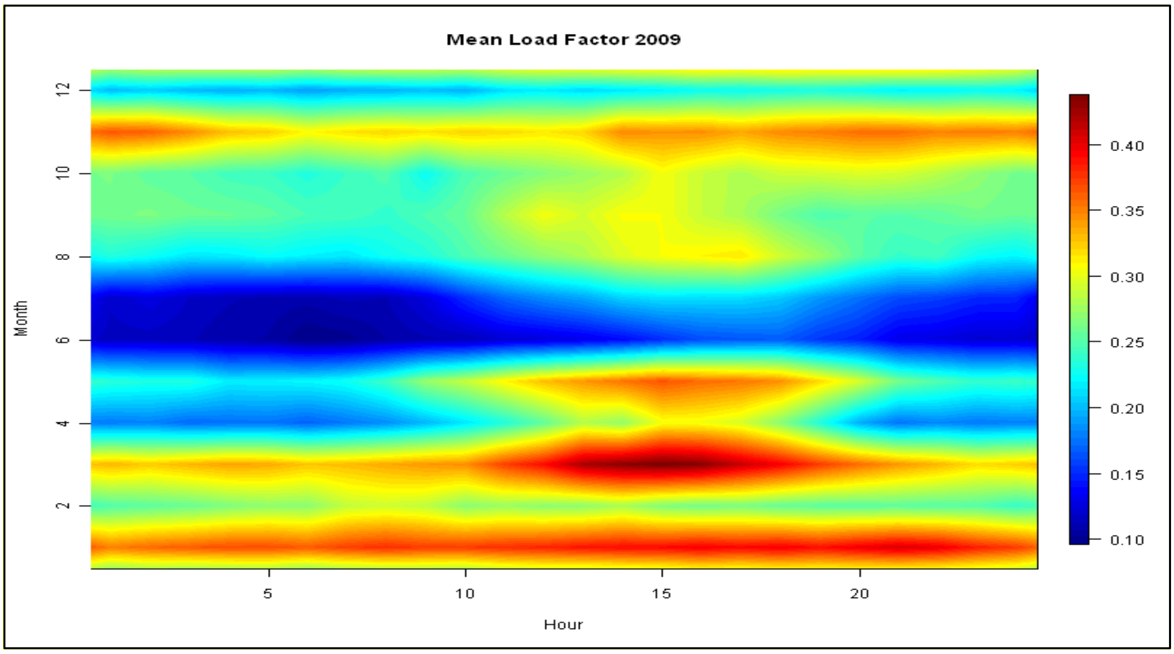


Figure 12: Recorded wind load factors 2009

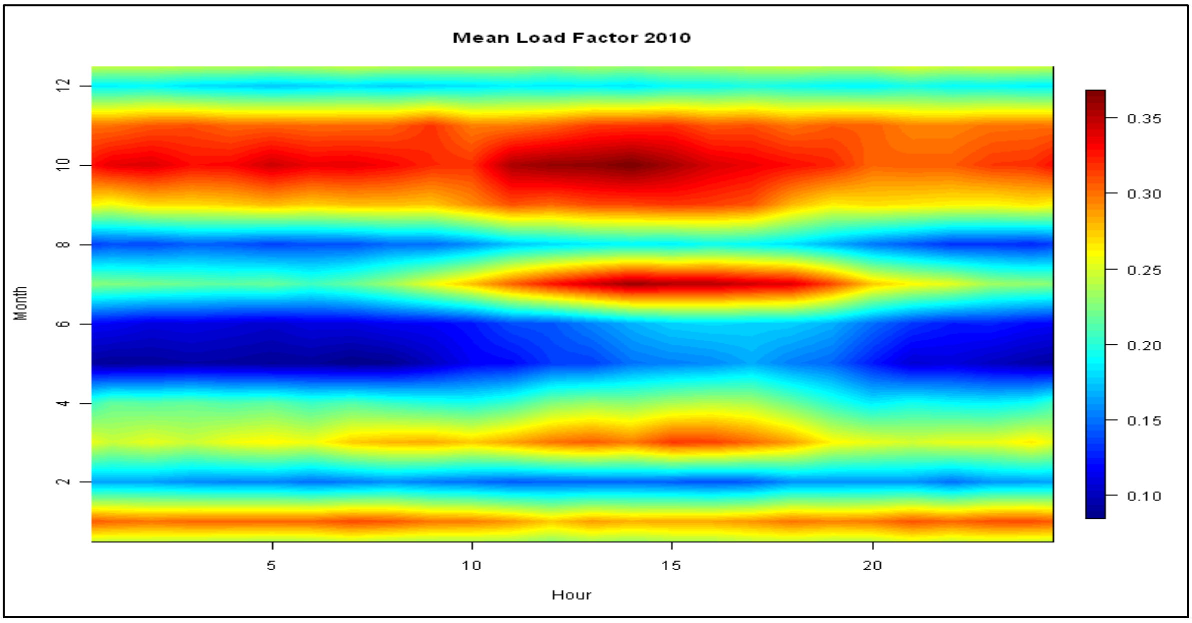


Figure 13: Recorded wind load factors 2010

Operating at minimum demands

6.42 At all times, National Grid has to maintain sufficient flexible upward and downward reserves to manage the fluctuations in generation output and demand.

6.43 In sections 5 and in section 6 so far, an explanation was given to the drivers and subsequent requirements pertaining to the provision of upward reserve and response.

6.44 It is also necessary to be able to manage the largest credible demand loss and this is termed the 'negative reserve' requirement. In the event of a demand loss, there should be sufficient levels of generation that can be instructed to reduce output to a minimum technical output level (SEL). Alternatively, a demand loss may be countered by increasing demand elsewhere, although the only credible means of doing this currently is through reducing imports across interconnectors via inter-trip, of other system operator to system operator services such as cross border balancing.

6.45 Minimum electricity demands in Great Britain occur across weekend and bank holiday weekend periods at about 04:30 hours. Demand levels can reduce to such an extent that flexible generators have to reduce output to minimal technical sustainable levels or shut down for a period in order to follow prevailing demand.

6.46 However, it is often the case that indicative generation profiles submitted to National Grid do not provide sufficient negative reserve to cater for the largest credible demand loss. In this circumstance, National Grid will take a range of measures that may include re-dispatch or de-synchronisation of generation and use of alternative balancing services as described in [6.44].

6.47 Historically, the generation availability will decline in the summer as maintenance outages are taken to align with underlying demand. The key driver to any actions the NETSO will have to take to create negative reserve will be the amount of 'inflexible' generation on the system. Inflexible generation is defined as;

- Technically driven - such as nuclear generation or CHP connected to other processes
- Commercial - such as renewable generation ensuring recovery of obtainable ROCs.

6.49 It is not clear whether the proposed new nuclear generation will provide greater flexibility, or to what extent other price signals will influence generation output from CHP and renewable sources. For the purposes of this analysis, it is assumed there is no significant change.

6.50 The levels of minimum demands in the future are difficult to forecast as embedded generation, energy efficiency and the potential for load shifting will all have an impact.

6.51 Currently, the average negative reserve requirement for overnight periods is approximately 1450MW. Typically a higher requirement is necessary overnight compared to daytime periods, although the requirement can change as a function of the level of pumping demand at risk from a circuit or SGT loss or from an exporting interconnector loss.

6.52 Pumping demand historically has occurred during the overnight periods when prices have always been lower. It is important to note that pumping demand may move towards other periods of the day, for example during days of high wind output. Furthermore, operating profiles may change with a subsequent impact on demand profiles.

6.53 Table 3 provides a view of the deemed inflexible plant mix for 2010/11, 2015/16 and 2020/21, together with demand and pumping load. These figures assume 75% availability across the nuclear fleet, and 50% availability of must run CHP and interconnectors at float.

	Load Factor	2010/11 (MW)	2015/16 (MW)	2020/21 (MW)
Nuclear	75%	8131	7088	8430
Must run CHP	50%	1117	1117	978
Sub Total		9248	8205	9408
Wind	75%	2,852	8,904	20,078
Wave Tidal	75%	0	0	1,074
Interconnectors		0	0	0
Total Generation		**12,099**	**17,109**	**30,561**
Demand		22000	22000	22000
Pumping Load		1000	1000	1000
Total Demand		**23000**	**23000**	**23000**

Table 3: Generation availability assumptions for minimum demand assessment

6.54 Two scenarios, average and high output levels are considered in respect to output from renewable sources of wind, wave and tidal.

6.55 A 20% load factor is assumed for average output and a 75% load factor for high renewable output.

6.56 As indicated in Figure 14, at average output it is not envisaged that there will be any significant problems for negative margin.

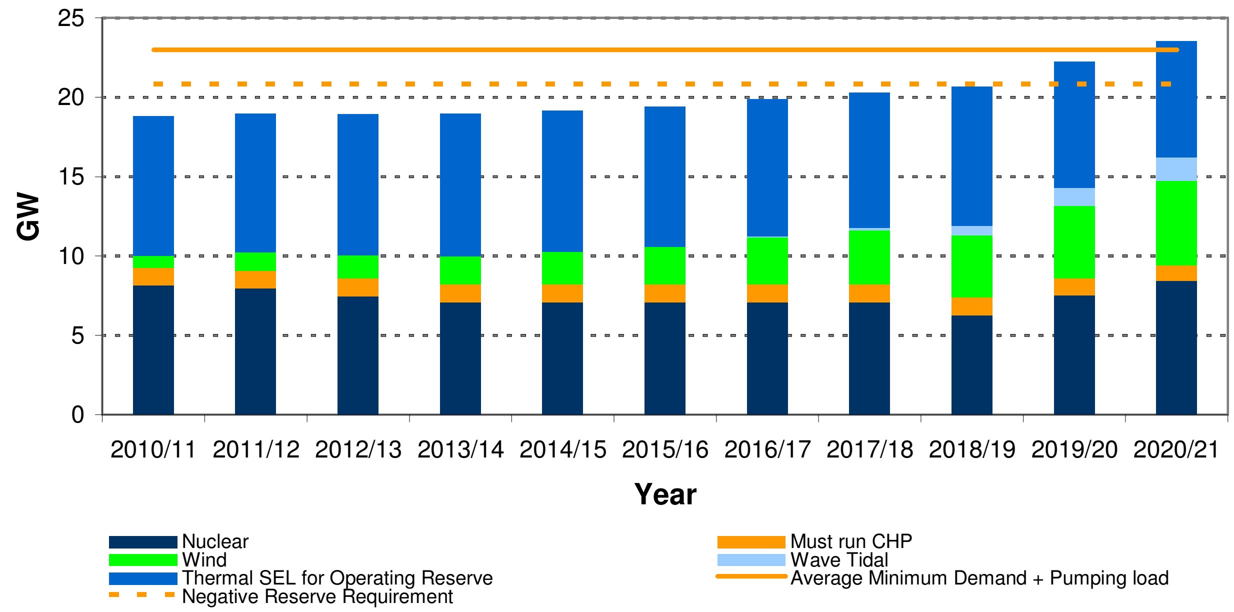


Figure 14: Average renewable generation output at demand minimums under 'Gone Green' Scenario

6.57 Included in the calculation are the corresponding requirements for operating reserve. This is important for the reason described in [6.36] to [6.39]. As the generation from wind increases, additional thermal generation will have to be synchronised to SEL to provide the operating reserve.

6.58 Therefore, as more thermal plant is synchronised, there has to be sufficient demand on the system to accommodate generation from inflexible generation, wind and thermal plant loaded at SEL. As the thermal generation is required to provide low frequency response and regulating reserve, no downward actions are taken on thermal plant.

6.59 In the high renewable output scenario, it is assumed that wind generators will spill onto the system and the NETSO will balance the system though curtailing wind generation and use of bi-lateral system operator cross border balancing services across interconnectors.

6.60 For the purposes of this analysis it is assumed that no more than 1000MW will be exported across interconnectors by market participants and that 500MW is available on cross border balancing (CBB) services. Figure 15 below shows the amount of pullback that would be required in a high renewable output scenario.

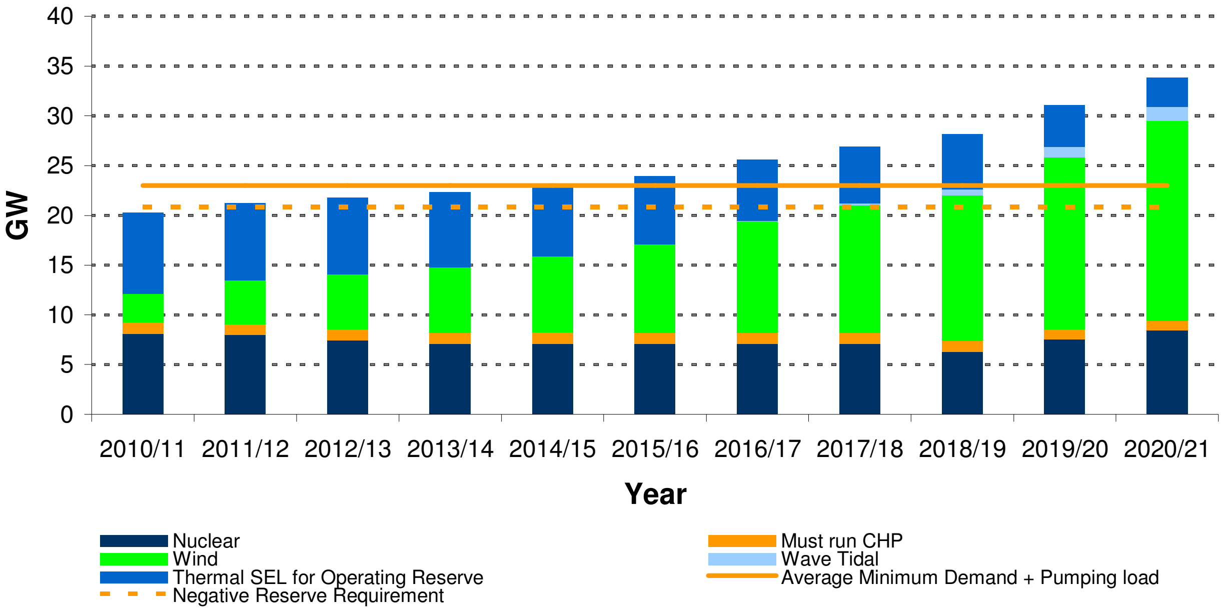


Figure 15: High renewable generation output at demand minimums under 'Gone Green' Scenario

6.61 It is apparent that when output is sufficiently high, less thermal plant is required and clearly this is because even in the event of a loss of 40% of output, there would still be sufficient generation to meet demand.

6.62 In these instances it may be possible to put some wind generation on response. However although wind generation can provide response, it is unlikely that a significant proportion of the total requirement would be carried on wind. This is principally due to the cost of the response holding in comparison to carrying it on the thermal plant already synchronised for intermittency reserve, but also because such response provision is still unproven.

6.63 Table 4 provides an estimate of how much it would cost per occasion that wind will have to be curtailed.

	Availability	2010/11	2015/16	2020/21
Nuclear	75%	8131	7088	8430
Must run CHP	50%	1117	1117	978
Sub Total		9248	8205	9408
Wind	75%	2,852	8,904	20,078
Wave Tidal	75%	0	0	1,074
Total Generation		12,099	17,109	30,561
Demand		22000	22000	22000
Pumping Load		1000	1000	1000
Total Demand		23000	23000	23000
Negative Reserve Requirement				
Negative Regulating Reserve		900	900	900
Negative Reserve for Response		1250	1250	1250
Operating Reserve				
Reserve Requirement (*Basic Reserve + Reserve for Response+Reserve for wind*)		5412	7833	12303
Inflexible Generation		9248	8205	9408
Flexible MEL Required		16313	13724	5817
Sync MEL		25561	21929	15225
Sync SEL (Inflexible + Flexible)		17404	15067	12316
Sync SEL + Wind		20256	23971	32395
Total Generation (inc Op Res)		20,256	23,971	32,395
Total Demand		23,000	23,000	23,000
Total Balancing Actions Required for Generation=Demand		0	971	9,395
Interconnector export (market)		0	971	1,000
SO to SO Interconnectors (MW)		0	0	500
Wind Curtailment Required		0	0	7,895
Estimated Cost £M		**0.0**	**0.0**	**3.5**
Negative Regulating Reserve Cost £M		0.03	0.03	0.03
Negative Response Cost (only in event of demand loss) £M		0.55	0.55	0.55

Table 4: Estimated Cost for management of Negative Reserve Requirement

6.64 It is apparent from this analysis that the cost of actions in 2020 will increase from current levels. An output of greater than 35% of wind capacity by 2020 is expected to result in it being necessary to curtail wind generation output on about 38 days[28] per year. However, it is estimated that the number of occurrences where higher wind outputs of 75% or more combine with low demand is in the order of 3 times per year.

6.65 An alternative to constraining wind would be to use storage technologies to capture renewable output that is not aligned with demand or operational system requirements. In this example, the contribution from electric vehicles is not considered as they are considered to have minimal impact over low demand periods (this is discussed further in section 15). However as time of use tariffs become more prevalent after 2020, their contribution to demand is expected to increase.

6.66 The costs in Table 4 clearly only reflect those associated with operational energy balancing of the system and does not reflect the additional value that would be gained by supplier companies or other participants' who would look to capture additional value through price arbitrage.

6.67 As we move towards 2030, there may also be an increasing value to DNO's to assist in managing thermal flows on their networks that may arise from an increase in embedded generation.

7 Response Requirements

7.1 System frequency is a continuously changing variable that is determined and controlled by the second-by-second balance between demand and total generation.

7.2 The system frequency is controlled by Frequency Response and this response serves two purposes on the GB system: i) to contain system frequency in the event of either a generation loss or demand loss; and ii) to correct short term frequency deviations caused by the delay in balancing actions taking effect because of the manual process used between National Grid and Balancing Participants to initiate these actions.

7.3 After a demand or generation fault, system frequency will change as a result of the mismatch between generation and demand. National Grid operates the system in a manner that a

- The maximum deviation of frequency after a normal loss is no greater than 0.5Hz
- The maximum deviation of frequency after an infrequent loss is no more than 0.8Hz

[28] Derived from historical data where wind output has been >=35% of total capacity and demand less than 50% of peak demand.

- Any deviations outside 49.5Hz and 50.5Hz do not exceed 60 seconds

7.4 National Grid uses three response services, primary, secondary and high frequency response, in order to meet the obligations described above.

7.5 Primary and secondary response is an automatic increase in generation (or reduction of demand) when the frequency is below 50Hz. Primary response is delivered within 10 seconds, whilst secondary response is delivered within 30 seconds.

7.6 High frequency response is a reduction in generation (or increase in demand) when frequency is above 50Hz, delivered within 10 seconds.

7.7 As noted earlier in section 6, the principle change to response requirements will occur in 2014/15 when the largest credible in-feed loss is expected to increase from 1320MW to 1800MW. These larger generation units, offshore or double circuit spur connections will increase the primary and secondary response requirements[29] and this, in turn has the potential to increase costs in overall operating reserve. It is important to note however, that until the larger generation sets connect, the higher requirement may only be required during certain transmission outages. Therefore potential costs will be considered alongside other applied engineering solutions.

7.8 Currently, it is not expected that the largest credible demand loss will increase by 2020. Whilst it should be noted that circuit outages can increase the largest demand loss, these instances are not systemic and thus the average requirement remains unchanged.

7.9 Figures 16 to 18 show the minimum, average and maximum requirement for the three response services through to 2025/26.

[29] SQSS review GSR007 contains a detailed study of this effect.

