Issue	Revision
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nationalgrid

Demand Side Balancing Reserve and Supplemental Balancing Reserve

Volume Requirements Methodology

Produced in accordance with Special Condition 4K of the NGET Transmission Licence

Effective from 7th June 2014 to 31st March 2016

DOCUMENT HISTORY

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Introduction

This document describes the main principles behind the modelling methodology that National Grid Electricity Transmissionplc (NGET) will use to determine any requirement for Supplemental Balancing Reserve (SBR) and Demand Side Balancing Reserve (DSBR). This methodology has been written in accordance with the requirements of Part A of Special Condition 4K of NGET's Electricity Transmission Licence.

Modelling Methodology

The methodology has a number of stages listed below:

1. Take the 2014/15to 2017/18 electricity demand projections and generation backgrounds from each of NGET's latest Future Energy Scenarios[1] (FES). In 2014 there will be four scenarios. These scenarios are designed to be credible and internally consistent and will cover a range of uncertainties such as demand levels, plant closures, mothballing, DSR and levels of connected wind capacity. This will be carried out in April / May after:
    - the Average Cold Spell (ACS)"restricted" peak demand projections for each scenario have been updated following the end of the most recent winter ("restricted" peak demands take into account projected levels of triad avoidance); and
    - the generation backgrounds for each scenario have been revised based on the latest market intelligence (including anyTEC notifications received at the end of March).Note that any known SBR contracted plant will not be included in the generation background as it will be held outside the market for the duration of the contract but it will be taken into account when assessing the volume requirement.

    NGET has a well established and extensive consultation process via its FES consultations which incorporates industry workshops, a summer seminar and one to one meetings with stakeholders. The scenarios are heavily influenced by stakeholder engagementto ensure the resulting scenarios are holistic, self-consistent and plausible. Stakeholder feedback (pre-scenario development) will be used to provide evidence of the credibility of these scenarios as part of the justification. The stakeholder feedback document[2] (published annually before the scenarios are developed) contains details showing how stakeholder feedback directly influences the choice of scenarios and axioms underpinning the scenarios. This document contains details of the questions asked and the range of stakeholder responses.

    The main justificationsfor using these scenarios in the volume assessment are that they are credible (as evidenced by stakeholder feedback) and that they have been developed through extensive industry consultation to give a plausible range of future energy outcomes.All scenarios will be treated as equally likely as it is not possible or appropriate to assign probabilities or weightings to a particular case. Since the scenarios are credible, they are not intended to be extreme cases, but their Loss Of Load Expectation (LOLE) will lie somewhere in the central range of potential outcomes.

    These scenarios are also used by NGET to support the development of both gas and electricity networks, regulatory price controls (RIIO) and identifying opportunities for new connections.Theywill also be used as inputs to the Electricity Capacity Report to be produced for DECC to support them in setting a volume requirement for the Capacity Market.

[1] http://www2.nationalgrid.com/uk/industry-information/future-of-energy/future-energy-scenarios/
[2] Available at http://www2.nationalgrid.com/UK/Industry-information/Future-of-Energy/Future-Energy-Scenarios

