Promoting choice and value
for all gas and electricity customers

Electricity Capacity Assessment

Ofgem report to Government

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Overview:

This document is Ofgem's Electricity Capacity Assessment report to the Secretary of State. It estimates a set of plausible electricity capacity margins that could be delivered by the market over the next four years and the associated risks to security of supply.

We assess that the risks to electricity security of supply will increase in the next four years. In particular, we expect that electricity de-rated capacity margins will decrease significantly from the current historically high levels. In parallel, the risk of electricity customer disconnections will appreciably increase from near zero levels. This is primarily because of a significant reduction in electricity supplies from coal and oil plants which are due to close under European environmental legislation.

Although it is clear that risks to security of supply will increase, it is very difficult to accurately forecast the level of security of supply provided by the market. This is because of uncertainties regarding commercial decisions about generating plants, electricity interconnection flows to and from the Continent, and the level of demand. We have developed several sensitivities to capture these uncertainties.

Context

Ofgem's[1] principal objective is to protect the interests of existing and future consumers. The interests of consumers are their interests taken as a whole, including their interests in the reduction of greenhouse gases and in the security of the supply of electricity to them.

The Electricity Act 1989[2] obliges Ofgem to provide the Secretary of State with a report assessing different electricity capacity margins and the risk to security of supply associated with each alternative. Ofgem's capacity assessment report is to be delivered to the Secretary of State by 1st September every year, starting in 2012.

Fulfilling this obligation in the Electricity Act 1989 has required a one-off exercise to develop a model which assesses the risks to electricity security of supply. This model will be updated on an annual basis to fulfil the Authority's obligation for annual reporting. The Electricity Act allows for the modelling to be delegated to a transmission licence holder and we delegated the construction and updating of the model to National Grid Electricity Transmission plc.

This document is Ofgem's report to the Secretary of State. It assesses electricity capacity margins for a range of sensitivities and the risk to security of supply associated with each alternative. It also covers the assumptions and methodology used in the study.

Associated documents

- Energy Act 2011
- Consultation: Electricity Capacity Assessment: Measuring and modelling the risk of supply shortfalls.
- Decision document: Electricity Capacity Assessment: Measuring and modelling the risk of supply shortfalls
- Department of Energy and Climate Change, *Electricity Market Reform White Paper 2011* "Planning our Electric Future: A White Paper for Secure, Affordable, and Low-Carbon Electricity".

[1] In this document the Gas and Electricity Markets Authority is referred to as "the Authority" or as "Ofgem".
[2] Section 47ZA as inserted by the Energy Act 2011.

Contents

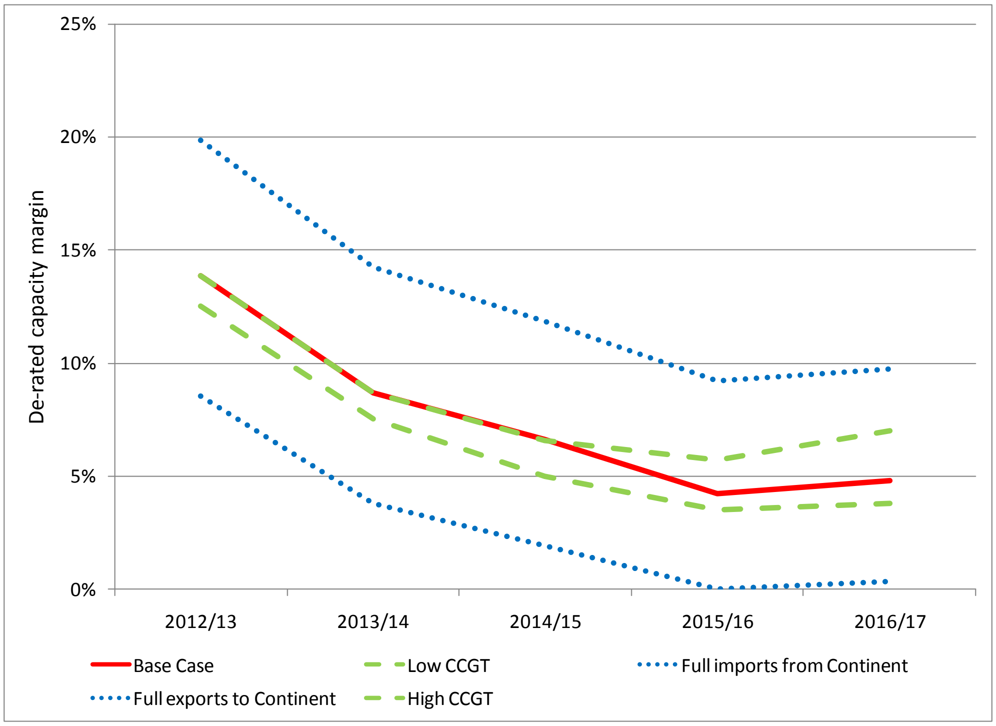
Executive Summary

The high level of spare capacity in the GB electricity market is set to end quite rapidly over the next few years. As identified in our 2009 Project Discovery analysis the impacts of replacing older coal and oil power stations under EU environmental legislation together with changes to the generation mix over the next decade pose new challenges to security of supply. Recent developments have strengthened this view. Indeed, power stations 'opted out' under the LCPD are using up their running hours faster than expected: most LCPD opted out plant will come off the system well before the 2015 deadline.

This report sets out our assessment of capacity margins that could be delivered by the electricity market over the next four years and the risks to security of supply associated with these, as required by the Electricity Act 1989. The assessment needs to capture uncertainty related to intermittent wind generation, together with uncertainty on interconnector flows, investment and plant retirement decisions, and overall electricity demand. We use a combination of a probabilistic approach with sensitivity analysis to assess this uncertainty.

Even during this relatively short forecast period, such uncertainties are large, given current developments in the electricity markets. Their impact is potentially profound given the declining capacity margins (see figure below). We therefore present a 'Base Case' with a number of sensitivities around it. Some of the most difficult issues on which to form a firm view are whether new gas fired generation will be built over the next 4 years; whether power stations that have been taken out of operation ('mothballed') will return; and how interconnectors will flow at times of peak demand. There is also uncertainty as to the level of demand, given the uncertain economic outlook and the potential for demand reduction through efficiency measures.

The figure below shows de-rated capacity margins for the Base Case and for sensitivities on interconnectors and CCGT mothballing and new build assumptions (for further sensitivities see sections 1 and 3 of the report). The Base Case takes a cautious approach assuming no net imports from Continental Europe, whilst maintaining exports to Ireland. In general, we would expect increases in the levels of interconnection to improve Britain's security of supply because of the benefits arising from being a part of a larger and more diverse electricity system. At the same time, GB will be exposed to risks from the actions of players beyond the control of the GB market. With the potential for more interconnection, it will be important in future years to carefully consider developments and the level of security of supply in neighbouring Member States.



The figure above shows that de-rated margins are expected to decline significantly over the coming four years. Demand is expected to remain broadly flat in the Base Case, with relatively modest demand increases driven by economic growth offset by improvements in energy efficiency and the availability of demand side response measures. However, there will be a significant reduction in electricity supplies from coal and oil plants over the period, primarily driven by closures required by European environmental legislation. Reflecting this, estimated margins decline from around 14% this year to just over 4% by 2015/2016 in the Base Case. The high and low CCGT sensitivities show the range of uncertainty in CCGT mothballing and new build assumptions. Assuming full imports from the Continent, margins decline from around 20% to just over 9% over the four years. In the (highly unlikely) event of full exports to the Continent at times of peak demand, margins would not be positive in 2015/2016.

The de-rated capacity margins presented in the figure are not directly comparable with previous estimates for EMR by DECC. The main differences are assumptions on interconnector flows; the likely availability of different generation technologies; and the generation capacity requirements for the stability of the electricity system.

While margins illustrate the trend in security of supply, they are not in themselves a measure of the risk to security of supply. The report illustrates the risk and the impact of supply shortfalls using well-established probabilistic measures: "Loss of Load Expectation" (LOLE) and "Expected Energy Unserved" (EEU).

The risk of electricity shortfalls is expected to be highest at the end of the period, in 2015/2016 and 2016/2017, mirroring the declining margins. Under the Base Case, the expected volume of demand that may not be met because of an energy shortfall in 2015/2016 is around 3400 MWh. For the purpose of illustration, this volume equates to the annual demand of approximately a thousand households. However, the most likely implications are small, occasional shortfalls which could be dealt with by National Grid through demand-side action, with little or no impact on customers. The annual loss of supplies arising from transmission and distribution outages is typically more than three times this amount. Indeed, the associated LOLE is within the reliability criteria used by neighbouring European countries including France, Ireland and Belgium.

We also estimate the risk of customer disconnections. In the Base Case, we assume that, before disconnecting customers the electricity system operator is able to make use of 2 GW of emergency interconnection services. These services are not taken into account in the capacity margins above. The chance of an event requiring the disconnection of customers (which would be equivalent to a shortfall exceeding 2.75 GW), is estimated to be around 1 in 12 years under the Base Case in 2015/2016.

The assessment of risk is highly sensitive to assumptions around the Base Case. For example, were GB to import at maximum capacity from the Continent at peak, it would result in around 200 MWh of expected energy unserved (equivalent to the annual demand of approximately 60 households) with possible customer disconnections of around 1 in 50 years in 2015/2016. On the other hand, were there to be full exports to the Continent, expected energy unserved in 2015/2016 would increase to around 29,600 MWh (equivalent to the annual demand of approximately 9000 households). Low investment in, and early closures of, gas plants ("Low CCGT" sensitivity) would result in 6100 MWh of expected energy unserved. This would increase the chance of customer disconnections to 1 in 7 years in 2015/2016.

Ofgem and National Grid have consulted widely on the methodology used for the analysis described in this report. The modelling was delegated to National Grid Electricity Transmission plc (NGET) given their capabilities and pre-existing requirements for generators to provide them with up-to-date information.

The key results are presented in Section 1 of the report. Section 2 covers sensitivity assumptions. The de-rated capacity margins are presented for the Base Case and main sensitivities in Section 3. Detailed modelling results, including probabilistic measures, are presented in Section 4. A more detailed description of the sensitivities and the probabilistic analysis can be found in the report's Appendices.

1. Key results

1.1. This section summarises our assessment of the trends in electricity security of supply and the risk of supply shortfalls for the next four years.

1.2. We use several measures to assess electricity security of supply. We report plausible de-rated capacity margins that could be delivered by the market. De-rated capacity margins are useful for understanding trends in security of supply. In addition, we illustrate the risk and the impact of supply shortfalls using two well-established measures: Loss of Load Expectation (LOLE) and Expected Energy Unserved (EEU). Finally, we estimate how frequently electricity customers may be disconnected and the potential size of these disconnections.

1.3. The methodology used to arrive at the above measures combines a probabilistic approach with sensitivity analysis. The probabilistic approach captures short term uncertainty due to intermittent generation, plant faults and the effect of weather on demand. The sensitivity analysis takes into account the long term uncertainty in investment and retirement decisions, and interconnector flows.

1.4. We start by presenting margins, first for the Base Case, then for some key sensitivities. The second part of this Section sets out the risks to security of supply in the Base Case and for the key sensitivities. Some of the most difficult issues to form a firm view on are whether new gas fired generation will be built over the next 4 years, whether gas power stations (CCGTs) that have been taken out of operation ('mothballed') will return, and how interconnectors will flow at times of peak demand. In addition, there is uncertainty on the level of demand, given the uncertain economic outlook and the potential for demand reduction through efficiency measures. To reflect these uncertainties we present a number of key sensitivities around the 'Base Case'.

De-rated capacity margin

1.5. We first present a commonly used indicator of security of supply: the de-rated capacity margin. The de-rated margin represents the excess of available generation capacity to peak demand and is expressed in percentage terms. Available generation takes into account the contribution of installed capacity at peak demand by adjusting it by the appropriate de-rating factors.[3]

1.6. The de-rated capacity margins presented here are not directly comparable to DECC's technical update paper for EMR. The main differences are assumptions on

[3] The de-rating factors are derived from the analysis of the historical availability performance of the different generating technologies. See Section 3 for details of the de-rating factors used by technology.

interconnector flows, the likely availability of different technologies, and the generation capacity requirements for the stability of the electricity system.

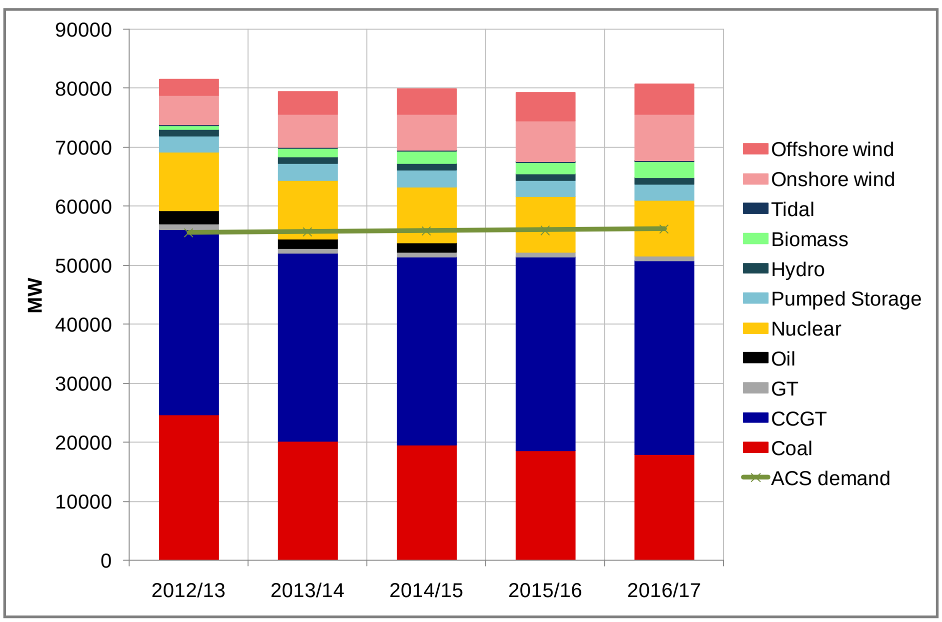
Base Case

Electricity demand and supply

1.7. Electricity demand in Great Britain is forecast to be relatively stable over the period 2012/2013 to 2016/2017 in our analysis. At the same time, GB supply is evolving. The GB supply mix is shown graphically in Figure 1.1 which also shows average peak winter demand (or Average Cold Spell demand – ACS green line).[4]

1.8. Old plants (11 GW) are being replaced by new wind (5 GW) and biomass generation. In particular, older coal and all oil plant will close due to requirements of European environmental legislation. In addition, some older combined cycle gas turbine plants (CCGTs) have recently closed for refurbishment. Some nuclear generation capacity will also be retired over the period.

Figure 1.1 Base Case installed capacity by plant type and average peak winter demand

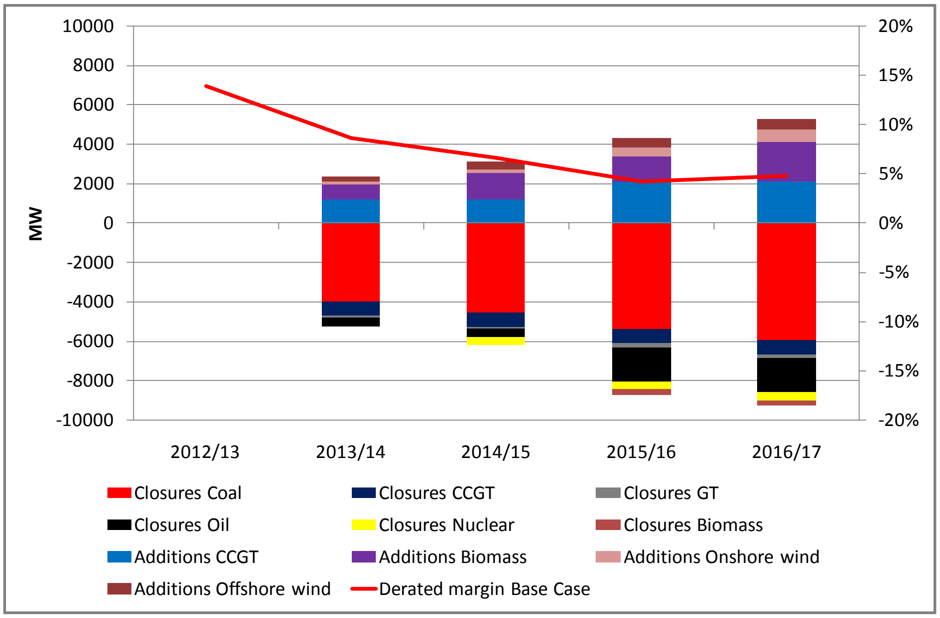


1.9. Figure 1.2 below shows the de-rated margin in the Base Case as well as the changes in de-rated capacity over the forecast period. The de-rated capacity margin in 2012/2013 is relatively high by historical standards, but is forecast to fall over the

[4] ACS demand is Average Cold Spell Demand, ie demand at winter peak under normal winter weather conditions.

next few years to a low of 4.2% in 2015/2016 in the Base Case. The slight uplift in 2016/2017 reflects renewable build at the end of the period.

Figure 1.2 Base Case de-rated margin and de-rated capacity changes



1.10. The de-rated margin projections demonstrate that electricity security of supply in the Base Case is expected to reduce over the coming four years. While the margins towards the end of the period are lower than today, they are not unprecedented. De-rated margins in the middle of the last decade were of a similar level. The low margins towards the end of the period are primarily due to the net decrease in conventional thermal capacity (see Figure 1.2) and the intermittent nature of wind generation, which is de-rated more compared to thermal generation.

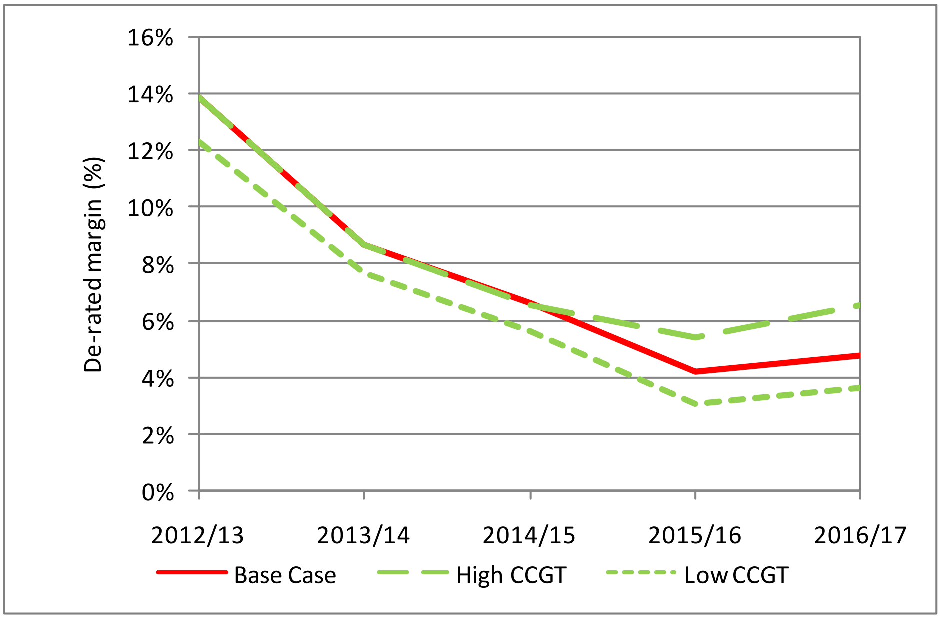
Sensitivities

1.11. The analysis has also explored a range of sensitivities to capture uncertainty in key assumptions concerning mothballing and investment decisions of gas plants, flows on interconnectors, and underlying demand for electricity. We have tried to cover a reasonable range of potential developments to the GB electricity system over the next four years.

CCGTs

1.12. Decisions on whether power stations close, return to service or are built depend on companies' specific commercial and financial position, the outlook for energy prices as well as the energy policy environment. It is very difficult to form a firm view on these very specific commercial decisions. In particular, we recognise that it is possible that in expectation of tighter margins at the end of the period, some new gas generation becomes operational or returns to service from mothballing (high CCGT sensitivity). However, there is also a downside risk (low CCGT sensitivity) that some of the older gas plants that are currently mothballed do not return to service and others close earlier than anticipated. This range is shown in Figure 1.3 below.

Figure 1.3 Base Case and gas sensitivity de-rated capacity margins



1.13. Figure 1.3 shows that in 2015/2016 the de-rated margins could vary between 3% under the low CCGT sensitivity and 5.4% in the high CCGT sensitivity.

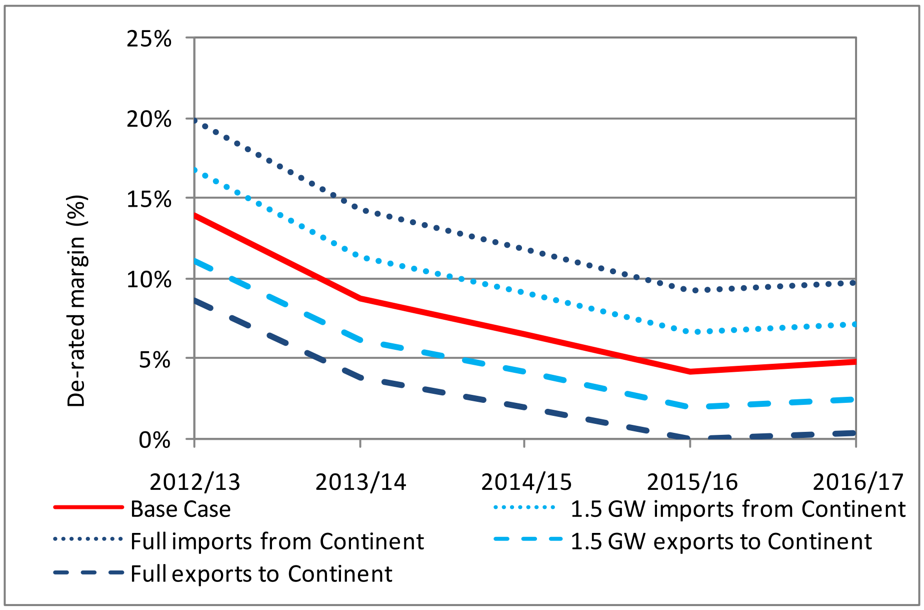
Interconnection

1.14. As we move to a more integrated European electricity market we will benefit from increased security through greater diversification of supply sources and interconnection. At the same time, GB will be exposed to risks from the actions of players beyond the control of the GB market.

1.15. Our Base Case takes a cautious approach to interconnector flows. In particular, we assume interconnectors to the Continent do not export or import at peak, whereas GB exports electricity to Ireland. Historically, GB has exported to Ireland at peak. Irish margins are expected to remain broadly flat over the coming years so this trend is likely to remain the same. On the other hand, interconnection with France and the Netherlands is less certain. It is therefore difficult to base future flows on historical patterns due to the high level of uncertainty on capacity margins in some key European countries.[5]

1.16. Our interconnector sensitivities take into account potential exports and imports from the Continent at peak. The de-rated margins under these sensitivities are illustrated in Figure 1.4. Due to the significant level of interconnection in GB (4 GW total), the range of potential de-rated margins is wide. For instance in 2015/2016, it could range from approximately 0% to 9.2% depending on the direction and size of flows assumed.

Figure 1.4 Base Case and interconnection sensitivity de-rated margins



1.17. Full electricity exports to the Continent coinciding with peak GB demand is highly unlikely. Such a case would require a combination of low generation availability both in GB and Europe as well as coincidence of peak demand conditions. The case of imports from the Continent being available to GB at peak times is more likely. If GB experienced low capacity margins, wholesale electricity prices should rise to reflect scarcity. This should provide incentives to generating companies abroad to sell energy to GB via the interconnectors, which in turn would help margins recover to higher levels. However, given the potential for low margins in key European countries we assume no Continental imports in the Base Case.

1.18. While GB and other countries may be facing tight margins simultaneously it is highly unlikely we will be facing risks of blackouts at the same time. When estimating

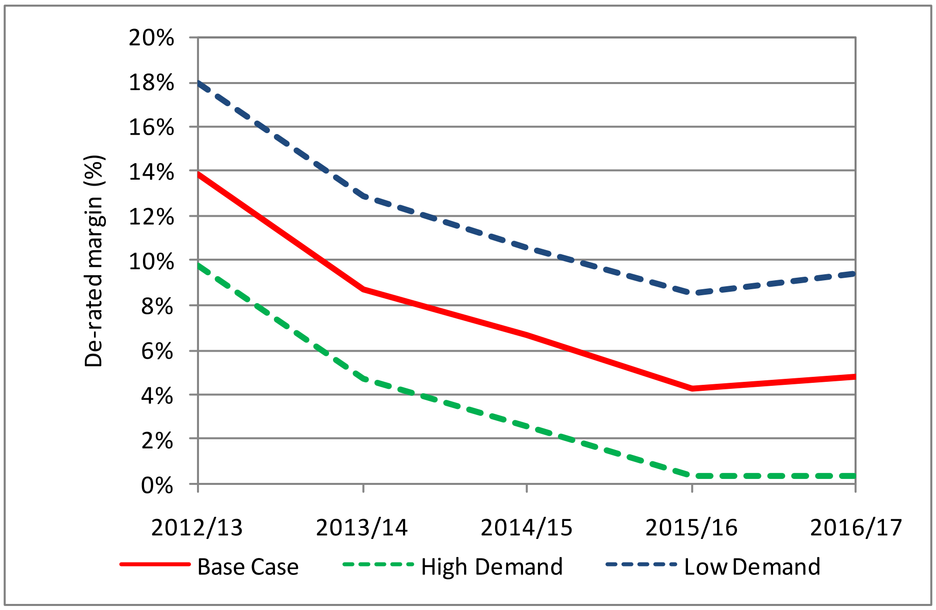
[5] France is expected to face increased risks over the next 4 years and the Netherlands potential constraint issues. Due to this high uncertainty we have taken the cautious approach of assuming neutral interconnection with the Continent and presented scenarios around interconnection flows. The Base Case assumes full exports to Ireland.

the risk of customer disconnections (see next section), we therefore assume that the system operator will be able to make use of emergency interconnector services ahead of customer disconnections.

Demand for electricity

1.19. The demand used in the modelling is Average Cold Spell (ACS) demand. This is an estimate of winter peak demand under normal winter weather conditions. Demand for electricity primarily depends on economic growth and energy efficiency measures. Figure 1.5 shows how de-rated margins can be affected by a sensitivity characterised by high economic growth and the low penetration of energy efficiency measures and vice versa.