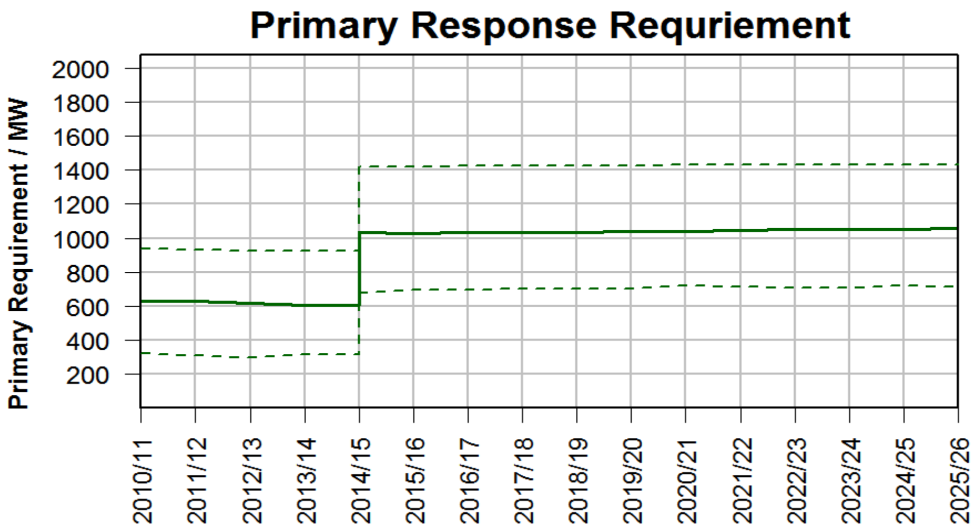


Figure 16: Primary Response Requirement

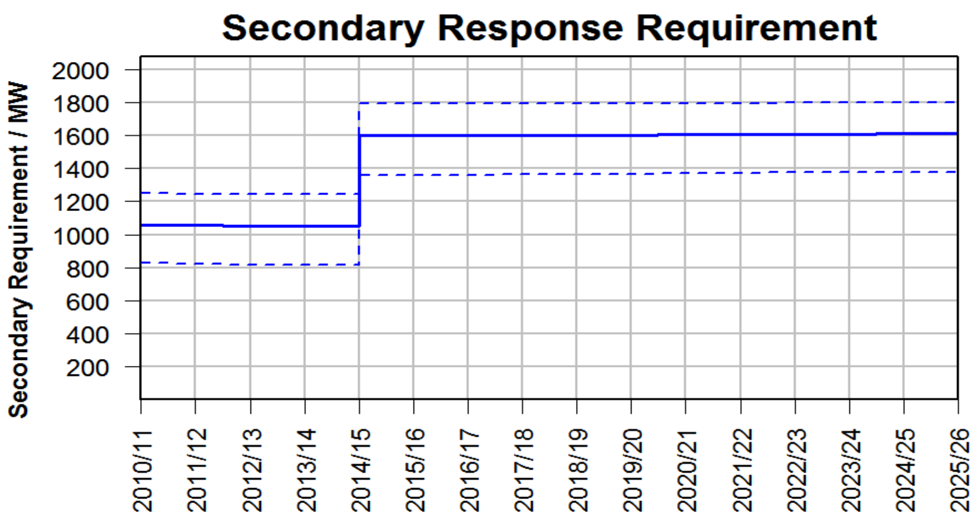


Figure 17: Secondary Response Requirement

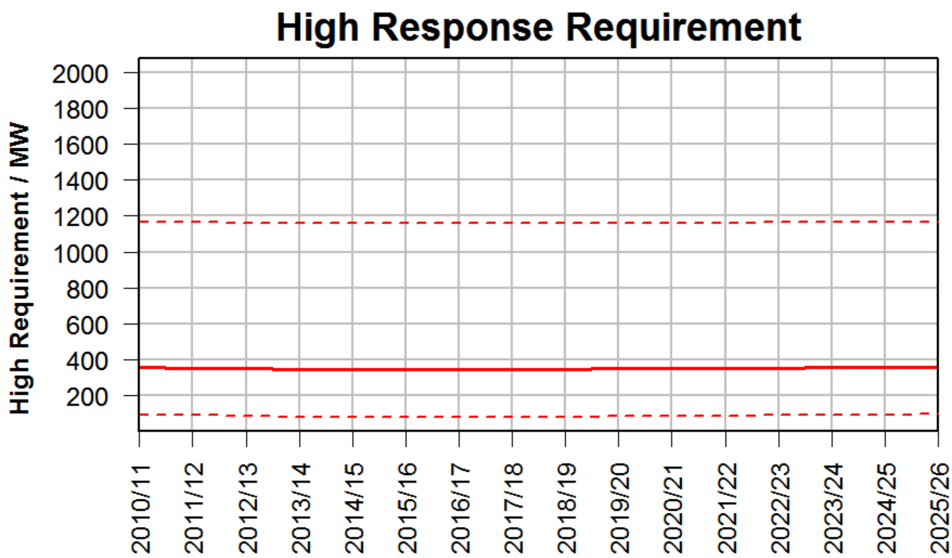


Figure 18: High Response Requirement

7.10 Figures 19 & 20 describe the daily profile for each frequency service (Primary, secondary and high) for both summer and winter 2020/21.

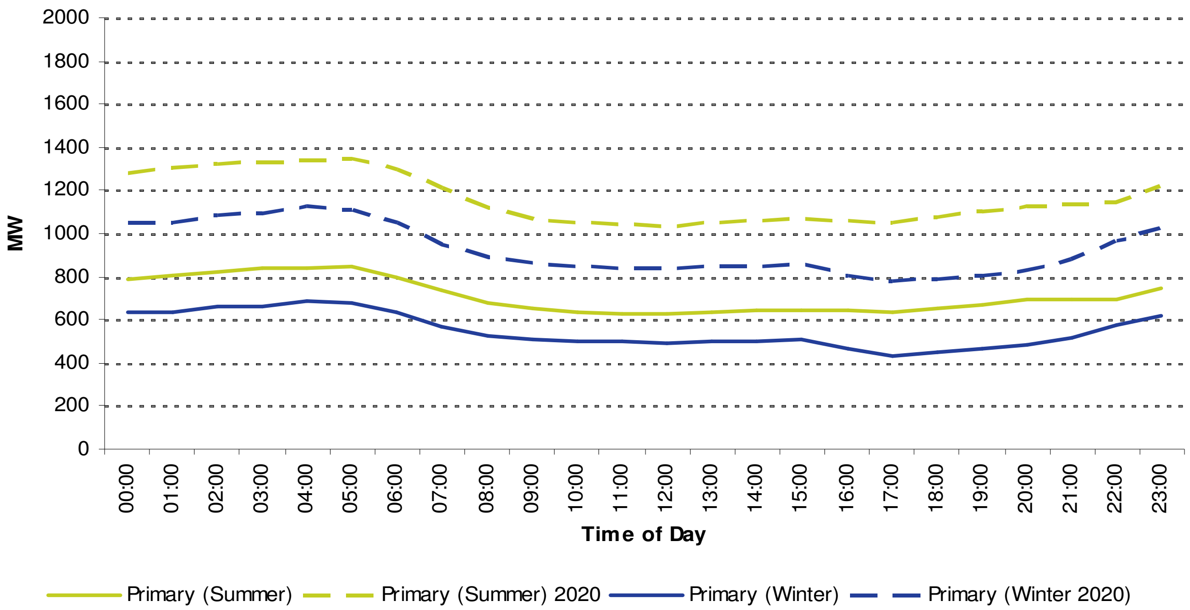


Figure 19: Seasonal Daily Primary Response Profile 2010/11 & 2020/21

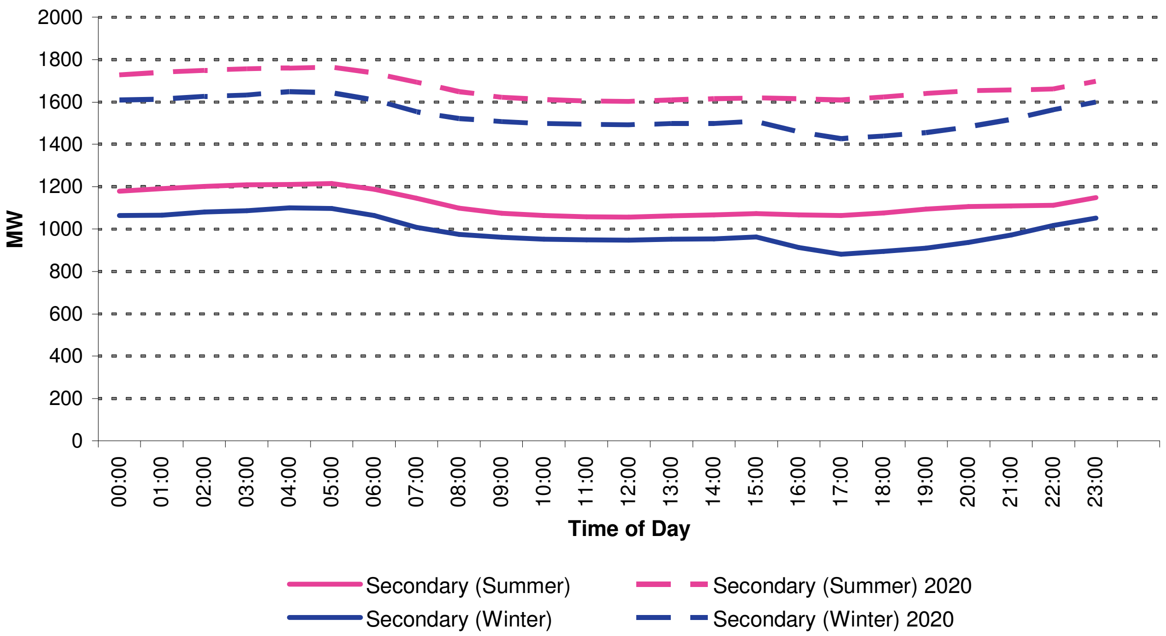


Figure 20: Seasonal Daily Secondary Response Profile 2010/11 & 2020/21

7.11 The overall response requirement is higher by 2020/21, reflecting the changes noted earlier in section 6, although, the diurnal profile is unchanged from current profile. Generally, higher levels of response are required overnight, as the lower system demand provides less response during these periods. Therefore as demand falls overnight, the response has to be made up across the generation portfolio. Likewise, higher levels of response are required in the summer in comparison to the winter season, due to the lower levels of demand.

7.12 The profile of high frequency response (Figure 21) requirement is not expected to change between now and 2020 as this is driven by the largest credible demand loss.

7.13 The higher overnight requirement reflects, the additional demand from pump storage stations as when they are pumping, they become the largest credible demand loss. Therefore, the high frequency response holding typically increases overnight to match the typical pumping profile of these sets.[30]

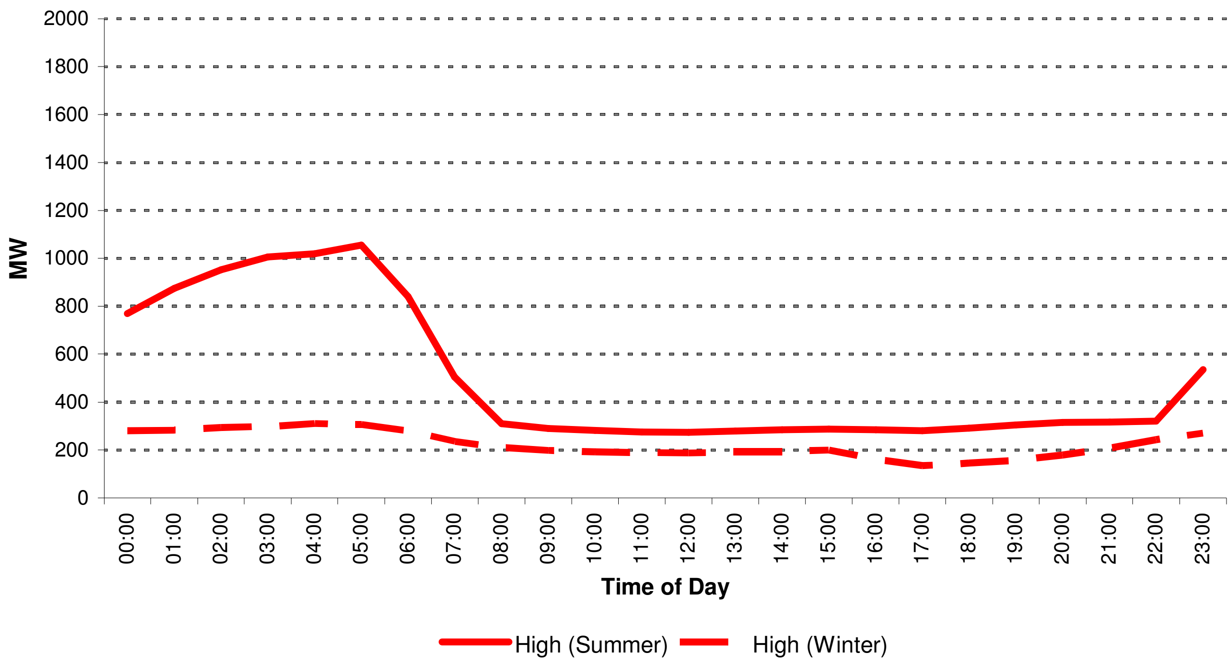


Figure 21: Seasonal Daily Profile for High Frequency Response Requirement

[30] Pumping demand is typically price driven and there is a possibility that high wind output with low system prices may shift pumping demand away from the current profile.

7.14 By 2020/21, the wind capacity is significant as a proportion of the GB generation fleet. On days where wind power is contributing significantly to the energy mix, the damping effect or system inertia that conventional generators provide will reduce. However, wind generators connecting to the GB Transmission System should be capable of providing synthetic inertia, so it is assumed that the overall system inertia will be comparable with today's values.

7.15 There remains an area where further understanding needs to be developed and that is to what extent additional response may be required for the issues discussed in section 6 around "cut-out" and "gusting wind" .

7.16 There is the potential that on high wind days, gusting winds could accelerate the output from wind turbines for short periods. Short bursts of additional generation will cause the system frequency to go higher and there is operational experience of this effect already.

7.17 Additional primary or more likely secondary response will be required to manage "cut-out" risk. Some of the proposed Round 3 wind farms will be of a significant capacity and it is not clear whether output from large capacity wind farms concentrated in a comparatively small geographic area will behave in a uniform manner.

7.18 This issue will not actually mean a higher reserve requirement volume, more an issue as to how the reserve requirement between reserve for response and regulating reserve is allocated.

7.19 Currently, no allowance is included in our forecasts for this although National Grid intends to investigate this issue further as wind capacity increases and further experience of high wind days is gained. Alternatively, a different approach to manage frequency deviations could be taken

7.20 Frequency response controls the short term frequency deviations that occur as a consequence of real time error between instructed generation and actual demand and this is set to increase with the connection of large volumes of intermittent generation.

7.21 As frequency deviations exceed the governors control system deadband (+/- 0.015 Hz from 50 Hz), generators respond by providing frequency response, until the error is corrected by either a bid or an offer being accepted and acted upon, to restore the balance.

7.22 Until this correction takes place, some of the frequency response needed to contain a large in-feed loss is used up, a feature which needs to be given consideration when setting response requirements.

7.23 Corrective actions can also be slow to take effect due to the process used to initiate them and the time needed to respond. As a result, the frequency response deadband is almost continuously being exceeded with consequent wear and tear on responsive plant.

7.24 National Grid is exploring new approaches to managing frequency, including enhanced systems for creating and issuing balancing service instructions, Automatic Generation Control (AGC), and changes to governor characteristics.

7.25 AGC is used to control frequency throughout the world (e.g. Continental Europe, North America, and Japan) and all modern generator control systems and modern control centre systems have AGC provision as standard.

7.26 National Grid is of the view that short term frequency control capability could be improved with consequent savings in costs for this service. These become more significant with the approaching challenges of intermittency, decreasing generator inertia and larger secured in-feed losses.

7.27 National Grid recognises that the GB system is operated as an independent synchronous system and that the method of control of frequency has developed over years to meet the particular conditions pertaining to GB plant design and operating practices, but would be interested in the views of industry in improving the current methods on managing frequency deviation.

Q3. How do you think that controlling frequency deviations with AGC would impact on the underlying costs of generating plant providing response and on rotating plant as a whole?

Q4. How ready is generation on the GB system to providing AGC and

a) how might AGC be provided within existing services?

b) and the current market rules and design?

Q5. Are there any further benefits (or detriments) to managing frequency more tightly on the GB system

8 Operating Margins in Gone Green

8.1 Figure 22 provides our latest view of operating margins over the next 15 years. This is constructed as per our Winter Outlook Report methodology, whereby National Grid discounts the output from the generation fleet to reflect our historic observation of plant performance. Interconnector flows are assumed to be at float and operating reserve is added to demand.

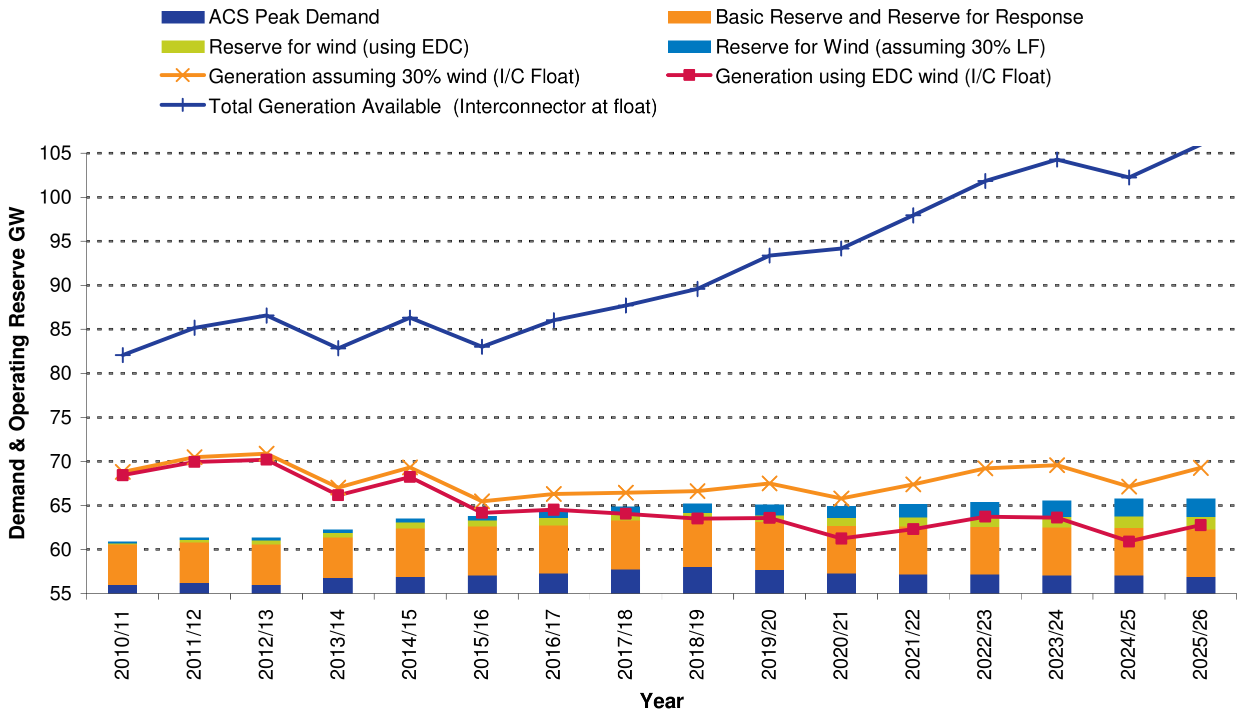


Figure 22: Operating Margins in Gone Green Scenario 2020

8.2 The graphs shows two scenarios of capacity credit attributed to wind output at times of peak. The first is average load factor demand for wind of 30% of installed capacity, whilst the second approach is based on the EDC[31] concept developed by Dr Chris Dent[32]from Durham University.

8.3 Since the previous report the recession of 2008 to 2009 has resulted in a reduction in demand of approximately 2.5GW. We believe a significant proportion of this lost

[31] EDC – Equivalent Derated Capacity. Concept explained in Winter Outlook Report 2010/11 Consultation http://www.nationalgrid.com/uk/Gas/TYS/outlook

[32] Dr. Dent - There is considerable uncertainty over the quantitative results in the Appendix due to the small quantity of historic data directly relevant to assessing wind's contribution to supporting at extreme demands.

demand is unlikely to return to the underlying average demand profile, although similar peak demands may be witnessed during periods of very cold weather.

Q6. Do you agree that there has been a permanent loss of demand as a result of the recession?

8.4 Table 5 shows the operating margin for the next 10 years after discounting the output across the GB generation portfolio, assuming interconnectors at float and applying EDC methodology to derive a capacity credit for wind generation. This shows that by 2017/18, a contribution from wind of less than 16% will mean imports across interconnectors may be required to meet peak demand.

GW	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21
Peak ACS Demand	56.2	56.0	56.8	56.9	57.1	57.3	57.8	58.0	57.7	57.3
Total Generation Available (interconnectors at float)	85.2	86.6	82.8	86.3	83.0	86.0	87.7	89.6	93.4	94.2
Total De-rated Generation (exc wind and interconnectors at float)	68.7	68.6	64.4	66.2	61.9	61.8	61.3	60.8	60.6	57.7
Wind Generation Capacity	5.8	7.4	8.8	10.2	11.9	14.9	17.1	19.5	23.0	26.8
Capacity Credit (EDC)	21%	21%	20%	20%	19%	18%	16%	14%	13%	13%
Wind Generation	1.2	1.6	1.8	2.0	2.3	2.7	2.7	2.7	3.0	3.5
Basic Reserve & Reserve for Response	4.6	4.6	4.6	5.5	5.5	5.5	5.5	5.5	5.4	5.4
Reserve for Wind (on EDC credit)	0.3	0.5	0.5	0.6	0.7	0.8	0.8	0.7	0.7	0.9
Total Reserve	4.9	5.0	5.1	6.2	6.2	6.3	6.3	6.2	6.2	6.3
Surplus	8.8	9.2	4.3	5.2	0.9	0.9	0.0	-0.7	-0.3	-2.4
Operating Margin	16%	16%	8%	9%	1%	2%	0%	-1%	-1%	-4%

Table 5: Great Britain Operating Margins- Winter Outlook Methodology

8.5 Expected margins have slightly improved since our previous consultation assuming a 30% load factor on wind, principally as a result of a lower demand forecast, although under the EDC approach to wind capacity credit there is a shortfall from 2017 onwards. We previously stated that we would expect the balance to be made up from interconnector flows (some 5.7GW by 2020), and in the responses to the earlier consultation, respondents concurred with this view. However we need to consider the possibility that on low wind days in GB, Continental Europe may also experience tighter margins that could result in lower flows, as weather affecting Great Britain is often also affecting Continental Europe. Similarly, on high wind days there may be some inter-region transfer capacity changes across Europe (may be significant if wind speed is approaching cut-out threshold as described earlier in section 6).