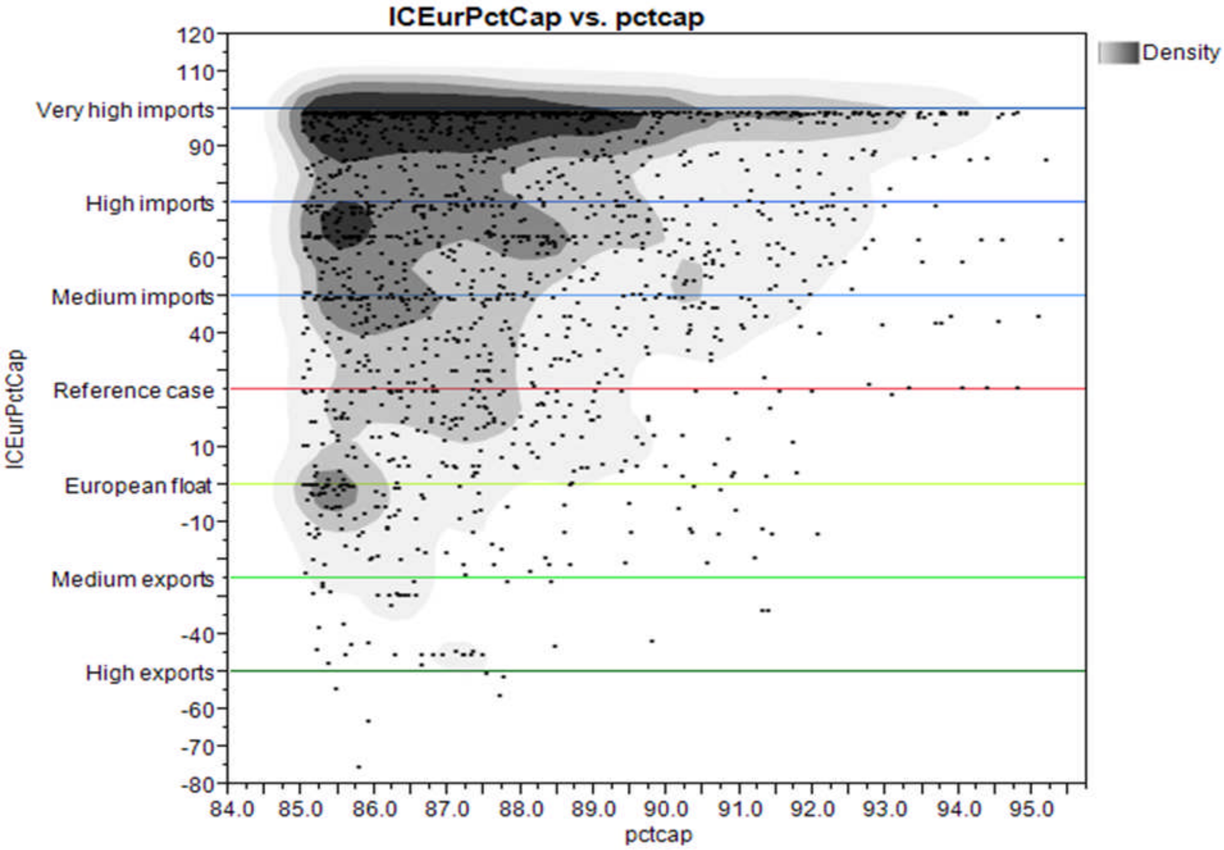
2. Define and justify a number ofsensitivities around the scenarios covering a credible and reasonable range of uncertainties for elements that may vary independently of the demand and generation mix without affecting the internal consistency of the scenario. The sensitivities chosen will satisfy the following criteria:
    - They are designed to model uncertainties over the short-term (e.g. unforeseen events) where the market does not have time to respond.Note that these sensitivities are designed to capture the range of short-term effects on one variable that do not impact other variables – the scenarios capture longer-term impacts on all variables over which period the market has time to respond. For example, interconnector flows can reverse at short notice due to unforeseen events in other countries (e.g. a cold snap on in France can increase French electricity demand dramatically due to a high incidence of electric heating, resulting in a switch from imports to exports on the French interconnector at the time of GB system peak), or conventional plants can experience a higher (or lower) level of unplanned outages on high demand days. In both these examples, the market would not have time to respond quickly by building new conventional plants,bringing back mothballed plants or returning any plant that is unavailable due to maintenance. This illustrates how one variable can change in isolation without other variables responding and without the internal consistency of the case being affected.
    - They are sensitivities that are considered by NGET's operational teams when planning for the winter, for example generation availabilityrates, unavailable (mothballed) generation, interconnector flow levels and demand levels under differentwinter weatherconditions

    Specifically we are intending to model the following sensitivities that cover ranges in the key variables:
    - Shifts in GB net interconnector flows applied to one scenario to cover a range of credible flows at winter peak based on historical evidence.These shifts may happen independently of the generation mix as a result of short-term fluctuations in price, demand or generation availability in other countries. As these shifts can happen at any time during the winter, the shifts will be applied to the whole winter period to capture the potential impacts on security of supply. The credible range of interconnector flows (including intermediate steps) will be determined from updated analysis that takes into account evidence from interconnector flows over recent winters as well as other recently published analysis on interconnector flows.