Figure 1.5 Base Case and demand sensitivity de-rated capacity margins



Gas stress test and other extreme events

1.20. The current study has looked into the risk to security of supply of a shortage in gas supplies (see Appendix 2 for details). Our estimates show that the electricity capacity margins would only be impacted if GB faces a combination of significant infrastructure failures (eg no imports via the Norwegian pipeline) and supply shortages due to considerable tightness in world gas markets (eg limited LNG imports).

1.21. This study has not modelled the impact of other extreme adverse events on capacity margins. One such event could be the closure of part or all of the nuclear AGR fleet for precautionary reasons in the case of an accident or a fault being found with one of them. In such extreme cases GB would have to rely on imports to serve electricity demand during peak demand periods.

Post 2016/2017

1.22. The analysis covers the period to 2016/2017 as specified by the Electricity Act.[6] Beyond that, the exact nature of the Electricity Market Reform (EMR) package will determine the size and type of new sources of generation. Without more specific detail on EMR it is very difficult to estimate capacity margins any further out. We have therefore restricted our modelling of margins and the associated risks to security of supply to the period specified in the Electricity Act.

Measures of risk and impact on customers

1.23. While the de-rated capacity margin is an indicator of the trend in security of supply it is not in itself a measure of risks to security of supply, nor does it provide information on how large an outage event may be. In this section we use two well established measures to express the risks to security of supply associated with the generation mix and demand levels discussed above. We also describe the potential risks of disconnecting electricity customers.

Measures of risk

1.24. The two probabilistic measures of security of supply used in this study are:

- *Loss of Load Expectation* (LOLE) - the number of hours per year for which supply may not meet demand; and
- *Expected Energy Unserved* (EEU) - the amount of electricity demand that may not be served in a year. EEU combines both the likelihood and the potential size of any supply shortfall.

1.25. LOLE and EEU results are not to be interpreted as literal predictions of what will actually happen in a year. In practice, for a given level of LOLE and EEU electricity systems may experience small frequent events or large infrequent events. We return to this point when we describe the impact of supply shortfalls on households.

1.26. Both LOLE and EEU increase from very low levels in 2012/2013, mirroring the declining de-rated margins as shown in Figure 1.6. LOLE estimates indicate that in 2015/2016 supply may not match demand for approximately 2.7 hours in the Base Case. For comparison purposes a LOLE of 2.7 hours is within the reliability criteria

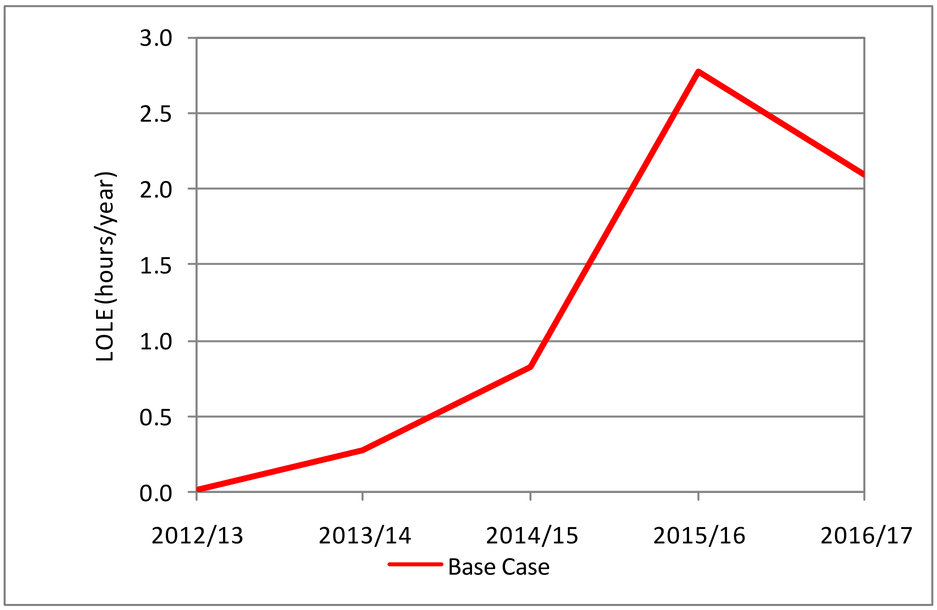
[6] Section 47ZA Electricity Act 1989 (inserted by the Energy Act 2011) requires the forecast periods in relation to the Authority's report to be each of the four years immediately following the year of the report or any other periods specified by the Secretary of State.

used by other European countries such as France, Ireland and Belgium (see Figure A6.7).

1.27. For the high and low CCGT sensitivities, the LOLE estimates range from 1.5 to 4.7 hours per year in 2015/2016. Exports and imports to and from the Continent have a large impact on LOLE which could range from 0.22 to 18.9 hours per year in 2015/2016 depending on the sensitivity.

1.28. EEU gives an indication of the size of that potential shortfall. In 2015/2016, the expected energy unserved in the Base Case is 3370 MWh. For comparison, the typical annual loss of supplies arising from transmission and distribution outages is typically more than three times this amount.

Figure 1.6 Base Case results for LOLE



Impact on electricity customers

1.29. In this section we translate LOLE and EEU into tangible impacts for electricity customers. Outage events are rare events and as such it is not easy to predict exactly how the electricity system will cope. Therefore, our description of the impact of outages is based on judgement around how the electricity system would operate and the order and size of mitigation actions taken.

1.30. When there is a short and small outage event the system operator can mitigate its impact by first reducing demand (ie voltage reduction). Once voltage reduction is exhausted it can aim to increase supply. This consists of two phases.

First, the SO can instruct plants to generate at their maximum level. It can then also avail of emergency interconnection services.[7] The impact of these actions is not generally noticeable to electricity customers. It is also worth noting that these mitigation actions only occur when a shortfall exists and as such are not included in the de-rated margin calculations.

1.31. The mitigating tools that NGET has at its disposal may not be available for more than few hours. Longer and larger outage events (ie larger than 2.75 GW) will eventually result in electricity customer disconnections. Industrial customers would be disconnected before households.

1.32. In Figure 1.7 we illustrate the impact of potential outage events in equivalent household (HH) numbers disconnected as well as the overall probability of disconnections.

1.33. We do not attach probabilities to individual potential outcomes (e.g. supply shortfall of 1.5-2.75 GW for 2-4 hours), but in general, the magnitude of a supply shortfall is positively correlated to the duration of the outage, i.e. outcomes on the diagonal (Northwest to Southeast) are more likely than other outcomes. In addition, one would expect that more severe events are less likely than smaller and shorter outages. The inclusion of industrial demand disconnections would also significantly reduce the number of households disconnected.

Figure 1.7 Impact on electricity customers in household equivalent

		Supply shortfall*			
		0 -1.5 GW	**1.5 – 2.75 GW**	**2.75 - 5 GW**	**5+ GW**
Hours of outage	**0 – 2**	Dimming lights	Dimming lights	Black-outs <1.5m HH	Black-outs >1.5m HH
	2 – 4	Dimming lights	Possible black-outs <1m HH	Black-outs <1.5m HH	Black-outs >1.5m HH
	4 – 6	Possible black-outs <1m HH	Possible black-outs <1m HH	Black-outs <3.3m HH	Black-outs >3.3m HH
	6+	Possible black-outs <1m HH	Black-outs <1m HH	Black-outs <3.3m HH	Black-outs >3.3m HH

Probability of being in the amber or red zone

2012/13 **1-in-3300 years** → **2015/16** **1-in-12 years**

*Industrial demand would typically be disconnected before household demand. 0.75GW of industrial demand curtailment would reduce the impact on households by 0.5m.

1.34. The figure is in line with previous evidence. The significant reduction in capacity margins will result in an appreciable increase in the risk of electricity

[7] Max gen is an instruction that the SO can issue to generators to generate at maximum output. The SO can also make use of the provision of emergency services via interconnectors.

customers facing disconnections. More specifically, the risk of disconnections increases from near zero levels in 2012/2013 to 1-in-12 years in 2015/2016 in the Base Case. In the case of 3 GW of interconnector imports from the Continent, the probability of disconnections is 1-in-52 years. On the other hand, if the mitigating actions available to Grid were 1 GW lower than those expected here (ie 1.75 GW instead of 2.75 GW), the risk of disconnections would increase to 1-in-6 years. More detailed results on the de-rated capacity margin estimates are presented in Section 3 and detailed risk results are presented in Section 4.

2. Demand and generation assumptions

2.1. This section provides the assumptions used as a basis for an outlook of the GB electricity sector until 2016/2017. We developed a Base Case which draws on National Grid's Gone Green 2012[8] scenario, includes the latest public information on recent and future capacity changes but also reflects uncertainty in future market conditions and policy. This report presents results for the Base Case with a number of sensitivities around it.

2.2. Some of the most difficult issues to form a firm view on are whether new gas fired generation will be built over the next 4 years, whether gas power stations (CCGTs) that have been taken out of operation ('mothballed') will return, and how interconnectors will flow at times of peak demand. In addition, there is uncertainty on the level of demand, given the uncertain economic outlook and the potential for demand reduction through efficiency measures.

2.3. The most difficult issues to form a firm view around are whether power stations that have been taken out of operation ('mothballed') will return and whether new gas fired stations will be built in the next four years. We describe the assumptions underlying the sensitivities reflecting these particular uncertainties.

2.4. A description of sensitivities not shown in the main report (relating to assumed availabilities, biomass conversions, and alternate Grid scenarios) and the results for these sensitivities, can be found in Appendix 1.

2.5. We first describe the assumptions underlying the Base Case. We then describe the assumptions and rationale behind the main sensitivities on CCGTs, interconnector flows and finally demand.

Base Case

2.6. Assumptions for the Base Case centre on demand forecasts and the generation portfolio (supply side) which we present in turn here.

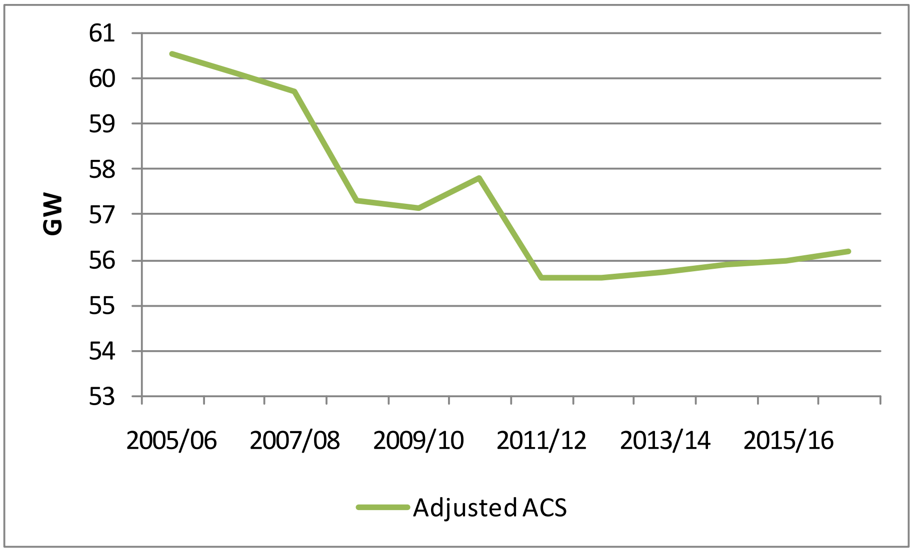
Demand

2.7. Demand for electricity has been declining since 2008 due mainly to the effects of the recession and but also due to energy efficiency measures. Electricity demand is not expected to rebound significantly in the near future due to low forecasts of

[8] The Gone Green scenario is one of the Future Energy Scenarios developed annually by National Grid to illustrate potential scenarios of the future development of the GB electricity (and gas) sectors. Our Base Case draws on a provisional version of Gone Green 2012. Last year's report is available at:
http://www.nationalgrid.com/uk/Gas/OperationalInfo/TBE/Future+Energy+Scenarios/

GDP growth. Figure 2.1 shows peak demand for electricity supplied and forecast to be supplied through the transmission network[9] over the period 2005 to 2017, adjusted for the effect of year-on-year weather variations (this demand is called Average Cold Spell demand).[10]

Figure 2.1 ACS peak for the years 2005-2017



2.8. The ACS peak demand forecast is derived in part from assumptions on GDP growth (see Figure 2.2) and in part by assumptions on energy efficiency and the changing sources of demand for energy, discussed below.

Figure 2.2 Base Case GDP growth assumptions

	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17
GDP used for Base Case (2010/11 = 100)	100	100.8	101.1	102.6	104.6	106.7	109
% change year-on-year		0.8%	0.2%	1.5%	1.9%	2.0%	2.2%

2.9. The Base Case also assumes an increase in energy efficiency with lighting, appliances and insulation, all contributing to electricity demand reduction in the domestic sector. This contributes a reduction in annual demand of 11.6 TWh (or 3.7%) in 2016. The Carbon Reduction Commitment (CRC)[11] is assumed to drive energy efficiency in industrial and commercial sectors. The net effect of these

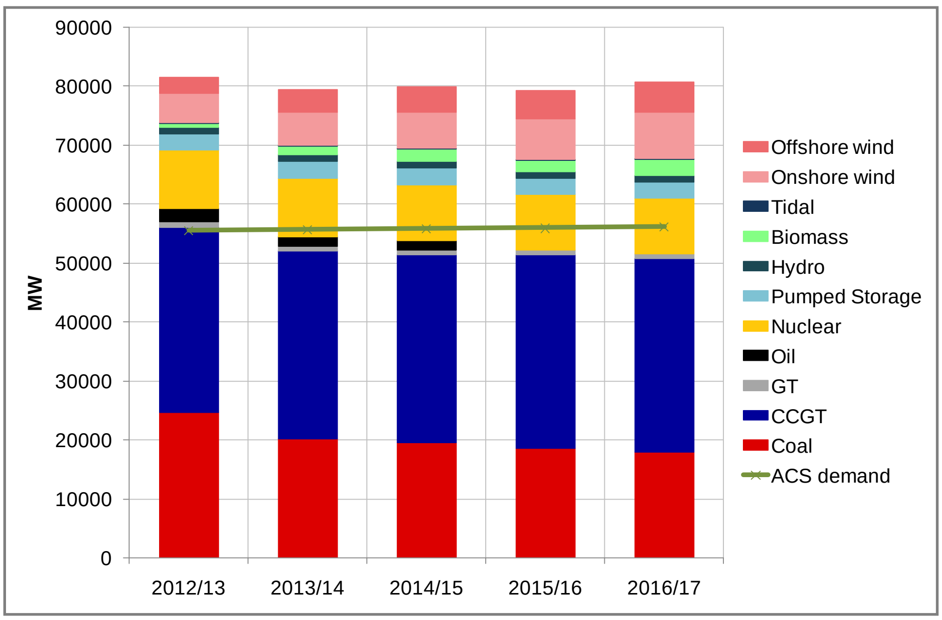
[9] I.e. excluding demand supplied via embedded generation connected directly to the distribution networks.
[10] ACS peak demand is a value that is calculated to remove the effects of weather fluctuations on peak demand. To calculate the ACS demand, the actual peak value is adjusted to the demand that would have been expected in an average cold spell.
[11] See http://www.decc.gov.uk/en/content/cms/emissions/crc_efficiency/crc_efficiency.aspx

assumptions results in the transmission system peak demand projection remaining broadly flat (and lower than recent history) over the analysis period (see Figure 2.3).

Supply

2.10. Figure 2.3 shows the Base Case assumptions for capacity by plant type, alongside the peak demand assumptions. Total installed capacity is approximately 82 GW in 2012/2013 and between 79 and 81 GW in the following years. The capacity mix evolves over this period, with a reduction in fossil fuel capacity and an increase in wind capacity.

Figure 2.3 Base Case installed capacity by plant type



2.11. The key changes in the capacity mix between 2012/2013 and 2016/2017 are set out below.

Large Combustion Plant Directive (LCPD)

2.12. Under the LCPD, a total of 12 GW of coal and oil-fired capacity will have to retire by the end of 2015. These plants have been opted out of the LCPD, and have 20,000 hours of operation to use between 1 January 2008 and 31 December 2015. Current usage patterns[12] and market announcements suggest that 4 GW of the coal plant will close at the beginning of 2013/2014. The remaining LCPD opt out closure occurs at the end of 2014/2015 (a further 0.9 GW). Two plant which are opt out coal

[12] High dark spreads have encouraged coal plant to operate at high load factors.

station are converting to generate from biomass. 1.6 GW of oil plant is expected to stay on the system until 31 December 2015.

Industrial Emissions Directive (IED)

2.13. The IED will place restrictions on the operation of some existing coal and older CCGT stations from after 2016/2017.[13] As such the IED does not affect the supply assumptions for this study.

Nuclear

2.14. A number of nuclear stations are coming close to the end of their operational lives. One plant of approximately 0.5 GW is planned to close in 2013 but no further nuclear closures are assumed in the analysis period.[14]

Mothballing and new builds

2.15. Some of the most difficult issues to form a firm view on relate to mothballing and new build. Recent high capacity margins and low profitability have been cited as the reasons for mothballing some of older gas-fired generation capacity. Up to 3 GW of CCGT capacity is mothballed as of 2012/2013. Further assumptions relating to CCGTs in the Base Case include nearly 1 GW of CCGT new build coming into service in 2015/2016 when margins begin to tighten. Since 2010, 6 GW of new CCGT capacity has been commissioned and a further 3 GW is expected to be operational by the end of 2012.

Wind

2.16. We expect the deployment of onshore and offshore wind to continue. The installed capacity of onshore wind grows from 5 GW (including embedded wind) in 2012/2013 to nearly 8 GW in 2016/2017. Offshore wind grows from 2.7 GW to 5.2 GW over the same period.

Biomass

2.17. The Base Case assumes approximately 2.8 GW of biomass by 2016/2017 of which one is a former LCPD opt out plant which stays open due to re-licensing. The Base Case also takes into consideration any recently announced plans by plant to convert to biomass.

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[13] Under IED coal and old CCGT plants can either fit emission reduction equipment to comply with the requirements, or take one of two derogations available. The hours based restriction (Limited Lifetime Obligation, LLO) and emissions based restriction (Transitional National Plan) will both limit the load factors of these stations.
[14] Two of the Advanced Gas Cooled Reactors (AGRs) are currently scheduled to retire in 2016; however the Base Case assumes these reactors get life extensions.

Interconnection capacity and flows

2.18. Interconnector capacity assumptions are shown in Figure 2.4. No other new interconnectors are assumed to come online within the analysis period. The Moyle and East-West interconnectors both connect to the Single Electricity Market (SEM), which is the all-island market combining Northern Ireland and the Republic of Ireland.[15]

Figure 2.4 Interconnector capacity assumptions

Name	To	All years (MW)
Moyle	Single Electricity Market (Northern Ireland)	450
East-West	Single Electricity Market (Republic of Ireland)	500
IFA	France	2000
BritNed	Netherlands	1000

2.19. Our Base Case takes a cautious approach to interconnectors' flows. In particular, we assume interconnectors to the Continent do not export or import at peak, whereas GB is exporting electricity to Ireland.

2.20. Historically, GB has exported to Ireland at peak. Irish margins are expected to remain broadly flat over the coming years so this trend is likely to remain the same – although we do assume a reduction in the level of exports at the end of the period. On the other hand, interconnection with France and the Netherlands is less certain. It is therefore difficult to base future flows on historical patterns due to the high level of uncertainty in Europe.

2.21. Due to this uncertainty, we run sensitivities relating to interconnection separately. The year by year assumptions for net imports at peak are shown in Figure 2.5.

Figure 2.5 Base Case interconnector import/export at peak (negative is export from GB)

Name	To	2012/13 (MW)	2013/14 (MW)	2014/15 (MW)	2015/16 (MW)	2016/17 (MW)
Moyle	SEM (NI)	-450	-450	-450	-450	-360
East-West	SEM (RoI)	-500	-500	-500	-500	-400
IFA	France	0	0	0	0	0
BritNed	Netherlands	0	0	0	0	0

[15] Further interconnection projects including further links to France, Belgium and Norway are currently various stages of planning (eg ElecLink NEMO etc) but are not expected to be commissioned before 2016.

Sensitivities

2.22. Recognising that there is uncertainty in some key factors, e.g. CCGT new build and mothballing, interconnection, demand, we have developed a number of key sensitivities.

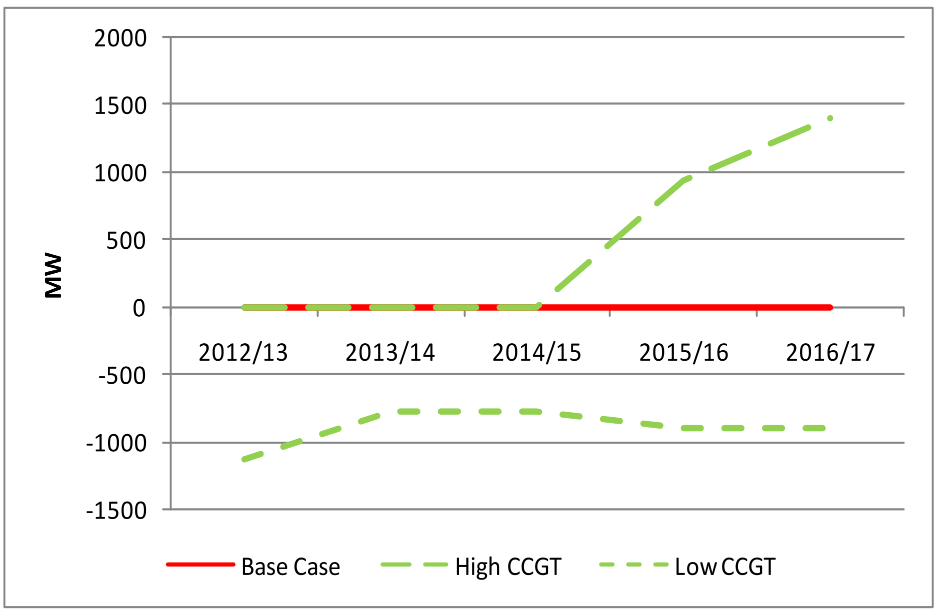
Key sensitivities

CCGTs

2.23. Due to the challenge involved in forming a view on changes to GB's generation capacity over the next four years we have run two sensitivities around CCGTs reflecting possible upside and downside risks.

2.24. *Upside risks*: In the next four years, compared to our Base Case GB security of supply could be improved by mothballed plant being brought back online and the construction of new CCGT plant. In the "high CCGT" sensitivity we have included approximately an additional 900 MW of new CCGT plant coming online in 2015/2016 and an additional 500 MW in 2016/2017.

Figure 2.6 Aggregate changes in installed capacity compared to the Base Case



2.25. *Downside risks*: On the other hand, GB's security of supply situation could worsen over the next four years. There is quite a lot of uncertainty surrounding mothballing decisions and closures of older CCGT plants. In the "low CCGT" sensitivity, given low spark spreads, we assume that old CCGT plant are mothballed in 2012/2013 (approximately 1.1 GW), but brought back online in 2015/2016 when margins get tight. No other mothballed plant are brought back online and no new plant get built within the timeframe.

2.26. The changes in installed capacities for the Base Case and CCGT sensitivities are illustrated in Figure 2.6. We have not attached probabilities to any of these sensitivities.

Interconnection

2.27. As we move to a more integrated European electricity market we will benefit from increased security through greater diversification of supply sources and interconnection. At the same time, GB will be exposed to risks from the actions of players beyond the control of the GB market. We have run a range of sensitivities looking at both imports to GB as well as exports from GB at peak.

2.28. Interconnection flows are very difficult to model and predict during peak times because flows depend on circumstances on both sides of the borders (with France, the Netherlands and Ireland). Therefore, a range of interconnector sensitivities have been run which make different assumptions on imports/exports with the Continent at peak. These are:

- Full import/export sensitivities assume +/- 3 GW interconnection flows with France and the Netherlands compared to the Base Case (full exports of 950 MW to Ireland assumed)

- Half import/export sensitivities assume +/- 1.5 GW interconnection flows with France and the Netherlands compared to the Base Case (full exports of 950 MW to Ireland assumed)

2.29. If GB experienced low capacity margins relative to the neighbouring countries, wholesale electricity prices should rise to reflect scarcity of generation assets. This should provide incentives to generating companies abroad to sell energy to GB via the interconnectors. To the extent that companies could respond to these price signals, margins should recover to higher levels. Full electricity exports to the Continent coinciding with peak GB demand is highly unlikely. Such a case would require a combination of low generation availability both in GB and Europe as well as coincidence of peak demand conditions. The case of imports from the Continent being available to GB at peak times is more likely. In general, we would expect increases in the levels of interconnection to improve Britain's security of supply because of the benefits from being a part of a larger and more diverse electricity system.

Demand

2.30. Electricity demand is highly dependent on economic growth and weather conditions. Therefore, we run high and low ACS peak demand sensitivities around the Base Case, which are based on the inner range shown in the Statutory Security of Supply Report by DECC and Ofgem published in November 2011.[16] The range for these sensitivities is shown in Figure 2.7.

Figure 2.7 Assumptions on deviations from Base Case ACS demand for ACS demand sensitivities

GW	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17
High demand	0.0	+1.6	+2.3	+2.4	+2.6	+2.6	+3.0
Low demand	0.0	-1.5	-2.1	-2.3	-2.3	-2.6	-2.8

2.31. The high and low demand sensitivities provide an inner and outer range of peak demands based on a range of factors, for instance prices, the economy etc. Peak demand could also be affected by the type of winter weather, eg mild or severe. To fully reflect the range of outcomes the high and low sensitivities range from 3 GW higher to 2.8 GW lower.

Additional sensitivities

2.32. We have run a range of sensitivities relating to differences in supply assumptions. The first set of sensitivities relate to changes around availability assumptions. These are set out below:

- **Winter Outlook Report (WOR) availabilities**: This sensitivity puts the analysis on a more comparable basis with the published Winter Outlook Report 2011/12. It indicates the sensitivity of the LOLE and EEU results to availability assumptions for non-wind generators. The method for estimating availabilities for the WOR is similar to the method used in this study for the Base Case, but differs in some of the assumptions. Note that the WOR value of 8% for wind is not used in the sensitivity and the wind EFC is calculated in the same way as for the Base Case.

- **Reduced plant availabilities:** This sensitivity explores the impact on capacity adequacy if the rate of unplanned (forced) outages for CCGTs increases as a result of changing operational patterns. In future, CCGTs may be required to change output levels more frequently and start and stop more often. In this sensitivity we assume that the mean availability for CCGTs reduces by 1% per annum, such that in 2016/2017 the availability is 4% less than in the Base Case.