9 Thermal Operating Regimes – Energy Balancing

9.1 Two significant drivers will impact on the regimes of the GB generation portfolio in the coming decade. The first is the impact of plant closures as a result of the LCPD, and the second is the increased penetration of wind capacity. Figure 23 shows the change by fuel type and the net capacity change for the next 10 years.

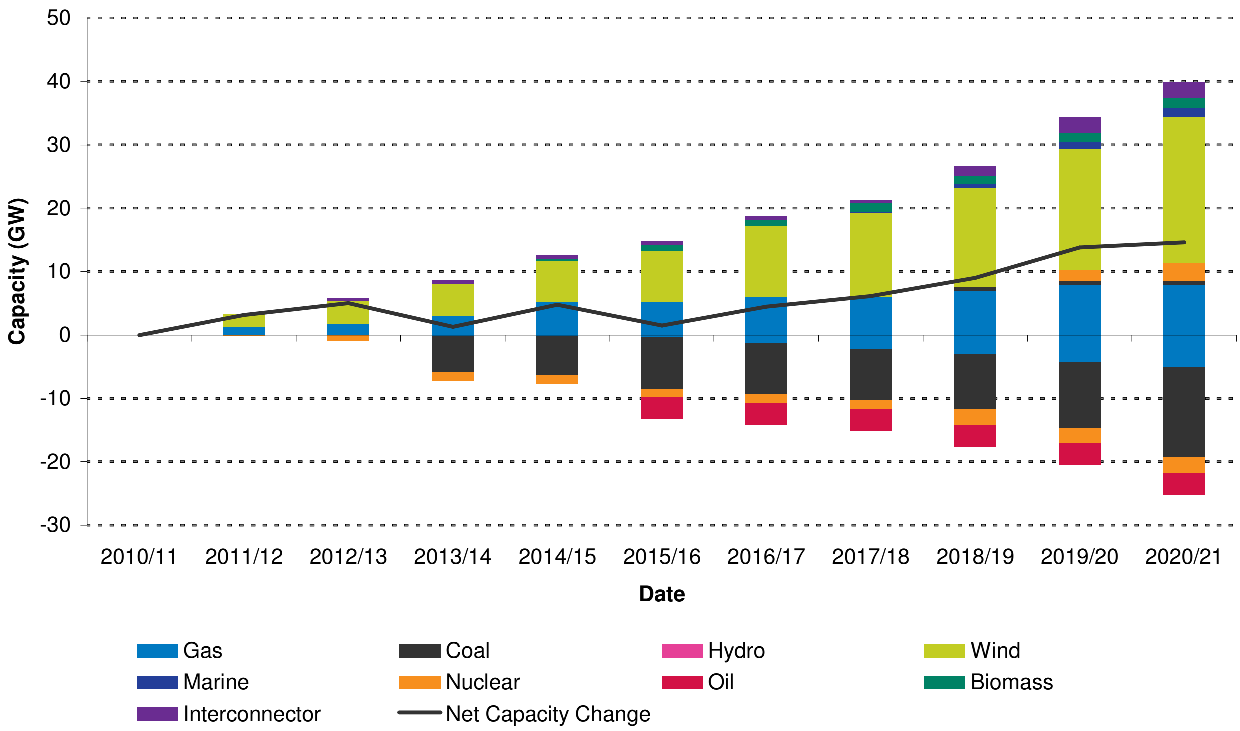


Figure 23: Net change in GB Transmission Connected Capacity to 2020/21

9.2 We are interested to understand how operations of thermal plant are likely to change in response to the change in the GB generation portfolio.

9.3 To understand how the operation of thermal generation will change, it is important to recognise how the profiles for GB demand and wind output correlate. Figure 24 below shows the GB demand profile for January 2010, together with a scaled January 2010 wind generation profile that reflects the wind capacity in January 2021.

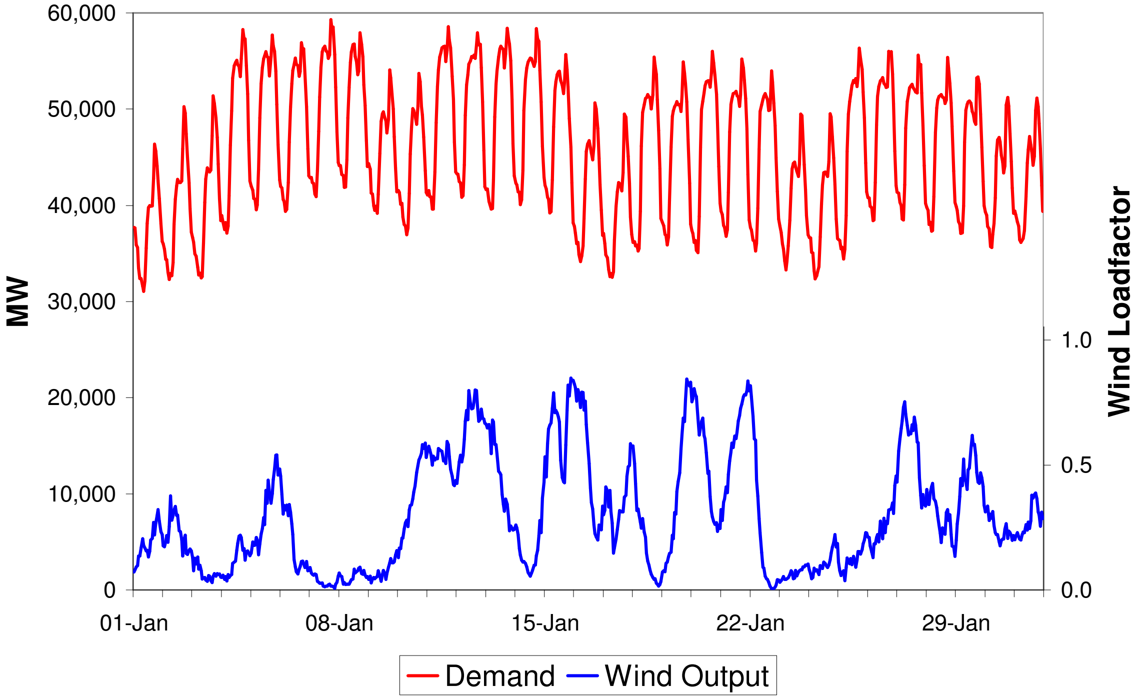


Figure 24: GB Demand and Wind Generation profile or January 2010

9.4 The blue line demonstrates the variability of the wind generation, with load factors ranging from ~5% to ~80%. The demand profile is more consistent in respect of diurnal shape, but with lower levels across weekend and holiday periods.

9.5 Figure 25 shows the thermal plant requirement, using a profile that reflects GB demand net of wind (scaled to 2021 capacity of 26.7GW). This profile of the difference between GB demand and the output from wind generation and the graph represents the profile that will have to be met by thermal generation.

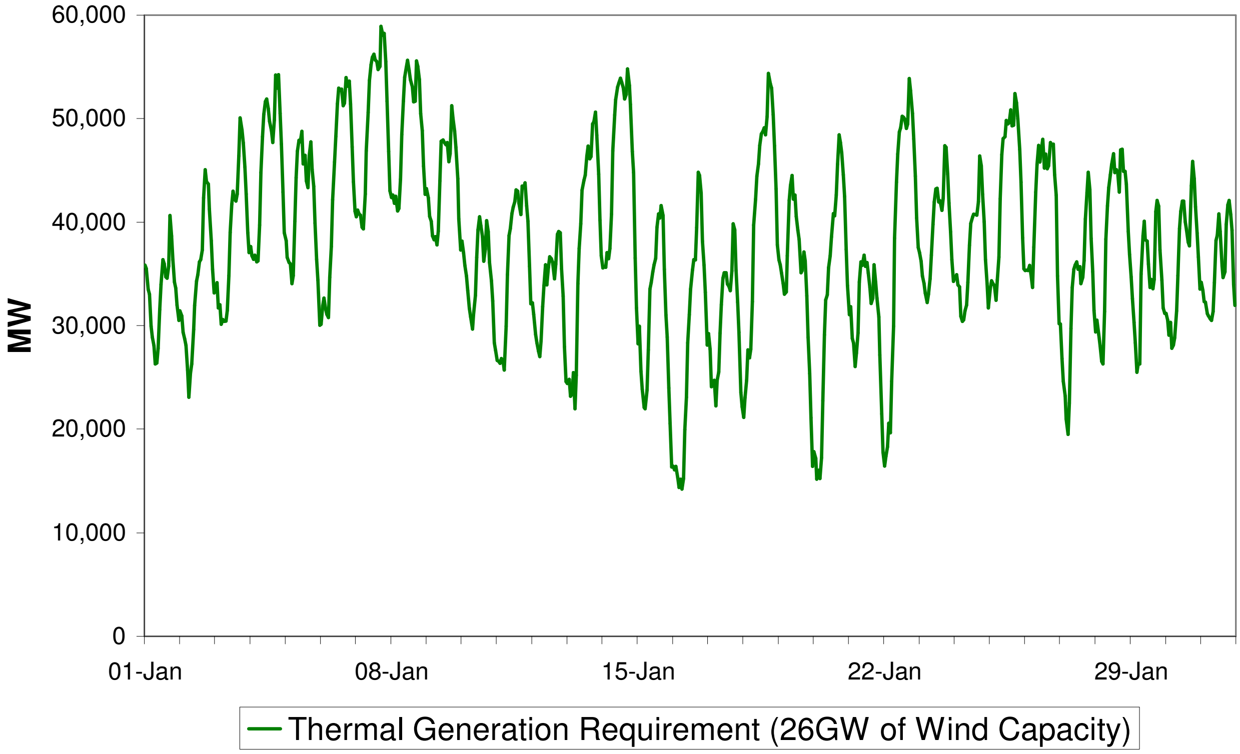


Figure 25: Thermal Generation Requirement (demand net wind)

9.6 As discussed in previous sections, the variability of wind generation in particular will have a second order impact on thermal generation. It is assumed that wind will not be curtailed to provide operating reserve (with the exception of periods where total inflexible generation + wind exceed demand – see [5.33]) principally due to the cost implications of compensation for the forgone ROC revenues. Therefore, thermal plant will have to meet the operating reserve requirement.

9.7 Figure 26 shows the breakdown of operating reserve on the same basis i.e. GB demand for January 2010, with wind output scaled to 2021 capacity. This highlights the different components of the operating reserve requirement namely;

- Basic Reserve – reserve for demand forecast error and conventional generation loss
- Reserve for Response – reserve carried in order to carry sufficient response holding for largest in-feed loss (1800MW in this instance)
- Reserve for Wind – additional reserve required to manage variability of wind output.

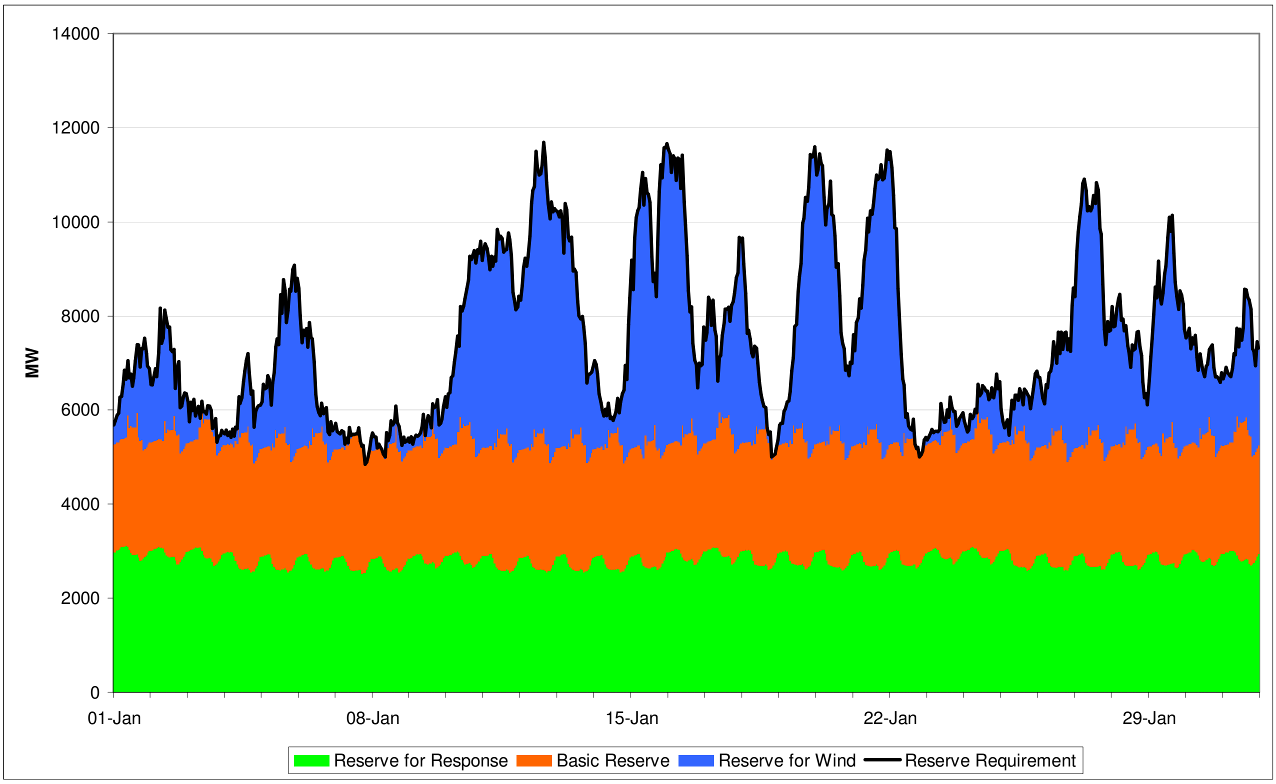


Figure 26: Volatility of Operating Reserve Requirement January 2020.

9.8 As would be expected, the reserve for wind requirement will drive an increased requirement for flexibility with daily and intra-day requirements fluctuating up to 6 GW.

9.9 To further examine operating regimes, a more detailed model was developed that modelled an annual thermal plant regime for three different years. This included more accurate modelling of the wind generation fleet in terms of location, to see if geographical dispersion has an effect on thermal generation requirements.

9.10 A scheduling tool[33] was used, to determine the expected output of the GB generation fleet across the three years. The scheduling function takes account of plant efficiency and current fuel input and carbon prices are used to determine the generation pattern.

9.11 It is not clear how market participants will manage their own uncertainty in respect of wind generation and hence the model takes no account of how market participants might manage any uncertainty around generation and demand profiles.

[33] PLEXOS – this is a scheduling and network model tool, currently used in forecasting the costs of system operation and agreement of incentive schemes. This has been calibrated against actual generation profiles

9.12 However in order to ensure thermal plant is synchronised to the system in a timely manner, National Grid under current practice would make commitment decisions 4 hours ahead of real time[34].

9.13 Therefore, the scheduling tool was set up to look at demand and operating reserve requirements on a 4-hour-ahead basis, with six optimisations runs per day. This broadly aligns with what we believe to be a typical length of time required to synchronise a thermal unit. Reserve was scheduled against wind output in line with the policy described in section 6.

9.14 A physical wind model[35] that models future wind output by using historic wind speeds at the proposed locations of future wind farms was used to generate the wind forecast. This was modelled against expected wind capacity for each of three years, 2005/06, 2015/16 and 2020/21, generating a wind output profile for each year.

9.15 As explained previously, National Grid expects demand to remain flat in the next 10 years. Therefore, the wind profile for each of the three years was netted from a demand forecast profile for 2009/10, thus giving a demand net wind profile or thermal plant requirement for each year.

9.16 To ensure that only the impact of the wind generation was isolated, the GB generation portfolio of 2009/10 was used for each time period examined. Although the LCPD opted out plant will be retired by 2015/16, a majority will be replaced with new CCGT or wind capacity as shown earlier in Figure 23.

9.17 Since it is not the aim to identify individual station outputs but to understand how the increase in wind generation will impact thermal plant as a whole, the actual unit availability within the thermal generation fleet is not relevant to this analysis.

9.18 Finally, the availability profile of the generation fleet reflects that of 2009/10, as do the fuel input prices for coal, gas and carbon i.e. to ensure a relevant comparison the same price basis of 2009/10 has been used.

9.19 For clarity, on all the following graphs, other generation sources, including interconnectors, pumped storage and hydro etc has been grouped as “other”. Nuclear is assumed to remain inflexible and thus is shown to have no variation.

9.20 The daily range of operation for coal-fired, gas-fired and other generation was calculated for each year 2005/06, 2015/16 and 2020/21. This is the difference between the highest and lowest output for the plant type. The tighter the range, the less marginal the fuel type and vice versa.

9.21 Figure 27 shows the daily range for each fuel type for 2005/06. At this time there was limited wind capacity connected to the transmission system, but as expected the flexibility is provided by coal and gas fired plant. In this model, gas is the

[34] This does not include providers of generation/demand under STOR contracts which have to have notice period to deviate from zero (NDZ) of less than or equal to 240mins
[35] The model used is a Poyry model which reflects the location of future wind farms. We also compared this to our own operational data scaled to 2020 wind capacity and found little difference in result.

cheaper fuel for most of the year marginal in the summer periods, before becoming the marginal fuel in the winter (January through to March).

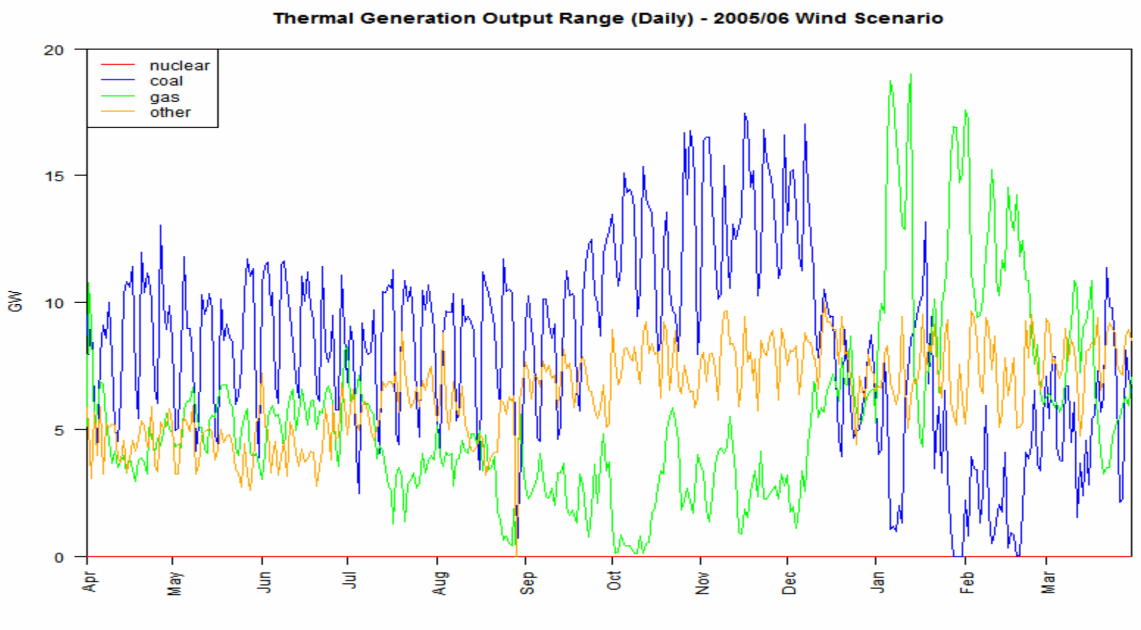


Figure 27: Impact of wind penetration on thermal generation 2005/06

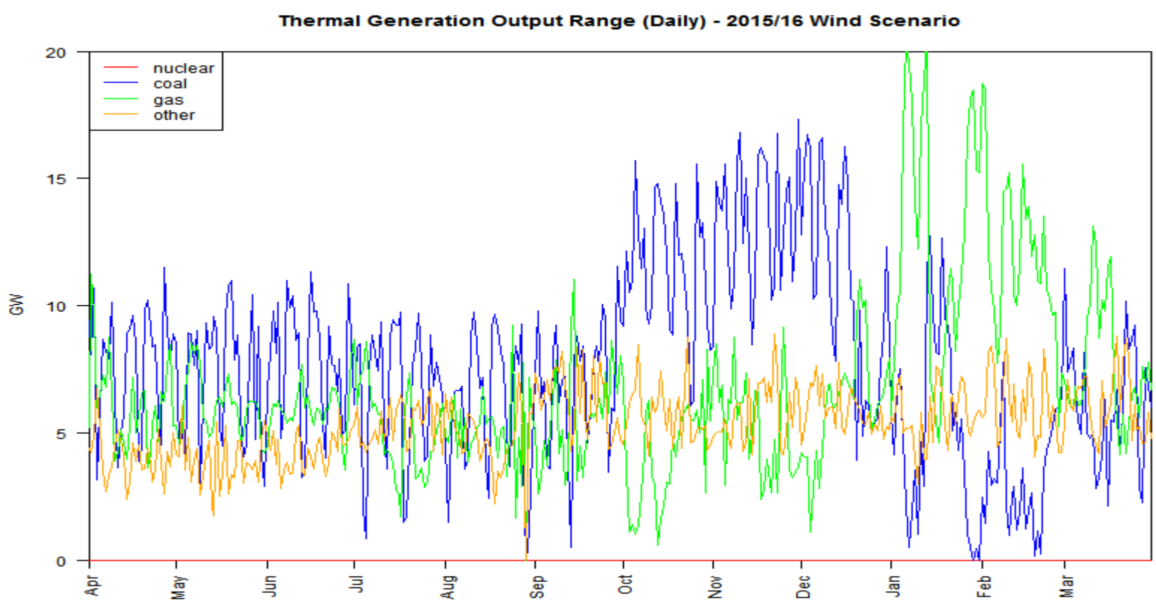


Figure 28: Impact of wind penetration on thermal generation 2015/16

9.22 In Figure 28, the overall range of operations across thermal generation is broadly the same as in 2005/06, despite the higher wind contribution. However there are instances where the maximum range output on thermal generation has actually increased. For example in early January, the range on gas-fired generation exceeds 20GW. This could reflect a period of variable intra-day wind generation, where thermal plant will be increasingly used to meet demand at periods of low wind and operating reserve during high wind periods.