      Specifically the interconnector sensitivities will be based on or validated by an analysis of:
        - GB demand (INDO) and interconnector flows from April 2005 up to and including the most recent winter.
        - INDO demandexpressed as a percentage of winter de-rated generation capacity (a measure of system tightness in each half hour period)
        - A dispatch model of Ireland.
        - French demands from 2005 to most recent winter.
        - Weekday prices for UK, France and Germany from 2012.
        - ENTSOE Scenario Outlook and Adequacy Forecasts.

      Irish interconnector flows are generally exporting at maximum capacity when GB demand is high. Continental interconnector flows have varied from full imports to full export with a bias towards imports. The range varies from year to year and at different demand levels. Mathematical models are unstable, with slight changes to the data selected producing big changes in the results. Therefore interconnectors are best modelled using a range of sensitivities that reflect the range of credible flows that could occur. The range and intermediate steps will be chosenby examining a density plot of interconnector flows as a percentage of capacity against demand expressed as a percentage of winter de-rated generation capacity(above 85%) asillustrated inFigure 1 below.

Figure 1: Illustrative density plot of Continental interconnector flows as a percentage of capacity (currently 3 GW) against INDO demand expressed as a percentage of winter de-rated generation capacity above 85%.



The range chosen will cover over 99% of the observed percentage flows at times of system tightness (demand expressed as a percentage of winter de-rated generation capacity is above 85%.) i.e. the range will cover from 0.5% to 99.5% of the range of observed percentage flows when the system is tight. For example, based on the illustrative chart above, during periods of system tightness, over 99% ofcontinental interconnector flows lie in the range from 100% imports to 50% exports with a reference assumption of 25% imports.Once the range is determined, intermediate steps will be chosen to split the range into equal intervals to give between five and ten interconnector sensitivities. In the illustrative example above, steps of 25% of total continental interconnector capacity have been used to divide the range into intermediate sensitivities - this step size is supported by the density shading which appears to cluster around the chosen steps. This choice would result in six interconnector sensitivities around the reference assumption.

- A range of low and high conventional plant mean winter availability values fortwo key technologies (CCGTs and nuclear) based on evidence (these may vary independently of the generation mix as a result of different levels of unplanned outages) applied to one scenario. The credible range of values will based on evidence from analysis of historic values as well as published reports on plant availabilities.

Specifically, the analysis will involve the following steps:

- o Calculate mean station availabilities by generation technology based on actual MEL (Maximum Export Limit) data from the most recent seven winters data available at the time of the analysis (e.g. 2006/7 to 2012/13) covering December to February and periods when demand is above the 50th percentile.
- o The one exception to this will CCGTs,for which the mean availability will be based on the periods when demand is above the 95th percentile. This is to allow for the fact that spark spreads have been low over the last few years and thus have artificially deflated availabilities so we need to consider periods when demand has been very high i.e. when the incentive is at its highest to be available. This also moves towards the international benchmark for CCGTs which is higher and based on countries (in particular the USA) where spark spreads are more favourable.
- o The mean availabilities for the other technologies have been validated by external benchmarking against other countries around the world.
- o The ranges to be utilised for sensitivity analysis will be based on the key technologies (CCGTs and nuclear) with the greatest uncertainty i.e. largest standard deviation from the mean availability and with aggregated capacity large enough to be material. This approach is considered more likely than assuming all technologies would be high or low at the same time.
- o The mean availabilities for CCGT and nuclear will both be set to one standard deviation below and above the mean values used in the scenarios in the low and high availability sensitivity respectively.

- Reduced availability of wind at times of higher demand – this may happen over short timescales without time for the market to respond by increasing conventional generation. This sensitivity will assume a reduction in the available wind resource for demand levels higher than 92% of ACS peak demand. The maximum reduction will be assumed to be 50% for demand levels higher than 102% of ACS peak demand(compared to the base scenario) and the reduction will fall linearly between demand levels of 92% and 102% of ACS peak demand. The analysis behind the choice of these numbers is shown in Appendix 4. Note that there is no evidence to support an upside sensitivity for wind availability at times of higher demand.