- **Lower wind at peak:** This sensitivity scales down the distribution of wind output by 25%. We have assumed that wind and demand are independent at peak

[16] Statutory Security of Supply Report: http://www.decc.gov.uk/en/content/cms/meeting_energy/en_security/sec_supply_rep/sec_supply_rep.aspx

times. There is no strong evidence of a dependency, or of the form of any dependency. This sensitivity tests that assumption by assuming wind is less available at times of peak demand.

The final set of sensitivities relate to various generation side assumptions as set out here:

- **Biomass conversion not relicensed**: We also build a sensitivity in which a converted LCPD opt out plant does not continue operating after 2015/2016. This is a reduction of approximately 750 MW in 2016/2017.

- **No single largest infeed loss**: This sensitivity excludes the capacity sterilisation of plant contracted for reserve for response to cover for the single largest infeed loss. This enables quantification of the impact of this assumption on the adequacy measures. This sensitivity is reflected in the modelling by removing the Base Case capacity adjustment of 700 MW up to 2013/2014 and 1572 MW thereafter.

- **No exports to Ireland:** This sensitivity assumes that GB does not export to Ireland at peak. This is an increase of 950 MW until 2015/2016 and of 760 MW in 2016/2017.

- **Gone Green 2012 provisional**: This sensitivity uses the generation background from the provisional Gone Green 2012 scenario provided by National Grid specifically for the capacity assessment project.

2.33. The details on the assumptions in these sensitivities are outlined in Appendix 1. The next section presents the de-rated capacity margin calculations for the Base Case and the key sensitivities.

3. De-rated capacity margins

3.1. The de-rated capacity margin is an indicator of security of supply. It is defined as the expected excess of available generation capacity over demand. Available generation capacity is the part of the installed capacity that is expected to be accessible in reasonable operational timelines, ie it is not decommissioned or offline due to maintenance or forced outage. The available generation capacity will also take into account any expected intermittency of the generation fleet.

3.2. This section first presents the measures of generation availability used in the calculation of the de-rated margins in winter and summer as well as other adjustments made to the figures. It then presents the de-rated margin results for the Base Case (in winter and summer) as well as the CCGT, interconnection and demand sensitivities. Finally it presents the results of the gas stress test.

Generation availabilities and adjustments

3.3. In order to estimate available capacity we need the installed generation capacity by generation type as well as the corresponding availabilities. Availabilities are shown by generation type in Figure 3.1 and they are estimated using historical evidence.

Figure 3.1 Generator availability

Fuel Type	Winter Availability	Summer Availability
Coal (and Biomass)	87%	61%
Gas CCGT	86%	69%
OCGT[17]	77%	63%
Gas CHP	86%	89%
Hydro	92%	84%
Pumped Storage	95%	95%
Nuclear[18]	83%	71%
Oil	81%	47%
Wind	20-22%	11%

3.4. The contribution of wind is measured by the Equivalent Firm Capacity (EFC), which is calculated for each year and for each sensitivity.[19] The EFC shows the

[17]OCGTs do not tend to have planned outages. However we do occasionally see small changes to MEL. Therefore, for OCGTs we based de-rating on full 6 year history which reflects mainly breakdown as this closely aligns with the 80% de-rated capacity we expect from STOR units.
[18]Nuclear planned outages and breakdown rates were volatile over the period (2008/09-2010/11) as a result of type faults on some AGR reactors and an extended outage on a PWR in 2010. We also noted that Magnox reactors will all be retired for the period of capacity assessment. For this reason we aligned the assumed breakdown rate with the Winter Outlook Report for 11/12
[19] The EFC represents the firm capacity that can be replaced by a certain volume of wind generation to give the same security of supply, as measured by LOLE or EEU. A more detailed explanation of these values and the drivers of variations are given in Appendix 4.

contribution of wind generation to security of supply by taking into account both demand and wind patterns of the GB system.[20] The EFC values are in the range 20-22% of the installed wind capacity depending on the year and whether we are looking at onshore or offshore wind. Appendix 4 presents a more detailed description of how the EFC is calculated and describes the various wind availability figures as calculated by the model.

3.5. The de-rated capacity margin also includes an adjustment for assumed flows on the interconnectors (exports to Ireland) and the reserve held by the System Operator (SO) for single largest infeed loss.[21] This type of reserve is required in order to maintain the stability of the system, and therefore disconnection of demand would occur in preference to use of this reserve (whereas other forms of reserve would be used to prevent supply shortfalls).[22] As it is a form of reserve that must be maintained we therefore include it as "demand" in the analysis.

3.6. The interconnection and reserve adjustment are applied as increases to GB demand. The assumptions are shown in Figure 3.2 below.

Figure 3.2 Adjustments to ACS peak demand for interconnection and reserve

	2012/13 (MW)	**2013/14 (MW)**	**2014/15 (MW)**	**2015/16 (MW)**	**2016/17 (MW)**
Winter peak demand (ACS)	55614	55734	55873	55985	56173
Exports to Ireland	950	950	950	950	760
Reserve for largest infeed loss	700	700	1572[23]	1572	1572
Winter demand (ACS) – adjusted	57264	57384	58395	58507	58505
Summer peak demand - adjusted	40200	40279	41242	41314	41441

De-rated margins - Base Case

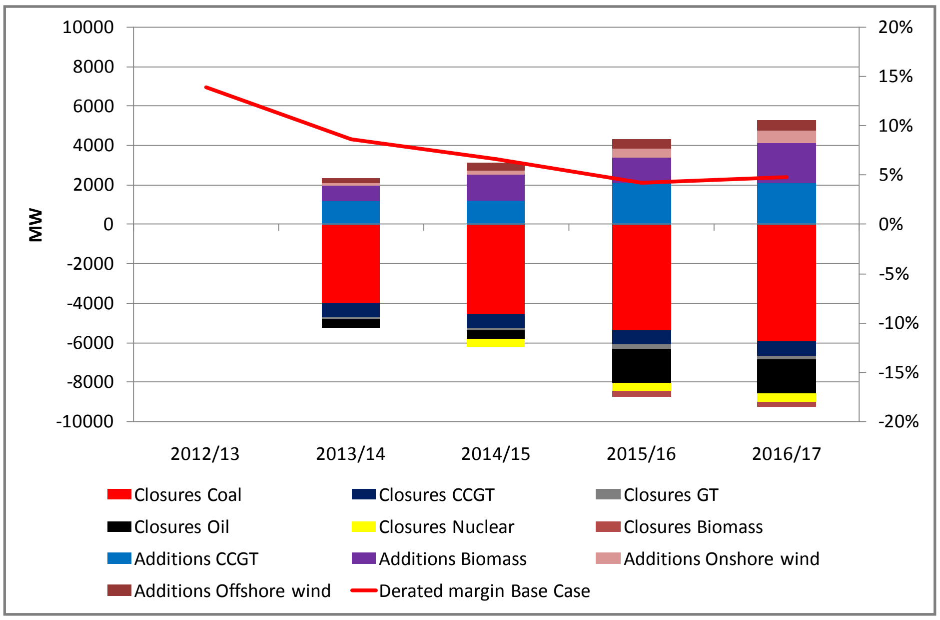
3.7. We have estimated de-rated margins for the winter demand peak as well as for the summer demand peak. In this section we present both winter and summer margins for the Base Case. As the lowest margins are seen in winter, the remainder of the sensitivities presented in Section 3 are for winter demand peak only.

[20] This method is superior to the mean availability factors used in other studies, which takes into account only the wind patterns.
[21] The SO also holds other types of reserves. However, it will not disconnect demand to preserve their level.
[22] This reserve is a sub-set of the full reserve requirement that the SO holds in order to manage the system on operational timescales.
[23] Practically, National Grid will only hold enough response to cater for events that can happen on any individual day – so one needs to check when the largest loss actually increases. At the moment National Grid uses about 700MW of capacity to meet the response requirement. From winter 2014/2015 this number will increase by 872MW to 1572MW.

Winter de-rated margins

3.8. Figure 3.3 shows the winter de-rated capacity margin for the Base Case between 2012/2013 and 2016/2017 along with the capacity additions and losses by generation type. The winter de-rated capacity margin declines over the analysis period from 13.9% in 2012/2013 to a low of 4.2% in 2015/2016. Losses in generation capacity from coal and oil are the main cause of the reduction. These are replaced by wind capacity, which makes a smaller contribution to the de-rated margin compared to conventional capacity.

Figure 3.3 Base Case de-rated margin (winter) and capacity changes



3.9. We now present de-rated capacity margin estimates for summer peak.

Summer de-rated margins

3.10. The de-rated margins for the summer peak were calculated using a different set of assumptions. There are two key factors which distinguish de-rated margins in the summer from de-rated margins in the winter. The first is the lower level of peak demand. The second is the planned maintenance outages that have historically occurred mainly in the summer.

3.11. Figure 3.2 shows the summer peak demand assumptions in comparison to the winter ACS peak demand assumptions. Summer peak demand is estimated to be about 17 GW lower than winter peak ACS demand, consistent with observed historical differences.

3.12. The summer availabilities per plant type are shown in Figure 3.1. These are derived from the likely availability of generators, taking account of both unplanned (forced) outages and planned maintenance. The forced outage assumptions are consistent with those used in the winter analysis.

3.13. The planned maintenance assumptions are based on historical average summer maintenance by generator type. Planned maintenance is typically scheduled when margins are expected to be high.[24] A portion of this planned maintenance may have the flexibility to be rescheduled in response to short term indications of low capacity margins. We have estimated the proportion of planned maintenance as 2.35 GW. This assumed level of maintenance is added back into the de-rated margin.

3.14. The summer value has not been calculated probabilistically. The mean wind generation in summer is less than in winter (the EFC is approximately 11% compared to 21% in winter). With lower wind output we expect a lower wind EFC.

3.15. The calculated Base Case summer and winter de-rated margins are shown in Figure 3.4.[25] The summer margin is approximately 5 GW higher than the winter margin in 2012/2013. The de-rated margins for both seasons decline through to 2015/2016 at a similar rate. By 2016/2017 the summer margin is 21% or 8.7 GW. This is still higher than the 2012/2013 margin in winter (7.9 GW). For illustrative purposes, Figure 3.5 presents the summer and winter margins in percentage terms. Due to the size of the estimated margins in summer, the risks to security of supply are low. As such, the next section will focus on a range of sensitivities relating to the winter margins.

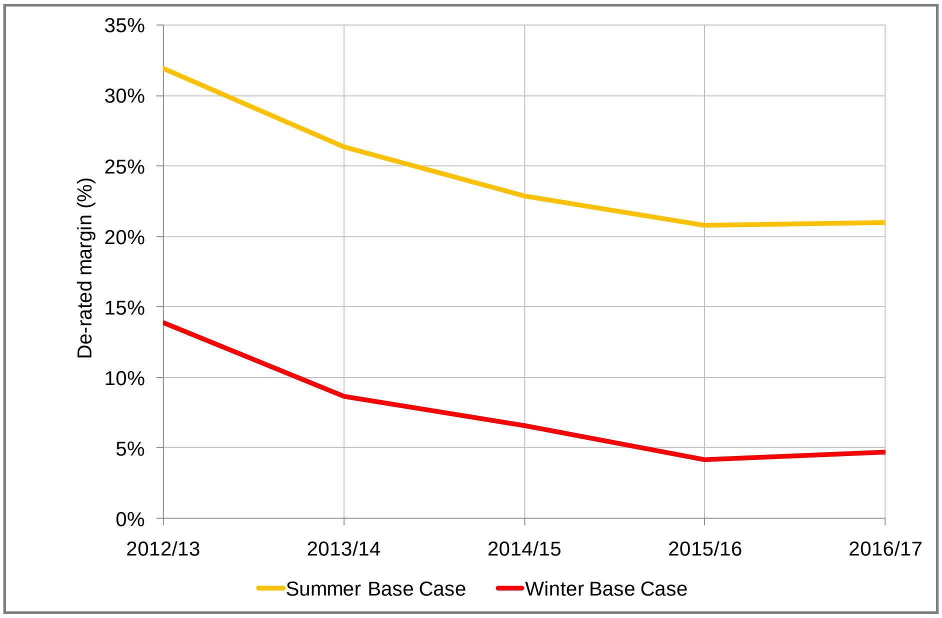
Figure 3.4 Base Case de-rated margins for summer and winter (MW)

De-rated margin	2012/13 (MW)	2013/14 (MW)	2014/15 (MW)	2015/16 (MW)	2016/17 (MW)
Base Case Summer	12833	10633	9439	8597	8714
Base Case Winter	7948	4983	3845	2457	2779

[24] The timing and the length of maintenance outages can be affected by the availability of resource to carry out maintenance work, the terms of contracts with maintenance service providers, and the requirement of statutory outages, including restrictions on the maximum number of Equivalent Operating Hours (EOH) between maintenance intervals.

[25] The de-rated margins are presented here in MW terms rather than as a percentage of peak demand. This removes the distortion that is observed if the margins are presented as a percentage of peak demand due to summer peak demand being lower than winter ACS demand.

Figure 3.5 Base Case summer and winter de-rated margins (%)



Sensitivities de-rated margins

3.16. We have constructed sensitivities around CCGT investment, interconnector flow assumptions and peak demand levels. The de-rated margins associated with these sensitivities are now presented in turn. Further sensitivities (on plant availabilities, biomass relicensing, etc) are discussed in Appendix 1.

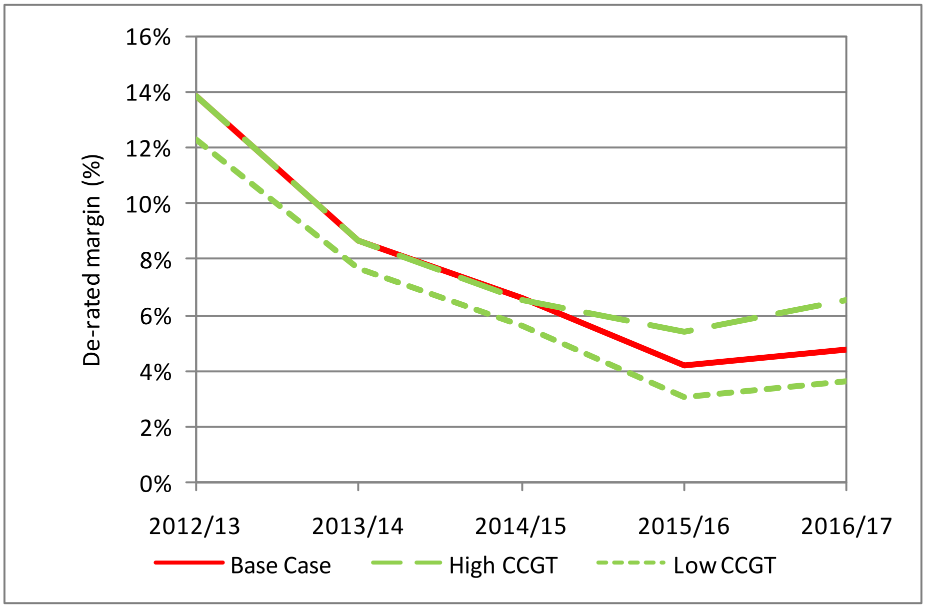
CCGTs

3.17. Commercial decisions such as bringing back to service old mothballed plants or building new plants depend on companies' commercial and financial position, the outlook for energy prices as well as the energy policy environment. It is very difficult to form a firm view on these very specific commercial decisions.

3.18. In order to capture this uncertainty we run two sensitivities around the Base Case. In particular, we recognise that it is possible for some new gas generation to become operational or to return to service towards the end of the period (high CCGT sensitivity). However, there is also downside risk (low CCGT sensitivity) that some of the older gas plants that are currently mothballed do not return to service, others close earlier than anticipated and no new CCGT plant get built over the analysis period.

3.19. The winter de-rated margin for the high and low CCGT sensitivities are presented in Figure 3.6. Both sensitivities are intended to reflect the uncertainty going forward surrounding decisions regarding new builds of CCGTs and the mothballing of plants. The de-rated margin at the lower end of the scale, ie 2015/2016, ranges between 3% and 5.4% depending on the sensitivity.

Figure 3.6 De-rated margins for Base Case (winter) and High and Low CCGT sensitivities



Interconnection

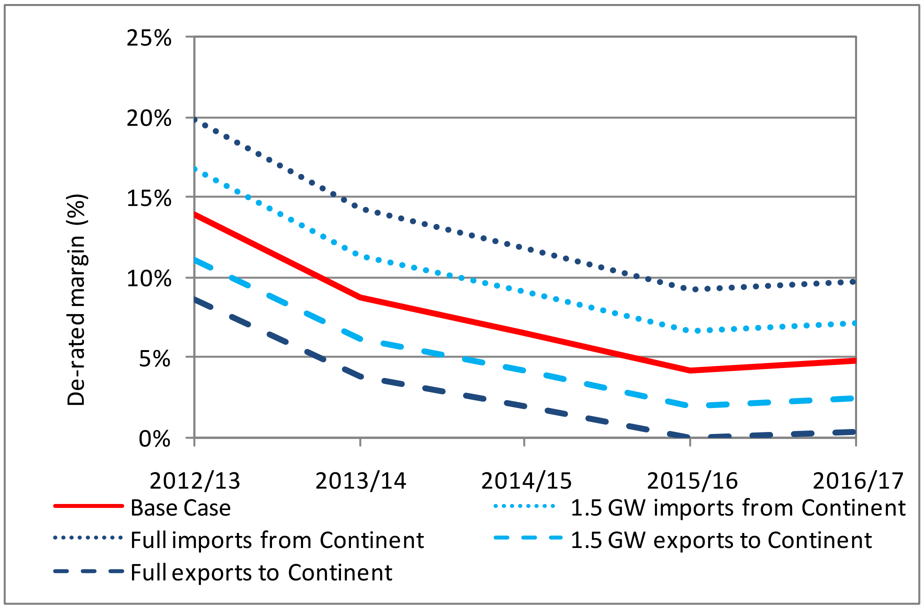
3.20. As we move to a more integrated European electricity market we will benefit from increased security through greater diversification of supply sources and interconnection. At the same time, GB will be exposed to risks from the actions of players beyond the control of the GB market.

3.21. Our Base Case takes a cautious approach to interconnector flows. In particular, we assume interconnectors to the Continent do not export or import at peak, whereas GB is exporting electricity to Ireland. Historically, GB has exported to Ireland at peak. Irish margins are expected to remain broadly flat over the coming years so this trend is likely to remain the same. On the other hand, interconnection flows with France and the Netherlands are less certain. It is therefore difficult to base future flows on historical patterns due to the high level of uncertainty in Europe.

3.22. France is facing increased risks over the next 4 years (due to LCPD closures and a high increase in peak demand). The Netherlands, despite healthy margins is facing constraint issues which may affect its availability to export. Due to this high uncertainty we have taken the cautious approach of assuming neutral interconnection with the Continent and presented sensitivities around interconnection flows.

3.23. Our interconnector sensitivities take into account potential exports and imports from the Continent at peak. The de-rated margins under these sensitivities are illustrated in Figure 3.7. Due to the large level of interconnection in GB (4 GW total), the range of potential de-rated margins is wide in 2012/2013, ie from 8.5% to 19.8% depending on the direction and size of flows. The Base Case assumes exports to Ireland and float with the Continent but in a shortfall situation, 2 GW of emergency services is assumed to be available from the interconnectors. These services would be used as a mitigating action ahead of customer disconnections.

Figure 3.7 Base Case and interconnection sensitivity de-rated margins



3.24. If GB experienced low capacity margins relative to neighbouring countries, wholesale electricity prices should rise to reflect scarcity of generation assets. This should provide incentives to generating companies abroad to sell energy to GB via the interconnectors. To the extent that companies could respond to these price signals, margins should recover to higher levels. In general, we would expect increases in the levels of interconnection to improve Britain's security of supply because of the benefits from being a part of a larger and more diverse electricity system.

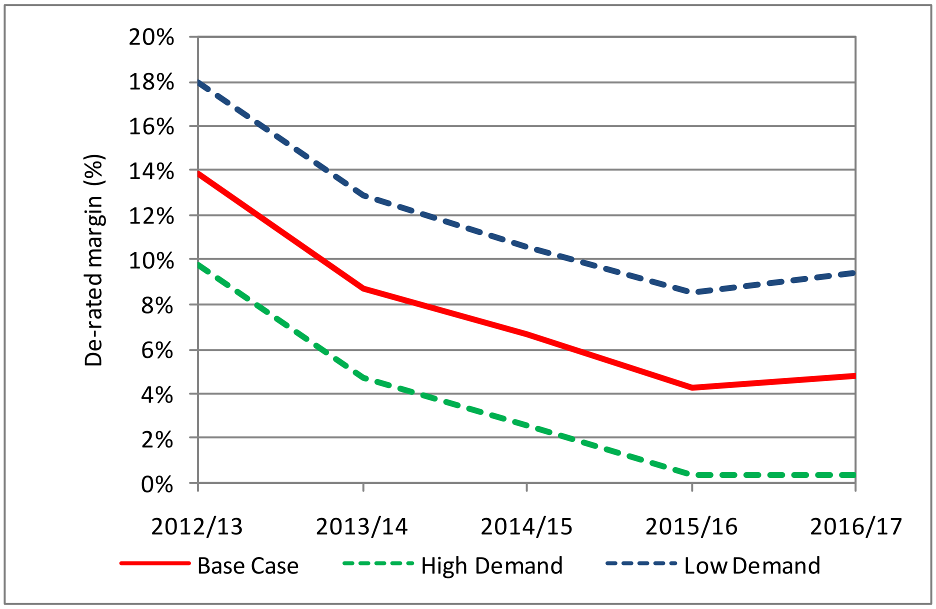
3.25. Sensitivities around interconnection create a band of approximately 4 GW around the Base Case. Thus, in 2015/2016, de-rated margins can reduce to approximately 0% or be as high as 9.2%.

Demand

3.26. The demand used in the modelling is Average Cold Spell (ACS) demand. This figure relates to winter peak demand under normal winter weather conditions. Demand for electricity primarily depends on economic growth and energy efficiency measures.

3.27. The high and low demand sensitivities we present here provide an inner and outer range of peak demands based on a range of factors, for instance prices, the economy etc. Peak demand could also be affected by the type of winter weather, eg mild or severe. To fully reflect the range of outcomes the high and low sensitivities range from 3 GW higher to 2.8 GW lower than Base Case demand.

Figure 3.8 Base Case and demand sensitivity de-rated capacity margins



3.28. The margins for the demand sensitivities are shown relative to the Base Case in Figure 3.8. In the High ACS peak sensitivity, the de-rated margin is 0.4% above peak demand in 2015/2016. In the low ACS peak sensitivity, the de-rated margin is 8.5% in 2015/2016. These sensitivities show how de-rated margins can be affected by a situation characterised by high economic growth and low penetration of energy efficiency measures and vice versa.

Supply

3.29. The de-rated margins have also been estimated for a range of supply sensitivities (such as sensitivities around plant availabilities, biomass conversions, or wind availabilities as described in Section 2). These results are presented in Appendix 1 but not discussed in detail here.

Gas stress test

3.30. The aim of the gas stress test is to analyse the impact of a drop in gas supplies to GB on de-rated generation capacity margins. Two tests are considered;

the potential impact on margins during an n-1 event[26], and how much gas could be lost from peak day deliverability before margins are impacted.

3.31. To work out any potential impact on capacity margins, we assess how much gas would be demanded from the power sector if all gas-fired generation was running (distillate back up is not considered). We then compare this with total peak day deliverability. Should peak day deliverability be lower than the combination of total demand from the non power sector and potential demand from the power sector, we believe this may impact on the de-rated capacity margin, as gas plant (which may be sitting idle) could not be utilised if called upon.

3.32. Our estimates show that the electricity capacity margins would only be impacted if GB faces a combination of significant infrastructure failures (eg no imports via the Norwegian pipeline) and supply shortages due to considerable tightness in world gas markets (eg limited LNG imports). Details of the data and results are presented in Appendix 2.

3.33. Section 3 presented the de-rated capacity margins for the Base Case as well as sensitivities for CCGTs, interconnection and demand. It also described the potential impact on margins of a shortage in gas supplies. The de-rated capacity margin is a good indication of the trend in security of supply over the next four years. However it is not a measure of the risk of supply shortfalls or the potential impacts on customers of such shortfalls. For this purpose, we use a probabilistic analysis which produces well established measures of risks. We then translate the results of this analysis into impacts on customers. These results are presented in Section 4.

[26] ie in the case of the loss of the largest piece of gas infrastructure.

4. Measures of risks and impacts on customers

4.1. The de-rated capacity margin projections in section 3 indicate that electricity security of supply is expected to reduce over the coming four years. In this section we assess the risk of supply shortfalls by using two well established probabilistic measures of security of supply:

- *Loss of Load Expectation* (LOLE) is the probability of demand being higher than available capacity in any year. This measure is expressed in hours per year.

- *Expected Energy Unserved* (EEU) is the corresponding volume of demand that is expected not to be met in any year. EEU combines both the likelihood and potential size of any supply shortfall.

4.2. We also describe the consequences of possible outage events by showing their potential magnitude expressed in equivalent numbers of households affected, and their frequency and duration.

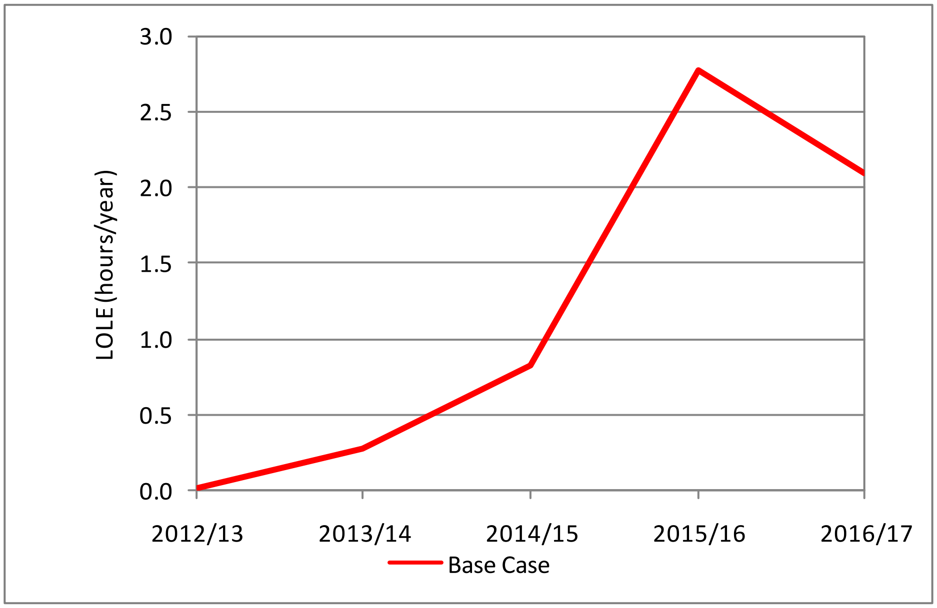
4.3. We start with the Base Case. In addition to presenting risks for GB as a whole, we also show how the risk of supply shortfalls is affected by the constraints in the transmission system between England and Scotland. We also present the risk metrics for summer. The impact of the uncertainty around our stochastic distributions on the Base Case's risk estimates is presented. Finally, we cover the results for the primary CCGT, interconnection and demand sensitivities. The results for the additional sensitivities can be found in Appendix 1.