9.23 Likewise during late February and early March, the range in gas output reduces, whilst coal-fired generation range exceeds 10GW at times as it moves towards being the marginal fuel.

9.24 An increasingly volatile trend across the three periods emerges as reflected on gas-fired generation during the summer and autumn periods in 2015/16.

9.25 The pattern of increased volatility for thermal generation in 2020/21 is repeated in Figure 29.

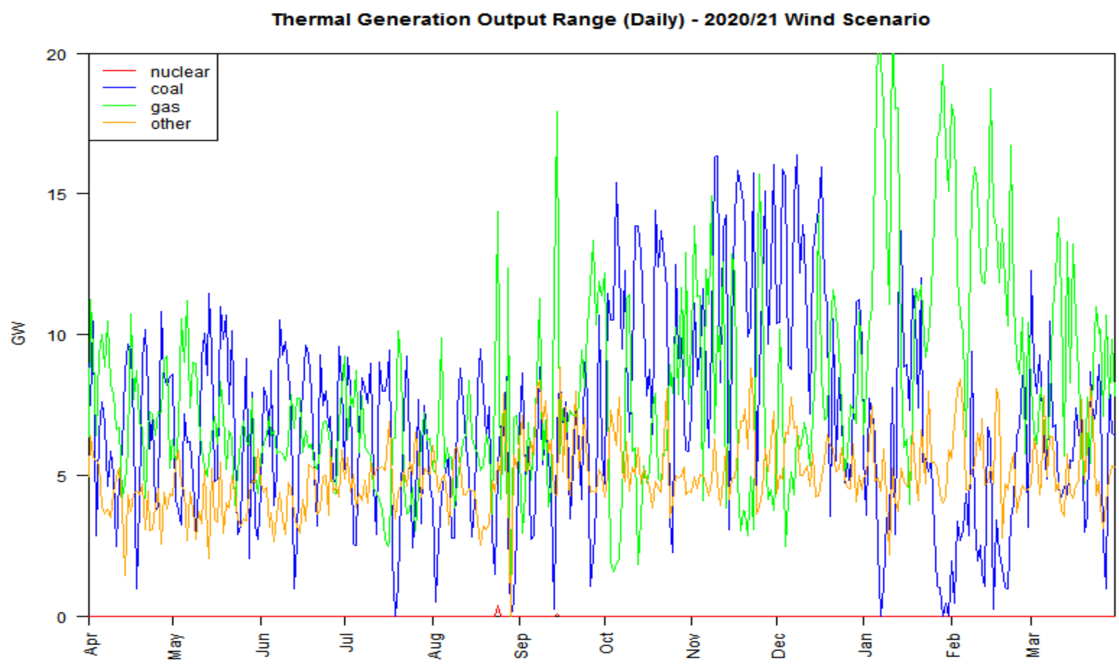


Figure 29: Impact of wind penetration on thermal generation 2020/21

9.26 In section 6, an explanation was given to how the higher contribution from wind generation will result in a higher operating reserve requirement, to cover the potential variability in wind output and this was also discussed earlier in this section.

9.27 To demonstrate this it is easier to look at thermal plant regimes over a shorter time period. Figures 30 to 32, show output across the three main fuel types, nuclear, coal and gas, together with wind output.

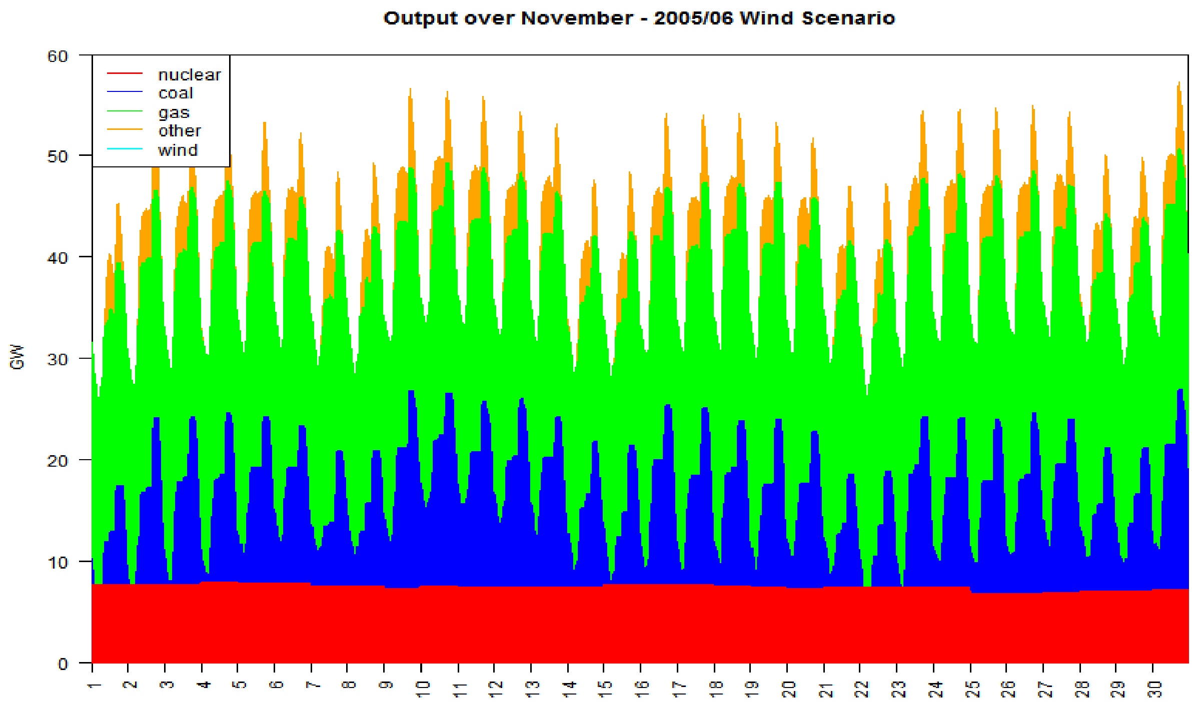


Figure 30: Thermal Generation Requirement for November 2005/06

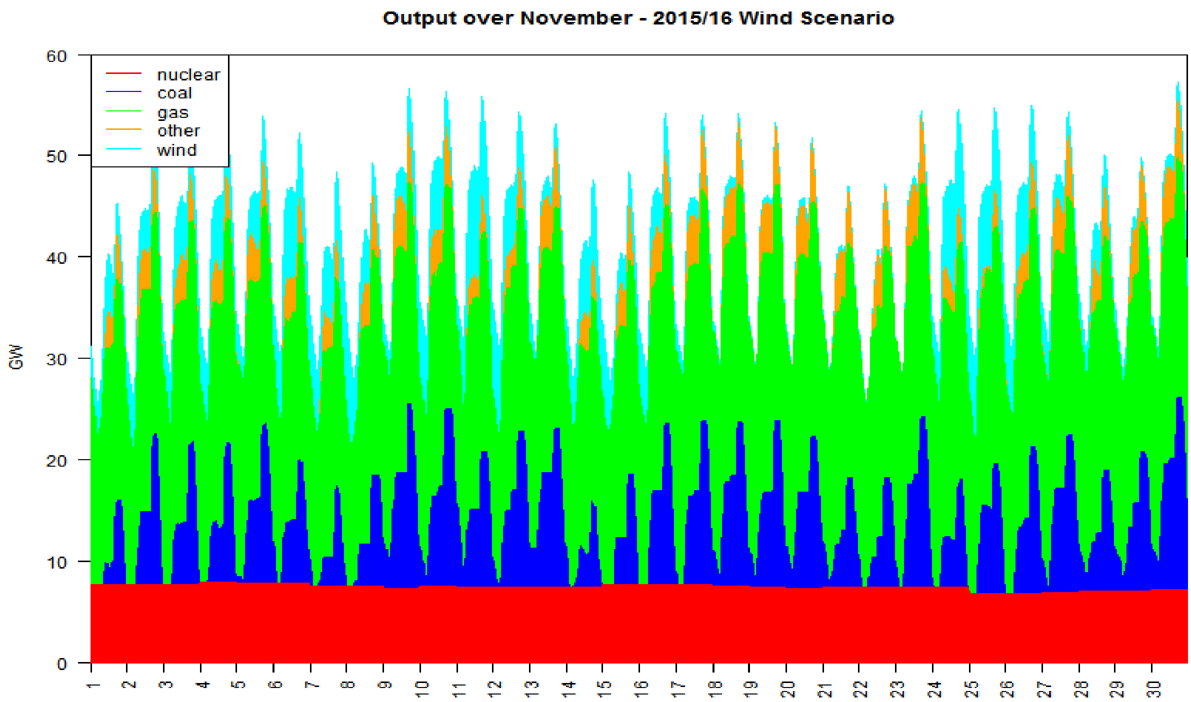


Figure 31: Thermal Generation Requirement for November 2015/16

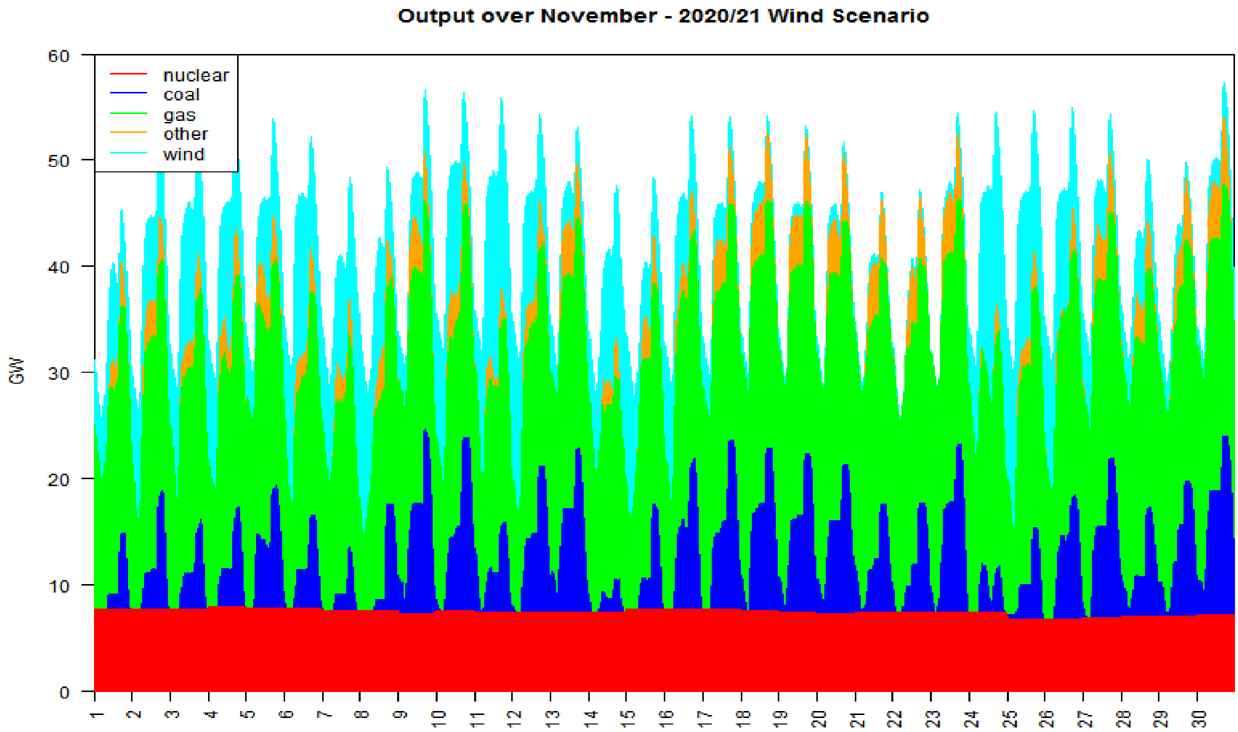


Figure 32: Thermal Generation Requirement for November 2020/21

9.28 By looking at the month of November, it is easier to see the trend of output for coal and gas plant identified earlier in this section. It clearly shows the increasing variation in output on the marginal thermal plant, by 2015/16, as the increasing wind contribution displaces thermal plant.

9.29 In the subsequent 5 years from 2015/16 to 2020/21 however, despite a doubling of wind capacity in the period, the maximum output level from thermal plant does not change significantly and clearly this is on days where wind output is minimal. This will lead to a greater number of starts for the marginal sets.

9.30 The increased reserve requirement during periods of high wind output is also evident on certain days. In Figure 32, for example, over the demand peak on the 24th November 2020, the wind output is ~15GW compared to ~9GW in 2015/16 (see Figure 30). However, the combined thermal output from coal and gas has fallen comparatively less from ~27GW in 2015/16 to ~23GW in 2020, the difference representing the additional reserve requirement.

9.31 The average load factor for thermal plant inevitably reduces as wind generation meets an increasing proportion of demand. In this analysis, coal-fired generation is the marginal thermal generation for a majority of the time and this is reflected in a

12% fall in average load factor from 37% to 25% compared to a 6% reduction in gas-fired generation from 68% to 62%.

9.32 The additional flexibility required from thermal generation is highlighted by the increase in the number of starts by 2020, which reflects the increase in 2-shifting. Table 6 summarises load factor and number of starts by year.

Fuel Type	**2005/06**	**2015/16** **Number of starts**	**2020/21**	**2005/06**	**2015/16** **Load Factor**	**2020/21**
Coal	6010	5410	4852	37%	30%	25%
Gas	5247	6312	7135	68%	65%	62%
Coal % change from 2005/06	-	-11%	-24%	-	-7%	-12%
Gas % change from 2005/06	-	17%	26%	-	-2%	-6%

Table 6: Load factor and cycling regime for thermal plant

9.33 Coal-fired generation actually sees a reduction in the number of starts. This may suggest that running hours predominantly accumulate where there is a lower contribution from wind generation and hence profiles are more predictable or possibly that it runs to meet reserve requirements on high wind days.

9.34 The analysis suggests a significant increase by 2020 in the number of starts on gas-fired generation, despite a higher load factor. Since the average load factor of wind generation is about 30%, it would be expected that the cheaper thermal plant would accommodate the variability and additional reserve requirements.

9.35 This analysis gives an insight into the possible operating regimes of thermal plant, but is by no means extensive. A significant proportion of CCGT and coal-fired plant could be low merit in 2020. In particular, the increase in 2-shifting across the CCGT fleet and the increasing variability of output whilst synchronised will have an impact on both the operating costs of CCGT and the operation of the gas networks.

Q7. How significant would a 25% increase in starts be to the operation and maintenance of a CCGT?

10 Interconnectors

10.1 GB currently has a number of existing and planned interconnectors amounting to 5.7GW of capacity. These are listed in Table 7.

Interconnector		2011/12	2012/13	2018/19	2019/20
IFA	GB to France	2.0	2.0	2.0	2.0
Britned	GB to Netherlands	1.2	1.2	1.2	1.2
East-West	GB to Ireland		0.5	0.5	0.5
IFA2	GB to France				1.0
NEMO	GB to Belgium			1.0	1.0
Total		3.2	3.7	4.7	5.7

Table 7: Future Interconnector Capacity to GB

10.2 The transfers of energy across the interconnectors are largely determined by market participants' although there are differences in process between interconnectors in both temporal activity and how flows are determined. For example, across the GB-France (IFA), capacity procurement is on an explicit basis with energy nominations made on a multi-participant basis, whereas the GB-Netherlands (Britned) has a combination of explicit capacity auctions and market coupling. The arrangements on each Interconnector determine the part they may play in balancing the system.

10.3 National Grid currently trades on a bi-lateral basis with market counterparties who hold capacity on IFA. This enables National Grid as NETSO, to procure directional volume at a market derived price to manage reserve and congestion management issues. This is predominantly an on the day activity that often necessitates a significant volume to be procured or sold, in compressed timescales.

10.4 In addition to the market arrangements, there are also agreements between the NETSOs that are connected to each other by the interconnectors. These agreements provide a range of cross border balancing or emergency assistance services to ensure that system security can be maintained.

10.5 As the name implies, emergency assistance services are generally considered to be a last resort service and hence are used in exceptional circumstances. In respect of cross border balancing services, whilst these are firm upon the acceptance of a request, they are not always available as each NETSO has the ability to withdraw the service within any timescale.

European initiatives and a consideration of their impact on system operation

10.6 Implementation of the EU Third Energy Package will bring significant changes to the balancing tools that may be available to National Grid. Probably the most significant change is the move towards implicit auction mechanisms and associated market coupling processes.

10.7 With the removal of explicit capacity regimes, there will result a loss or dilution of some of the current pre-gate tools available to the NETSO that assist in reserve and congestion management activities. As third parties can currently buy capacity rights on the Interconnectors, it enables National Grid to procure volume in a particular direction. However, with implicit mechanisms, capacity is released to an exchange and the price differential between the markets dictates direction and volume of flow, thus removing the ability of a third party to provide directional services to National Grid.

Q8. Do you agree that the introduction of implicit mechanisms will remove the ability for National Grid to procure services with market participants across interconnectors?

Q9. Are you aware of any other market based mechanisms used in Europe to help NETSO manage flows on Interconnectors?

10.8 Currently, trades conducted on the IFA for example, are an efficient means of managing congestion issues and reserve procurement, and they are often complimentary[36] in nature, hence reducing the overall cost to balance the system. The density and variable nature of future generation capacity across wind generation and interconnectors combined with the high demand in the region means potentially more costly alternatives will have to be deployed, or appropriate balancing tools will have to be modified or developed to manage the prospective increase in the variability in transmission flows. This may take the form of contracting flexible generation or demand facilities in the region.

10.9 There are number of regional initiatives ongoing and National Grid is taking part in the NWE (North West Europe) project. It is expected that the project will complete by end of 2012. The principle aims of the project are;

[36] Due to the high level of generation in the south east, exports on the interconnector often exacerbate transmission flows in the region, particularly during outage periods. Therefore generation in the region may be curtailed to manage transmission flows. By reducing exports through counter-trading we can reduce flows without curtailing generation.

- To develop day-ahead and intra day implicit auctions
- Develop continuous trading on Interconnectors
- One hour gate closure
- Formation of a co-ordinating entity to facilitate market functions of a shared order book (SOB) and capacity management.

10.10 There is expected to be further development of European wide balancing codes that may incorporate cross border balancing. As previously indicated, arrangements between Réseau Transport d'Électricité (RTE) and National Grid across IFA are well developed in this area, however as national markets move towards closer integration, the volumes available between the two NETSO for real time balancing are likely to reduce as limited resources are shared between a greater number of NETSOs.

Current Activity on IFA

10.11 National Grid currently makes use of pre-gate trading and cross border balancing towards operating reserve. It is apparent that with increased market coupling through parallel day-ahead implicit auctions, some of the tools currently used by National Grid, such as pre-gate trading, will not be available.

10.12 Furthermore, any sharing of reserves between different markets through cross border balancing arrangements are likely to offer reduced certainty in respect of volume within planning timescales. Therefore, it is likely that a significant proportion of operating reserve currently procured on interconnectors will move towards GB providers.

10.13 As can be seen from Figure 33, volume for margin (operating reserve) is often procured on the interconnector across demand peaks.

10.14 Volume is consistently procured for trading periods (Electricity Forward Agreement - EFA) 5 and 6 across the year, whilst during the summer period's volume is sold to assist with meeting downward margin issues.