- Demand variation due to winter weather conditions. For example, analysis of cold (1 in 20) peak demand conditions is included in our Winter Outlook Report[3] as it represents a sensitivity considered by NGET's operational teams when looking at the winter ahead and is used in planning the GB gas network. In addition, 1 in 20 peak demand conditions are widely used for network planning. A 1 in 20 peak demand represents a credible outcome (albeit less likely than ACS) – indeed we have experienced conditions around 1 in 20 in recent years (e.g. Winter 2010/11). Similarly the Winter Outlook Report looks at a demand levelthat is lower than ACS demand namely the peak weather corrected demand (derived from the highest weekly peak demand projection under normal weather conditions).

[3]http://www2.nationalgrid.com/UK/Industry-information/Future-of-Energy/FES/Winter-Outlook/

Although demands from recent winters (including cold and mild winters) are included in the stochastic demand distribution used in the modelling, this distribution is an average of the years used to compile it and is also scaled to projected ACS conditions for each modelled case and year and does not model the full range of weather uncertainty. Therefore in order to model the impact of weather uncertainty on demand, we are intending to run sensitivities around one scenario based on the coldest and warmest individual year demand distributions (2005/06 onwards) used in compiling the average stochastic demand distribution. The coldest and warmest winter will be selected from a ranking of winters based on scenario LOLE values. For example, based on the winters from 2005/06 to 2013/14, a2010/11 winter sensitivity will be used to model cold winter weather conditions and a 2006/07 winter sensitivity will be used to model the impact of a mild winter. Note that demand distributions based on individual winters will still be scaled to projected ACS conditions for each modelled case and year.

- A range of mothballed capacity. Plantmay mothball over short timescales without time for the market to respond by increasing conventional generation. We will include a sensitivity where CCGT capacity (up to 1 GW) mothballs at short notice.This will be based on CCGT capacity that has mothballed in previous years. We will include the additional mothballing in each of the mid-decade years to assess the impact in each year as the mothballing could potentially happen in any of the years. Given the unfavourable economics for gas generation over the short term, there is less evidence to support a sensitivity on mothballed CCGT plant returning. Nevertheless due to the uncertainty surrounding mothballing, we will also include an upside sensitivity where less CCGT capacity (up to 1 GW) is mothballed for years where some mothballed capacity is assumed.

The selection criteria for the sensitivities in the volume assessment(based on historical / other evidence) should ensure that outlier cases with extreme values of LOLE and energy unserved are not modelled. Note that not all sensitivities will be applied to each scenario to keep the total number of cases (scenarios / sensitivities) to a manageable level (maximum 20). For example, the demand wind sensitivity takes a long time to run to produce the EEU / LOLE curves at the required resolution. The sensitivities will be applied to a scenario that lies in the middle of the scenario LOLE range for the mid-decade years i.e. the scenario with LOLE closest to the mean LOLE from all scenarios.Assuming that there are four scenarios and that the number of interconnector sensitivities remains at six, the number of cases modelled would be 17 i.e. 4 scenarios plus 13sensitivities (6 interconnectors, 2 availabilities, 2 winters, 2 mothballed plant, 1 low wind availability).We are intending to model the four years prior to the start of the capacity mechanism (2014/15 to 2017/18) recognizing that if a volume requirement is identified beyond 2015/16, it may be more economic to offer a DSBR / SBR contract that is longer than one or two years. However we recognise that the duration of any contracts may be less than this four year period.

3. Input demand and generation data for the cases (scenarios and sensitivities)and years into NGET's capacity adequacy stochastic model,including assumptions onconventional plant mean winter availability values for each technology, net GB interconnector flows and reserve for response required to cover the largest infeed loss[4]. Note that the range of values used for reserve for response requirement may vary across the scenarios if

[4]NGET holds frequency response in order to prevent a single large unit failure from causing widespread disconnections. This response holding is made up (in part) by de-loaded generation in frequency response mode. The total amount of de-loaded capacity is referred to as "reserve for response".

demand levels are significantly different between scenarios or the connection dates for the power stations that change the largest single loss are different.

4. Run the model for each case and year. The model outputs includethe Loss Of Load Expectation (LOLE) and Expected Energy Unserved (EEU) before mitigation for each case in each year.