Base Case

Measures of risk

4.4. 0 shows the LOLE in the Base Case. LOLE is very low in 2012/2013 (0.01 hours). LOLE increases in later years, corresponding to the declining de-rated margins as shown in Section 3. By 2015/2016 under the Base Case assumptions there is a statistical expectation that some level of supply shortfall will occur in 2.7 hours (i.e. 2 hours 42 minutes) during the winter. By 2016/2017, this risk has fallen back somewhat to 2.1 hours (i.e. 2 hours 6 minutes). For comparison purposes a LOLE of 2.7 hours is within the reliability standard used by other European countries such as France, Ireland and Belgium.

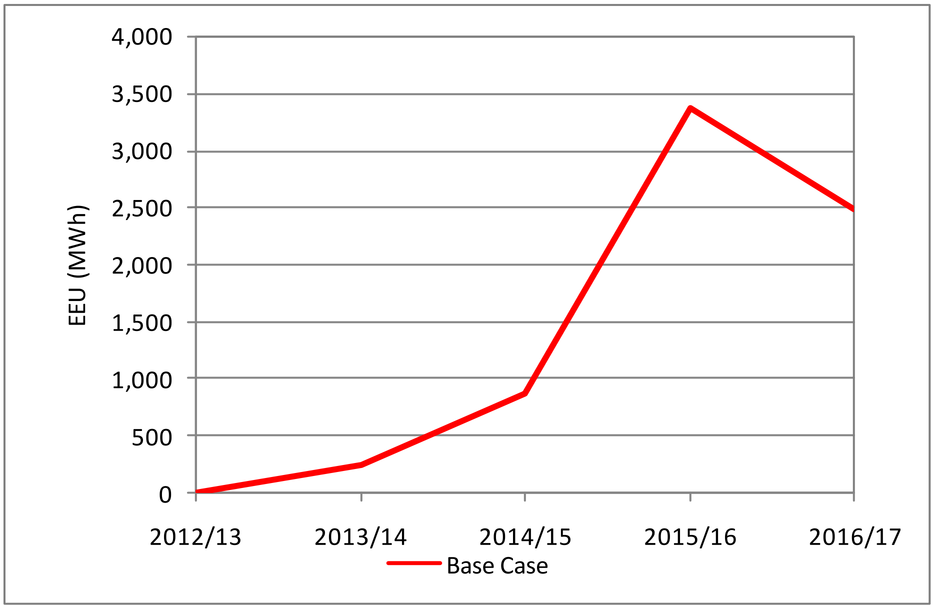
Figure 4.1 Base Case Loss Of Load Expectation (LOLE)



4.5. Figure 4.2 shows the Base Case estimate for EEU. EEU follows the same trend as LOLE, peaking in 2015/2016. EEU in 2015/2016 under the Base Case is approximately 3370 MWh. This number is relatively small compared to supply lost due to power cuts on the transmission and distributions networks, which in 2011 were around 11 GWh.[27]

[27] http://www.nationalgrid.com/NR/rdonlyres/54CF2C41-A1C5-45DD-AB31-2653615B1790/49386/NationalElectricityTransmissionSystemPerformanceReport2010201119.pdf

Figure 4.2 Base Case Expected Energy Unserved (EEU)



Impact of Cheviot boundary on capacity adequacy

4.6. When transmission constraints exist within a country, a situation could arise where nationally there is enough available generation capacity, but demand in an area of the country still cannot be met. This is because there may be insufficient transmission capacity to transfer power from the area with surplus generation to the one with a generation deficit.

4.7. Currently, there are a number of boundaries where constraints can occur even in the absence of transmission outages. The Cheviot boundary, between Scotland and England, is the constrained boundary expected to be most significant over the period covered in this report. Figure 4.3 shows the England and Wales (E&W) and Scotland (Sc) demand and installed capacity in each year, and the Cheviot boundary capacity. Although demand in the two areas remains approximately the same, generation capacity in Scotland increases mainly due to new wind capacity. England and Wales, though, experience a reduction in generation capacity primarily due to decommissioning of old plants.

Figure 4.3 Base Case E&W and Sc demand and installed capacity

	2012/13 (MW)	**2013/14 (MW)**	**2014/15 (MW)**	**2015/16 (MW)**	**2016/17 (MW)**
E&W Demand	50136	50250	50395	50517	50703
Sc Demand	5478	5484	5478	5468	5470
E&W installed capacity	70051	68261	68360	66728	67339
Sc installed capacity	11572	11249	11666	12618	13403
Cheviot boundary capacity (winter)	3300	3300	4300	6400	6400

4.8. We have undertaken an analysis considering the GB system as two interconnected regions: England & Wales and Scotland. The two region model estimates the increase in the risk metrics due to finite capacity of the Cheviot transmission link. This additional LOLE and EEU can be added to the single region estimate. The model is described in Appendix 3.

Figure 4.4 Base Case additional LOLE and EEU due to Cheviot boundary

	2012/13	**2013/14**	**2014/15**	**2015/16**	**2016/17**
GB LOLE	0.010	0.267	0.822	2.770	2.089
Extra LOLE	0.0001	0.0028	0.0010	0.0000	0.0000
GB EEU	8	255	874	3370	2494
Extra EEU	0.041	0.985	0.371	0.005	0

4.9. Figure 4.4 suggests that the Cheviot boundary does not have a significant impact on electricity security of supply for GB due to the planned investment in upgrading Cheviot’s capacity. We do not expect the Cheviot link to experience significant constraints when generation needs to be channelled from Scotland to England in order to serve an outage and vice versa.

Summer

4.10. Summer has historically been characterised by a very high level of capacity margin due to the lower peak demand. In the previous section we show that the same holds for the next four years. We have therefore taken a simplified approach to assessing the risks to security of supply. In particular, we extrapolate the relationship between de-rated margin and the risk measures, LOLE and EEU, by looking at the results for winter. We then apply this relationship to the summer de-rated margins to calculate the summer LOLE and EEU.

4.11. We conclude that for the Base Case, LOLE and EEU in all five summers are very low. In particular, the 2015/2016 summer margin of 8.6 GW is higher than the winter 2012/2013 margin of 7.9 GW. Therefore, LOLE for summer 2015/2016 should be below 0.6 minutes and outage events are expected to be less frequent than 1 in 3300 years.[28]

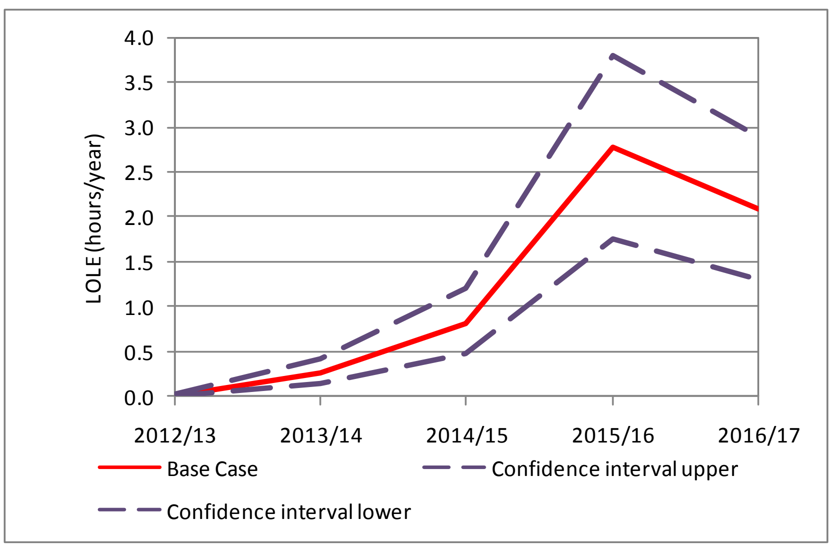
Uncertainty analysis: demand and wind confidence intervals

4.12. The Base Case estimates of LOLE and EEU depend on input assumptions (e.g. future installed capacity) and the stochastic distributions used for the analysis (e.g. demand variation). We have captured the uncertainty in input assumptions (eg generation capacity) by presenting results for a range of sensitivities.

4.13. With regards to the distributions used, we appreciate that future demand and wind distributions may vary from the historical distributions used for the modelling. This potential variance introduces some uncertainty around the Base Case risk estimates. This uncertainty can be estimated using a standard statistical technique known as bootstrapping. For more details on this technique, see Appendix 3.

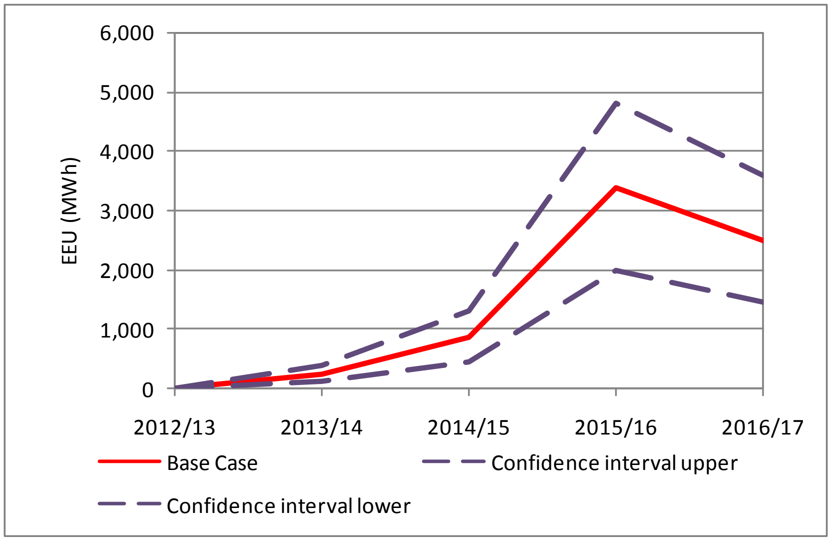
4.14. In the case of demand uncertainty, Figure 4.5 and Figure 4.6 show a range of LOLE and EEU around our Base Case estimates. The estimates suggest that in 2015/2016 LOLE in the Base Case could range between 1.8 hours per year and 3.8 hours per year. The EEU in the same year could range between 1990 MWh and 4820 MWh.

Figure 4.5 Base Case LOLE central estimate and confidence intervals



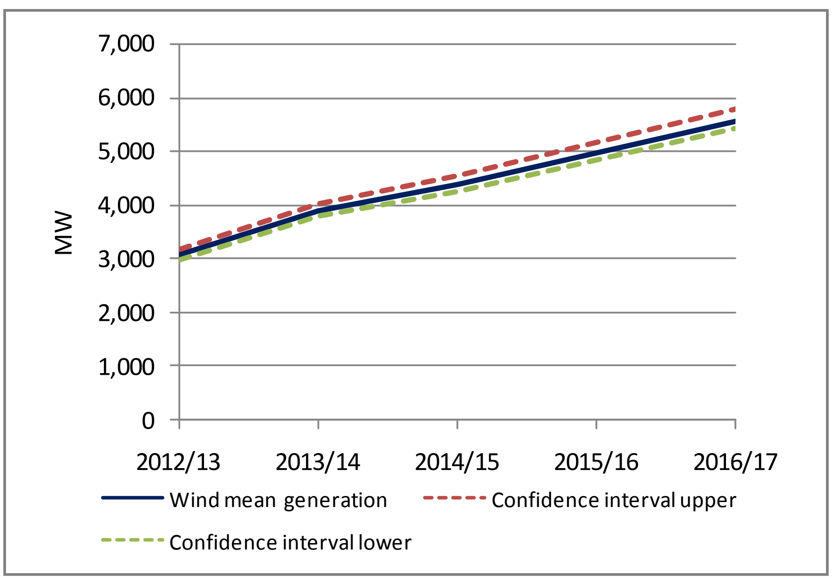
[28] To draw these conclusions about the absolute level of summer capacity adequacy based on modelling of the winter, we have to make the assumption that the characteristics of demand and generation capacity availability are sufficiently similar between the summer and winter. A combination of high levels of inflexible planned maintenance combined with low levels of wind output could lead to risks to capacity adequacy which are not captured by this analysis. Whilst this introduces some additional uncertainty, we can still conclude that the risk in the summer is likely to be very low in the Base Case.

Figure 4.6 Base Case EEU central estimate and confidence intervals



4.15. Figure 4.7 shows the uncertainty around wind output due to the distribution of wind. The mean value increases over the modelling period as the installed capacity of wind increases. The intervals are around 3% above and below the mean value. The uncertainty in the wind output has not been translated into ranges for LOLE and EEU[29] because of the small width around the wind output.

Figure 4.7 Base Case wind output estimate and confidence intervals



[29] Uncertainty may also arise due to errors in the wind speed data used and the transformation from wind speeds to wind output. However, we do not envisage this to materially affect the LOLE and EEU ranges presented here.

Impact on customers

4.16. In this section we translate the risk measures into tangible impacts for electricity customers. Outage events are rare and thus it is difficult to come to a view of how large and long an outage will be and what the impact will be on electricity customers. Therefore, our description of the impact of outages is based on judgement around how the electricity system would operate and the order and size of mitigation actions taken.

4.17. The system operator, National Grid, could take some mitigating actions in cases of supply shortfalls. Figure 4.8 shows the mitigating actions and their effect in terms of MW. When there is a short and small outage event the system operator can mitigate its impact by first reducing demand (ie voltage reduction). Once voltage reduction is exhausted it can aim to increase supply. This consists of two phases. First, the SO can instruct plants to generate at their maximum level. It can then also avail of emergency interconnection services.[30] The impact of these actions is not generally noticeable to electricity customers and they can be used concurrently. It is also worth noting that these mitigation actions only occur when a shortfall exists and as such are not included in the de-rated margin calculations.

Figure 4.8 Mitigating actions available to the system operator ahead of disconnections

Action	Comments	Assumed effect in MW
Voltage reduction	Reduce demand by instructing distribution network owners (DNOs) to reduce voltage	500
Maximum generation	Increase in supply by instructing generating plants to increase generation to maximum	250
Provision of emergency services through interconnection	Increase in supply through interconnection services with neighbouring countries (various services available, eg Emergency Instruction, Emergency Assistance and Cross-Border Balancing)	2000

4.18. The availability of the mitigating actions may be restricted to no more than a few hours. In addition, the effect of the maximum generation and the provision of emergency services from interconnection are dependent on the prevailing conditions of the electricity system on the day. For example maximum generation depends on how many plants are available to run on the day and whether they could be deployed quickly. At the same time emergency services via the interconnector depends on the prevailing circumstances of the neighbouring countries, eg France. If France experienced very low margins, then this level of services from the interconnectors could be reduced.

[30] Max gen is an instruction that the SO can issue to generators to generate at maximum output. The SO can also make use of the provision of emergency services via interconnectors.

4.19. Therefore, short and small outages could be managed by NGET with negligible effects on customers, eg dimming lights. On the other hand, in the case of larger and longer events the system operator may be forced into curtailing demand through controlled disconnections. In that case, industrial demand will be disconnected first, then household demand if the former is not sufficient.

4.20. Figure 4.9 shows the impact of potential outage events expressed in millions of households. The significant increase in LOLE will result in an appreciable increase in the risk of customers (industrial and households) facing disconnections. More specifically, in the Base Case where we assume 2 GW of emergency services from interconnection, the risk of disconnections increases from near zero levels in 2012/2013 to 1-in-12 years in 2015/2016. Were we to assume half the amount of emergency interconnector services (ie 1 GW) this figure would be 1-in-6 years.

Figure 4.9 Base Case event frequency and potential mitigation measures

	2012/13	**2013/14**	**2014/15**	**2015/16**	**2016/17**	**Mitigation options**
0-10 MW	1-in-7	3.7-in 1	11-in-1	33-in-1	33-in-1	no impact
10-500 MW	1-in-37	1-in-1.3	2.3-in-1	7.6-in-1	5.9-in-1	voltage reduction
500-750 MW	1-in-1,634	1-in-62	1-in-20	1-in-6	1-in-7.9	voltage reduction and max gen
750-2750 MW	1-in-837	1-in-32	1-in-10	1-in-3	1-in-4	voltage reduction, max gen and emergency services from interconnection
2750 + MW	1-in-3,307	1-in-126	1-in-41	1-in-12	1-in-16	controlled disconnections

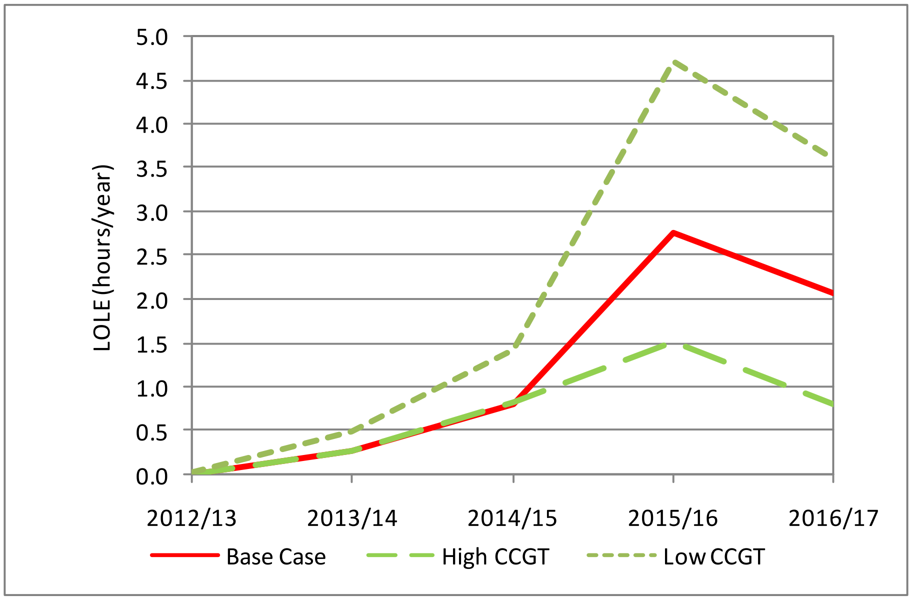
Sensitivities

4.21. This section presents the risk metrics and the impact on customers for the sensitivities around CCGTs, interconnection and demand assumptions. Details on the assumptions and results for the full list of sensitivities can be found in Appendix 1.

CCGTs

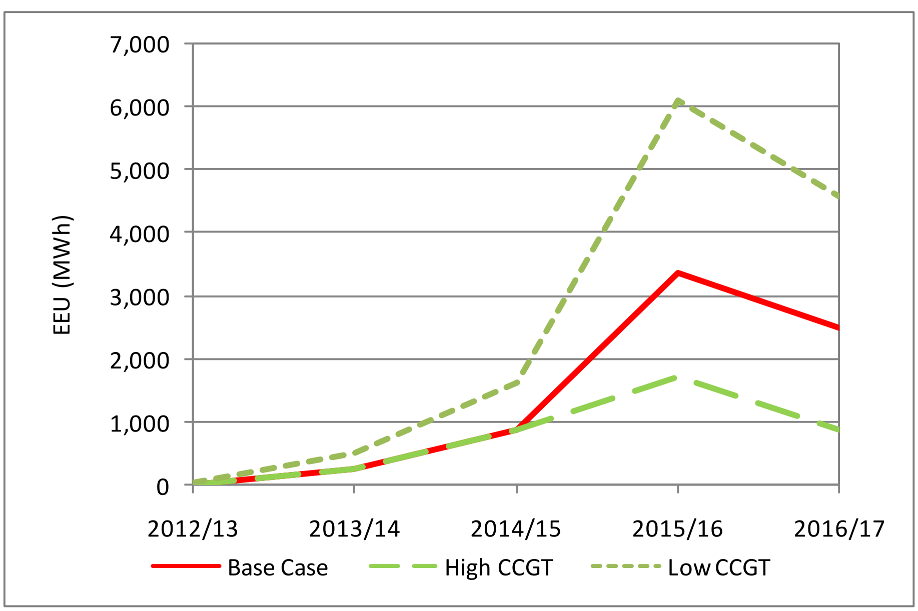
4.22. In this section we present the CCGT sensitivities, which reflect the uncertainties around mothballing decisions and new plants builds. The high CCGT sensitivity assumes approximately 0.9 GW of plants return to the market from mothballing (2015/2016) and approximately 0.5 GW of new CCGT build (2016/2017) compared to the Base Case. The low sensitivity assumes no new CCGT plants get built over the period, and plant which get mothballed at the beginning of the period return to service when margins get tight.

Figure 4.10 Base Case and CCGT sensitivities Loss Of Load Expectation (LOLE)



4.23. Figure 4.10 shows the LOLE in the Base Case and the CCGT sensitivities. The figure illustrates the significant impact commercial decisions with regard to CCGT investment and mothballing can have on security of supply. The LOLE in 2015/2016 could vary from a low of 1.5 to a high of 4.7 hours depending on the sensitivity examined. Figure 4.11 shows the estimated EEU for the CCGT sensitivities. Similarly, the EEU can vary from 1717 MWh to 6094 MWh in 2015/2016 depending on the sensitivity.

Figure 4.11 Base Case and CCGT sensitivities Expected Energy Unserved (EEU)



Interconnection

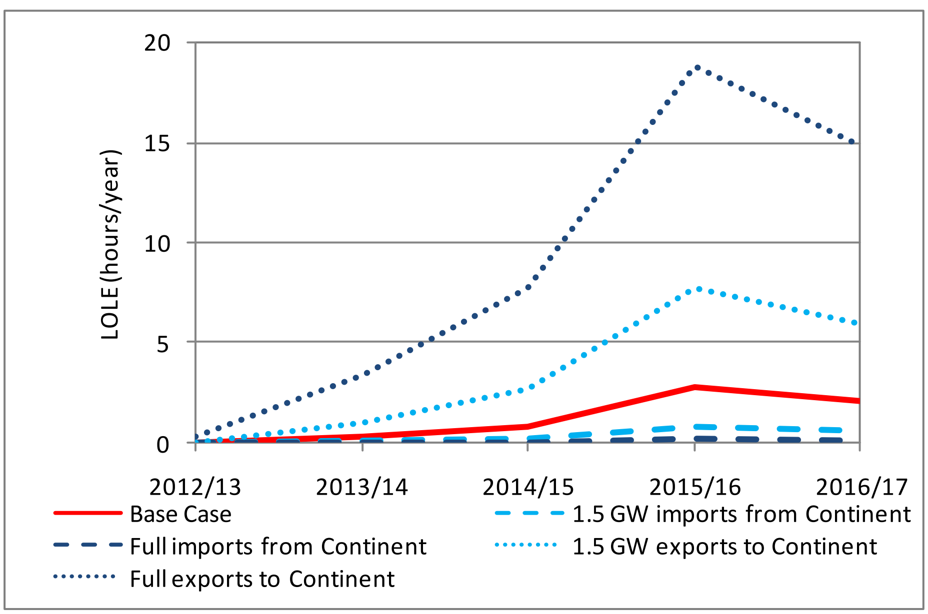
4.24. In general, we would expect increases in the levels of interconnection to improve Britain's security of supply because of the benefits gained from being a part of a larger and more diverse electricity system. In particular, if GB experienced an outage event, wholesale electricity prices should rise to reflect scarcity of generation assets. This should in turn provide incentives to generating companies abroad to sell energy to GB via the interconnectors, which should help in relieving the shortfalls.

4.25. In our Base, we assume interconnectors to the Continent do not export or import at peak. In addition, we assume exports to Ireland of 950 MW in a first instance and 760 MW (from 2016/2017). When estimating the risk of disconnections, we also take into account the provision of various emergency interconnector services (2 GW in the Base Case) that the GB system operator can make use of in case of a shortfall.

4.26. We explore four sensitivities which cover a wide range of Continental interconnector flows from 3 GW exports to 3 GW imports.

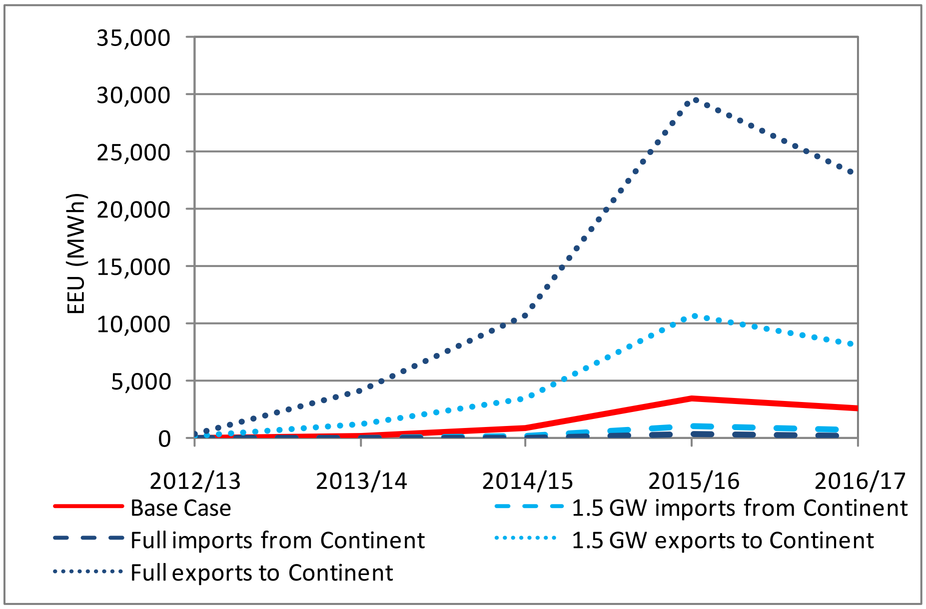
4.27. The LOLE results for these sensitivities are shown in Figure 4.12. The swing from 3 GW Continental imports to 3 GW Continental exports moves the GB system from a very low LOLE of 0.21 hours in 2015/2016 to a higher LOLE of 18.5 hours in 2015/2016.