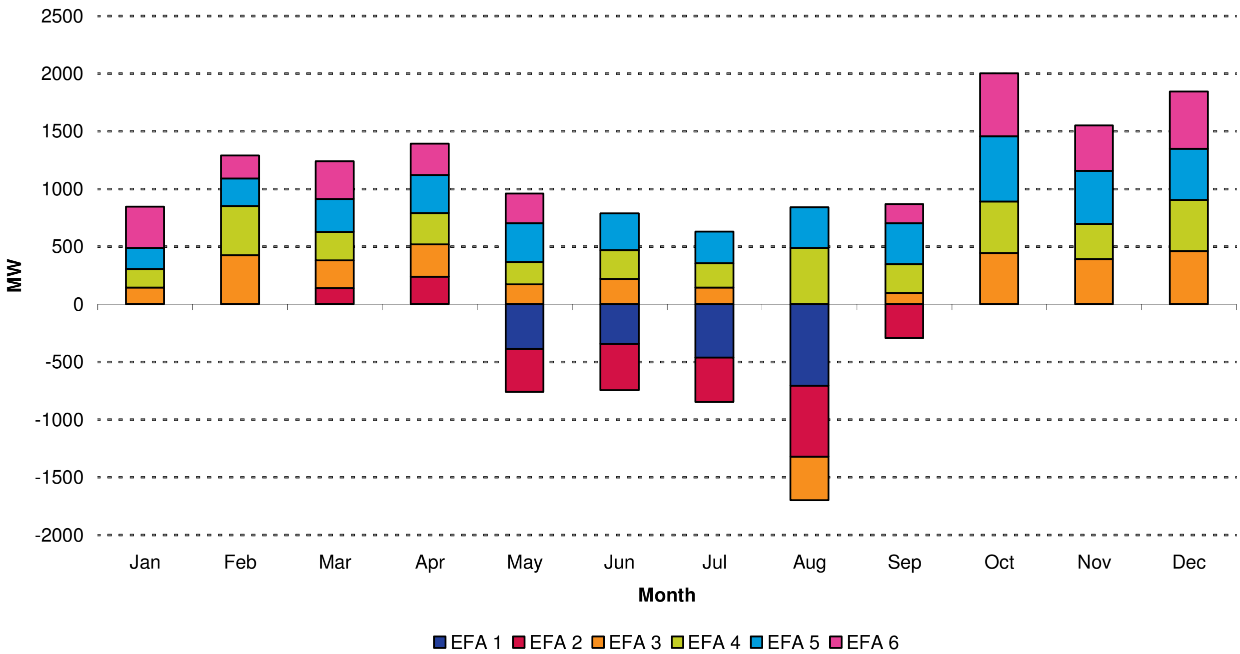


Figure 33: Average[37] Traded Interconnector Volumes for upward and downward margin (operating reserve) on IFA

10.15 The IFA connects into the GB Transmission System where constraints are often active, particularly when transmission capacity is restricted. Capacity on interconnectors is not restricted by any internal congestion issues.

10.16 Therefore, in order to manage and secure the network to GB SQSS, it is often necessary for the NETSO to counter-trade with market participants' in order to manage flows on the interconnector. Prior to the introduction of the use it or sell it regime, this activity would occur on varying timescales but generally after the intra-day capacity auctions have taken place.

10.17 This is often the most efficient way for National Grid to manage constraints on the GB system particularly against an export constraint, where generation often has to be restricted in order to manage thermal flows in an area, thus impacting on energy balance.

10.18 Figure 34 shows the average volume by EFA block of trades for constraint management purposes over the past three calendar years. Whilst the level of trading will vary year on year, it gives an indication that actions are often necessary across the year and at varying times of the day

37 Typical volume traded when trades are executed

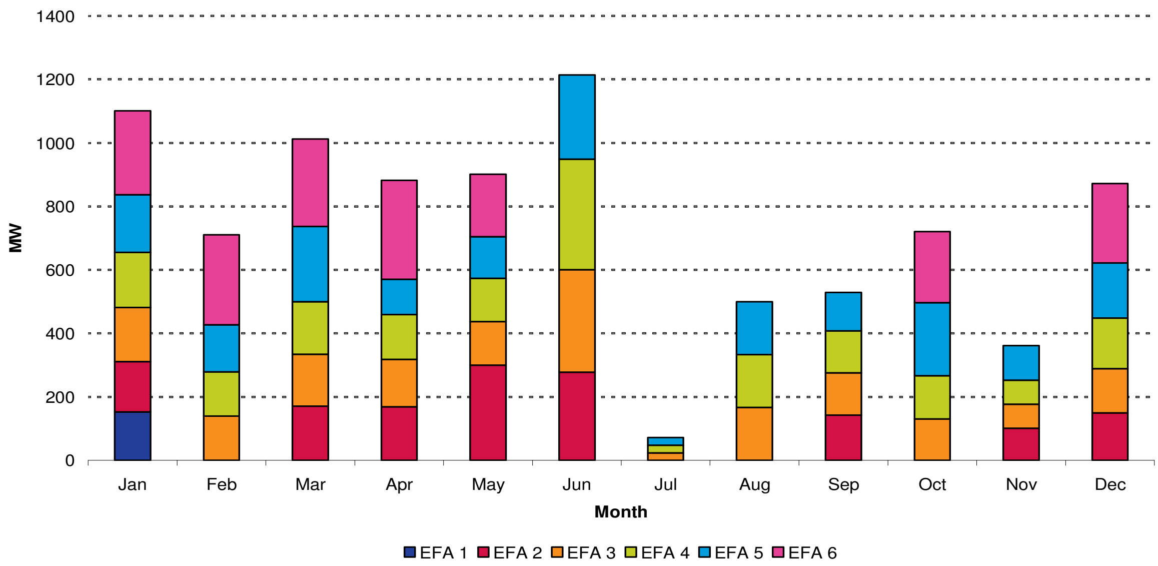


Figure 34: Average Volume of Trades for constraint management on IFA 01-Jan-07 to 31-Dec-10

10.19 An additional means of managing interconnector flows are through agreed bi-lateral arrangements with neighbouring NETSOs. National Grid has such an arrangement with RTE and makes considerable use of the service as shown in Figure 35.

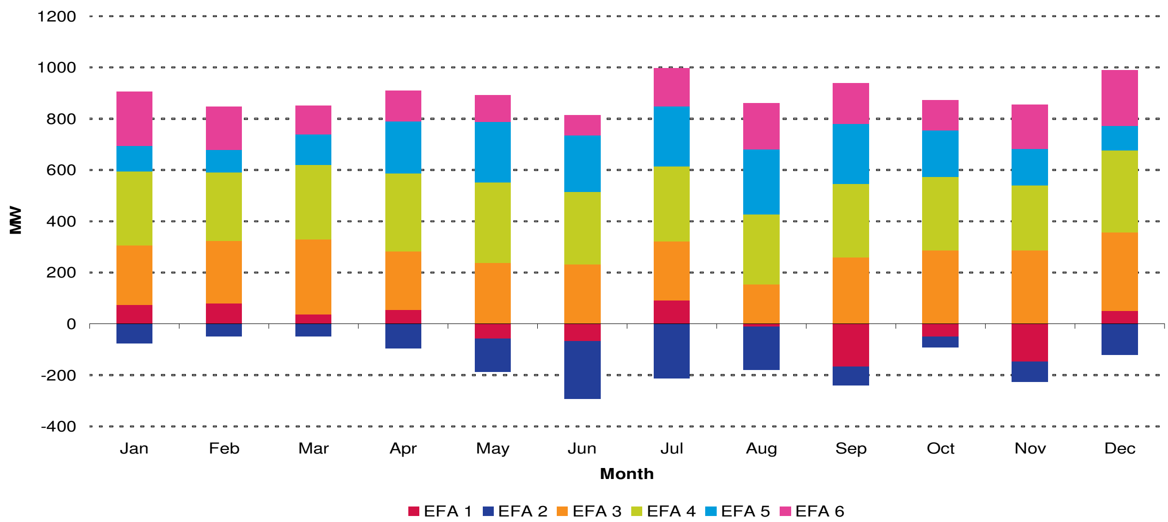


Figure 35: National Grid instigated CBB[38] average volume of trades 2007 - 2010

[38] CBB – Cross Border Balancing is the name of the bi-lateral agreement between RTE and National Grid

10.20 Whilst it is anticipated this service will remain in place, moving forward it is still unclear as to how arrangements will develop for cross border balancing between NETSOs. However, as previously noted in [10.5], whilst the price of CBB is firm, the volume is only firm on acceptance of a request. Therefore it is not always an appropriate tool to manage transmission constraints as the service may not be available for extended periods.

10.21 Table 8 below summarises the number of settlement periods where National Grid has traded, including the context of the trade i.e. margin, constraint or through cross border balancing (which could be both for margin or constraint).

EFA Period	Total No. of periods	No. of periods where where Pre-Gate Trades executed		CBB Trades	% of periods where where Pre-Gate Trades executed (incl reason)		CBB Trades
		Energy/Margin	Constraint		Energy/Margin	Constraint	
EFA 1	11680	34	16	552	0.3%	0.1%	4.7%
EFA 2	11680	420	86	1769	3.6%	0.7%	15.1%
EFA 3	11680	570	702	2640	4.9%	6.0%	22.6%
EFA 4	11680	570	714	2517	4.9%	6.1%	21.5%
EFA 5	11680	1106	594	2802	9.5%	5.1%	24.0%
EFA 6	11680	262	210	1736	2.2%	1.8%	14.9%
Total	70080	2962	2322	12016	4.2%	3.3%	17.1%

Table 8: Trading activity on GB-France (IFA) Interconnector

10.22 The changes National Grid will be predominantly concerned about are those that occur with a short notice period, particularly those gate closures that contain settlement periods that include the demand peaks.

10.23 Since the introduction of the capacity management system on IFA, which introduced the use it or lose it/sell it regime, we have witnessed an increase in intra-day activity on the GB-France interconnector. This introduced two intra-day capacity auctions that occur after the day-ahead nominations, each auctioning capacity for the subsequent three post auction gate periods.

10.24 Currently there are six gate periods on IFA. As explained in [10.9], it is expected that shorter gate closures will be implemented across existing interconnectors over the next few years.

10.25 National Grid has limited experience of the volume of change that may be experienced between day-ahead programmes and intra day programmes on interconnectors.

10.26 However, we have witnessed significant changes to flows on IFA in short timescales since the introduction of the CMS[39] and the associated Use It or Sell It mechanism.

[39] Capacity Management System

As an export flow to France is essentially an increase in demand on the GB system, changes in expected exports across the IFA can significantly impact on operating margins (and constraint management).

10.27 In the absence of a forward curve and recognising that price signals will be the principle driver of directional flow on the interconnector, we have looked at the amount of change between day ahead and intra day nominations for the calendar year, 2010[40].

10.28 Figure 36 demonstrates the changes in flow between day ahead and final gate closure nominations. A positive change indicates the absolute change in flow France to GB; a negative indicates a change in direction GB to France. This demonstrates that 90% of changes are within 500MW of day-ahead nominations, although 5% of the time the changes are in excess of 1000MW towards France. A change of this level at short notice (<4 hours) would be significant to National Grid. Table 8 describes the distribution.

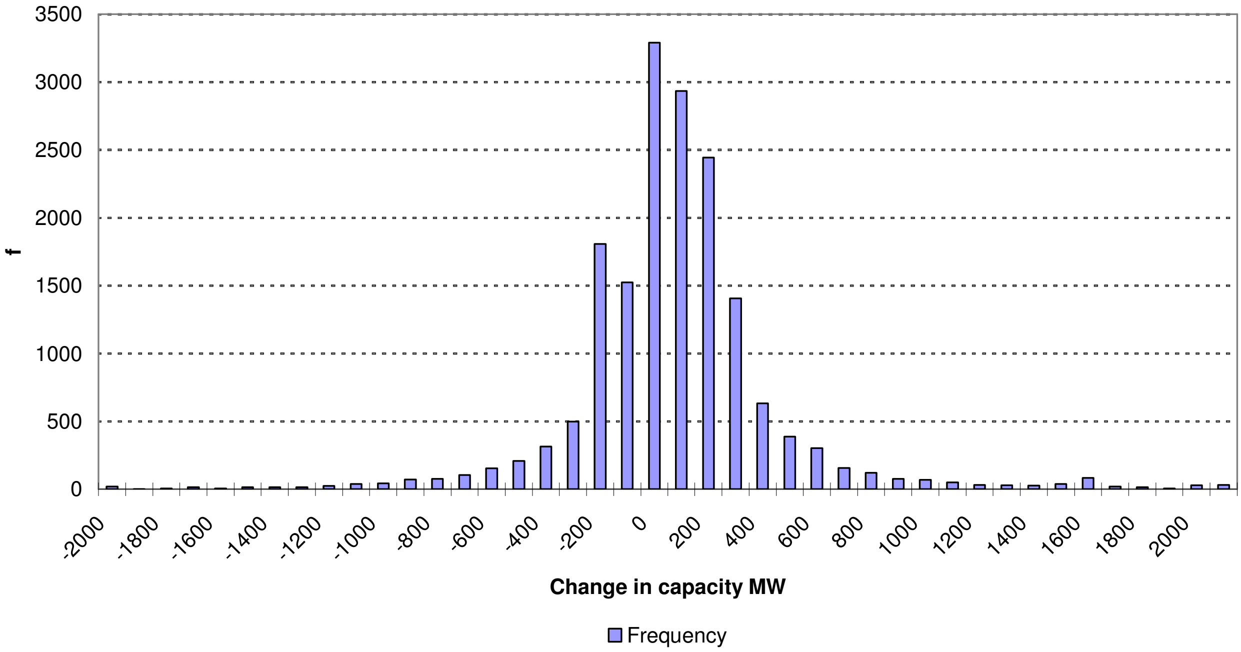


Figure 36: Change in IFA volumes between day ahead & gate closure nominations

[40] Data compares day ahead nomination at 13:00 D-1 to final gate closure for corresponding settlement period, data sample 01-Jan-10 to 23-Dec-10. We have excluded the Christmas period as activity over this period is not representative of most of the year

	Change in flow								
	Change in flow towards France					Change in flow towards GB			
	-2000	-1500	-1000	-500	0	500	1000	1500	2000
Number of instances	60	136	616	4140	3291	7419	1044	206	192
Proportion of changes	0.4%	0.8%	3.6%	24.2%	19.2%	43.4%	6.1%	1.2%	1.1%

Table 9: Change in flow on GB –France Interconnector

10.29 Whilst changes in excess of 500MW in either direction do not occur often, a short term change in excess of 1000MW towards France has occurred approximately 5 % of the time. Further data describing the distributions by EFA period are in Appendix 1.

10.30 Currently, the less frequent number of gate closure periods compared to the GB market can often provide a challenge to plant schedules in the event of large short term changes in IFA nominations. However there is usually sufficient time to utilise operating reserve to mitigate short term changes in interconnector nominations. Furthermore, existing arrangements allow National Grid to manage such a risk through bi-lateral trades and CBB. Furthermore, National Grid have always made the underlying assumption[41] that against existing gate closure arrangements, an increase in export would be offset by an increase in generation from within the GB market.

10.31 Whilst this assumption may hold true, the impact on system reserves can still be detrimental if the volume is not met through additional BMU synchronisations in GB. Currently, our ability to bi-laterally trade pre-gate closure, allows some of the volume risk to be mitigated, particularly for constraint management purposes.

10.32 In addition to price, changes on interconnectors' nominations will also be influenced by market liquidity, cash-out regimes between neighbouring markets and potentially wind generation.

10.33 If GB is experiencing significant levels of wind generation that subsequently drives the price spread to Continental Europe, it may be the case that excess generation is sold into Europe.

10.34 Whilst this is not a problem in itself, the impact on reserve procurement decisions may be significant if market behaviour changes significantly from that which is currently witnessed.

10.35 As now, unit commitment decisions often have to be made several hours in advance of gate closure. However due to the nature of wind generation (as discussed in

[41] We assume that any export across an interconnector will be matched by an increase in energy output from the GB generating fleet. However this may reduce the amount of synchronised margin available to National Grid and hence impact on Operating Reserve

section 6) it is possible that market participants will trade out variability much closer to gate closure. This may ultimately impact on how much reserve is available in real time to the system operator.

Q10. How will shorter gate closures impact on interconnector nominations? Will interconnector transfers become more volatile?

Q11. Do you think that National Grid as System Operator should take account of potential short term changes on the Interconnector in reserve policy (operating reserve)?

Q12. How important is market liquidity and cash-out arrangements on interconnector flows

10.36 There are two approaches that could be taken to manage this;

- Carry additional reserve against changes in interconnector flows at all times
- Carry additional reserve against changes in interconnector flows on high wind days only

10.37 The first approach may be difficult to derive an appropriate level of extra reserve as it would be a complex derivative of numerous drivers. However, a transitional policy of increasing the level of reserve linearly with interconnector capacity could be a means of managing the risk.

10.38 For example, the data in Table 8 indicates that 24.2% of the time, the change between day ahead and final gate closure (when flows increase to France) on IFA is less than 500MW[42]. Therefore we could take an approach of carrying a percentage of the total available[43] interconnector export capacity (i.e. additional demand) e.g. 12%[44].

10.39 The second approach, which is essentially probabilistic, is an extension of the approach to reserve holdings described in section 6, wherein we carry proportionately more reserve on high wind generation days. However, as with the first option, this component would be a derivative of many complex drivers, rather than a function of wind persistence and forecasting performance.

10.40 Under both approaches, it would be advantageous to have more balancing services that can be utilised with short notice to delivery, to minimise the amount of regulating reserve requirement.

[42] This is clearly a small data sample and is only used in this instance to explain the premise
[43] This would be calculated on a net flow basis i.e. if day ahead flow is 500MW to France to GB on IFA, available capacity would be calculated as 2.5GW
[44] This is assuming changes in volume are uniformly distributed between 0MW and 500MW

Q13. Which approach of those described above do you think would be most appropriate to manage uncertainty around interconnectors?

10.41 With the recent removal of TRIAD charges to exports on interconnectors, the propensity that third parties will export to mainland Europe over high demand periods has increased. Together with the potential of continuous trading over the interconnector and shorter gate closures, it may realise a requirement to consider "trading losses" within the operating reserve. This would necessitate understanding the co-variance between conventional generation losses, wind intermittency and demand error along with the variability between connected market prices.

Q14. Do you agree that the propensity to export to Continental Europe has increased with the removal of TRIAD?

10.42 In this section so far, consideration has only been given to the impact of interconnector variability on operating reserve levels, however the management of circuit outages will also increase in complexity with more variable interconnector flows.

10.43 When taking a circuit outage, to accommodate the reduction in capacity, the transmission network is often reconfigured so that in the event of a fault, the integrity of the system is maintained.

10.44 As interconnectors can be large generation sources or significant additional demand then their mode of operation can have a significant impact on system operation.

10.45 The effect on the transmission system is dependent on generation output and demand in that region. For example, if an interconnector is importing into a part of the transmission system where there is a high concentration of generation, then an export constraint can be activated as the combined generation from the area moves towards the demand centre.

10.46 Likewise, if interconnectors are exporting (demand) then it will pull additional power through the transmission circuits in the region. Again this may result in thermal overloads or voltage issues.

10.47 Generally, the transmission system is optimised ahead of time to ensure it can cope with a number of fault scenarios. However it is often the case with certain faults, that additional pre or post fault re-dispatch[45] of generation is required.

[45] This can be pre-fault or post-fault. Pre-fault is carried out when in the event of a fault occurring there would be insufficient time to re-despatch the required plant. Where in the event of a fault there would be sufficient time to re-dispatch then this is know as post-fault

10.48 It is therefore essential that to manage system security and costs, National Grid takes account of the likely interconnector flows. Appropriate risk mitigation actions can then be considered and implemented.

10.49 As explained in paragraphs [10.6] to [10.7], likely developments in respect of interconnector trading arrangements will potentially restrict or remove some of the strategies currently available to National Grid.

10.50 In [10.36] a number of options were discussed that could help mitigate the impact of interconnector variations on operating reserve. The combination of additional uncertainty, fewer balancing tools and shorter gate closures will have a similar impact on managing system access.

Q15. What is your view on how the NETSO best manage the additional uncertainty in the context of system access?

10.51 Representatives from ENTSO-E are now currently forming teams to begin work on drafting the various codes for the harmonisation of codes across the European transmission system.

Q16. How should consideration be given to the trade-off between unrestricted trading on interconnectors and the cost of risk mitigation?

10.52 In this section we have explained the challenge in managing the potential variation of flow on the existing interconnectors. By 2020, the capacity of interconnection is expected to have almost doubled to 5.7GW. This will mean that the potential changes in flow across all interconnectors will be 11.4GW (full import to full export). It will be imperative that National Grid have the tools and services available to anticipate and to manage the magnitude of these potential short term transitions.

11 Cost of Operating Reserve

11.1 In the previous consultation, an indicative forecast for the cost of operating reserve by 2020[46] was provided. The costs were calculated by extrapolating a 4 year average of historic volumes and applying the additional volume required to manage variability of wind under average conditions.

11.2 The majority of the responses to the consultation suggested that the price of reserve would be higher than that suggested. The principal reason for this view was that higher prices would be required to attract providers of reserve services. As National Grid could not offer a meaningful price forecast for 2020, the nominal price for the 2009/10 incentive scheme were used.

11.3 It is clear that significant uncertainty exists around the costs of reserve and thus it may be useful to consider how reserve costs may be affected by the different drivers of the requirement, notably wind and interconnector variability, together with the larger potential in-feed loss.

11.4 For the purposes of this analysis, it has been assumed that margin costs rise in line with the underlying power price. The cost of margin is set as a premium to the underlying power price, starting at £25/MWh in 2010/11.

11.5 The forecast power price is expected to be approximately double the 2010 baseload electricity price in real terms (i.e. the effect of inflation has been removed), moving from £41.80/MWh in 2010 to £84.10/MWh in 2020.