   Our view is that the reliability standard of a loss of load expectation (LOLE) of 3 hours takes into account the range of all key uncertainties (not just those that can be modelled stochastically). The stochastic modelling currently takes into account variations around a mean in:
   - demand (assuming average winter weather conditions, a particular level of underlying ACS peak demand and a particular level of net GB interconnector flows)
   - available conventional generation (assuming a particular mix of connected conventional generation and assumed mean availability percentages for each technology)
   - availablewind generation (assuming a particular level of connected wind capacity and assuming wind availability is independent of demand). Note that there is insufficient statistical evidence for wind availability reducing at times of high demand[5].

   The scenarios and sensitivities cover the credible range of key statistical uncertainties not modelled stochastically. In particular:
   - the scenarios cover a range of connected conventional generation mixes, connected wind capacity levels and underlying ACS peak demand values for each year
   - the sensitivities cover a range of net GB interconnector flows, conventional generation mean availability values and wind availability reducing at times of high demand
   - the sensitivities cover a range of winter weather conditions away from the average by modelling demand distributions based on individual historical years.

5. Using the methodology illustratedin Appendix 1, calculate the minimum additional firm generation capacity(or demand reduction) required (if any) for each case (scenario or sensitivity) and year that would be required to reduce the LOLE to 3 hours.

6. Assessan indicative target volume (additional generation reserve or demand reduction reserve capability) to procure in each year.The target volume will be the total quantity of de-rated SBR and DSBR required to reduce the LOLE to 3 hours for a chosen marginal case. Assuming that the tendering takes place after the target volume assessment has been made, the costs of DSBR or SBR will be unknown and hence the decision on which is the marginal case will be a judgement based on anticipated costs and benefits. The steps listed below will be used to validate the judgment made and as a guide to narrow down the choice of potential volumes to a single number based on a chosen marginal case tocover:

   a. Thetarget volume will reduce the LOLE to 3 hours or below for a proportion of the cases (scenarios and sensitivities).The exact number of cases covered by the target volume may change from year to year as for example, the “least worst regret” analysis (see “d” below) may suggest that a different number of cases should be covered in different years.The target volume chosen as a result of the

[5]See page 35 of https://www.ofgem.gov.uk/publications-and-updates/electricity-capacity-assessment-report-2013

least worst regret analysis corresponds to the marginal case and this volume will cover a proportion of the scenarios and sensitivities.

b. The target volume isbelow the volume cap to be determined separately (see section below). To ensure this, a case will be excluded from the "least worst regret" analysis in a particular year if the volume required to reduce its LOLE to 3 hours is above the volume cap in that year.

c. A check will be made that the benefit to consumers from procuring the volume (based on an assumed cost per kW) would not exceed the benefit to consumers in terms of the reduced cost of unserved energy (costed atDECC's central estimate ofVoLL(£17/kWh)[6]. This estimate of VoLL was used by DECC[7] to set the LOLE target of 3 hours. A VoLL value of £17/kWh is also used in DECC's impact assessments to estimate the cost to consumers of unserved energy[8]. For an example of this check, see Appendix 2.

d. To inform the decision on how many cases to "cover", a "least worst regret" approach will be applied to the different potential volume levelsbased on an assumed central cost per kW and the cost of unserved energy calculated from the EEU for the different options (costed at £17/kWh – DECC's central estimate of VoLL – see step c). For the first assessment if there is no information from tender bids, the central cost will be based on the cost estimated for SBR as part of the final consultation on the SBR/ DSBR[9], adjusted to be on a de-rated basis (This cost was based on the estimated revenue of STOR providers and validated against published O&M costs for CCGTs.See Appendix 2 for further details on this and for an illustrative example of this "least worst regret" approach). We will be looking to find the "least worst regret option" in each year and we anticipate that on most occasions that this option will cover for at least the scenarios in that year.

   For information only, a check will be made as to how sensitive the "least worst regret" analysis is to the assumed cost per kW by using an assumed low and high cost per kW. For the first assessment if there is no information from tender bids, these low and high costs will be estimated from costs for gas plants published by DECC[10](given that marginal gas plants are the most likely to provide SBR) and adjusted to be on a de-rated basis (see Appendix 2 for further details). If the "least worst regret" option is different for all three cost per kW options, we would choose the "least worst regret" option for the central cost per kW. In the illustrative example shown in Appendix 2 for 2014/15 a volume of 570MW (de-rated) would be the chosen option. The assumed low, central and high cost per kW will be updated in future analysis to take account of updated information such as the range of bids received in previous tendersor updated analysis on generation costs.