Figure 4.12 Base Case and interconnector sensitivities LOLE



4.28. In EEU terms, full exports to the Continent would raise the expected energy unserved to 29658 MWh in 2015/2016. On the other hand, 3 GW of imports from Europe reduce EEU to a level of 205 MWh as shown in Figure 4.13.

Figure 4.13 Base Case and interconnector sensitivities EEU

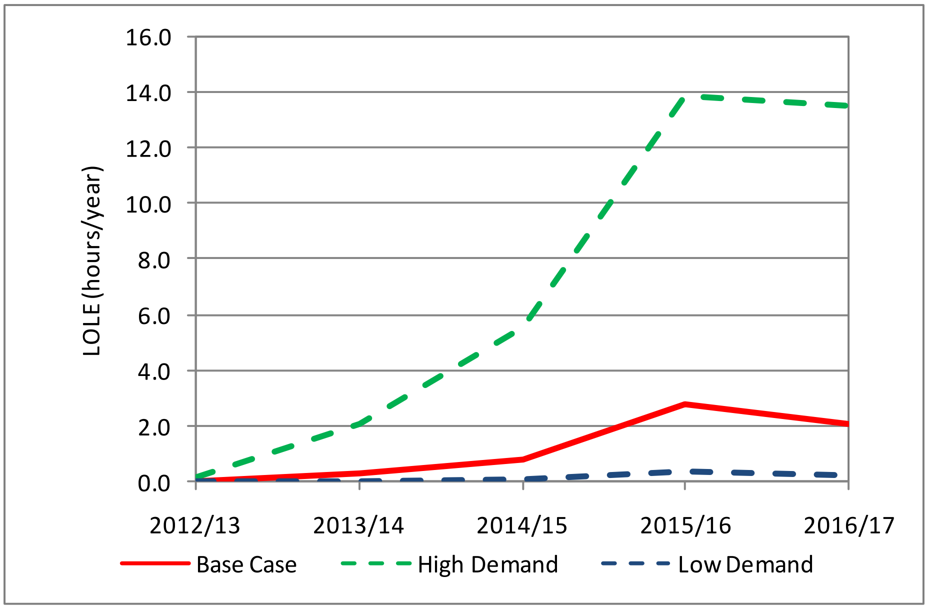


Demand

4.29. Demand for electricity depends on a range of factors such as economic growth and energy efficiency measures. Peak electricity demand could also be affected by the type of winter experienced, eg mild or severe. The high and low demand sensitivities provide an inner and outer range of peak demands due to these factors. To fully reflect the range of demand outcomes the high and low sensitivities range from 3 GW higher to 2.8 GW lower than the Base Case demand assumptions.

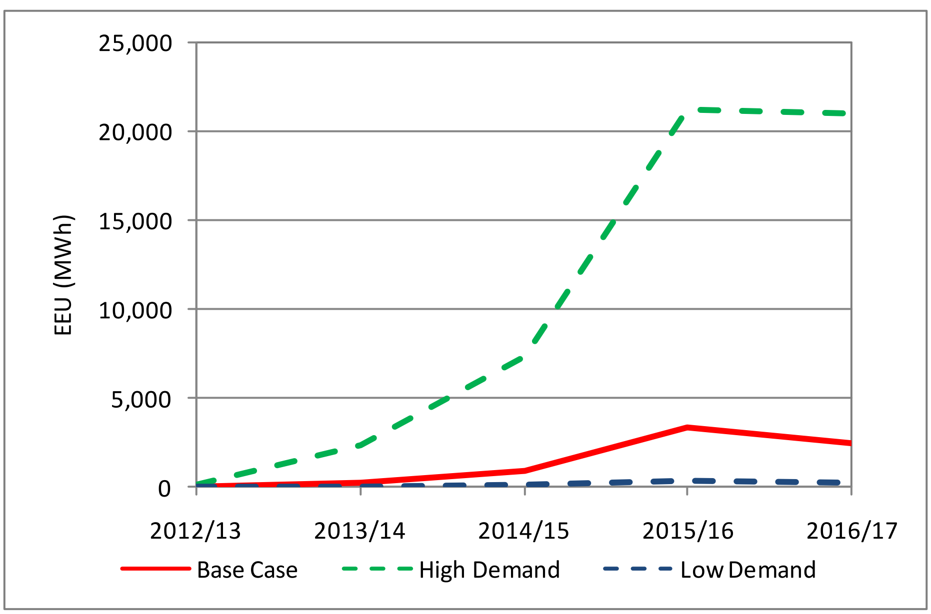
4.30. LOLEs for the two demand sensitivities are shown in Figure 4.14. In the High Demand sensitivity, the LOLE reaches a peak of 13.8 hours in 2015/2016. This is 5 times greater than under the Base Case. Under the Low Demand sensitivity, the LOLE is low throughout, reaching a peak of 0.32 hours in 2015/2016.

Figure 4.14 Base Case and demand sensitivities LOLE



4.31. EEU for the two demand sensitivities is shown in Figure 4.15. The trend is very similar to the trend in LOLE. In the High Demand sensitivity, the EEU reaches a peak of 21281 MWh in 2015/2016. Under the Low Demand sensitivity, the EEU is low throughout, reaching a peak of 319 MWh in 2015/2016.

Figure 4.15 Base Case and demand sensitivities EEU



Impact on customers

4.32. Figure 4.16 summarises the probabilities of disconnections for the above sensitivities.[31] High demand and maximum exports to Europe are the most risky of all sensitivities. We estimate that disconnections of electricity customers can occur as frequent as 1-in-2.4 years. At the other end of the spectrum, in the case where electricity demand is kept subdued, the risk of disconnections falls to 1-in-102 years.

Figure 4.16 Probability of disconnections across sensitivities in 2015/2016

Sensitivity	Probability of disconnecting electricity customers in 2015/16 (1-in-x years)
Base Case	1-in-12
High CCGT	1-in-22
Low CCGT	1-in-7
Maximum exports to Europe	1-in-4
Medium exports to Europe	1-in-8
Medium imports from Europe	1-in-33
Maximum imports from Europe	1-in-52
High demand	1-in-2.4
Low demand	1-in-102

[31] The assumptions on the availability of interconnectors to provide emergency services vary depending on the scenario. For instance, in the case of full imports from the Continent, only 0.5 GW is assumed to be available (from Ireland) and when assuming full exports to the Continent 3 GW is assumed to exist.

Appendices

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Appendix 1 – Additional sensitivities

1.1. This appendix contains details for additional sensitivities which are not covered in the main body of the report. We describe the assumptions and results for each sensitivity. The sensitivities are:

- Winter Outlook Report (WOR) availabilities
- Reduced CCGT availability
- Lower wind at peak
- Biomass conversion not relicensed
- No single largest infeed loss
- No exports to Ireland
- National Grid's Gone Green 2012 (provisional)

Assumptions

1.2. The **WOR sensitivity** puts the analysis on a more comparable basis with the published WOR 2011/12. It indicates the sensitivity of the LOLE and EEU results to availability assumptions for non-wind generators.

1.3. The availabilities used in the WOR sensitivity are shown in Figure A1.1. The method for estimating availabilities for the WOR is similar to the method used in this study for the Base Case, but differs in some of the assumptions.

Figure A1.1 Base Case and WOR availabilities

Fuel Type	Capacity Assessment	WOR
Coal (and Biomass)	87%	86%
Gas CCGT (and CHP)	86%	89%
OCGT	77%	98%
Hydro	92%	70%
Pumped Storage	95%	96%
Nuclear	83%	83%
Oil	81%	70%

1.4. **Reduced CCGT availability:** this sensitivity explores the impact on capacity adequacy if the rate of unplanned (forced) outages for CCGTs increases as a result of changing operational patterns. In future CCGTs may be required to change output levels more frequently and start and stop more often. In this sensitivity we assume that the mean availability for CCGTs reduces by 1% per annum, such that in 2016/2017 the availability is 4% less than in the Base Case.

1.5. **Lower wind at peak:** this sensitivity scales down the distribution of wind output by 25% compared to the Base Case. For the Base Case and the main sensitivities we have assumed that wind and demand are independent at peak times as there is no strong evidence of a dependency, or of the form of any dependency. This sensitivity tests the effect of relaxing this assumption by assuming wind is less available at times of peak demand.

1.6. **Biomass conversion not relicensed:** this sensitivity reduces installed capacity in 2015/2016. It assumes a converted LCPD opt out plant is unable to relicense and does not continue operating after 2015/2016. This is a reduction of approximately 750 MW in 2016/2017.

1.7. **No single largest infeed loss**: this is a sensitivity which ignores the requirement to hold reserve for response to cover for the single largest infeed loss. This enables quantification of the impact of this assumption on the adequacy measures. This sensitivity is reflected in the modelling by removing the Base Case capacity adjustment of 700 MW up to 2013/2014 and 1572 MW thereafter.

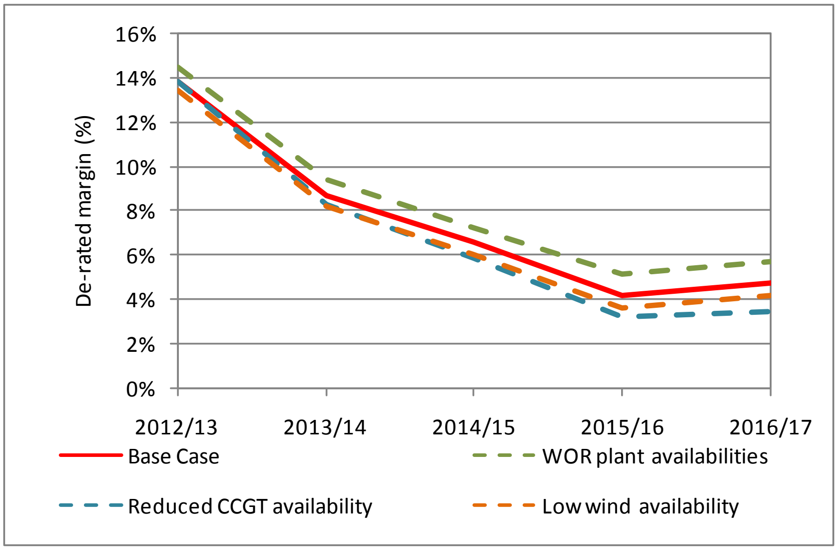
1.8. **No exports to Ireland**: this sensitivity assumes that GB interconnection with Ireland is at float (ie no exports and no imports). This results in an increase of 950 MW until 2015/2016 and of 760 MW in 2016/2017.

1.9. **Gone Green 2012 (provisional)**: this sensitivity uses the generation background from the provisional Gone Green 2012 scenario provided by National Grid specifically for the capacity assessment project. The main differences in assumptions relate to public announcements regarding mothballed plant and early closures which were made after the provision of the assumptions. Other differences include assumptions regarding dates relating to new build plant coming online and the return of mothballed plant later in the period.

Results – availability sensitivities

1.10. Three of the additional sensitivities (WOR, wind and lower CCGT) relate to availability assumptions. The results for these are presented here. The de-rated margins for the availability sensitivities are shown in Figure A1.2. The Winter Outlook Report availabilities produce an increase in margin from 4.7% to 5.7% in 2016/2017. The sensitivities relating to CCGT and wind availability produce reductions in de-rated margin which (by coincidence) are very similar to each other. In 2015/2016 the de-rated margin in the low wind sensitivity is 3.6% and in the CCGT low availability sensitivity it is 3.2%. Whereas CCGT availability is reduced by just 1% per annum, wind availability is reduced by 25% to achieve the same result. The de-rated margin is more sensitive to changes in CCGT availability because of the higher installed capacity of CCGT and the wind EFC of approximately 22% compared to CCGT availability of 86%.

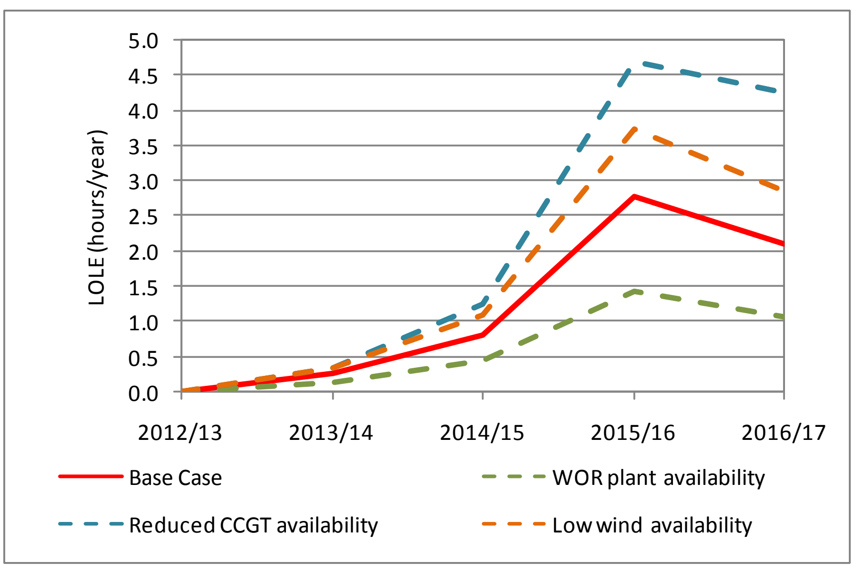
Figure A1.2 De-rated margins for Base Case and availability sensitivities



1.11. As a group, these sensitivities create a relatively narrow range in results. Given the uncertainty in availability assumptions, it would be possible to consider more extreme variations which would give a wider range of de-rated margins.

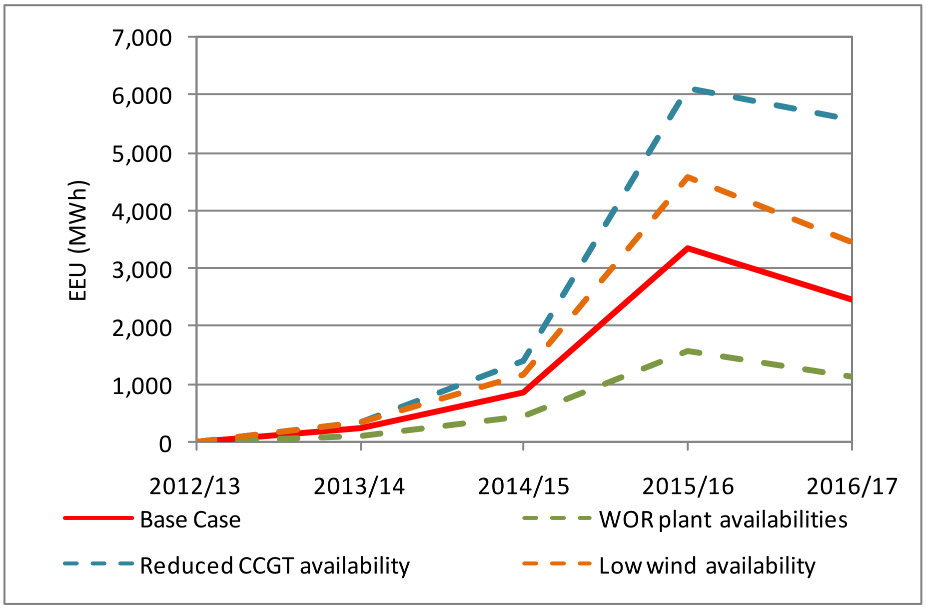
1.12. Figure A1.3 shows the LOLE for the availability sensitivities. The LOLE is approximately half the Base Case level when WOR availabilities are used. This shows that changes in these input assumptions do have a material impact on the LOLE result. The increases in LOLE for the Reduced CCGT availability and Lower wind sensitivities are almost identical throughout the period, mirroring what is observed for the de-rated margins.

Figure A1.3 LOLE for Base Case and availability sensitivities



1.13. Figure A1.4 shows the EEU for the availability sensitivities. The results show similar trends to the LOLE results. Note that EEU under the Reduced CCGT availability sensitivity is nearly double the Base Case EEU in 2015/2016.

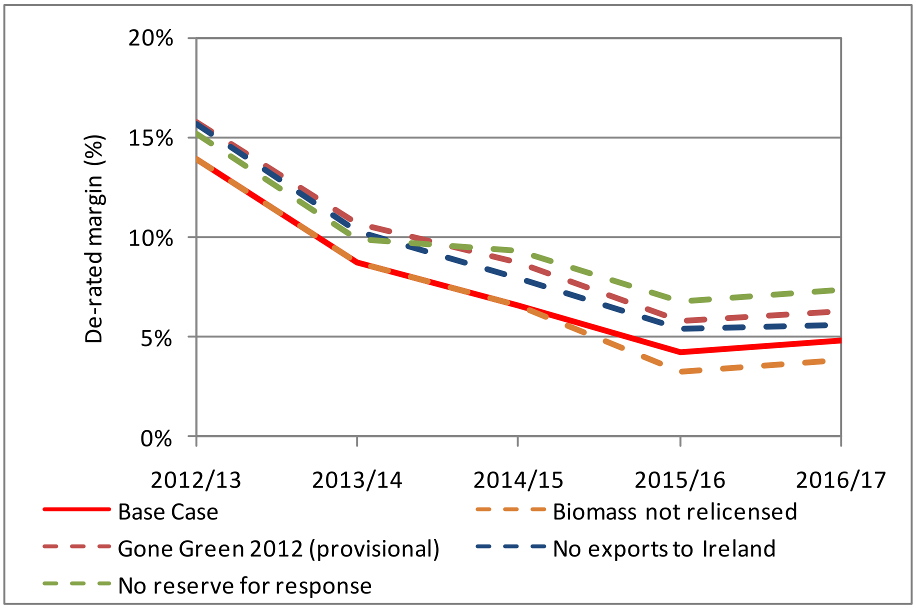
Figure A1.4 EEU for Base Case and availability sensitivities



Results – other sensitivities

1.14. Four additional sensitivities have been run. The de-rated margin results for these sensitivities are presented in Figure A1.5 below. The `no reserve for response' sensitivity increases the de-rated margin by about 1% in 2012/2013 and 2013/2014 and by 2.5% thereafter. Similarly the `Gone Green 2012 (provisional)' and `no exports to Ireland' sensitivities also increase the de-rated margin compared to the Base Case. The increase ranges between 0.8% and 2% depending on the year and sensitivity. Biomass not relicensed is the only sensitivity which results in lower margin estimates. The margin in 2015/2016 is 3.2% in this sensitivity compared to 4.2% in the Base Case.

Figure A1.5 De-rated margins for Base Case and other sensitivities



1.15. Figure A1.6 and Figure A1.7 show the LOLE and EEU results for the other sensitivities. The results follow the trend in the de-rated margins. Note that in 2016/2017, small differences in the de-rated margin translate into appreciable differences in LOLE and EEU.

Figure A1.6 LOLE for Base Case and other sensitivities

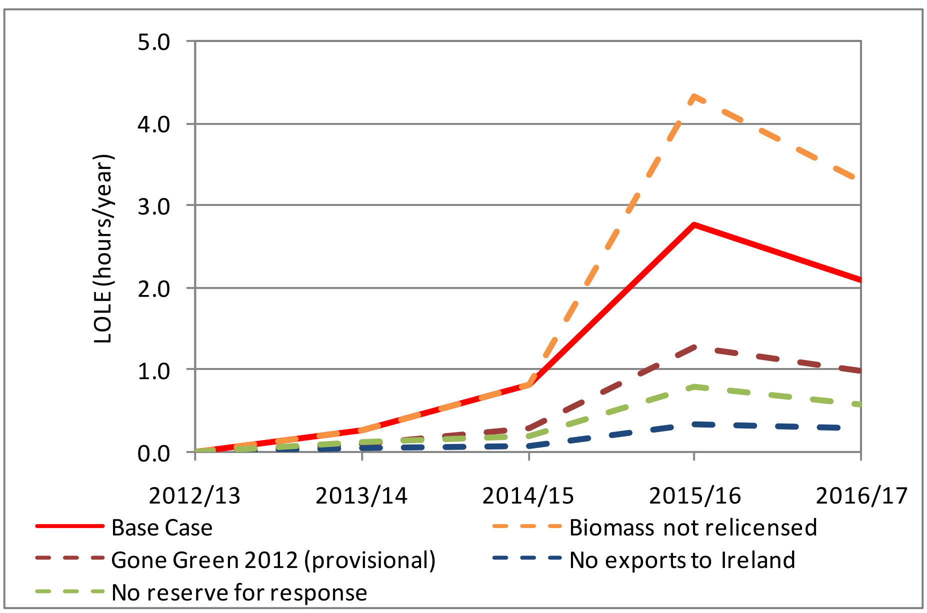
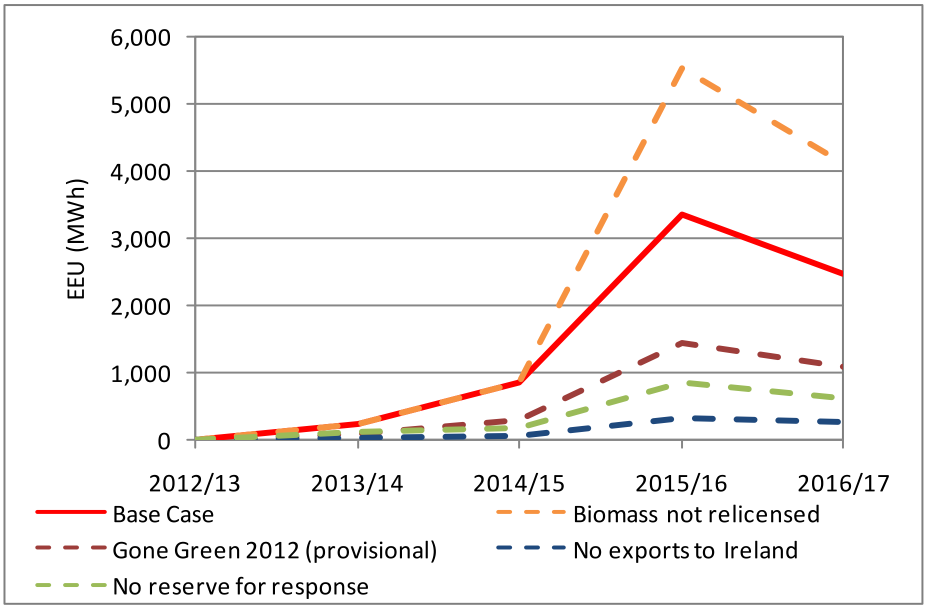


Figure A1.7 EEU for Base Case and other sensitivities



Appendix 2 – Gas stress test

Aim

1.1. The aim of the stress test is to analyse the impact of a drop in gas supplies to GB on de-rated generation capacity margins. Two tests are considered; the potential impact on margins during an n-1 event, and how much gas could be lost from peak day deliverability before margins are impacted.

Methodology

1.2. To work out any potential impact on capacity margins, we assess how much gas would be demanded from the power sector if all gas-fired generation was running (distillate back up is not considered). We then compare this with total peak day gas deliverability. Should peak day deliverability be lower than the combination of total demand from the non power sector and potential demand from the power sector, we believe this may impact on the de-rated capacity margin, as gas plant (which may be sitting idle) could not be utilised if called upon.

1.3. To undertake both of these stress tests, assumptions must be made to produce an estimate for total potential gas demand from the power sector. To do this, we utilise data from National Grid (for the generation background) and Mott MacDonald (who provide estimates of efficiency for all plant currently connected to the grid). We combine these figures to create a fuel used metric by:

- Multiplying capacity by 24 (to give energy generated in GWh)
- Multiplying by 1/plant efficiency (to obtain fuel used in GWh)
- Multiplying by assumed availability (85%)

1.4. Any new CCGT plant is assumed to be 52% efficient. Plants are assumed to be running at a consistent load throughout the day. This provides us with the demand figures in Figure A2.1.

Figure A2.1 Potential demand for gas

MCM/day	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17
Potential demand from power (GG 2012 prov)	124.52	128.74	129.14	130.28	130.28	136.89	136.03
Total demand from Non Power (GG 2011 TYS)	440.94	433.76	423.80	414.49	408.46	397.69	389.30
Total demand (Potential Power + Non Power)	**565.46**	**562.49**	**552.94**	**544.76**	**538.74**	**534.57**	**525.33**

Test 1: n-1

1.5. Utilising the figures derived above, we can compare total potential demand (potential power *plus* forecast non power demand from the TYS) against total peak supply availability. The results below (Figure A2.2) show that in an n-1 scenario, generation margins will not be impacted due to a reduction in gas availability.

Figure A2.2 Supply surplus (n-1) against total potential demand

MCM/day	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17
Peak Supply Availability (GG)	672.88	660.79	698.36	713.81	713.68	715.24	718.20
Peak Supply Availability (GG) n-1[32]	602.88	590.79	612.36	627.81	627.68	629.24	632.20
Supply surplus (n-1) against total potential demand	**37.42**	**28.30**	**59.42**	**83.05**	**88.94**	**94.67**	**106.87**

Test 2: Potential gas losses before capacity margins are hit

1.6. An extension of this analysis is to assess how much peak day gas availability could be lost before potential demand for gas from power could not be served.

Figure A2.3 Total surplus supply against total potential demand

MCM/day	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17
Peak Supply Availability (GG)	672.88	660.79	698.36	713.81	713.68	715.24	718.20
Supply surplus against total potential demand	107.42	98.30	145.42	169.04	174.94	180.67	192.87

1.7. Figure A2.3 shows that under these assumptions just under 100 mcm/day of availability would have to be lost before generation capacity margins were impacted by a loss of gas on the system.

[32] n-1 taken as Langeled or IUK (70 mcm/day) up to 2011/12, Milford Haven (86 mcm/day) from then on.

Appendix 3 – Probabilistic analysis

1.1. In this appendix we describe the modelling approach. We first give an overview of the modelling, and then give a description of the model design and structure, including the source of key assumptions. A short overview of the wind modelling methodology is also included in this appendix. A more detailed discussion is given in Appendix 4.

Aims and overview of modelling

1.2. The aim of the study is to produce a range of forecasts of electricity de-rated margins, and for each forecast estimate the risk that there is not sufficient capacity to meet electricity demand.

Sensitivity development

1.3. A key part of this study has been to develop a Base Case view of the future electricity demand and supply background over the next five winters. This Base Case covers assumptions on:

- Electricity demand at ACS peak
- Installed generation capacity, including new builds, retirements and mothballing
- Interconnector capacity and import/export at peak
- Generator availabilities

1.4. A set of sensitivities has also been developed to test the impact on capacity adequacy of key uncertainties in the Base Case sensitivity assumptions.