11.6 This has been derived using forecasts for the commodity complex (mainly oil and gas price) that is correlated to the electricity price. This is consistent with the methodology for forecasting future prices that has been consulted on with industry[47] and has been calibrated using external sources[48] .

11.7 The proportion of the reserve requirement carried for demand forecast error and plant losses is termed the basic reserve requirement. The volume forecast results from the assumption that an action will have to be taken by National Grid for 25% of periods (2160 hours).

11.8 For volume forecasts, the main drivers of the anticipated increase in operating reserve are increased wind capacity and the larger response requirement from 2014, both of which were explained in previous sections. The marginal impact of wind is assumed to reduce to 30% by 2020, that is to say we carry an additional 0.3MW of reserve for each additional MW of wind generation.

11.9 The volume forecast for the reserve for response requirement is derived on the same premise as that noted in [9.7] for the basic reserve requirement.

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[46] Operating the Electricity Transmission Networks in 2020 Table 5 – Reserve Volume increases in the Gone Green Scenario

[47] These price forecasts have been used to form the basis of National Grid's own use utilities for RIIO submission

[48] Wood Mackenzie

11.10 Using a 30% load factor for wind, it is assumed that additional margin actions will be required to meet reserve requirements, 50% of the time or 4320 hours per annum.

11.11 Finally, in the context of the issues discussed in section 10 around interconnectors, an allowance for uncertainty surrounding interconnector flow has been included in the requirement from 2013/14 onwards.

11.12 As it is not possible to understand how changes on interconnector flow might be managed, two scenarios are presented.

11.13 The first assumes that there is constant variability across the daytime periods and as a result, additional reserve is synchronised by National Grid to manage the variation. This scenario uses the margin price for synchronised plant.

11.14 The second scenario assumes that the variation in interconnector flows is centred on the demand peaks of the day, one in the morning and one in the evening. This assumes a lower volume requirement (6 hours per day) but assumes it is met through static reserve with short notice delivery. This scenario therefore reflects a price level consistent with a low utilisation service that may be procured under the existing STOR framework.

11.15 Table 10 shows a forecast of the costs for procuring operating reserve across the three periods. This breaks down the cost of each component of operating reserve in each year, clearly identifying how the expected cost increase is forecast to occur in 2015/16 and 2020/21. It should be noted that the potential for the additional cost forecast against interconnector uncertainty first would occur in 2013/14, as will the additional cost of reserve for response when the GB SQSS standards for higher in-feed losses are applied from April 2014.

Drivers	2010/11	2015/16	2020/21
Price			
Power Price £/MWh	41.82	66.96	84.08
Margin Price £/MWh	25	39	49
STOR Price £/MWh (utilisation only)	350	544	685
Volume			
SEL:MEL Ratio	0.6	0.6	0.6
No. of hours	4320	4320	4320
Basic Reserve			
Basic Reserve Requirement	2525	2525	2525
No. of hours	2160	2160	2160
Total Basic Reserve TWh	3.3	3.3	3.3
Total Cost £M	**81.8**	**127.2**	**160.0**
Reserve for Wind			
Wind capacity	3,802	11,872	26,771
Expected Average Wind Output*	641	3062	7531
Wind Load Factor	30%	30%	30%
Marginal Wind Effect	50%	39%	30%
Total Reserve for Wind TWh	0.83	3.09	5.86
Total Cost	**21**	**120**	**286**
Reserve for Response			
Largest Loss	1320	1800	1800
Response Delivery	0.55	0.55	0.55
No. of hours	2160	2160	2160
Total Reserve for Response Holding (TWh)	3.11	4.24	4.24
Total Cost £M	**0**	44	55
Reserve for Interconnector variance	0	500	500
Hourly Variation Across daytime peak (met through add. Regulating) TWh	0	1.296	1.296
Demand Peak Variation only (met through STOR) TWh	0	0.648	0.648
Hourly Variation Cost £M		50	63
Demand Peak Variation Cost £M		353	444
Total Cost + Interconnector (hourly variation)	**102.6**	**341.6**	**565.1**
Total Cost + Interconnector (demand peaks variation)	**102.6**	**643.9**	**945.3**

* Less 500MW as no additional reserve carried for wind output less that this

Table 10: Total Operating Reserve Costs in the Gone Green Scenario

12 Transmission Network System Access and Control

12.1 It is expected that an increase in variable, renewable generation will make it more complex to gain access to the system for maintenance and construction outages and this was mentioned in the context of interconnectors in section 10.

12.2 The intermittency of renewable generation and in particular wind, will significantly change both the real-time operation of the transmission system and the management of access to the system i.e. outage placement and associated risk mitigation.

12.3 Section 6 described the probable effect of larger wind generation on the NETSO role in energy balancing. In respect of the transmission perspective, the impact of wind is likely to revolve around two issues; increasingly variable transmission flows and access to the transmission system.

12.4 It is envisaged that as weather systems move around the country, the variability in flows across major circuit boundaries will increase. For example, renewable generation in the west of Great Britain may experience high levels of output in the morning before tailing off as the weather front moves to the east at which point renewable generation on that side of the country increases.

12.5 This may lead to a requirement to hold reserve on a more regional basis than current protocols (although additional reserve is sometimes held in the south of the country under certain conditions). Such "locational reserve" could mitigate rapid transitions in power flows, particularly when the transmission system is depleted as a result of outages.

12.6 Over the coming decade there will be many changes to the transmission system in respect of generation connections and transmission upgrades such as additional Quad Boosters, further interconnection to Europe and upgrades to transmission capacity. Furthermore, existing STOR providers are likely to be retired as the main generation sets that the auxiliary Gets tend to be sited within, close under LCPD. The scale of change over the coming decade will therefore change many of the current operating characteristics we are familiar with and hence reserve allocations will necessarily be an evolutionary process as we learn more about the impact of wind variability on the transmission system.

12.7 However, we can attempt to isolate where significant variations in transmission flows are likely to occur to highlight those areas that will be most at risk. For example, we can map proposed wind farms against the MITS[49] and model the potential variation in flows into a particular transmission zone. Whilst it will not necessarily isolate the impact of wind generation alone, we should be able to understand the level of variation across transmission zones and understand the potential implications of increasingly variable power flows.

[49] Main Interconnected Transmission System

12.8 It is known, that more variable active power flows will increase the complexity of managing the control of voltage. In steady state conditions, voltage profiles can be adjusted through tap changes on SGTs or the use of reactive compensation equipment such as capacitors and reactors, or despatching generation to target reactive power output.

12.9 The requirements for the use and frequency of instruction across these options can currently be modelled with reasonable accuracy against current generation and demand profiles. This comparative predictability enables the allocation of resource in Electricity National Control Room (ENCC) for voltage control to be matched accordingly.

12.10 The displacement of thermal generation by wind may result in diminution of reactive capability. Although wind generators can in theory offer reactive capability, it is not clear that the generators will be of sufficient size or have the necessary control systems to match the provision currently provided by thermal generation. Therefore it is envisaged that the frequency of instruction and despatch of compensation equipment on the transmission system will increase. This will significantly increase workload in the context of despatch instructions and more frequent modelling of system stability will be required.

12.11 Geographic dispersion may assist network management but, the impact of large off-shore wind farm connections, in combination with an increase in other variable sources such as interconnectors will need to be understood and managed. We intend to develop models in the coming year to assess the potential impact of wind generation on the transmission network.

12.12 Reliable access to the transmission system is always required to facilitate maintenance outages. Significant investment in the GB Transmission System over the next decade will also mean longer duration construction outages and their associated local works will need to be accommodated.

12.13 When taking circuit outages on the transmission system the resultant impact on system security is assessed and appropriate risk mitigating actions are taken to maintain GB SQSS. When regional constraints are active, these can be managed by reconfiguring the system or through the re-dispatch of generation plant.

12.14 In certain circumstances, transmission circuits or plant can also be returned to service although this can result in knock-on impacts to maintenance or construction outages. Certain construction outages will mean that a route can only be reinstated or commissioned when the outage has been completed.

12.15 Securing outages on super grid transformers (SGT) is principally driven by the underlying demand at the Grid Supply Point (GSP). Outages are usually facilitated during lower demand periods or through transferring demand out of the affected GSP.

12.16 There are many GSPs where demand levels mean that SGTs are operating at higher loads and thus outage placement is critical and hence placements are made by taking into account the time of year and the underlying demand in a GSP.

Ensuring that the demand forecast is accurate is therefore critical in assessing the loads that the in service SGTs will have to meet.

12.17 When forecasting demand, it is necessary to understand the level of embedded generation within the group, as this offsets demand at a GSP level. The 'Gone Green' scenario includes an assumption of a significant increase in embedded generation over the next decade.

12.18 The nature of the possible mix of embedded generation is discussed further in Section 13; however it is expected that a significant proportion will be made up of variable renewable generation such as PV and wind.

12.19 It is therefore important that National Grid has a good understanding of potential fluctuations in daily demand levels. This will require improved visibility of metered output from embedded sources in order that appropriate demand assessments can be made.

12.20 Understanding the intrinsic level of demand (net of generation) therefore will be increasingly important, not only in the context of taking SGT outages but also to highlight where anticipatory transmission investments or locational STOR contracts may be required.

Higher Line Capacities

12.21 The transmission system will have to be able to cope with many changes in the following decades that will challenge the way National Grid operates the networks. Historically, transmission owners have designed the system in such a way as to be consistent that across a range of scenarios, the networks can be operated in accordance with GB SQSS.

12.22 There are always competing trade-offs between network design and the subsequent operating costs of the transmission networks. The impact of larger generation sources from an energy balancing perspective was discussed in sections 6 and 7; however there will also be a requirement to consider the implication around network design and current GB SQSS.

12.23 The following paragraphs discuss one of many potential scenarios, where network design will have implications for operating costs from a balancing services perspective.

12.24 Significant reinforcements will occur to overhead line capacity (OHL) over the next 10 years that will include the up rating of many 2GW circuit routes to 3GW. Whilst there are some 3GW capacity circuits already in service, the example described below discusses a likely future scenario.

12.25 New OHL routes and capacity will be required, particularly as new renewable generation sources such as wind will increasingly connect to the extremities of the GB transmission network. However it is also important to understand that by using existing routes in addition to new routes, cost and environmental impact can be minimised.

12.26 The scenario discussed here covers how the National Grid would, under current operating procedure (under GB SQSS); re-secure the transmission system after the loss of a double circuit. Whilst National Grid does not cover for second order faults, it is required to re-secure the transmission system as soon as practicably possible.

12.27 Figure 37 illustrates a scenario where a double circuit fault has occurred (B). The group consists of three, 6.0 GW rated double circuits and to which 12GW of generation is connected.

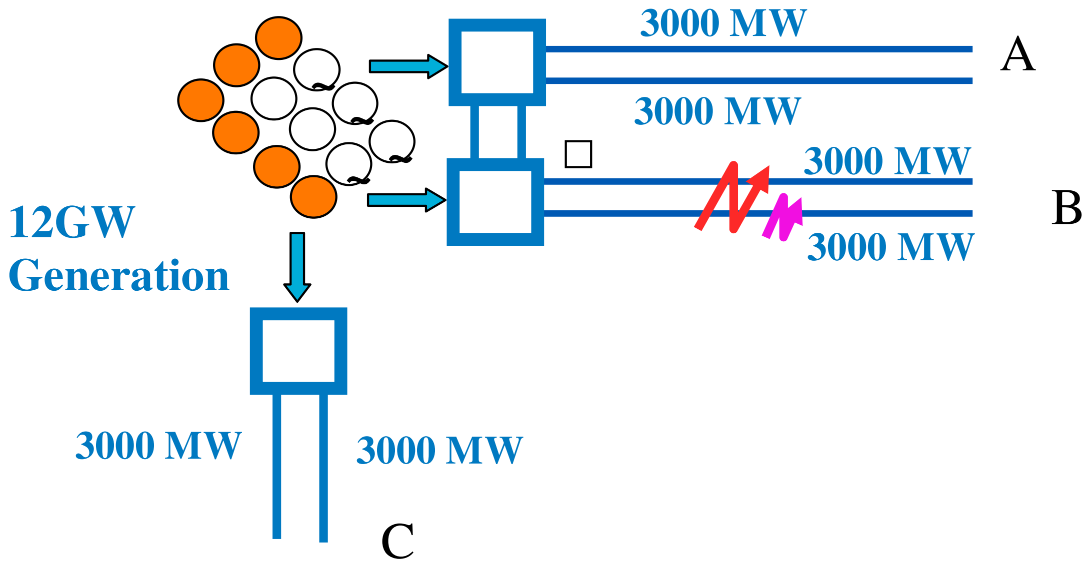

Figure 37: Example of 2nd order fault risk

12.28 In the event of a continuous double circuit loss (B), the next credible double circuit fault may result in the requirement to pull back a significant level of plant. This example would be deemed a credible risk in the instance of an enduring lightning storm, where the probability of a circuit tripping is significantly increased

12.29 12GW of generation exporting onto 12GW of OHL capacity. In order to secure the transmission system for the next double circuit fault e.g. circuit A, 6GW of plant would have to be pulled back so that for the fault, there would be sufficient capacity remaining to export the generation.

12.30 Therefore in the example above, for the fault indicated on circuit B, 6GW of additional re-dispatch will have to be scheduled outside of the area, to replace the generation that will be restricted in the group against a double circuit fault on A or C. Depending on the underlying generation mix[50], this would require access of up to 6GW of short notice generation.

12.31 Currently, the transmission configuration is such that the maximum double circuit capacity is complementary to volumes of regulating reserve and STOR. Therefore, assuming the system is always secure for the first double circuit fault the system can be re-secured for the next double circuit loss by reducing generation in the group and replacing the restricted generation through existing regulating reserve and STOR dispatch.

12.32 For a low probability event such as that described above, services from interconnectors or widespread demand reduction may be a more appropriate tool

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[50] It may be that some of the generation in the export group is wind. Therefore if the system operator were to restrict wind, the amount of replacement generation may be lower than expected due to the now lower wind reserve requirement [see section 6]

with which to manage the risk, rather than contracting larger volumes of generation assets. Of course, interconnectors are only of use if they are not fully importing.

Q17. Do you agree that wide spread demand response may be a more appropriate means of managing a low probability risk?

12.33 Enacting significant volumes described in the example above would potentially have a second order impact on prompt energy markets as capacity is essentially sterilised behind a constraint. It is also against current philosophy to contract for balancing services that would essentially be covering for the second order fault described above. However, a second order fault that would potentially increase the risk of widespread demand reduction may change that view.

12.34 Clearly, the issue highlighted in the preceding paragraphs is just one scenario of many potential issues that could arise on the transmission network. This has been highlighted purely as an example and is described in the context of existing Security of Supply standards.

12.35 It may be the case that the costs of maintaining existing security of supply criteria will not always be the most appropriate. National Grid will continue with stakeholder engagement to discuss what level security of supply is appropriate over the coming two decades.

13 Embedded Generation

13.1 In our previous consultation it was assumed that there would be a 6GW increase in embedded generation capacity by 2020/21 to almost 15GW. This total is forecast to be made up from 7GW CHP, with the remaining 8GW consisting of other renewable sources such as solar, wind, tidal, biomass and hydro power. Since these forecasts were made, the investment climate from a financing perspective may have changed. No explicit view is given in regards to the current investment climate although consideration is given in this section to some of the issues that may impact on project viability.

13.2 The economics of wind power are reasonably well understood, in that they tend to have higher capital costs but lower variable costs i.e. fuel cost and moderate maintenance costs (for onshore wind). However, revenue is principally driven by ROCs and hence they will generate whenever possible to ensure an appropriate return on investment.

13.3 The other key technology is CHP and which makes up for the majority of embedded generation growth in our Gone Green Scenario. It was suggested in our previous consultation, that a majority of the 7GW of CHP assumed in Gone Green is likely to consist of district heating schemes, using technologies such as gas, energy from waste (EfW) and anaerobic digestion.

13.4 There is also the possibility that forms of micro CHP may emerge, that are able to follow domestic demand for electricity to approximately 1.5kW, with the subsequent heat being used to meeting hot water and space heating requirements[51].

13.5 Depending on the technology, some of the waste heat may not always be useful (e.g. space heating in the summer periods), however there are some forms of technology, that are better able to match seasonal requirements.

Q18. Do you agree that larger scale CHP such as district heating scheme developments are more probable or is there a larger role for domestic level or micro-CHP?

13.6 Currently there is 0.4GW of CHP on the OFGEM register[52], of which approximately 90MW has been commissioned since 2009. This is in addition to transmission connected CHP of 1.9GW by 2020 (from current 2.2GW).

13.7 The cost of CHP generation is predominantly driven by the value of the heat. For example, in a CCGT process, producing a high temperature heat/steam pressure reduces electrical efficiency as opposed to a lower temperature heat/steam pressure; however the lower overall cost of heat offsets the impact on electrical efficiency.

13.8 Obviously, a key driver of how much CHP growth there may be is the cost of the technology. Assuming the market for large heat users such as refineries and paper mills, is saturated, any future CHP will be centred on district heating systems. These will therefore have to meet seasonal heating loads and thus recover capital over a shorter period of operating hours. They are also likely to be of smaller capacity than established CHP.

13.9 The source of fuel will also be a key driver as handling and gate costs of the fuel will vary considerably depending on the technology. For example EfW (using syngas) may incur additional costs on fuel handling and heat content of the feedstock. Likewise anaerobic digestion (AD) feedstock tends to have lower heat content and thus it is not economic to transport very far. Whilst the fuel is probably low cost (or negative), in this instance capital costs may be higher as connection to the grid may be more expensive.

13.10 The final economic driver to consider is the Good Quality CHP qualification. This provides 2 ROCs under the current renewable obligation (RO) and thus would possibly preclude flexible operation as being economically infeasible.

13.11 From a NETSO perspective, the growth rate of CHP will have an impact on GB demand levels.

[51] Additional space heating requirements met by gas, are likely to be required for peak heating
[52] Renewables and CHP Register

Q19. Taking into account the points raised, is our assumption on CHP growth realistic in regards to

a) the investment climate?

b) the additional points raised above?

13.12 In the latest National Grid Gone Green scenario, it is assumed that 1.5GW of PV will be installed by 2020.

13.13 However, in the previous consultation, an assumption was made that a large amount of solar photovoltaic panels (PV) of 3.5GW will emerge, which was informed by experience in Germany. This growth is principally expected to be driven by the FITS scheme that was introduced into Great Britain in April 2010. Table 10 shows how much PV has connected under the scheme between April 2010 and March 2011.

Installation Type	Declared Net Capacity kW		
	Transferred from RO	Post Apr-10 Commission	Total
Community	1512	519	2031
Domestic	11086	61520	72606
Non Domestic (Commercial)	919	1295	2214
Non Domestic (Industrial)	55	244	299
Total	13572	63579	77151

Table 11: Installation of PV under FITS[53]

13.14 This shows that there is currently total of ~77MW of PV installed capacity, 82% of which was commissioned after April 2010, a vast majority of which has been on domestic premises. In order to achieve 3.5GW by 2020, the installation rate would have to increase by 47% year on year.

[53] Feed in Tariff Scheme – data from OFGEM Feed in Tariff Report 1 April2010 to 31 March 2011

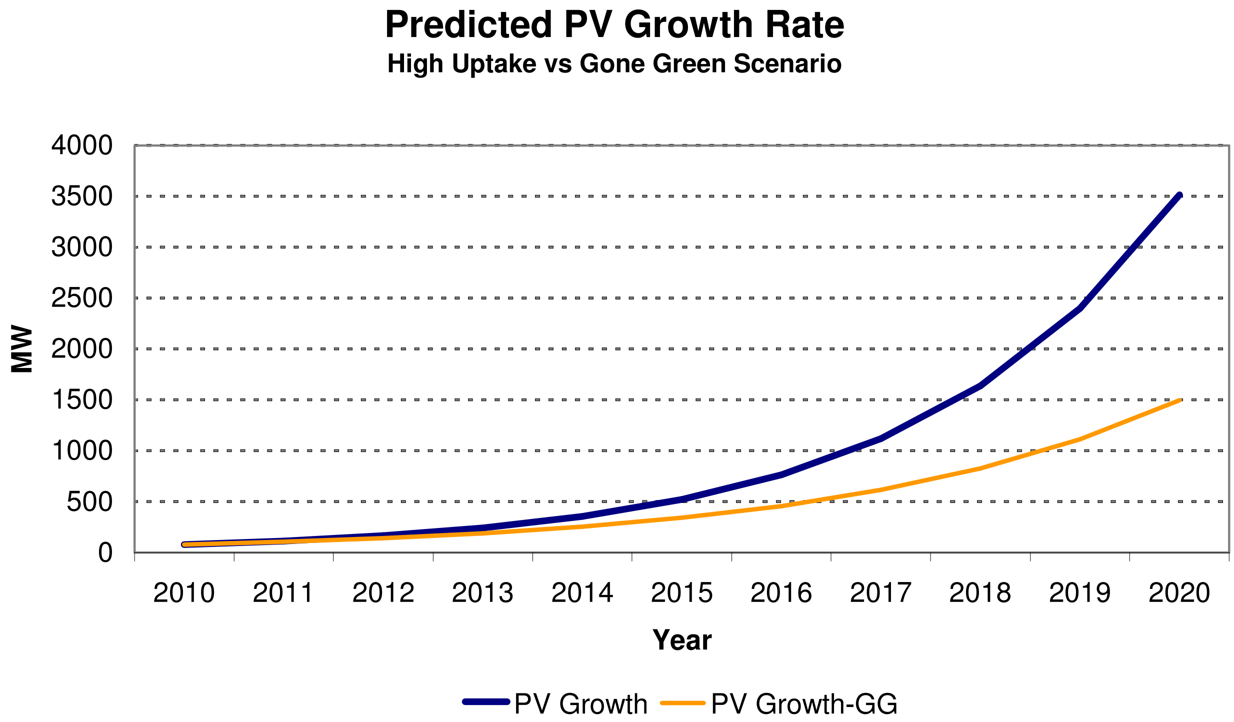

Figure 38: Potential Growth rate of photovoltaic installation to 2020/21

Q20. What is a realistic view to the amount of PV installed capacity by 2020?