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[6] See https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/224028/value_lost_load_electricty_gb.pdf

[7] See https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/267613/Annex_C_-_reliability_standard_methodology.pdf

[8] e.g. See page 33 of https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/268202/Delivery_Plan_IA.pdf

[9] http://www.nationalgrid.com/NR/rdonlyres/F3F35BA1-8FCA-4206-9234-85D59B2ADB66/62904/FinalProposalsConsultationDSBRSBR10thOctober2013Final1.pdf

[10] See https://www.gov.uk/government/organisations/department-of-energy-climate-change/series/energy-generation-cost-projections

For the illustrative example used in Appendix 1 and 2 the target volume for 2014/15 resulting from applying the methodology would be 570MW (covers for 93% of cases) and the target volume for 2015/16 would be 1140MW (covers for 93% of cases) as the “least worst regret” approach indicates a volume lower than that required to cover 100% of cases in these years. However, the target volumes for 2016/17 and 2017/18 in this illustrative example would be 0 MW (i.e. no requirement for SBR / DSBR in those years). Note that these are illustrative volumes only and certainly not the final volumes.

When additional (non-wind) generation (or demand side response capability) is contracted under SBR / DSBR, it is unlikely to provide firm response capability i.e. be 100% available and hence its equivalent firm capacity (EFC) value is required when assessing the tenders. For this purpose, we will calculate an approximation of this by multiplying the capability of the provider by itsstated/ assumed availability (see Appendix 1) – this is known as its de-rated capability. NGET will look to contract with sufficient providers in order that the sum of the de-rated capabilities of the contracted providers adds up to the target volume. The target volume will be a total de-rated capability number; how that volume is met and the contribution of individual providers will be assessed as part of the tender process.

7. The output from applying the methodology will be an indicativetarget volume (de-rated) of SBR and DSBR to procure each year. The actual volume procured under the tender process may be different to the target volume if for example, it is not cost effective to procure this volume or the total tendered de-rated capability is below the target volume.

   For information to the market,an indicative range (lower and upper bounds)will be calculatedfromthe minimum and maximum of the (non-zero) potential volume levels considered that are below the volume cap.

   In addition, the outputsfor each year would includeLOLE and EEU curves showing the relationship between LOLE / EEU and additional de-rated capability for the marginal case covered in each year to be used as part of the economic assessment of SBR and DSBR tenders. Pages 12and 13in Appendix 1 show LOLE and EEU curves in 2014/15 and 2015/16 for the marginal cases covered in the illustrative example.

8. Once the tender bids have been received, the “least worst regret” analysis will be repeated and used to reassess the volume requirement by using actual costs (on a bid-by-bid basis) from the tender process to calculate the procurement costs for each potential volume. This may result in a contracted volume that is different from the indicative target volume but it should lie within the indicative range.

9. NGET may update the assessment periodically to take account of material changes to the market (e.g. where plant is withdrawn having secured a SBR contract or other plant returns to the market or closes after the volume assessment is carried out).

Volume Cap

The maximum aggregate volume of de-rated Supplemental Balancing Reserve and Demand Side Balancing Reserve will be set at 5% of the ACS[11] peak demand for each year of the assessment, based on the scenario with the highest demand projections in NGET's Future energy Scenarios (FES).

Given that the market would be expected to respond if the de-rated margin falls to 0% by returning plant to market, SBR and DSBR would not be required to support margins below this level (the market has not allowed margins to drop below 0% over the past 10 years).

The Operating Reserve Requirement around four hours ahead of real time is set at approximately 3GW, which based on historic plant failures and demand forecast errors provides sufficient reserves to meet demand to a 99.7% confidence (i.e. there is only a 1 in 365 probability that load shedding will be required). If the level of available reserve drops significantly below this level, warnings including a Notice of Insufficient System Margin (NISM) can be issued by NGET to the market to encourage more generation to become available.

Assuming a peak Average Cold Spell demand forecast of 57GW (including likely interconnector exports), a 3GW operating reserve requirement equates to a margin of approximately 5%. This represents the operating margin below which additional interventions are required to maintain less than a 1 in 365 probability that load shedding will be required, but SBR and DSBR would not be required to support margins above this level.