1.5. Each sensitivity is used as an input to the probabilistic model, described below.

Probabilistic model

1.6. In normal circumstances there is a margin of spare generation capacity over electricity demand. The risks of supply shortfalls due to inadequate capacity occur at the extremes of high demand and/or low availability of generation capacity. We therefore take a probabilistic approach, using recent history to estimate the possible ranges of electricity supply and demand. We apply these distributions to sensitivity views of future capacity and electricity demand.

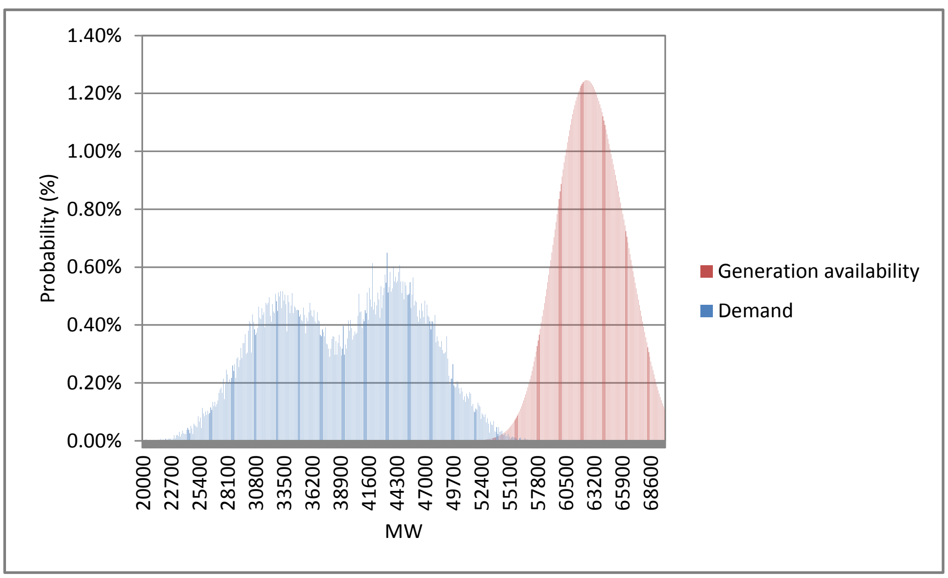
1.7. The constructed model is a probabilistic model of capacity adequacy in the GB electricity market. Given an input scenario of peak electricity demand and installed capacity, the model estimates the future distributions of electricity demand and generation capacity availability. By combining these two distributions, the model calculates the probability of electricity demand exceeding available generation capacity, for the five winters from 2012/2013 to 2016/2017.

1.8. The distribution of demand is based on recent historical half hourly demand for electricity on the system, for the winters 2005/06 to 2011/12. This distribution is adjusted for the scenario assumption on peak demand in each winter.

1.9. The distribution of future generation capacity availability is built up from two distributions with distinctly different characteristics. The conventional (non-wind) capacity distribution is calculated using the installed capacity and the mean winter availability of each generating unit. The mean availability has been estimated from 6 years of historical data, covering the period 2005/06 to 2010/11. The distribution of wind output availability is calculated from historical wind speed data covering the period 1979-2011 for current and future GB wind farm locations.

1.10. Figure A3.1 shows a schematic representation of the combination of distributions of supply and demand. The mean of the generation capacity availability distribution is higher than the mean of the demand distribution. There is a high, but not 100%, probability that supply exceeds demand.

Figure A3.1 Schematic diagram of electricity demand and capacity distributions



1.11. The model calculates two well-established metrics of security of supply, the Loss of Load Expectation (LOLE) and the Expected Energy Unserved (EEU). LOLE is the expected number of hours per year for which supply does not meet demand in any year. Expected Energy Unserved (EEU) is the corresponding volume of demand that is expected not to be met during the year. Thus, EEU combines both the likelihood and potential size of any supply shortfall.

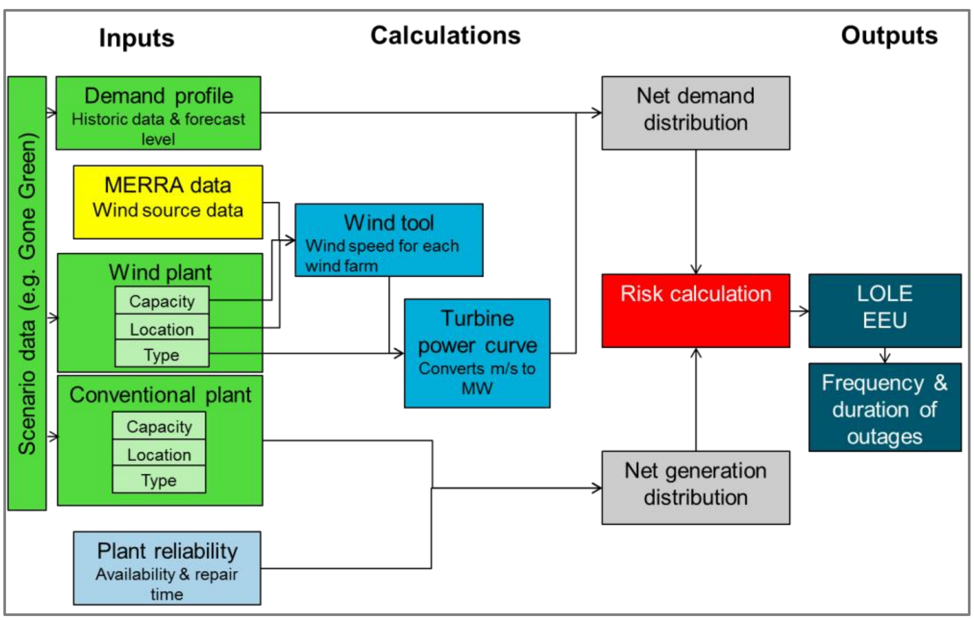
1.12. The model considers only the risks from a shortage of available capacity to meet demand. There are other reasons why electricity consumers might experience disruptions to supply, which are out of the scope of this assessment and thus not captured by this model, such as:

- **Flexibility**. The ability of generators to ramp up in response to rapid increases in demand or decreases in the output of other generators.
- **Insufficient reserve**. Unexpected increases in demand or decreases in available capacity in real time which must be managed by the System Operator through procurement and use of reserve capacity.
- **Network outages**. Failures on the electricity transmission or distribution networks
- **Fuel availability**. The availability of the fuel used by generators. In particular the security of supplies of natural gas at times of peak electricity demand. The gas stress test (Appendix 2) provides a separate analysis of this issue.

Model design and structure

1.13. A bespoke model has been designed and built for this study, based on the principles described above. Figure A3.2 is a schematic representation of the model structure, showing inputs, calculations, and outputs. We give a brief description here, with each component described in more detail in the following sections.

Figure A3.2 Model structure



1.14. The model inputs consist of the scenario views of future supply and demand backgrounds. This includes future demand distributions and levels, the capacities of generators and interconnectors, conventional generator availabilities, and the historical wind speed data.

1.15. There are two major calculation modules. The first deals with the construction of the wind distribution, and the second does the calculations of the security of supply metrics. These are covered in more detail in the relevant sections below.

1.16. The outputs are the LOLE and EEU results and the additional metrics of the frequency and duration of outages.

1.17. In addition, we calculate a commonly used indicator of security of supply: the de-rated capacity margin. The de-rated margin represents the excess of available generation capacity to Average Cold Spell (ACS) peak demand and is expressed in percentage terms. Available generation takes into account the contribution of installed capacity at peak demand by adjusting it by the appropriate de-rating factors.

Assumptions

Figure A3.3 Summary of common assumptions and data sources

Assumption	Source
Demand distribution	Historical Indicative Demand Outturn (INDO) data for 2005/06 to 2011/12 for the period in which GB is on Greenwich Mean Time. INDO data has been available since the formation of the GB BETTA[33] market in 2005. Defines the demand profile.
ACS Peak demand	Sensitivity variable. For Base Case, source is NGET provisional work for Future Energy Scenarios. Defines the overall level of demand growth.
Installed capacity	Sensitivity variable. For Base Case, the primary source is NGET provisional work for Future Energy Scenarios with some changes in assumptions. This provides the full portfolio of installed capacity for the next 5 winters.
Embedded wind capacity	NG provisional work for Future Energy Scenarios.
Conventional plant availability	Analysis of historical Maximum Export Limit (MEL) data and planned outage data.
Wind speed data	MERRA re-analysis data set.
Wind turbine power curves	Manufacturer data. Taken from publically available specifications.
Wind farm locations	NGET internal research.
Interconnector capacities	NGET provisional work for Future Energy Scenarios.
Interconnector peak flow	Sensitivity variable.
Demand Side Response	Current levels of DSR. DSR already exists in historical demand distribution data.

[33] British Electricity Trading Transmission Arrangements.

Demand

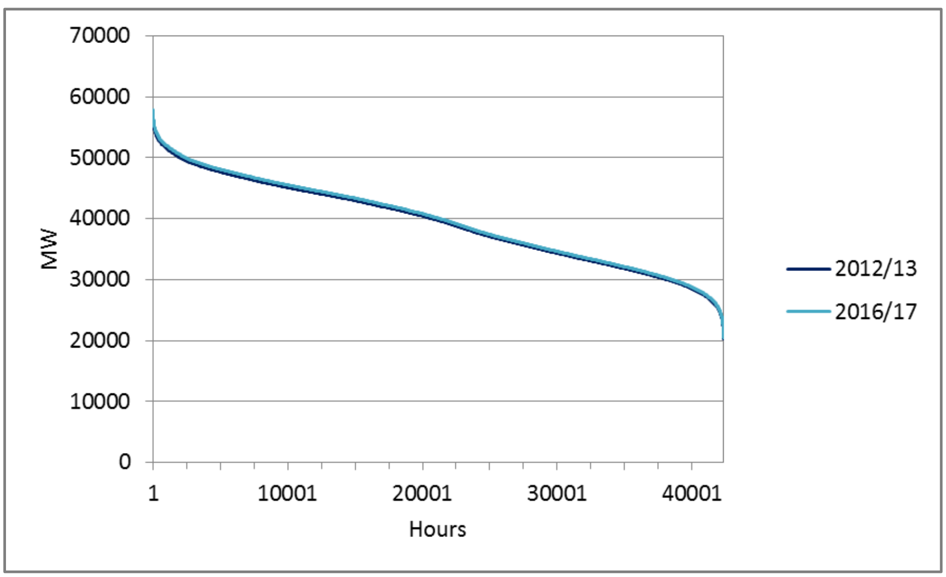
1.18. The starting point for the distribution of demand is the historical half hourly demand of the previous six winters (2005/06-2011/12). This data is the Indicative Demand Outturn (INDO) data, available for GB as a whole since the introduction of the British Electricity Trading Arrangements (BETTA) in 2005.

1.19. The distribution of each historical winter is rebased against the ACS peak demand value for that historical year.

1.20. For each historical year, the generation from embedded wind has been estimated using the wind model and added onto demand. The purpose of this is to allow all wind (both embedded and transmission connected) to be modelled explicitly on a consistent basis in the model.

1.21. To account for overall growth in demand, the distribution is scaled by the forward looking assumptions for ACS peak. Figure A3.4 shows the demand distribution for Base Case 2012/2013 and 2016/2017[34], as a Load Duration Curve.

Figure A3.4 Demand distribution Base Case 2012/2013



1.22. For each of the five future years, the highest demand in the distribution is higher than the quoted ACS peak demand, by about 1.8 GW. The difference exists for two reasons. Firstly, ACS peak does not represent the outturn peak in any one year. ACS peak demand is a value that is calculated to remove the effects of weather fluctuations on peak demand. To calculate the ACS demand, the actual peak value is adjusted to the demand that would have been expected in an average

[34]The highest value in the demand distribution is higher than the assumed ACS peak.

cold spell. If the peak day is colder than the average cold spell, then the outturn peak will be higher than the reported ACS value.

1.23. Secondly, the demand distribution used in the model included demand met by embedded wind, and so is higher than the ACS peak which does not include embedded wind.

1.24. The demand distribution for each of the future years is a direct input to the risk assessment calculation.

Conventional capacity

1.25. For the purposes of this study, when we refer to conventional generation capacity we mean the non-wind generators connected to the GB transmission system.

1.26. A standard approach to modelling the availability of conventional generators is to treat each generator as being either fully available or completely unavailable. Each generator is assigned a probability of being available, estimated from historical data.

1.27. The exception is for CCGTs which contain multiple Gas Turbine (GT) units. In this case, the failure of each GT unit has been modelled individually.

1.28. The availability assumptions for each generator type are estimated from analysis of historical availability as submitted by generators to National Grid. The data used is the Maximum Export Limit (MEL) submitted by generators for the six winters from 2005/06 to 2011/12.

1.29. The MEL data submitted by generators is commercial and a generator may declare itself unavailable for a number of reasons. There may be a planned maintenance outage, or a forced (unplanned) outage, or commercial reasons not directly related to technical availability. We assume that at times of system stress generators will only declare themselves unavailable if they are in fact technically unavailable.

1.30. The proportion of this unavailability that is due to planned maintenance was identified. On the assumption that under current market conditions this planned maintenance would not be scheduled for times of system stress, we exclude the planned outages from the unavailability.

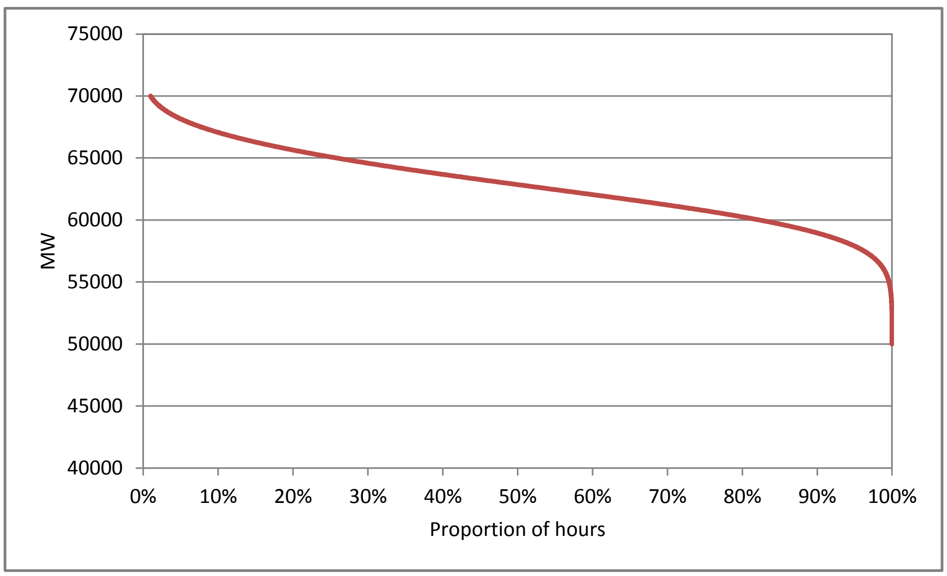
1.31. The final mean availability assumptions used in the Base Case are shown in Figure A3.5.

Figure A3.5 Generator availability assumptions

Fuel Type	Winter Availability
Coal (and Biomass)	87%
Gas CCGT	86%
OCGT	77%
Gas CHP	86%
Hydro	92%
Pumped Storage	95%
Nuclear	83%
Oil	81%
Wind	20-22%

1.32. The availability and capacities of individual generators are combined into a single capacity outage table, which is a distribution of the aggregate available capacity. The distribution is shown as a Capacity Duration Curve in Figure A3.6. For example, there is close to a 100% probability that there will be at least 50 GW of available capacity.

Figure A3.6 Conventional capacity distribution



Wind data source and modelling approach

1.33. The source for wind speed data is NASA's Modern Era Retrospective-analysis for Research and Applications (MERRA) reanalysis dataset. [35] This is a long term

[35]MERRA data used in this project have been provided by the Global Modelling and Assimilation Office (GMAO) at NASA Goddard Space Flight Center through the NASA GES DISC online archive. https://gmao.gsfc.nasa.gov/merra/.

(1979-2011) dataset built up from analysis of remote sensor (satellite) data. The full dataset is global in coverage and contains information on all aspects of climate.

1.34. For the purposes of this study, a subset of the MERRA data has been downloaded. The subset contains wind speeds at 2m, 10m and 50m height, for a grid covering the British Isles. The grid is at 0.5 degree longitude by 0.75 degree latitude which corresponds to approximately 50 km spacing over GB.

1.35. The model uses this data in combination with the capacity, hub height and coordinates of all transmission connected and embedded wind in GB.

1.36. The time series of wind speed is converted into a load factor series using either onshore or offshore turbine power curves, as appropriate.

1.37. For the capacity assessment model, wind output distributions are generated for each of the five winters for which the capacity assessment is performed. The distributions are calculated from the Sensitivity capacity mix, combined with the full set of wind speed data (1979-2011).

1.38. A single aggregate distribution of wind generation is created for each year. The wind distribution for each capacity year is convolved with the distributions of conventional generation and demand to create a distribution of the margin of supply over demand. The key metrics of LOLE and EEU are calculated from this distribution.

1.39. A large range of wind output levels can occur, with varying probabilities. It is useful to be able to translate this into an equivalent amount of firm capacity which provides the same contribution to security of supply, where the contribution to security of supply is measured in terms of LOLE or EEU.

1.40. We therefore use a standard measure known as Equivalent Firm Capacity (EFC). This is the amount of capacity that is required to replace the wind capacity to achieve the same level of LOLE. It is specific to a particular capacity and demand background.

1.41. EFC is a measure of the capacity adequacy provided by wind. A key use of the EFC is in the calculation of de-rated capacity margins, where the aim is to reflect the contribution of each generation type to capacity adequacy. It does not provide any insight on operational issues such as errors in wind forecasting.

1.42. Further details on the wind modelling approach can be found in Appendix 4.

Treatment of special cases

1.43. Here we discuss the treatment of special cases covering interconnectors, Demand Side Response (DSR), pumped storage and embedded generation.

1.44. Imports or exports on interconnectors to Ireland or Continental Europe are modelled as a decrease or increase in demand respectively. The assumptions on imports or exports over the interconnectors at peak vary between sensitivities. Exports are added directly to the demand distribution, and imports are subtracted from the distribution.

1.45. The availability of generation from pumped storage is modelled as conventional generation. The model does not take account of any constraints that may be imposed by the capacity of the storage, which could potentially limit the availability of generation from pumped storage across the peak period. Supporting analysis in National Grid's report suggests that the pumped storage generators have sufficient storage to operate across the peak period. This suggests that this limitation of the modelling is not significant for the five winters modelled.

1.46. Demand Side Response is assumed to continue at current levels. The model makes use of the actual historical demand data which already includes any demand reduction due to DSR. Using the historical data directly means that the impact of the current level of DSR is included in the model. We assume that there is no growth in DSR over the five year modelling period. This is consistent with National Grid's Future Energy Scenarios work.

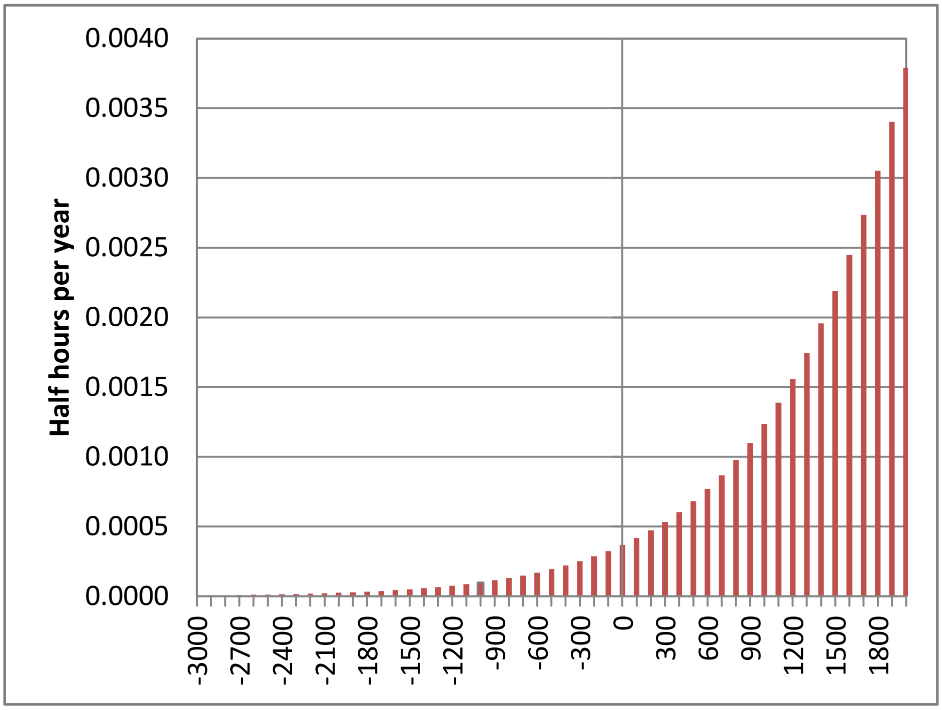
1.47. The historical demand data used is for demand met on the transmission system. Generation from embedded generators manifests as a decrease in demand on the transmission system. In this study, embedded wind generation is modelled explicitly as generation, and therefore the historical demand distribution is increased by an estimate of the demand met by embedded wind historically in each half hour. All other embedded generation (consisting of a range of technologies including for example small scale Combined Heat & Power, generation from landfill gas, and biomass) is implicitly modelled in the demand data. We assume there is no growth in non-wind embedded generation.

Calculation of Outputs

1.48. The distributions of conventional capacity and wind are combined to form a single distribution of generation capacity. The demand distribution is then subtracted to form a distribution of margins of supply over demand.

1.49. There is a small portion of the distribution for which demand exceeds supply and margins are negative. This is the left hand side of the distribution shown in Figure A3.7. Each bar represents the expectation of the number of half hours per year that the margin will be in that 100 MW tranche.

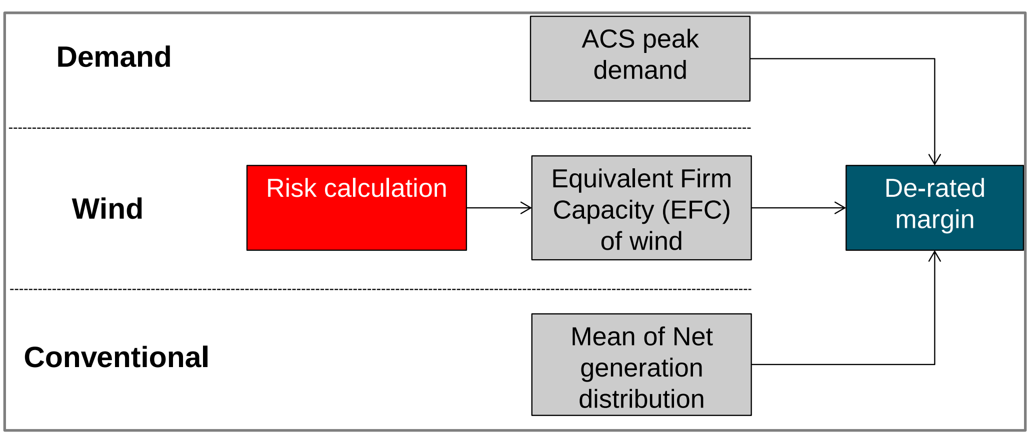
Figure A3.7 Distribution of margins (Base Case 2012/2013 MW)



1.50. The distribution of margins is used to calculate the risk and the impact of supply shortfalls by including two well-established probabilistic measures of security of supply analysis: LOLE and EEU. In addition, we calculate a commonly used indicator of security of supply: the de-rated capacity margin.

1.51. The calculation of the de-rated margin is shown schematically in Figure A3.8 below. There are three components: demand, wind generation and conventional generation. The de-rated margin can be stated in percentage terms as the excess of generator availability, divided by demand.

Figure A3.8 Calculation of de-rated margins



1.52. For demand, we use the ACS peak demand. As described above, it is possible for outturn demand to exceed this level. We also adjust at this point for the amount of generation that must be held as reserve against the largest loss on the system. Net exports over the interconnectors (which vary by sensitivity) are added to demand.

1.53. For conventional generation, the installed capacity of each generation type is multiplied by the mean availability of that type. The assumed availabilities are shown in Figure A3.5.

1.54. For wind capacity, the average availability of wind is not suitable as this would overstate the contribution of wind to security of supply. A more suitable value is the Equivalent Firm Capacity (EFC), estimated from the probabilistic model as described above. The model calculates the amount of firm capacity that would be needed to replace the wind capacity to give the same LOLE. This is lower than the mean winter load factor because of the chance that wind output will be very low.

1.55. The EFC is specific to any one sensitivity and year because it is dependent on the overall generation mix. The Base Case produces EFC values that are typically in the range of 20 -22%.

1.56. The de-rated capacity margin also includes an adjustment for assumed flows on the interconnectors and the reserve held by the System Operator (SO) for single largest infeed loss. This type of reserve is required in order to maintain the stability of the system, and therefore disconnection of demand would occur in preference to use of this reserve (whereas other forms of reserve would be used to prevent supply shortfalls).[36] As it is a form of reserve that must be maintained, we therefore include it as “demand” in the analysis.

1.57. The interconnection and reserve adjustment are applied as increases to GB demand. The assumptions for the Base Case are shown in Figure A3.9 below.

[36] This reserve is a sub-set of the full reserve requirement that the SO holds in order to manage the system on operational timescales.

Figure A3.9 Adjustments to ACS peak demand for interconnection and reserve

	2012/13 (MW)	2013/14 (MW)	2014/15 (MW)	2015/16 (MW)	2016/17 (MW)
Winter peak demand (ACS)	55614	55734	55873	55985	56173
Exports to Ireland	950	950	950	950	760
Reserve for largest infeed loss	700	700	1572[37]	1572	1572
Winter demand (ACS) – adjusted	57264	57384	58395	58507	58505
Summer peak demand - adjusted	40200	40279	41242	41314	41441

Estimation of impact on customers - Frequency and duration analysis

1.58. We have translated the risk metrics, LOLE and EEU, into the possible effects on electricity customers. We estimate the likely frequency and duration of shortfalls in supply and categorise these outages by severity. The categories are defined by the potential mitigating measures which may be available to the System Operator.