14 Storage

14.1 Throughout this paper, it is recognised that flexibility in the provision of energy and related ancillary services will become increasingly valuable.

14.2 National Grid believes that storage technology could play a significant role in the operation of the transmission networks through ensuring optimal utilisation of renewable generation, and provision of flexible balancing services.

14.3 Storage of electricity is possible in various forms and in the previous consultation[54], a number of potential storage technologies were highlighted including mature technologies such as pumped storage, and lesser known or used forms such as Compressed Air Energy Storage (CAES), and flywheels.

14.4 Additional means of electricity storage can also be achieved through heat or hot water storage and chemical mediums i.e. batteries and therefore an important role

[54] Operating the Transmission Networks in 2020

could be played by CHP in balancing the system, particularly if combined with heat storage.

14.5 As noted in [13.7], the majority of value of CHP is often realised through the sale of heat and as such the electricity production from CHP is usually aligned with the heat demands of a customer rather than being optimised against the electricity demand and associated pricing profile.

14.6 One means of allowing CHP to meet both optimal heat and electricity demands would be through the introduction of heat storage. This would enable the production of electricity to be decoupled from the heat process.

14.7 This introduction of storage would enable the generator to produce the heat at the optimal time from a revenue perspective and then use the storage to manage heat demand thereafter. It could also potentially optimise heat processes by taking power from the grid during times of high wind output and storing it as heat.

Q21. As the size of the CHP generation going forward is likely to be lower capacity, will inclusion into the FITS make flexible operation of CHP less likely?

14.8 A number of district heating schemes in Denmark already use the direct method of heating water using electricity and in Sweden large scale heat pumps are being used as a heat booster[55]. This would offer a potential “sink” for wind generation, particularly at minimum demand periods.

Q22. Are there any existing or proposed district heating schemes in GB that use these methods?

14.9 All of these technologies could be deemed as storage with generation and particularly with pumped storage and CAES, that are contingent of having the appropriate geological features.

14.10 However, storage technologies such as batteries and supercapacitors, could be deemed transmission related technologies.

14.11 Large scale battery storage could be adopted through having fewer large capacity batteries that may have directly associated generation assets e.g. wind farms, or be connected at strategic points on the transmission networks.

14.12 The latter form of connection could provide direct balancing services to the NETSO, for example supporting demand in areas that may be at risk of import constraints in the event of a sudden loss of localised generation, or to assist risk management of outages on the transmission networks. In this context, battery storage could be

[55] http://www.denmark.dk/en/menu/Climate-Energy/DistrictHeating

considered as a transmission asset, just like for example, an SVC (Synchronous Var Compensator).

14.13 Large scale battery storage is technically feasible, although currently the economics of the technology are not sufficiently competitive against available alternatives under existing NETSO procurement mechanisms.

Q23. Do you agree that battery technology used in the context described in 14.13 could be deemed transmission?

Q24. Is large scale battery technology economically feasible against existing revenue streams? What are the limiting factors to large scale battery storage capacity?

14.14 An alternative means of deploying batteries as a storage technology would be through geographically diverse storage across domestic or commercial premises, or indeed electric vehicles (this is discussed in more detail in section 15).

14.15 There is value that could be realised by suppliers and aggregators in using storage technologies to shift generation of renewable output to higher value, higher demand periods, thus offsetting the need to buy potentially more expensive alternatives.

14.16 Furthermore, storage technologies may also assist in the management of local network constraints on DNO systems, essentially acting as upward demand side response. Demand side response is discussed in more detail in section 15.0.

14.17 Storage technologies could be beneficial across the value chain, though currently it is possibly too expensive for any discrete part of the value chain to realise a sufficient return on investment. There is potentially significant value that could be realised against alternative generation technologies that also have high capital requirements but low utilisation.

14.18 It is therefore prudent to consider how such investments may be shared across the value chain and the term on which returns on investment are considered.

Q25. How could investment in storage technologies be made in order that the potential benefit is shared across all parts of the value chain?

14.19 A means of investing in installations such as those described in [14.13] would warrant further investigation.

14.20 As with CHP, storage capability with PV would offer additional value by matching the export of generation to the demand, rather than passive export during daytime periods. Again, the cost of these technologies necessitates the support from FITs and much of this will be on a deemed export basis rather than a metered export basis. Therefore any value proposition may not be directly linked to the actual output of the PV but how the energy will be stored and subsequently released to the grid.

15 Smart Grid and Potential of Demand Side

15.1 In this section, consideration is given to the potential of demand side services and how they might be realised.

15.2 We noted in our previous consultation document[56] that the term "smart grid" should be seen in the context of incorporating enabling communication and energy management systems on to DNO systems that will facilitate active network management and corollary an increase in demand side and embedded generation services.

15.3 Whilst it is expected that an increase in active network management will offset some infrastructure investment, the increased demand from the electrification of transport and space heating towards 2030 will increase daily electricity consumption by approximately 50%[57].

15.4 Without appropriate reinforcement of the distribution networks, it is not clear that the necessary infrastructure could be in place to accommodate demands at these levels and hence demand profiling will be required to manage the loads on DNO infrastructure. This may therefore put DNOs and suppliers in competition for Demand Side Response (DSR).

15.5 Therefore the potential for demand side services for energy balancing may not only be a function of supplier or aggregator requirements but also underlying DNO system capacity, as active management of domestic and commercial loads may be necessary if all demand is to be met.

> Q26. How significant will DNO network capacity be in establishing an increase of DSR services? Is a majority of the potential value more realisable by suppliers?

15.6 National Grid has previously suggested that there may be 11GW of instantaneous power demand across electric vehicles, domestic and light industrial or commercial loads, of which 8GW may be useable[58]. A number of responses to our earlier consultation suggested 5 % (3GW on peak) of demand may be discretionary or deferrable, although it was also noted that there is little evidence to support this assumption.

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[56] Operating the Electricity Transmission Networks in 2020 5.58
[57] ENA – Benefits of Advanced Smart Metering for Demand Response based Control of Distribution Networks
[58] Operating the Electricity Transmission Networks p.62

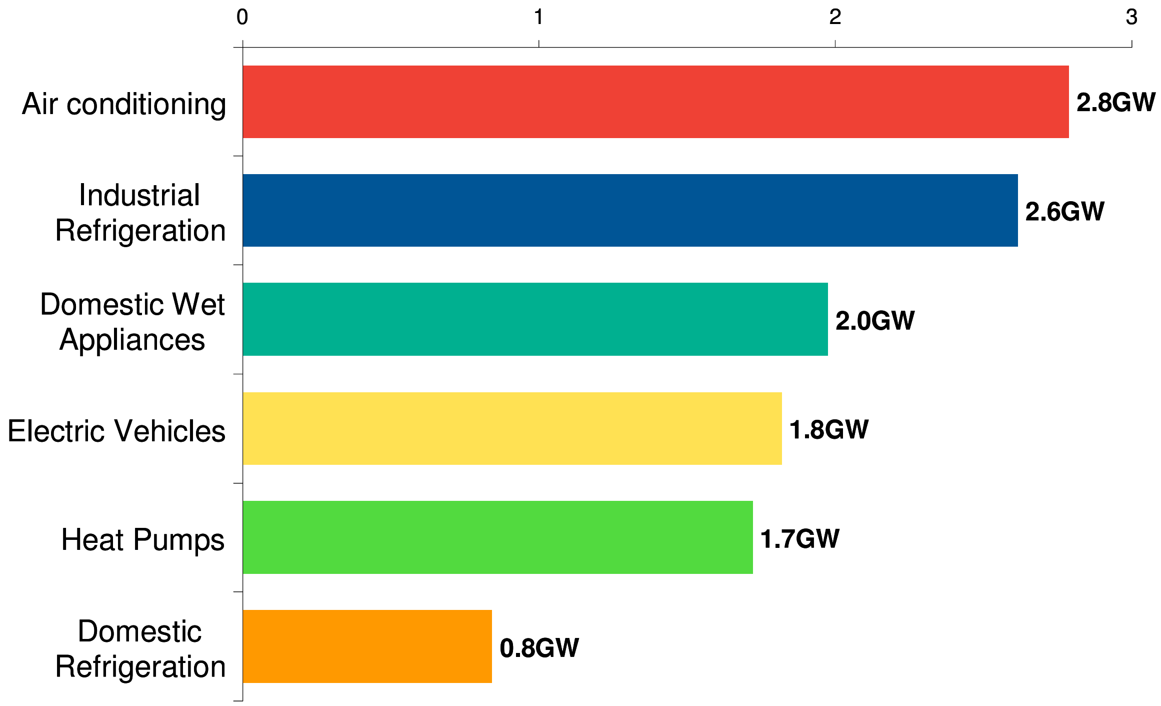

Figure 39: Potential Demand Side Contribution[59]

15.7 Figure 39 contains the estimates for potential demand side contribution used in our previous consultation. It is apparent from Figure 35 that a significant proportion (~50%) of the potential demand is held across industrial and commercial (I&C) sector load.

15.8 Services from industrial demand are already well established, through both TRIAD or peak management services between suppliers and their customers and through NETSO balancing services such as STOR.

15.9 As with domestic demand, commercial demand has historically been profiled in the settlement process, principally as a result of the lack of half hourly meters. With the roll out of advanced meters (AM), which is scheduled for completion in 2014, additional opportunities to capture further DSR[60] will arise.

15.10 Modern building management systems that manage cooling and heating demand in particular are well suited to providing DSR as the thermal inertia of the buildings minimises impact on the consumer whilst savings could be significant.

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[59] *National Grid Analysis based on 'Gone Green' and the MTP 'Early Best Practice' dataset. Load factor and time of use assumptions apply*

[60] BERR energy metering consultation suggest 170,000 sites in profile classes 5 - 8

15.11 In combination, the functionality that building management systems and new metering equipment provide should improve both the opportunity and the attraction of providing DSR[61] services. As approximately 70%[62] of the supply chain costs come from energy supply costs and margin it should be expected that suppliers, customers and the NETSO will seek out opportunities to obtain mutually beneficial services. If 30% of air conditioning or other thermal loads could be captured, this would equate to 840MW (2.8GW air conditioning load). In respect of industrial refrigeration, safety issues around food safety or other important associated processes may make it less attainable, but 10% capture would equate to 260MW.

15.12 Therefore, National Grid believes that the commercial/SME sector in particular is most likely to provide a majority of the new services in the next 5 years. The Carbon Reduction Commitment (CRC) has contributed to many businesses becoming increasingly proactive and conscious of their energy management.

Q27. How much demand could be captured from the industrial and commercial sector?

15.13 There is a view that the most likely demand load that could be managed in the domestic sector is that from appliances such as fridges and washing machines. However it is important to consider both the type of demand side response such appliances could provide and the basis on which this view is predicated.

15.14 For example, washing machines and dishwashers may better provide demand side services through shifting demand to off-peak periods as cycle run times are fixed and can be moved with minimal impact on customer utility. This type of service would have significant value to a supplier or aggregator who could bundle many customers' demands and offset electricity purchases over peak demand periods, for example.

15.15 Demand from fridge/freezers could be considered dynamic as demand from these appliances is a function of temperature control and therefore demand profiles are not consistent. However, so long as demand could be curtailed without impact on the temperature, loss of utility to the customer can be deemed zero. This demand type would be suited to short duration services, such as frequency response for the NETSO.

15.16 In respect of enabling dynamic demand, it is likely that appliances would have to be fitted with the relevant equipment on a mandatory basis. For example, fridges would require equipment that could communicate the status of the appliance i.e. where in the cooling cycle it was and for how long any service could be provided for. To

[61] Demand Side Response - DSR
[62] OFGEM Updated household bills 2009

retrofit outside of the manufacturing process is unlikely to be cost effective to the potential service providers.

15.17 Services from wet appliances, such as washing machines and tumble dryers would probably be accessed through some form of Time of Use (ToU) tariff and thus would be unlikely to require any mandatory directives for inclusion of certain equipment.

Q28. Do you believe that a mandatory inclusion of relevant technology in domestic appliances is required as a pre-requisite to enable and capture DSR?

15.18 Not withstanding the points raised in the preceding paragraphs, Table 12 below describes the power demand of a range of domestic appliances and their typical operating profiles.

15.19 For this analysis we have used data from the SMART-A[63] Project to determine the potential from domestic demand. This is an approximation derived from the data, which models the average load shape by EFA block for various appliances.

	EFA Period					
Appliance	**1**	**2**	**3**	**4**	**5**	**6**
Washing Machine (MW)	278	595	991	793	991	714
Tumble Dryer (MW)	347	347	902	763	763	867
Dishwasher (MW)	189	243	243	270	378	297
Refrigerator (MW)	965	965	1240	1240	1433	1378
Freezer (MW)	568	568	622	676	676	622
Oven (MW)	130	390	1560	962	780	260
Total (MW)	2476	3107	5558	4704	5021	4137
Domestic Wet (MW)	813	1184	2136	1826	2132	1878
Domestic Refrigieration (MW)	1532	1532	1862	1916	2109	2000

Table 12: Potential Demand Response from domestic appliances (MW)

15.20 The demand on the various appliances follows the general shape of demand with daytime period seeing the highest demand.

15.21 The demand shape from domestic appliances is driven by consumer behaviour. Therefore the amount that may be available for balancing needs will depend on how provision of demand side services impact on their fundamental utility. For example it is unlikely that a consumer would be willing to forgo demand from ovens at lunch and evening mealtimes, however domestic wet and refrigeration appliances, both of

[63] http://www.smart-a.org

which have higher peak loads, could well be deferred with minimal impact to the consumer.

15.22 If we assume load from domestic wet goods (washing machines and tumble dryers) and domestic refrigeration are the most likely sources of demand control, then a potential demand of ~4GW will be available across the daytime periods.

15.23 Using the assumption that 5% of the demand can be captured this would equate to approximately 200MW of load that may be available for provision of demand side services.

15.24 It is perhaps obvious that capture of demand side services will be driven by the whole customer proposition and that more than 5% could be captured as new providers enter the market. For example, lower per unit tariffs or other forms of reward[64] may be offered in exchange for allowing a service aggregator to offer demand services to National Grid or DNOs. However it is still unclear what level of discount will be required to attract customers into these services.

Q29. Do you agree that more than 5% of domestic demand could be managed or does 5% remain a reasonable assumption?

15.25 Indeed, price may not be the key driver to demand side services. An example of this is how some customers are willing to pay a higher price for green energy[65], which demonstrates that an ethics led proposition can be attractive over a price led proposition.

15.26 Therefore consumers are likely to engage on an enduring basis if the propositions make participation easy, with limited inconvenience and appropriate financial rewards.

Q30. What are the main barriers you see in capturing demand side services, in particular those from the domestic sector?

15.27 From a NETSO perspective, National Grid require products to manage what can be considered predictable behaviours but at different lead or delivery times.

15.28 National Grid has already had success in capturing demand side services through STOR contracts. These types of products are more aligned with those that suppliers may look to pursue.

[64] This may include vouchers, points etc but convenience and trust may be as important as price
[65] GreenEnergy

15.29 However, products that can be utilised for a short duration but can provide fast delivery would hold significant value to manage for events such as ramping on interconnectors, wind variability or rapid changes in demand, e.g. TV pick-ups. This type of product is likely to be of less interest to suppliers.

Q31. What does this mean for NETSO services? Do you believe the type of product described will be provided by particular sectors?

15.30 Future loads may include heat pumps and electric vehicles which unless managed in an appropriate way are likely to impact DNO networks significantly beyond 2020 in a 'business as usual' (BaU) scenario[66].

15.31 The demand characteristics of all the appliances in Table 4 are well established and should not have any incremental impact on DNO systems. Therefore it is safe to assume that with the advent of SMART meters, discretionary use of this load could be managed and sold under an attractive customer proposition.

15.32 The full impact of heat pumps and EV's are not as well understood in respect of how demand patterns may develop, but they are likely to have a significant impact on DNO networks, particularly beyond 2020. National Grid is partnering with several DNOs in their Low Carbon Network Fund (LCNF) projects and forthcoming tier 2 LCNF bids. These projects aim to improve industry wide learning over the coming years.

15.33 In our earlier document[67], we proposed indicative demand from heat pumps of 1.7GW[68].To put this into context, if only 10% of the 4 million, off-gas grid UK homes were to convert to a low carbon form of electrically derived [69]space heating over the remainder of the decade, this would amount to 400,000 or 1.5% of GB dwellings.

Q32. Do you believe that the heat pump penetration rate described above, is realistic?

15.34 An additional 3.1GW of heat pump demand may be available if the remaining housing stock and new build dwellings installed the technology at an annual rate aligned with the very low scenario[70] electrification of heating[71] as described in DECC 2050 Pathways document. This would give a maximum HP demand of 4.5GW.

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[66] ENA – Benefits of Advanced Smart Metering for Demand Response based Control of Distribution Networks
[67] Operating The Electricity Transmission Networks in 2020
[68] Based on National Grid Gone Green and Market Transformation Project
[69] Using very low scenario for electrification levels (Level 1) this would attribute 20% (5.2M dwellings) of all installations to be electrified by 2050.
[70] Installs at a rate to 2020 that would deliver Low scenario by 2050 i.e. 20% of UK built environment heat demand met by electric heating – this would also include commercial loads
[71] DECC 2050 pathways (p.119) suggests maximum possible rate of fit across all technologies would be 1.3M pa. This equates to approximately 4% of remaining housing stock over next 10 years.

15.35 An approximate demand profile from heat pump demand in 2020 is described in Table 13. This assumes a heat pump demand of 3.5kW, installed in 10% of off gas grid dwellings by 2020. In addition, a further 4 % of the remaining housing stock converts to an electric driven low carbon heat technology by 2020.

15.36 We have assumed that the use of heat pumps will follow a pattern similar to existing gas boiler regimes. It also assumes that there is no extensive uptake of Time of Use pricing tariffs.

15.37 An aggregated demand weighted profile of a heat pump[72] has been applied. We assume that a heat input of 3.5kW[73] will meet the peak requirement of an average home[74]

	EFA Period					
	1	2	3	4	5	6
HP Cycling Regime	6%	17%	20%	15%	25%	17%
Potential Demand (MW)	257	772	875	669	1133	772

Table 13: Estimated Potential Demand from Heat Pumps in 2020 by EFA block

Q33. Do you believe Table 13 reflects a realistic profile of potential demand from heat pumps? Will time of use tariffs (ToU) move some demand away from the peak?

15.38 Heat load may be a more attainable source of demand side response as thermal inertia would mean that the impact on the consumer would be minimal. Together with the assumption that early adopters of heat pump technology may be more energy conscious and price sensitive, if 50% of the demand could be moved from the peak this would equate to approximately 566MW. Clearly, the potential contribution from heat pumps will be seasonal.

15.39 We have assumed 1.1 million electric vehicles[75] will be in operation by 2020. It is expected that EV users will plug in their vehicle on arrival at home; therefore the demand from EV's will align with journey times. Assuming a 36km[76] per day journey

[72] Based on profile described in ENA report [29] figure 3.1
[73] Assuming a heat pump with a COP of 3 to meet a peak heating demand of between 8kW and 12kW
[74] This assumes high levels of insulation – lack of insulation in older housing stock may lead to a higher input
[75] 1,100,000 EVs is approx 4% of cars in UK [2007]. – Medium forecast in BIS report Investigation into the Scope of the Transport Sector to Switch to Electric Vehicles and Plug-In Electric Hybrid Vehicles
[76] DfT forecast transport statistics Great Britain 2009 [66]

distance by each vehicle, a 22KWh battery would be approximately 25% depleted. This would equate to an average maximum demand of 708MW[77].

15.40 An approximation has been made to derive the likely charging demand profile by EFA block by mapping daily journey profiles to EFA blocks[78].The profile assumes that average battery capacity will be 25% depleted[79] and hence require approximately 2 hours charging time in the subsequent EFA block to that in which the journey is made. This assumes limited time of use (ToU) pricing tariffs have been established. Table 14 summarises the data.

15.41 This would suggest that electric vehicle demand would be suited to being aggregated over fewer time periods (time of use tariffs) therefore shifting volume to more valuable periods from a cost of charging or demand management perspective.