Thus a maximum de-rated volume of SBR and DSBR that could be procured will be set as the difference between 0% and 5% i.e. 5% of ACS peak demand. This would equate to a de-rated requirement of around 2.8GW based on the demand projections in the 2013 Future Energy Scenarios.

[11]The Average Cold Spell (ACS) peak demand is the demand level resulting from a particular combination of weather elements that give rise to a level of peak demand within a financial year (1 April to 31 March) that has a 50% chance of being exceeded as a result of weather variations alone. The Annual ACS Conditions are defined in the Grid Code.

Appendix 1 - Methodology for estimating the additional de-rated capability required to reduce LOLE to 3 hours for each case

Overview of model and key output variables

As part of our wider capacity adequacy work, NGET has developed a stochastic model thatcan be used to determine metrics such as Loss of Load Expectation (LOLE),and Expected Energy Unserved (EEU)for a scenario / sensitivity by capturing the short term variability of inputs using probability distributions.

The model consists of a specification of the joint distribution of the random variables;

- X which represents available conventional generation;
- W which represents available wind generation; and
- D which represents demand

at a randomly chosen point in time, i.e. snapshot, during the winter season modelled. Then the random variable $Z = X + W - D$ models the excess of supply over demand at that snapshot in time.

We then define the snapshot Loss Of Load Probability (LOLP) and Expected Power Unserved (EPU) as

$$[LOLP] = P(Z \le 0)$$

$$[EPU] = E[\max(-Z, 0)] = \int_{-\infty}^{0} P(Z \le z)dz$$

The Loss Of Load Expectation (LOLE) for the season modelled is then defined to be the LOLP multiplied by the length of the season, and the Expected Energy Unserved (EEU) is defined to be the EPU multiplied by the length of the season.

The model also outputs the distribution of LOLE and EEU for different values (in 10MW increments) of Y, an independent random variable representing the addition of 100% available firm capacity (or the reduction of demand). The LOLE for Y = 0 is the LOLE without additional capacity (or demand reduction).

From theLOLE distribution, the value of Y required to reduce LOLE to a target value can be obtained. The change in EEU resulting from the addition of this additional firm capacity can also be obtained from the EEU distribution.

Appendix 3 gives a mathematical formulation for the addition of additional firm capacity (or reduction in demand) to a given scenario.Section2 of Appendix 3 gives a means of estimating the equivalent firm capacity (EFC) of additional generation (or demand reduction) if is not firm (i.e. not 100% available) for differentassumptions about the distribution of its available capacity.

Illustrative Example

To illustrate the methodology only, the outputsfrom existing NGET analysis have been utilised. We did not have a set of outputs from the FES scenarios and sensitivities matching our proposed approach as these do not currently exist and hence we can not illustrate the methodology exactly, but the principles can be illustrated using the outputs of existing analysis. This analysis consisted of 15 cases (NGET's 2013 Gone Green scenario,13sensitivities aroundthis scenario and one other case based on the 2012 Slow Progression scenario). These cases were input into NGET's capacity adequacy stochastic modelfor years including 2014/15 to 2017/18. These casesare denoted by letters "a" to "o". For the purposes of this document, these cases are purely illustrative and are not intended to give an indication of the final volume requirements for the years in question.

Note that some extreme cases analysed by NGET based on significantly different demands and maximum continental interconnector exports at peak have been excluded from the illustrative example along with other cases that are the same as 2013 Gone Green scenario for the years 2014/15 to 2017/18.