1.59. The probabilistic model does not produce the frequency and duration of outages directly as it does not account for the chronology of periods. We can estimate the frequency and duration of shortfalls using the following additional assumptions:

- We assume that the conventional plant availability is constant over the duration of an outage. This is reasonable given that typical repair times are longer than the peak period.
- We assume that the wind availability does not change over the duration of an outage. This is an approximation that is reasonable given the level of wind generation in the time horizon of the modelling, but which will become less valid in future years.
- We assume that outages occur on a typical peak demand day (a weekday in January).

1.60. Using the minute by minute demand profile for the typical peak demand day, for a shortfall of a particular size in MW, it is possible to calculate in how many periods in the day there would also be a shortfall (of a smaller size). For any shortfall size, we can derive the typical duration of the outage and the total MWh of energy unserved.

[37] Practically, National Grid will only hold enough response to cater for events that can happen on any individual day – so one needs to check when the largest loss actually increases. At the moment National Grid uses about 700MW of capacity to meet the response requirement. From winter 2014/2015 this number will increase by 872MW to 1572MW.

Figure A3.10 Mitigation measures

Action	Comments	Assumed effect in MW
Voltage reduction	Reduce demand by instructing distribution network owners (DNOs) to reduce voltage	500
Maximum generation	Increase in supply by instructing generating plants to increase generation to maximum	250
Provision of emergency services through interconnection	Increase in supply through interconnection services with neighbouring countries (various services available, eg Emergency Instruction, Emergency Assistance and Cross-Border Balancing)	2000

1.61. We define a set of shortfall categories to match the possible mitigation measures shown in Figure A3.10. The duration and energy unserved calculated for each of these categories is shown in Figure A3.11 for the Base Case. The mitigation measures are assumed to be always available and always taken in the order shown in this figure.

1.62. Controlled disconnections occur after voltage reduction, maximum generation services and emergency services from interconnectors have been exhausted. The modelling suggests that a shortfall in demand of 2.75 GW or greater will typically last 5 hours and the total energy unserved would be 22 GWh.

Figure A3.11 Outage categories with typical duration and typical size of outage

Event	Typical size	Typical Duration	Mitigation
	MWh	(mins)	(options)
0 – 10 MW	0.04	1.00	No impact
10-500 MW	32.66	8.76	Voltage reduction
500-750 MW	1,347.62	100.85	Voltage reduction and max gen
750-2750 MW	4,621.57	136.17	Voltage reduction, max gen and emergency services from interconnection
2750- MW	22,346.22	310.75	Controlled disconnections

1.63. Given this set of shortfall types, we need to find the frequency of each outage type that is consistent with the LOLE and EEU results for a particular sensitivity and year. Using the LOLE and EEU results, we fit a function which describes the distribution of margins shown in Figure A3.7.

1.64. There is a unique set of frequencies which obeys this function and also returns the correct LOLE and EEU for each year of each sensitivity.

1.65. The final values are a set of frequencies (1 in n years) for each shortfall category. The results should be considered approximate only, due to the additional assumptions required. There is also a risk that each of the mitigation measures may not be fully available to the System Operator when required.

Uncertainty analysis

1.66. In this section we describe the approach to quantifying the uncertainty inherent in this analysis.

1.67. The uncertainty can be characterised into three types:

- Statistical (internal) uncertainty
- Uncertainty due to independence assumptions within the model
- Uncertainty due to non-statistical modelling assumptions

1.68. We describe the approach to each of these in turn below.

1.69. Statistical (internal) uncertainty is the uncertainty in the probability distributions derived from historical data, in this case the probability distributions of demand and wind. It arises from the natural randomness in the finite sample of data used in the analysis.

1.70. Uncertainty in the probability distributions derived from historical data can be estimated through a resampling technique known as bootstrapping. This technique uses resampling and replacement of the dataset to estimate the uncertainty due to using the dataset.

1.71. In the case of demand, bootstrapping has been used to estimate 95% confidence intervals for LOLE and EEU based on the uncertainty in the demand distribution. The demand is divided into weekly blocks which are assumed to be independent, then resampled many times to produce a large number of bootstrap samples. Each sample produces a different estimate for LOLE and EEU. We find the 95% confidence intervals and report these in Section 4.

1.72. A similar technique has been used to assess the uncertainty due to the wind data. Due to the computational overhead of processing the wind data, it has not been possible to estimate the confidence intervals on LOLE and EEU. However, it has been possible to examine the confidence intervals in the wind distribution itself, which gives some insight into the scale of this uncertainty.

1.73. The distribution of conventional plant availability is derived from historical analysis of outage rates, and the uncertainty in this distribution is best characterised through sensitivity analysis on the outage rates used.

1.74. The assumption of independence of distributions is a source of uncertainty. The assumption that wind and demand are independent at times of system stress is a reasonable assumption given that there is no well characterised statistical relationship between the two. This assumption is an uncertainty which is tested to some extent through the “Lower wind at peak” sensitivity. This sensitivity assumes wind is lower at peak times, ie 75% of the Base Case value.

1.75. Many of the model inputs are assumptions for which sensitivity analysis has been carried out. These sensitivities are described in Appendix 1.

1.76. Figure A3.12 summarises the approach to the uncertainties on various parameters in the modelling.

Figure A3.12 Summary of approach to treatment of uncertainties

Uncertainty source	Uncertainty type	Approach
Demand	Statistical (internal)	Bootstrapping & sensitivity analysis
Wind	Statistical (internal) and data source, but dominated by independence assumption	Bootstrapping
Distribution of conventional capacity	Dominated by modelling assumptions about plant availability probabilities	Sensitivity analysis
Assumption of independence of demand and wind at time of system stress	Independence assumption in model	Sensitivity analysis, based on varying wind distribution at times of peak demand
Installed generating capacity	Modelling assumption	Sensitivity analysis
Forced outage rates	Modelling assumption	Sensitivity analysis: variation of forced outage rates by +-5%
Availability of capacity over interconnector	Modelling assumption	Sensitivity analysis

Two area model

1.77. This section describes the model used to estimate the impact of the Cheviot constraint on LOLE and EEU.

1.78. The two area model uses separate distributions of demand, wind and conventional generation availability for England and Wales and for Scotland, and imposes a constraint on the transfer of capacity across the Cheviot boundary. The model is specified to calculate the additional LOLE and EEU due to the constraint in additional to the LOLE and EEU already present in the unconstrained one-area system.

1.79. The additional GB LOLE and EEU are clearly defined results of these calculations. To split the LOLE and EEU into values for England and Wales and Scotland, additional assumptions are required:

- In a system without network constraints, demand reduction is assumed to be distributed geographically in proportion to demand in each area. Hence the LOLE in each area for an unconstrained system is equal to the GB LOLE, and the EEU divides in proportion to demand.

- The additional LOLE and EEU due to the finite boundary capacity is assigned to England and Wales and not Scotland. National Grid's examination of the pattern of boundary flows shows that at times of system stress the flow will be from Scotland to England in the great majority of cases.

1.80. In the two area model, the demand in England & Wales and the demand in Scotland are clearly not independent. The same is true of the wind distributions in the two areas. The implication of this is that the calculation of LOLE and EEU can no longer be achieved through the convolution of distributions for demand, wind and conventional generation.

1.81. Instead, the full computation would require a calculation using all combinations of historical wind with historical demand. This is computationally infeasible, and therefore the model uses an approach known as Importance Sampling to find a reduced sample which can be used to estimate the additional LOLE and EEU in a two area system. The additional uncertainty introduced by this approach is small and is reported as the standard error of the importance sample.

Appendix 4 – Wind model

1.1. In this section we describe the wind dataset and technical details of the wind modelling approach. We first give an overview of the data source, and then give a detailed description of the wind model design and structure. We include the results of comparisons to historical data.

Wind speed data source and extraction: MERRA dataset

1.2. The source for wind speed data is NASA's Modern Era Retrospective-analysis for Research and Applications (MERRA) reanalysis dataset. [38] This is a long term (1979-2011) dataset built up from analysis of remote sensor (satellite) data. The full dataset is global in coverage and contains information on all aspects of climate.

1.3. For the purposes of this study, a subset of the MERRA data has been downloaded. The download instructions have been posted online by Reading University. [39]

1.4. The subset contains wind speeds at 2m, 10m and 50m height, for a grid covering the British Isles. The grid is at 0.5 degree longitude by 0.75 degree latitude which corresponds to approximately a 50 km spacing over GB.

1.5. To access the raw data, University of Reading were contracted to build an extraction tool. The tool is written in FORTRAN 90 and compiled into a form which can be run on a standard Windows PC. The detailed description of this tool is online.[40] The tool can be run stand alone to extract the wind speed data for an individual wind farm location over a specified period of time (1979-2011). The tool interpolates between local grid points to derive the wind speed for the specified location. It also adjusts for hub height using a logarithmic relationship.

1.6. The wind extraction tool described above has been incorporated into the Capacity Assessment Data Extractor, which contains the capacity, hub height and coordinates of all transmission connected and embedded wind in GB.

1.7. The MERRA wind speeds have been calibrated against Met Office wind speed data for seven locations.

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[38]MERRA data used in this project have been provided by the Global Modelling and Assimilation Office (GMAO) at NASA Goddard Space Flight Centre through the NASA GES DISC online archive. https://gmao.gsfc.nasa.gov/merra/
[39] University of Reading Wind profile program
[40] University of Reading Wind profile program documentation

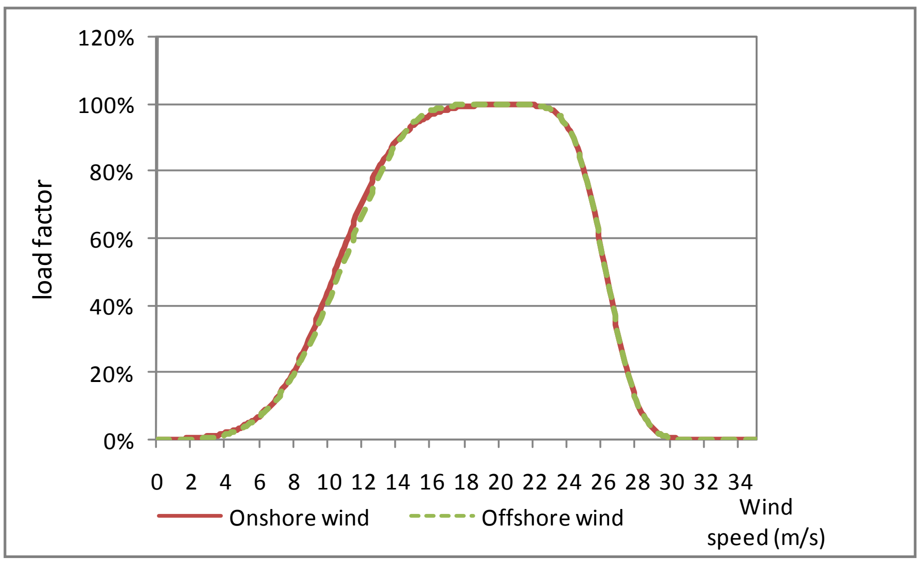
1.8. On average over the seven locations, the MERRA data overestimates wind speeds by 1.2 m/s compared to the Met Office data. As a result, the MERRA wind speeds have been reduced by this value. This simple adjustment removes the overall bias in the wind speed data, but does not correct for any issues which may exist at specific wind speed levels.

1.9. For example, National Grid's internal analysis suggests that the MERRA data contains too few wind speeds greater than 25 m/s, compared to Met Office data.

Conversion to wind output

1.10. The time series of wind speeds is converted into a load factor series using either the onshore or offshore turbine power curves shown in Figure A4.1, as appropriate. The turbine power curves are based on typical curves given in manufacturers specifications. The curves represent the expected load factor for a given wind speed. [41]

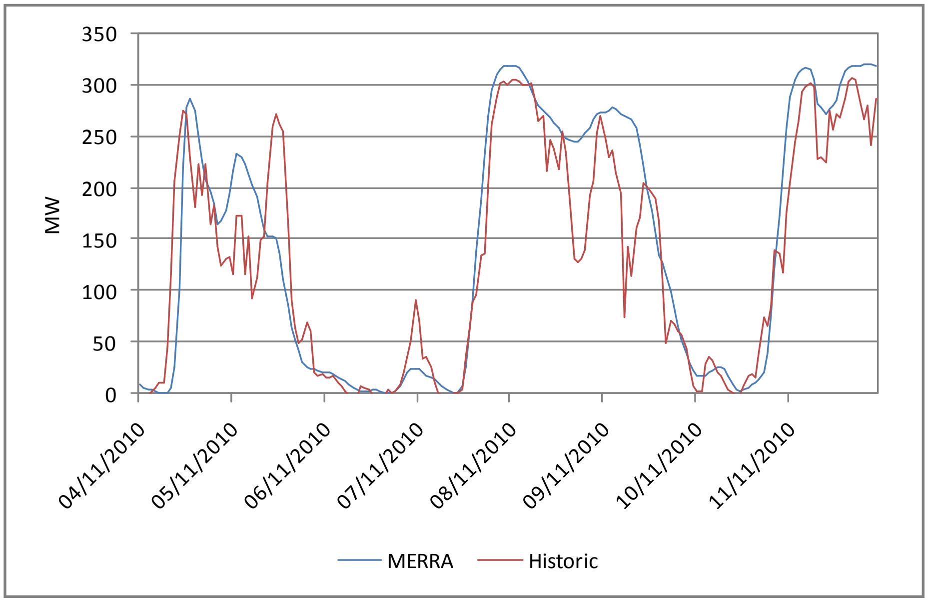
Figure A4.1 Onshore and offshore wind turbine power curves



1.11. As an example, Figure A4.2 shows the modelled wind output of an onshore wind farm for a week in November 2010 ("MERRA") compared to the historical output data for the wind farm ("Historic").

[41] Note that we assume a normal distribution around the point estimate of the wind speed that we get for that location at that point in time. The normal distribution has a standard deviation of 1.5m/s. The standard deviation represents the uncertainty in wind speed estimation at a specific wind turbine given a known wind speed at a single location in the wind farm.

Figure A4.2 Example wind farm output compared to historical data



Comparison with historical data

1.12. A backcast series of modelled wind output has been created using historical wind farm capacities. The load factors were compared at a monthly level to historical monthly profiles derived from data from the Renewables Obligation[42]. Additionally, the winter 2010/11 half hourly time series was compared to the same period of metered data.

1.13. Figure A4.3 and Figure A4.4 show the comparison of monthly load factors produced from the wind tool ("MERRA") to historical load factors ("RO"), for winters 2006/07 to 2010/11. The historical monthly load factors are derived from the number of ROCs produced by onshore and offshore wind in each month, and the associated accredited RO capacity in each month.

1.14. Figure A4.3 shows the comparison for onshore wind. The average onshore winter load factor from the modelling is 36%, compared to 30% from the historical data. Figure A4.4 shows the comparison of monthly load factors for offshore wind. The average offshore winter load factor from the modelling is 41%, compared to 36% from the historical data.

[42] Most wind generators in the UK are supported under the Renewables Obligation (excluding some onshore wind with <5MW installed capacity which is supported through the small scale Feed In Tariff). Under the RO, renewable generators receive certificates each month which are issued based on the generation in that month. This data can be used to derive historic load factors for each month.

Figure A4.3 Onshore wind load factors (winter months 2006/07 – 2010/11)

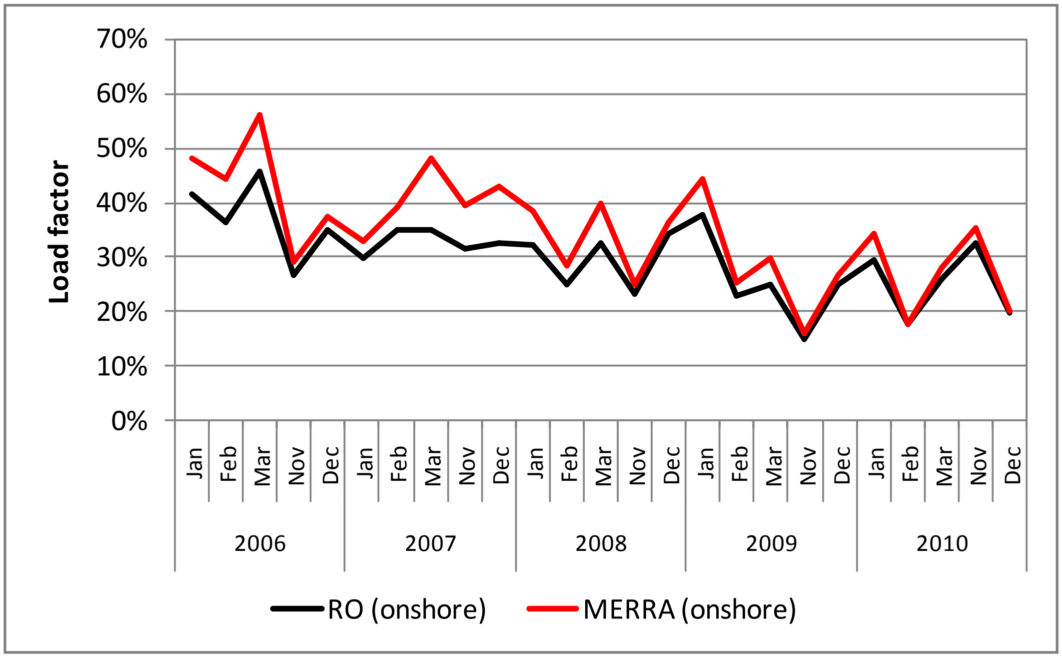
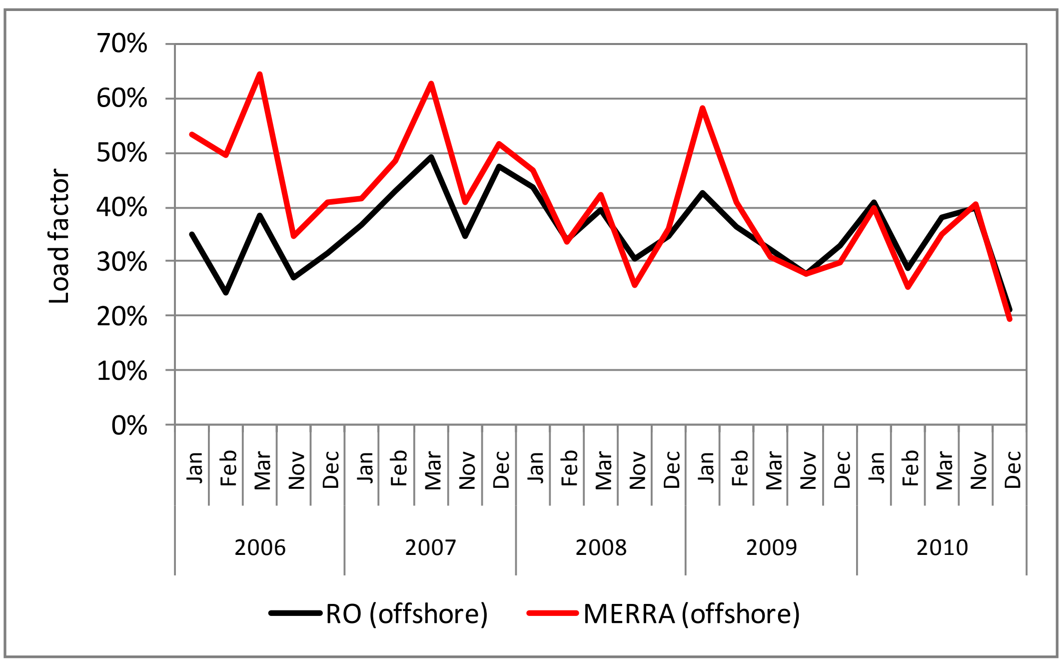


Figure A4.4 Offshore wind load factors (winter months 2006/07 – 2010/11)



1.15. From the charts, it is apparent that the match to historical wind load factors is out by as much as 20 percentage points of load factor in earlier months but is much better from November 2009 onwards. Indeed, if the comparison is made using the figures from 2009 onwards, for onshore wind the average load factor using the

MERRA data is 28% compared to 25% with the RO data. For offshore wind the average load factor is 35% for MERRA compared to 34% for RO. Below we discuss a number of potential reasons for this.

- **Turbine availability.** The model assumes that all turbines are available when the wind blows. In reality, some turbines will be unavailable due to maintenance or failures. Accounting for turbine unavailability would reduce modelled load factors.

- **Wind turbine curves.** The wind turbine curves are based on published data for two specific wind turbines. It is possible that this does not fully reflect the typical turbine in the GB wind fleet. In particular, the older turbines may be less efficient at converting wind speed into power. There may also be some degradation of turbine performance compared to manufacturer parameters.

- **Capacity mix.** The installed capacity is accurate on an annual basis, but does not reflect month-to-month increases in capacity. As new turbines are commissioned each month, the actual capacity mix will diverge from that modelled. If the new turbines have load factors which differ substantially from the capacity mix average in those months, then the actual capacity mix overall may have had a slightly different average load factor to that modelled. This is not expected to have a significant effect in the later years. It may have more impact for offshore wind earlier in the backcast period, where there were fewer offshore wind farms.

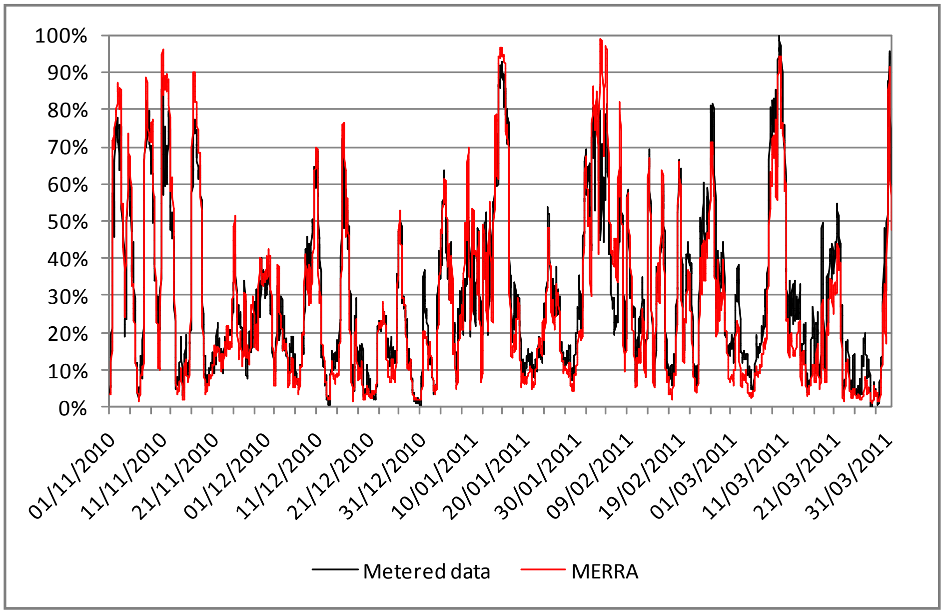
- **Quality of calibration data.** The historical load factors from the RO data are calculated from the monthly installed capacity and monthly ROCs awarded. Wind turbines commissioned at the end of a month would contribute in full to the capacity but only generate for a short period, leading to an underestimate of load factor.

- **Wind speeds**. The MERRA wind speeds have been calibrated against Met Office wind speed data for seven locations. The MERRA wind speeds have been reduced by 1.2 m/s, which is the average amount by which the original data overestimated the wind speed. However some deviations in the wind speed data will remain.

1.16. Wind speeds and turbine availability are likely to be the two largest effects.

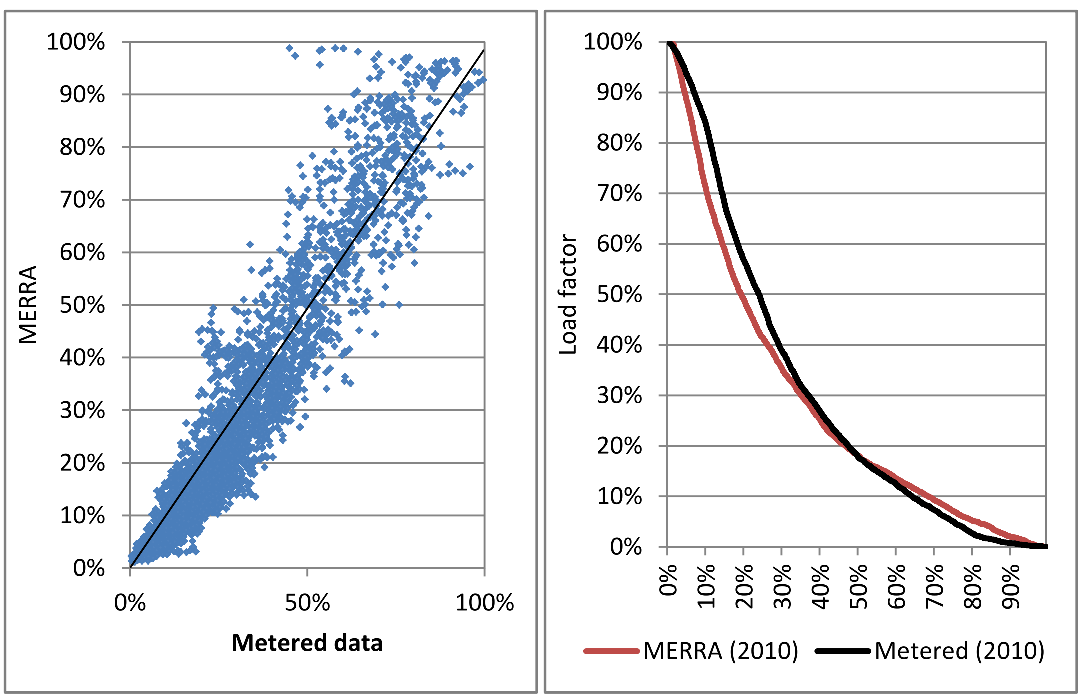
1.17. To complement the analysis of monthly load factors, a comparison on a half hourly basis has been performed. Figure A4.5 shows the half hourly time series of modelled load factors (“MERRA”) compared to National Grid’s historical metered wind farm output series for winter 2010/11.

Figure A4.5 Time series of modelled and historical load factors (winter 2010/11)



1.18. Figure A4.6 shows a scatter plot of the data above, as well as the duration curve. The standard deviation of the errors is 0.08 (i.e. eight percentage points).

Figure A4.6 Scatter plot and duration curve of modelled and metered wind load factors (winter 2010/11)



1.19. In principle, similar analysis could be performed for other historical years. However, this is limited by the available dataset of metered wind farm output. Earlier years have fewer metered wind farms included in the dataset.