	EFA Period					
	1	2	3	4	5	6
Journey Time Distribution	4%	7%	26%	24%	28%	11%
Potential Demand (MW)	39	14	25	92	85	99

** Assumes average maximum potential demand would be 708MW assuming 825k EV and 225k PHEV (PHEV is hybrid vehicle therefore only taking demand for 50% of average journey) ratio. Assumed demand based on preceding EFA block journey distribution.*

Table 14: Estimated Potential Demand from Electric Vehicles in 2020 by EFA block

Q34. Does the demand profile described in Table 14 for electric vehicles by time of day look realistic?

Q35. Is it likely that the demand profile will change through ToU charging tariffs? How elastic will demand from EVs be?

15.42 In total, the demand assumptions made in this section would suggest a total potential for new demand side services to amount to approximately 2GW. This would be;

[77] This assumes a maximum demand of 2888MW assuming 3kW demand from charging 1.1M vehicles split 75:25 EV and PHEV
[78] Appendix E.3 of document noted in [66]
[79] Assumes 54km/day journey using DfT 2007 forecast for 2020, 0.15kwh/k consumption, 22KWh battery capacity

- ~840MW from commercial load e.g. air conditioning
- ~260MW from industrial refrigeration
- ~200MW from domestic wet and refrigeration appliances
- ~570MW from heat pump demand
- ~100MW from electric vehicles

16 Enablers for demand side services

16.1 It is widely recognised that elasticity of domestic demand is currently quite low and that new Energy Supply Companies (ESCO) or Virtual Power Plant (VPP), along with existing suppliers, may offer the consumer propositions that make it attractive to participate in demand side services.

16.2 The types of Balancing Services that may be captured as the demand side potential increases will be dependent on communication infrastructure and how any customer propositions may be framed.

16.3 For example, in order to use DSR[80] for primary frequency response, a response time of 2 seconds is required. National Grid currently operates a minimum threshold of 3MW to participate in this service. Assuming the current ADMD[81] of 1.5kW to 2kW, this would infer approximately 1500 houses would have to be co-ordinated to provide a minimum level of service. In terms of service activation, this could be done automatically in response to frequency changes; however for dynamic demand in particular, constant updates of prevailing demand would likely be required. Therefore the speed and density of signal in order to communicate with potential providers would potentially need to be large and geographically widespread.

Q36. Do you agree with the estimate for the level of aggregation across domestic premises required?

16.4 A key enabler to successful integration of demand services into system balancing will therefore be high capacity 2-way communication or data flow as this will be important in the control and dispatch of potential services. Data volumes will be potentially huge[82] thus it is important that the various layers[83] of communication are

[80] Demand Side Response
[81] ADMD – After Diversity Maximum Demand
[82] 47M meters with reading every 30 minutes = 2.3 billion reads per day.
[83] Three principle layers to communication are HAN – Home Area Network, LAN – Local Area Network and WAN – Wide Area Network

interoperable in order that the future means of control of services (via Wider Area Network - WAN) are not compromised.

16.5 The customer meter is intended to be owned by the supplier energy services company, and the meter data is likely to remain on the customer meter (HAN[84]). In order to make use of the demand source, service suppliers will require regular transfer and be able to make use of the data. This raises three pertinent issues;

- **Data security** – with such large volumes of data being transmitted how will it be kept secure
- **Trust** – customers will need to have trusting relationship with their service provider
- **Value proposition & data ownership** – who does the data belong to, the customer or the service provider. In order to encourage participation in demand services use of data will be very important.

Q37. Do you agree with the issues raised and are they being addressed?

Q38. What do you believe are the important factors to developing and securing demand side services?

17 Operation of demand side services

17.1 In section 15.0, the potential sources of demand side response were discussed. It is apparent that suppliers, aggregators', the NETSO and DNOs will find value in such services, particularly as a means of managing peak load exposure. In this section, consideration is given to how the different participants may co-ordinate their utilisation of the services.

17.2 Responses to the previous consultation stated that it is not clear what market mechanism will deliver these services but it will be necessary to have a hierarchy of needs across the NETSO/TO and DNOs, which should be encapsulated in contractual terms. It is important to understand the nature of demand led developments in future years and how this may shape any hierarchy and thus design of services.

17.3 In its role as residual balancer, National Grid would be keen to procure economic services, either directly or through another market provider. We noted in the previous consultation[85] that there may be competition for such services across the

[84] Home Area Network
[85] Operating the Electricity Transmission Networks in 2020

value chain and some respondents noted that DNOs will have a role in providing or procuring services. However, with increased DSR, the interaction between the NETSO and DNOs may become increasingly relevant.

17.4 To a DNO, if such a service were provided from a small geographic area, (e.g. a village) it could have significant impact on the network, whereas the NETSO would need some information to avoid demand side services from aggregating significantly across transmission nodes, for example where tight stability or export constraints may be active.

17.5 Prior to 2020, we would expect that the principal relationship between the NETSO and DNOs will be improved sharing of metering data for embedded generation[86] and development of current operational planning relationships that will move closer to real time. The new relationships that may have to be developed prior to 2020 will be between suppliers, aggregators etc and DNOs. It will be critical for DNOs to understand the potential variance in demand from DSR in their network. This could be co-ordinated through a centralised meter data manager in the respect of supplier ownership and network operator.

Q39. Do you agree that the NETSO and DNO relationship will principally revolve around better co-ordination of generation patterns from embedded generators?

Q40. Do you agree that the supplier/DNO relationship will be critical in localised constraint management? How do you see services will be developed?

17.6 It is useful to describe a potential model as investments in infrastructure and technology will take place prior to 2020.

17.7 From a networks perspective, the impact of DSR services will be greater on the DNOs, although the level of co-ordination with the NETSO and other market participants will differ. Constraints on the distribution networks will most likely occur on transformers or feeder circuits, driven by underlying demand (transformers) and power flows (feeder circuits). Interaction with the NETSO is likely to be required more so with the latter, as high levels of embedded generation may result in exports to the transmission system.

17.8 Whilst demand services may be procured directly by the NETSO or through an aggregator, it is likely that these would be on a broad geographical basis and hence would be unlikely to significantly impact on a DNO[87]. Likewise, at times of high wind generation, an increase in demand (initiated by NETSO through EVs etc) may well align with embedded generation profiles.

[86] National Grid are currently undertaking a project with WPD for integrating SCADA data

[87] This excludes large industrial providers as such services already exist. The volumes required by GBSO means that potential of more discrete (domestic) demand being sufficiently concentrated is unlikely to cause any direct issues.

17.9 The most onerous constraints are most likely to be transformer or overloaded domestic, supply phases. This may be quite localised in areas that have high EV uptake and or heat pump penetration.[88]. The requirement for co-ordination between suppliers and the DNO will be required as EVs and HP penetration increase.

17.10 Figure 40 describes how the possible interactions between GBSO, DNO and Suppliers may occur. The key relationships between supplier, ESCO and GSO are already established through contracts such as STOR[89]. The key requirement is the improved data transfer of embedded generation between the NETSO and the DNOs.

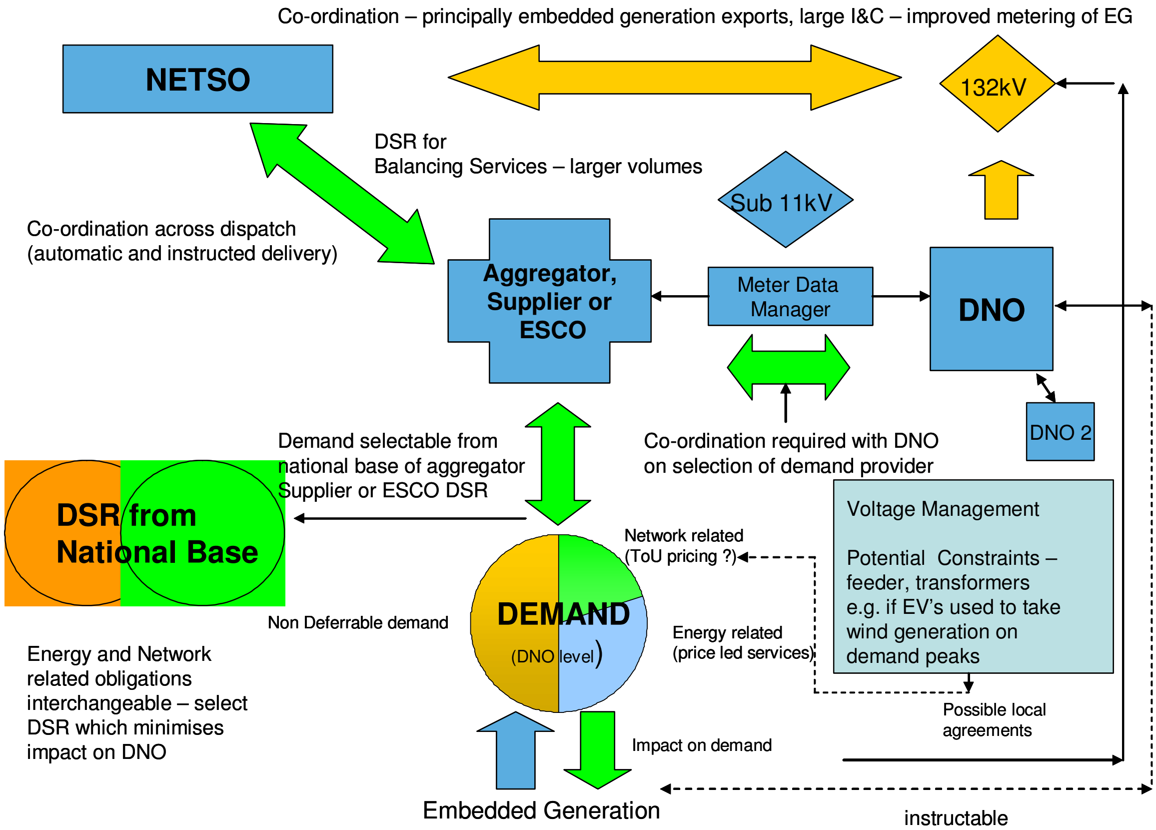

Figure 40: Potential operational relationships for demand side services

17.11 It also describes the concept of product differentiation in terms of the demand services that may be provided, with perhaps network led requirements driven by

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[88] ENA – Benefits of Advanced Smart Metering for Demand Response based Control of Distribution Networks p.28 – Even under a 25% HP/EV level, 40% of primary (33kV/11kV) transformers would be overloaded. 100% of LV transformers on basis of 5000 EV's in 1km²

[89] Short Term Operating Reserve

ToU pricing (perhaps serviced via a DNO contractual relationship) and energy related services driven by a value proposition which could be through a supplier or any other energy service marketer[90]. As noted in section 16.0, it does highlight the criticality of interoperability between participant systems.

Q41. How does this model align with your own understanding of how operational interfaces may work?

18 Enhanced SO capability

18.1 National Grid owns and operates the high voltage electricity transmission system in England and Wales and as National Electricity Transmission System Operator, operates the Scottish high voltage and offshore transmission system. System operation is managed in accordance with the Grid Code and Security and Quality of Supply Standard. These set out the way in which the networks should be designed and operated such that an acceptable balance is maintained between the reliability in supply delivered to end consumers and the costs that consumer bear.

18.2 The previous *Operating the Transmission Networks in 2020* consultation included a description of the scope and nature of changes across the transmission system. It explained that as 2020 approaches, the decarbonisation of the energy industry will impact on the operability of the transmission system.

18.3 The nature of many of the new challenges, services and interfaces that will have to be developed into the system operator function have been described in this paper thus far.

18.4 From a transmission perspective, additional complexity will be introduced to real time operations in the main through the combination of:

(a) an increase in the uncertainty, scale and volatility of power flows on the system due to generation developments necessary to facilitate decarbonisation and

(b) the management of larger power flows across key boundaries through the use of many more controllable transmission assets[91] such as Quad Boosters and Static Var Compensators

The introduction of such equipment will not only increase the complexity of operating the power system day to day but will also increase the number of actions

[90] Please note that the proportion of overall demand indicated for these services are for illustrative purposes only
[91] such as HVDC links, quadrature boosters and series compensation equipment

to be taken by the control staff in the Electricity National Control Centre [ENCC] to secure and optimise the network.

18.5 It was acknowledged in the previous consultation that the security of networks could be managed through procuring a wide range of Balancing Services; however this conservative approach would result in significantly higher costs and more constraints on the transmission networks and their users. National Grid stated the view that this would not be acceptable and respondents' to the consultation in general, indicated agreement with this sentiment.

18.6 The new complexity will require numerous enhancements to the SO capability in the ENCC. Investments in new technology will ensure that the system remains operable at an efficient cost for customers and consumers.

18.7 Customer benefits through investment in these new systems will occur through the mitigation of anticipated future costs associated with balancing the market. This will include improved management of system constraints, operating expenditure savings on internal system operator costs and gains in market efficiency. Importantly any investments would help to manage the increased security of supply risks that will arise under a more complex operating environment.

18.8 National Grid believe that it is necessary to invest in new and existing systems to cover four capabilities:

- **Enabling change**: investments to enhance data management, simulation and infrastructure to more efficiently enable future developments

- **Improved modelling and decision making**: enables more scenarios to be modelled, manages potential system stability issues and optimises flow management tools

- **Operational control and automation**: allows utilisation of improved functionality for controlling voltage and monitoring the power system

- **Situational awareness**: investments give the control engineer a more accurate and informative view of the state of the network and risks that exist at any one time

18.9 Through investing in new systems and taking advantage of new technologies for controlling the network, National Grid believe it will be possible to use fast acting systems and increased automation to make greater use of short term circuit ratings.

18.10 This in turn will allow secure system operation to minimise the level of future constraint volumes and maximise the overall output from renewable energy sources. Furthermore these systems will enhance the ability to grant additional system access in the future.

18.11 In addition to improved system security and network access, investment in automatic optimisation systems would also offset any potential increase in resources that would otherwise be needed to manage the increased levels of activity in control timescales.

18.12 As described earlier in this paper, improved real time monitoring and forecasting systems will be key, for example to further improve wind forecasting capability or to integrate new service providers.

18.13 Such systems can be described as ‘situation awareness’ tools. These give the control engineer a more accurate and informative view of the state of the network and the risks that exist at any one time. Incorporating these systems into ENCC will enable future margins for error to be reduced and allow the system to be run closer to its limits with more confidence.

18.14 National Grid believes that these types of investment will have benefits for overall security of supply, in particular in relation to events that lie just outside the formal security standards. For example re-securing the network following a major fault (like that described in section 12.26) or managing faults and recovery from events that lie beyond the formal standards will be far more complex than at present.

18.15 Improved study capability, automation of more routine switching activities and improved presentation of alarm and situation awareness information will all help to improve the timeliness and accuracy of response to these types of events.

<<END>>

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Appendix 1 - Changes in interconnector flows 2010 by EFA

EFA 1

	Change in flow								
	Change in flow towards France					Change in flow towards GB			
	-2000	-1500	-1000	-500	0	500	1000	1500	2000
Number of instances	0	36	78	501	470	1445	254	42	26
Proportion of changes	0.0%	1.3%	2.7%	17.6%	16.5%	50.7%	8.9%	1.5%	0.9%

EFA 2

	Change in flow								
	Change in flow towards France					Change in flow towards GB			
	-2000	-1500	-1000	-500	0	500	1000	1500	2000
Number of instances	4	20	156	868	508	1105	145	16	22
Proportion of changes	0.1%	0.7%	5.5%	30.5%	17.9%	38.9%	5.1%	0.6%	0.8%

EFA 3

	Change in flow								
	Change in flow towards France					Change in flow towards GB			
	-2000	-1500	-1000	-500	0	500	1000	1500	2000
Number of instances	8	22	140	1040	670	892	32	0	38
Proportion of changes	0.3%	0.8%	4.9%	36.6%	23.6%	31.4%	1.1%	0.0%	1.3%

EFA 4

	Change in flow								
	Change in flow towards France					Change in flow towards GB			
	-2000	-1500	-1000	-500	0	500	1000	1500	2000
Number of instances	8	8	44	728	660	1272	82	6	36
Proportion of changes	0.3%	0.3%	1.5%	25.6%	23.2%	44.7%	2.9%	0.2%	1.3%

EFA 5

	Change in flow								
	Change in flow towards France					Change in flow towards GB			
	-2000	-1500	-1000	-500	0	500	1000	1500	2000
Number of instances	20	32	76	371	452	1452	303	100	48
Proportion of changes	0.7%	1.1%	2.7%	13.0%	15.9%	51.1%	10.7%	3.5%	1.7%

EFA 6

	Change in flow								
	Change in flow towards France					Change in flow towards GB			
	-2000	-1500	-1000	-500	0	500	1000	1500	2000
Number of instances	4	18	122	632	531	1253	228	42	22
Proportion of changes	0.1%	0.6%	4.3%	22.2%	18.6%	43.9%	8.0%	1.5%	0.8%

Appendix 2 - Derivation of Reserve Levels

The process we use for deriving the Operating Reserve Requirements discussed 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:

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

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

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

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 3 - 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.

<u>Reactive Power</u>

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.

<u>Black Start</u>

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.

<u>Intertrips</u>

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, Cross Border Balancing (CBB) and Emergency Assistance. CBB 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 NETSOs 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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Appendix 4 - Questions and Responses

To feed back your comments on this consultation report please contact us at energy.operations@uk.ngrid.com

Q1. Do you agree that cut out will be an issue for GB or will wind (onshore and offshore) turbine technology compensate for the GB wind resource density?

Q2. Will wind turbines within a comparatively small geographical area behave in a consistent manner?

Q3. How do you think that controlling frequency deviations with AGC would impact on the underlying costs of generating plant providing response and on rotating plant as a whole?

Q4. How ready is generation on the GB system to providing AGC and

a) how might AGC be provided within existing services ?

b) and the current market rules and design?

Q5. Are there any further benefits (or detriments) to managing frequency more tightly on the GB system

Q6. Do you agree that there has been a permanent loss of demand as a result of the recession?

Q7. How significant would a 25% increase in starts be to the operation and maintenance of a CCGT?

Q8. Do you agree that the introduction of implicit mechanisms will remove the ability for National Grid to procure services with market participants across interconnectors?

Q9. Are you aware of any other market based mechanisms used in Europe to help TSO manage flows on Interconnectors?

Q10. How will shorter gate closures impact on interconnector nominations? Will interconnector transfers become more volatile?

Q11. Do you think that National Grid as System Operator should take account of potential short term changes on the Interconnector in reserve policy (operating reserve)?

Q12. How important is market liquidity and cash-out arrangements on interconnector flows?

Q13. Which approach of those described above do you think would be most appropriate to manage uncertainty around interconnectors?

Q14. Do you agree that the propensity to export to Continental Europe has increased with the removal of TRIAD?

Q15. What is your view on how the NETSO best manage the additional uncertainty in the context of system access?

Q16. How should consideration be given to the trade-off between unrestricted trading on interconnectors and cost of risk mitigation?

Q17. Do you agree that wide spread demand response may be a more appropriate means of managing a low probability risk?

Q18. Do you agree that larger scale CHP such as district heating scheme developments are more probable or is there a larger role for domestic level or micro-CHP?

Q19. Taking into account the points raised, is our assumption on CHP growth realistic in regards to

a) the investment climate?

b) the additional points raised above?

Q20. What is a realistic view to the amount of PV installed capacity by 2020?

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Q21. As the size of the CHP generation going forward is likely to be lower capacity, will inclusion into the FITS make flexible operation of CHP less likely?

Q22. Are there any existing or proposed district heating schemes in GB that use these methods?

Q23. Do you agree that battery technology used in the context described in 11.15 could be deemed transmission?

Q24. Is large scale battery technology economically feasible against existing revenue streams? What are the limiting factors to large scale battery storage capacity?

Q25. How could investment in storage technologies be made in order that the potential benefit is shared across all parts of the value chain?

Q26. How significant will DNO network capacity be in establishing an increase of DSR services. Is a majority of the potential value more realisable by suppliers?

Q27. How much demand could be captured from the industrial and commercial sector?

Q28. Do you believe that a mandatory inclusion of relevant technology in domestic appliances is required as a pre-requisite to enable and capture DSR?

Q29. Do you agree that more than 5% of domestic demand could be managed or does 5% remain a reasonable assumption?

Q30. What are the main barriers you see in capturing demand side services, in particular those from the domestic sector?

Q31. What does this mean for NETSO services? Do you believe the type of product described will be provided by particular sectors?

Q32. Do you believe that the heat pump penetration rate described above is realistic?

Q33. Do you believe Table 13 reflects a realistic profile of potential demand from heat pumps? Will time of use tariffs (ToU) move shift some demand away from the peak?

Q34. Does the demand profile described in Table 7 for electric vehicles by time of day look realistic?

Q35. Is it likely that the demand profile will change through ToU charging tariffs? How elastic will demand from EVs be?

Q36. Do you agree with the estimate for the level of aggregation across domestic premises required?

Q37. Do you agree with the issues raised and are they being addressed?

Q38. What do you believe are the important factors to developing and securing demand side services?

Q39. Do you agree that the TSO and DNO relationship will principally revolve around better co-ordination of generation patterns from embedded generators?

Q40. Do you agree that the supplier/DNO relationship will be critical in localised constraint management? How do you see services will be developed?

Q41. How does this model align with your own understanding of how operational interfaces may work?