1.20. Taken as a whole, the wind model is believed to be reasonable for the purpose of creating distributions to feed into the capacity assessment model. This is discussed in the next section.

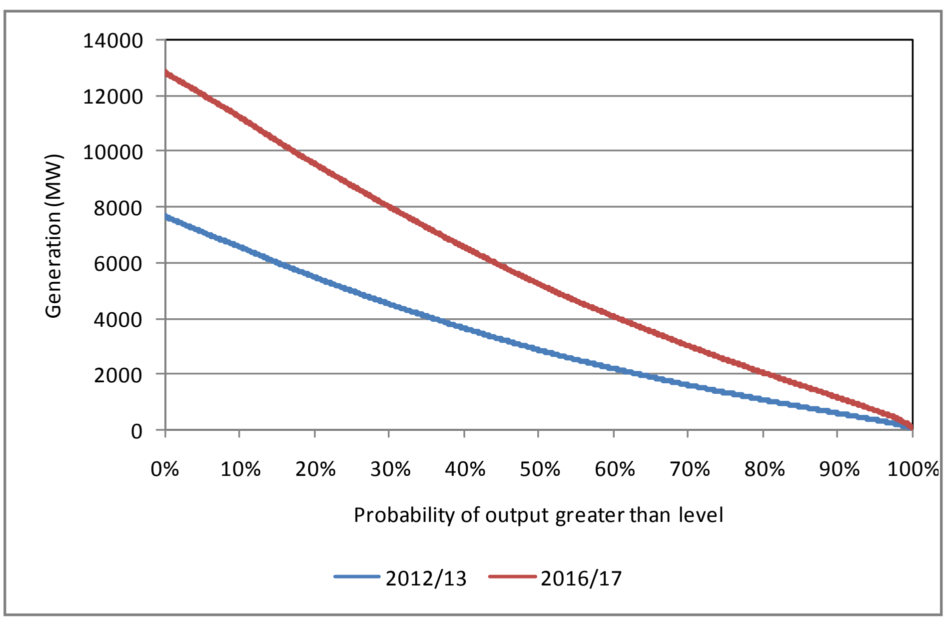
Wind output distributions

1.21. For the capacity assessment model, wind output distributions are generated for each of the five winters for which the capacity assessment is performed. The distributions are calculated from the scenario capacity mix, combined with the full set of wind speed data (1979-2011).

1.22. A single aggregate distribution of wind generation is created for each year, shown in Figure A4.7 for 2012/2013 and 2016/2017 in the Base Case. The installed wind capacity in 2012/2013 is 7.7 GW, and by 2016/2017 this has increased to 13 GW.

1.23. Figure A4.7 shows that there is nearly a zero probability of there being no output at all from wind.

Figure A4.7 Base Case 2012/2013 and 2016/2017 wind generation distribution



1.24. The wind distribution for each capacity year is convolved with the distributions of conventional generation and demand to create a distribution of the margin of supply over demand. The key metrics of LOLE and EEU are calculated from this distribution.

Equivalent Firm Capacity

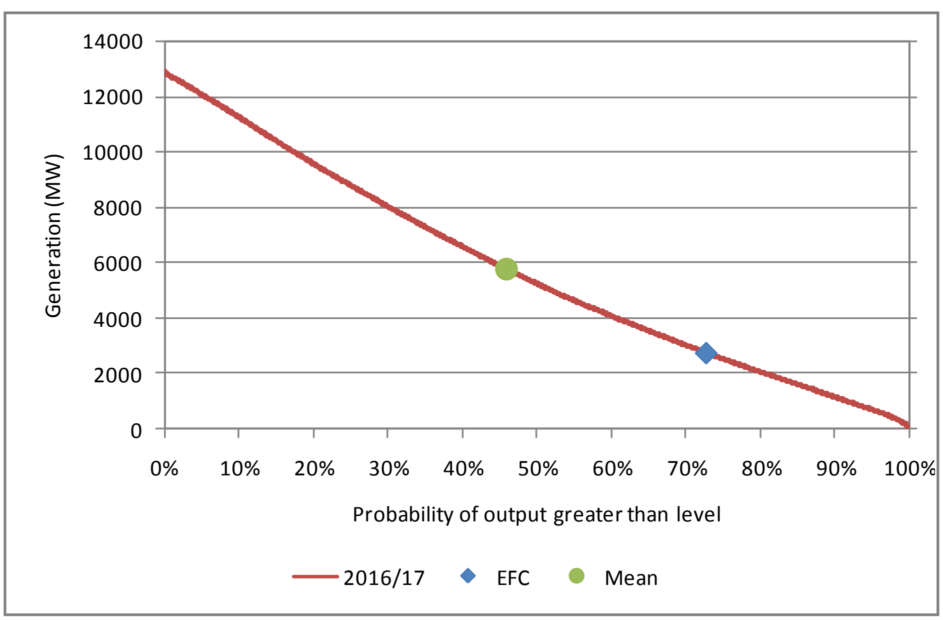
1.25. The wind distributions above show that a large range of wind output levels can occur, with varying probabilities. It is useful to be able to translate this into an equivalent amount of firm capacity which provides the same contribution to security of supply, where the contribution to security of supply is measured in terms of LOLE or EEU.

1.26. We therefore use a standard measure known as Equivalent Firm Capacity (EFC). This is the amount of capacity that is required to replace the wind capacity to achieve the same level of LOLE. It is specific to a particular capacity and demand background.

1.27. EFC is a measure of the capacity adequacy provided by wind. A key use of the EFC is in the calculation of de-rated capacity margins, where the aim is to reflect the contribution of each generation type to capacity adequacy. It does not provide any insight on operational issues such as errors in wind forecasting.

1.28. Figure A4.8 shows the 2016/2017 distribution with the average winter output in MW and the EFC plotted on the same chart. The EFC calculated is 2854 MW, which is 22% of the installed wind capacity in 2016/2017.

Figure A4.8 Comparison of wind distribution, average winter load factor and EFC



1.29. The EFCs calculated in this study are higher than other values that have been quoted for the contribution of wind to security of supply. For example, National Grid have previously used a value of 8% in the Winter Outlook 2011/12.

1.30. The large difference in these numbers reflects two very different approaches. The Winter Outlook approach is based on observations of the output of wind at peak times. By its nature this is a small number of observations, and it is therefore possible that the wind output at the time of observation could have been very different.

1.31. In contrast, EFC is a statistical approach which takes account of the *change* in risk to security of supply due to the intermittent nature of wind output. It recognises that the system already has some non-zero risk, and aims to calculate the level to which wind can be relied on so as to not increase this risk.

Appendix 5 – Governance and process

Project governance

1.1. Under the Electricity Act 1989[43] Ofgem is responsible for delivering an annual Electricity Capacity Assessment report to the Secretary of State. Fulfilling Ofgem's obligation required the development of a model which assesses the risks to electricity security of supply. The Act allows for the modelling to be delegated to a transmission licence holder. We decided to delegate the modelling to NGET in order to utilise its existing modelling capabilities as well as knowledge of the market and data. Delegating the modelling of the capacity assessment to the system operator is consistent with current international practice in Ireland, Australia, and some parts of the US.

1.2. We also appointed an academic advisory body, which consists of Prof. Goran Strbac, Imperial College London, Prof. Derek Bunn, London Business School, and Prof. Michael Grubb, University of Cambridge and Ofgem. The academic advisory body provided ongoing support from the beginning of the project. The academic advisory body has not been involved in the writing of this report.

Consultation

1.3. In October 2011 we published a consultation which presented our views on the assessment of the de-rated electricity capacity margin and the risks to electricity security of supply as well as the modelling approach. In preparation for the formal consultation we held an informal consultation during August and September. In particular, we organised an industry workshop to seek views on our preliminary thoughts on the approach and modelling options. In addition, we held a workshop (September 2011) with the UK Energy Research Centre (UKERC).

1.4. In January 2012 we published our final decision document taking into account and reflecting responses to our October 2011 consultation. In addition, given the importance of the capacity assessment project we held an industry workshop in conjunction with NGET in February to present the methodology and to seek further feedback from industry.

Next year's report

1.5. Ofgem is responsible for delivering the 2013 electricity capacity assessment and will do so by the 1st September 2013.

[43] Section 47ZA as inserted by the Energy Act 2011.

Appendix 6 – Detailed results tables

Figure A6.1 Average Cold Spell – by sensitivity (MW)

ACS peak (MW)	2012/13	2013/14	2014/15	2015/16	2016/17
Base Case	57264	57384	58395	58507	58505
High CCGT	57264	57384	58395	58507	58505
Low CCGT	57264	57384	58395	58507	58505
Interconnector 1.5GW Imports	55764	55884	56895	57007	57005
Interconnector 3GW Imports	54264	54384	55395	55507	55505
Interconnector 1.5GW Exports	58764	58884	59895	60007	60005
Interconnector 3GW Exports	60264	60384	61395	61507	61505
High Demand	59564	59784	60995	61107	61505
Low demand	55164	55084	56095	55907	55705
Base Case with WOR availabilities	57314	57434	58445	58557	58545
Reduced plant availabilities (-1% pa)	57264	57384	58395	58507	58505
Wind sensitivity (75%)	57264	57384	58395	58507	58505
Base Case with no single largest infeed loss	56564	56684	56823	56935	56933
No Irish Exports	56314	56434	57445	57557	57745
Biomass conversion not relicensed	57264	57384	58395	58507	58505
GG12	57264	57384	58395	58507	58505

Figure A6.2 Wind EFC – by sensitivity (MW)

Wind EFC (MW)	2012/13	2013/14	2014/15	2015/16	2016/17
Base Case	1636	2086	2346	2700	2854
High CCGT	1636	2086	2346	2604	2702
Low CCGT	1696	2148	2418	2792	2950
Interconnector 1.5GW Imports	1548	1956	2194	2518	2658
Interconnector 3GW Imports	1466	1836	2054	2350	2480
Interconnector 1.5GW Exports	1734	2228	2512	2898	3064
Interconnector 3GW Exports	1838	2380	2690	3108	3290
High Demand	1796	2332	2656	3068	3310
Low demand	1508	1882	2106	2378	2484
Base Case with WOR availabilities	1592	2012	2262	2572	2716
Reduced plant availabilities (-1% pa)	1636	2112	2406	2804	3002
Wind sensitivity (75%)	1410	1802	2030	2338	2484
Base Case with no single largest infeed loss	1594	2024	2188	2510	2650
No Irish Exports	1538	1944	2098	2402	2558
Biomass conversion not relicensed	1636	2086	2346	2778	2936
GG12	1598	2014	2248	2580	2734

Figure A6.3 De-rated margins – by sensitivity (MW)

De-rated margin (MW)	2012/13	2013/14	2014/15	2015/16	2016/17
Base Case	7945	4984	3846	2458	2782
High CCGT	7945	4984	3846	3167	3839
Low CCGT	7027	4372	3243	1767	2095
Interconnector 1.5GW Imports	9357	6354	5194	3776	4086
Interconnector 3GW Imports	10775	7734	6554	5108	5408
Interconnector 1.5GW Exports	6543	3626	2512	1156	1492
Interconnector 3GW Exports	5147	2278	1190	-134	218
High Demand	5805	2830	1556	226	238
Low demand	9917	7080	5906	4736	5212
Base Case with WOR availabilities	8308	5402	4254	3012	3334
Reduced plant availabilities (-1% pa)	7945	4781	3447	1870	2007
Wind sensitivity (75%)	7719	4700	3530	2096	2412
Base Case with no single largest infeed loss	8603	5622	5260	3840	4150
No Irish Exports	8797	5792	4548	3110	3246
Biomass conversion not relicensed	7945	4984	3846	1890	2218
GG12	9004	6119	5065	3364	3659

Figure A6.4 De-rated margins – by sensitivity (%)

De-rated margin (%)	2012/13	2013/14	2014/15	2015/16	2016/17
Base Case	13.88%	8.69%	6.59%	4.20%	4.75%
High CCGT	13.88%	8.69%	6.59%	5.41%	6.56%
Low CCGT	12.27%	7.62%	5.55%	3.02%	3.58%
Interconnector 1.5GW Imports	17%	11%	9%	7%	7%
Interconnector 3GW Imports	20%	14%	12%	9%	10%
Interconnector 1.5GW Exports	11%	6%	4%	2%	2%
Interconnector 3GW Exports	8.54%	3.77%	1.94%	-0.22%	0.35%
High Demand	9.75%	4.73%	2.55%	0.37%	0.39%
Low demand	18.0%	12.9%	10.5%	8.5%	9.4%
Base Case with WOR availabilities	14%	9%	7%	5%	6%
Reduced plant availabilities (-1% pa)	13.88%	8.33%	5.90%	3.20%	3.43%
Wind sensitivity (75%)	13.48%	8.19%	6.04%	3.58%	4.12%
Base Case with no single largest infeed loss	15%	10%	9%	7%	7%
No Irish Exports	16%	10%	8%	5%	6%
Biomass conversion not relicensed	13.88%	8.69%	6.59%	3.23%	3.79%
GG12	15.72%	10.66%	8.67%	5.75%	6.25%

Figure A6.5 LOLE – results by sensitivity (hours per year)

LOLE (hours per year)	2012/13	2013/14	2014/15	2015/16	2016/17
Base Case	0.010	0.267	0.822	2.770	2.089
High CCGT	0.010	0.267	0.822	1.507	0.810
Low CCGT	0.032	0.501	1.437	4.722	3.603
Interconnector 1.5GW Imports	0.001	0.057	0.207	0.845	0.621
Interconnector 3GW Imports	0.000	0.010	0.043	0.216	0.154
Interconnector 1.5GW Exports	0.058	1.038	2.735	7.754	5.990
Interconnector 3GW Exports	0.272	3.387	7.759	18.852	14.886
High Demand	0.133	2.038	5.545	13.854	13.508
Low demand	0.001	0.023	0.094	0.330	0.195
Base Case with WOR availabilities	0.005	0.135	0.456	1.425	1.058
Reduced plant availabilities (-1% pa)	0.010	0.341	1.252	4.699	4.257
Wind sensitivity (75%)	0.014	0.360	1.110	3.739	2.868
Base Case with no single largest infeed loss	0.004	0.133	0.193	0.794	0.583
No Irish Exports	0.001	0.048	0.072	0.340	0.294
Biomass conversion not relicensed	0.010	0.267	0.822	4.333	3.300
GG12	0.003	0.093	0.286	1.276	0.981

Figure A6.6 EEU – results by sensitivity (MWh)

EEU (MWh)	2012/13	2013/14	2014/15	2015/16	2016/17
Base Case	8	255	874	3370	2494
High CCGT	8	255	874	1717	878
Low CCGT	26	505	1613	6094	4557
Interconnector 1.5GW Imports	1	48	195	906	654
Interconnector 3GW Imports	0	7	36	205	144
Interconnector 1.5GW Exports	50	1120	3293	10720	8116
Interconnector 3GW Exports	261	4139	10608	29658	22933
High Demand	122	2395	7414	21281	21061
Low demand	0	18	82	319	182
Base Case with WOR availabilities	3	121	452	1586	1155
Reduced plant availabilities (-1% pa)	8	333	1394	6130	5570
Wind sensitivity (75%)	11	346	1187	4584	3450
Base Case with no single largest infeed loss	3	120	180	847	611
No Irish Exports	1	40	63	336	289
Biomass conversion not relicensed	8	255	874	5542	4139
GG12	2	83	282	1431	1086

Figure A6.7 GB Base Case LOLE and Reliability standards set by other countries

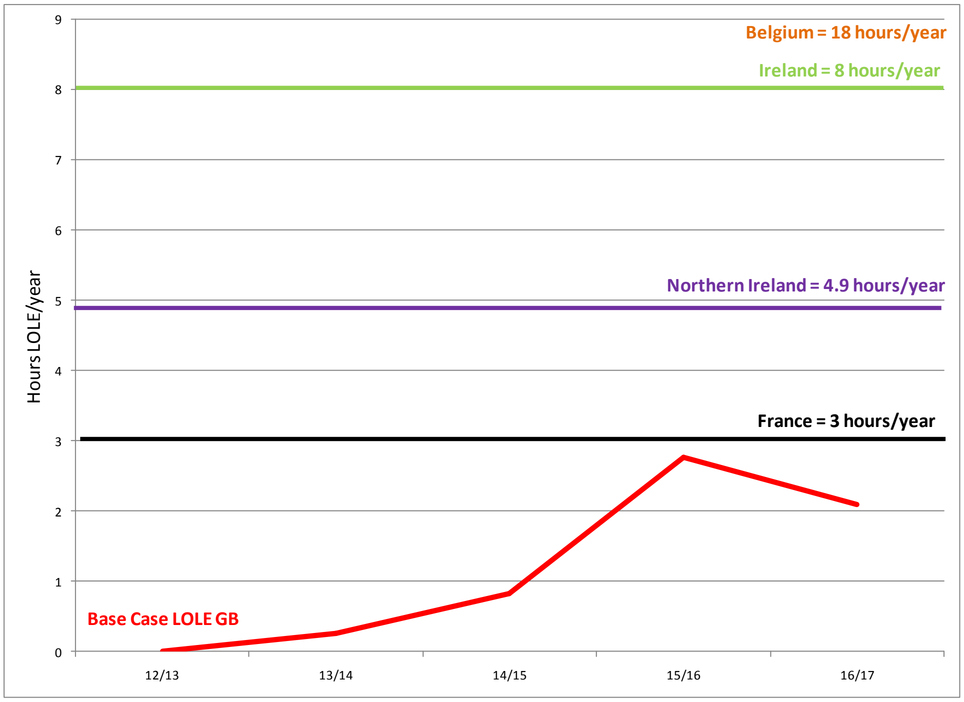
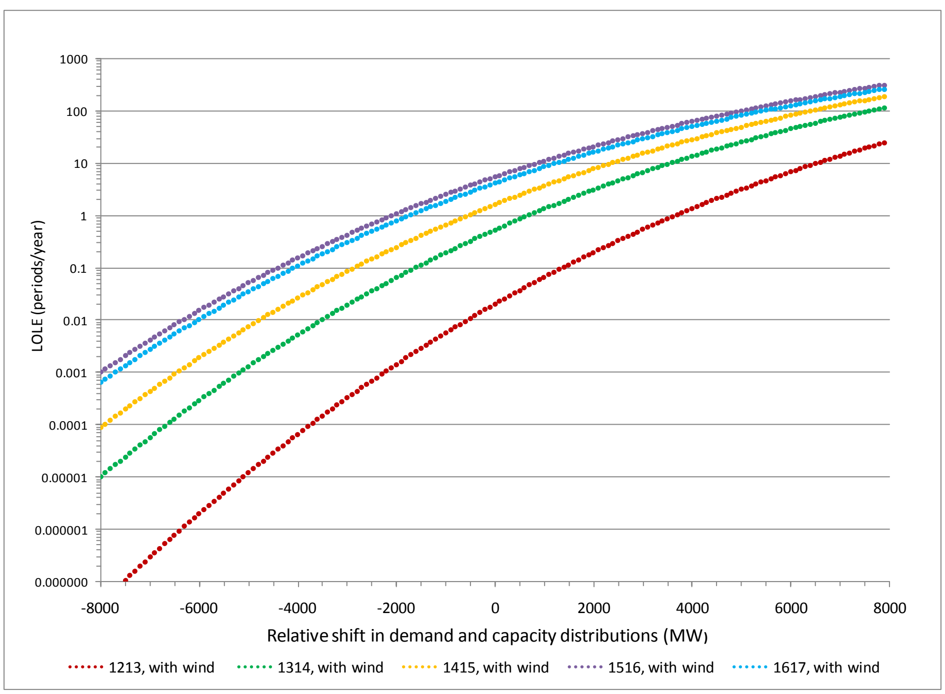


Figure A6.8 Generic relationship between LOLE and required margin (from zero, an additional 2 GW of capacity moves left along the horizontal axis)



Appendix 7 - Glossary

C

Capacity margin

The capacity margin is defined as the excess of installed generation over demand. It is sometimes referred to as reserve margin.

Capacity mechanism

Policy instrument designed to help ensure security of supply by providing a more secure capacity margin than that which would be determined by the market without intervention.

Capacity sterilisation

Capacity sterilisation refers to a situation where generation capacity is effectively not accessible to the system operator due to specific circumstances (eg located behind transmission constraints).

Combined Cycle Gas Turbine (CCGT)

A power station that generates electricity by means of a number of gas turbines whose exhaust is used to make steam to generate additional electricity via a steam turbine, thereby increasing the efficiency of the plant above open cycle gas turbines.

Combined Heat and Power (CHP)

The simultaneous generation of usable heat and power (usually electricity) in a single process, thereby leading to reductions in the amount of wasted heat.

Constraints (also known as congestion)

A constraint occurs when the capacity of transmission assets is exceeded so that not all of the required generation can be transmitted to other parts of the network, or an area of demand cannot be supplied with all of the required generation.

Consumer

In considering consumers in the regulatory framework we consider users of network services (for example generators, shippers) as well as domestic and business end consumers, and their representatives.

D

DECC

Department of Energy and Climate Change.

Decommissioning

A term often used for long term storage of Generating Units. Such plant is sometimes referred to as 'mothballed'.

Demand profile

The rate at which energy is required, expressed in kilowatts (kW) or megawatts (MW). It is usually related to a time period, typically half an hour, e.g. 1 kWh used over half an hour is a demand rate of 2 kW. A graph of demand rate over a typical day, for example, is the demand profile.

Demand Side Response (DSR)

An active, short term reduction in electricity consumption either through shifting it to another period, using another type of generation, or simply not using electricity at that time.

De-rated capacity margin

The de-rated capacity margin is defined as the excess of available generation capacity over demand. Available generation capacity is the part of the installed capacity that can in principle be accessible in reasonable operational timelines, i.e. it is not decommissioned or offline due to maintenance or forced outage.

Distribution Network Operators (DNO)

DNOs came into existence on 1 October 2001 when the ex-Public Electricity Suppliers were separated into supply and distribution businesses. There are 14 DNOs covering discrete geographical regions of Britain. They take electricity off the high voltage transmission system and distribute this over low voltage networks to industrial complexes, offices and homes. DNOs must hold a licence and comply with all distribution licence conditions for networks which they own and operate within their own distribution services area. DNOs are obliged to provide electricity meters at the request of a supplier.

E

Embedded generation

Any generation which is connected directly to the local distribution network, as opposed to the transmission network, as well as combined heat and power schemes of any scale. The electricity generated by such schemes is typically used in the local system rather than being transported across the UK.

EMR

Electricity Market Reform.

Energy efficiency

A change in the use of energy to reduce waste and lower energy use. For example, insulation in buildings, reducing demand from heat, or increasing the efficiency of appliances so they use less energy.

Expected energy unserved

This is a statistical measure of the expected volume of demand that cannot be met over a year because generation is lower than required.

F

Forced outages

The shutdown of a generating unit, transmission line, or other facility for emergency reasons or a condition in which the generating equipment is unavailable for load due to unanticipated breakdown.

I

Interconnector

Electricity interconnectors are electric lines or other electrical plants based within the jurisdiction of Great Britain which convey electricity (whether in both directions or in only one) between Great Britain and another country or territory.

Intermittent generation

Electricity generation technology that produces electricity at irregular and, to an extent, unpredictable intervals, eg wind turbines.

L

Large Combustion Plant Directive (LCPD)

An EU Directive placing restrictions on the levels of sulphur dioxide, nitrogen oxides and dust particulates which can be produced by combustion plants with a thermal output greater than 50MW. The implementation of the LCPD in the UK requires coal and oil plant to fit flue gas de-sulphurisation (FGD) equipment or have their total running hours restricted to 20,000 between 1 January 2008 and 31 December 2015 before closing prior to the end of that period.

Load curve

The relationship of power supplied to the time of occurrence. Illustrates the varying magnitude of the load during the period covered.

Loss of Load Expectation (LOLE)

LOLE is the probability of the capacity margin being negative or of demand being higher than generation capacity in the year.

M

Maximum Export Limit (MEL)

MEL is the maximum power export level of a particular BM Unit at a particular time.

Mothballed

A term often used for long term storage of Generating Units. Such plant is sometimes also referred to as 'decommissioned'.

N

National Electricity Transmission System (NETS) System Operator (SO)

The entity responsible for operating the GB electricity transmission system and for entering into contracts with those who want to connect to and/or use the electricity transmission system. National Grid is the GB electricity transmission system operator.

NETS SQSS

National Electricity Transmission System Security and Quality of Supply Standard.

NETS SYS

National Electricity Transmission System Seven Year Statement.

National Grid Electricity Transmission plc (NGET)

NGET is the Transmission System Operator for Great Britain. As part of this role it is responsible for procuring balancing services to balance demand and supply and to ensure the security and quality of electricity supply across the Great Britain Transmission System.

P

Peak demand, peak load

These two terms are used interchangeably to denote the maximum power requirement of a system at a given time, or the amount of power required to supply customers at times when need is greatest. They can refer either to the load at a given moment (eg a specific time of day) or to averaged load over a given period of time (eg a specific day or hour of the day).

Pumped storage

Process, also known as hydroelectric storage, for converting large quantities of electrical energy to potential energy by pumping water to a higher elevation, where it can be stored indefinitely and then released to pass through hydraulic turbines and generate electrical energy.

S

Scheduled outage

The shutdown of a generating unit, transmission line, or other facility for inspection or maintenance, in accordance with an advance schedule.

Sensitivity

This is a test whereby a single factor is changed (eg interconnector flows) keeping all other factors fixed to their base case value to see the effect the single factor produces on the model output (eg LOLE)

SSSR

Statutory Security of Supply Report.

T

Transmission Entry Capacity (TEC)

The Transmission Entry Capacity of a power station is the maximum amount of active power deliverable by the Power Station at the Grid Entry Point (or in the case of an Embedded Power Station at the User System Entry Point), as declared by the Generator, expressed in whole MW. The maximum active power deliverable is the maximum amount deliverable simultaneously by the Generating Units and/or CCGT Modules less the MW consumed by the Generating Units and/or CCGT Modules in producing that active power and less any auxiliary demand supplied through the station transformers.

Transmission Losses

Electricity lost on the Great Britain transmission system through the physical process of transporting electricity across the network.

Transmission System

The system of high voltage electric lines providing for the bulk transfer of electricity across GB.

The Authority/Ofgem

Ofgem is the Office of Gas and Electricity Markets, which supports the Gas and Electricity Markets Authority ("the Authority"), the regulator of the gas and electricity industries in Great Britain.

U

UKERC

UK Energy Research Centre.

W

WOR

Winter Outlook Report.