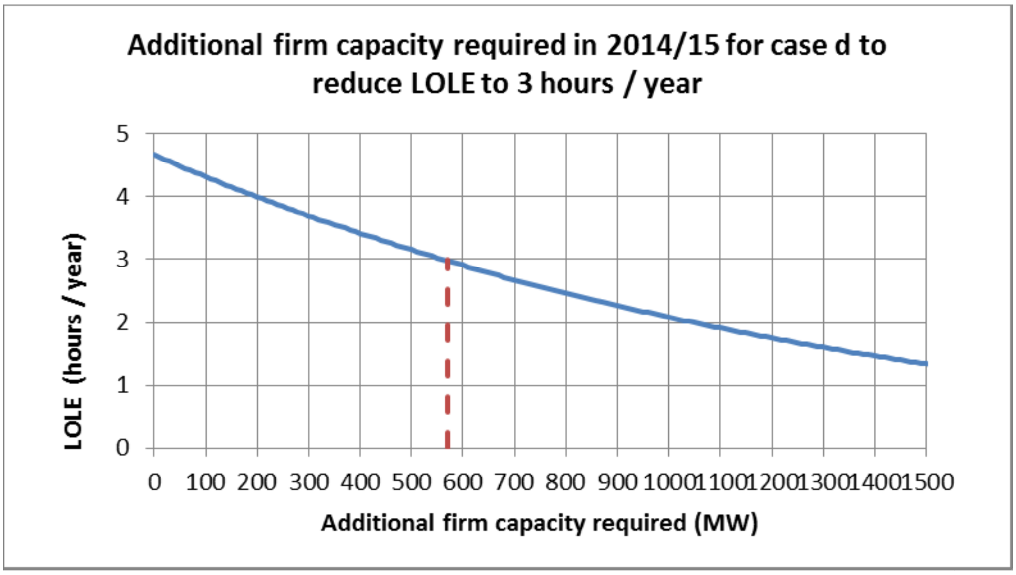
A brief description of the illustrative cases is shown below:

Letter	Brief Description Of Illustrative Case
a	NGET's 2013 Gone Green scenario
b	Interconnection to Continental Europe 1.5GW import at peak
c	Interconnection to Continental Europe 3GW import at peak
d	Interconnection to Continental Europe 1.5GW export at peak
e	Interconnection to Continental Europe float (0 MW) at peak
f	No Irish exports at peak
g	CCGT early closures & new slippage
h	CCGT deferred closures and early returns
i	Mothballed plant returning
J	Biomass conversions not relicensed
k	Biomass conversions relicensed
l	Low plant availabilities
m	High plant availabilities
n	DSR option
o	Case based on NGET's 2012 Slow Progression scenario

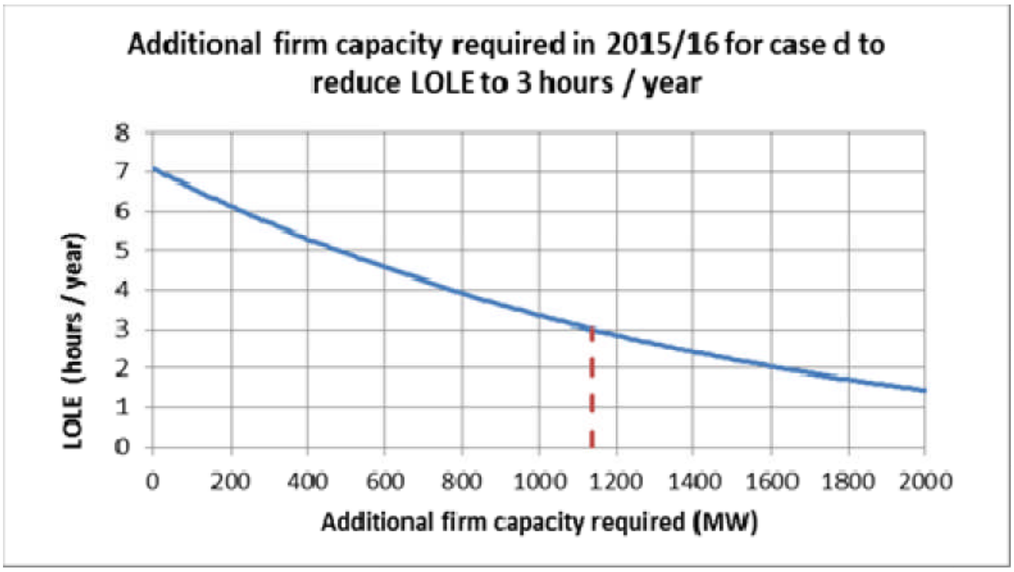
In the2013 Gone Green scenario, the assumed net GB interconnector flows are 0 MW at peak (i.e. exports of 750MW from GB to Ireland are matched by a similar level of imports to GB from Continental Europe).

The additional firm conventional capacity required (if any) to bring LOLE down to the Government's reliability standard (3 hours LOLE per year) for each case and year was obtained directly from the model output.

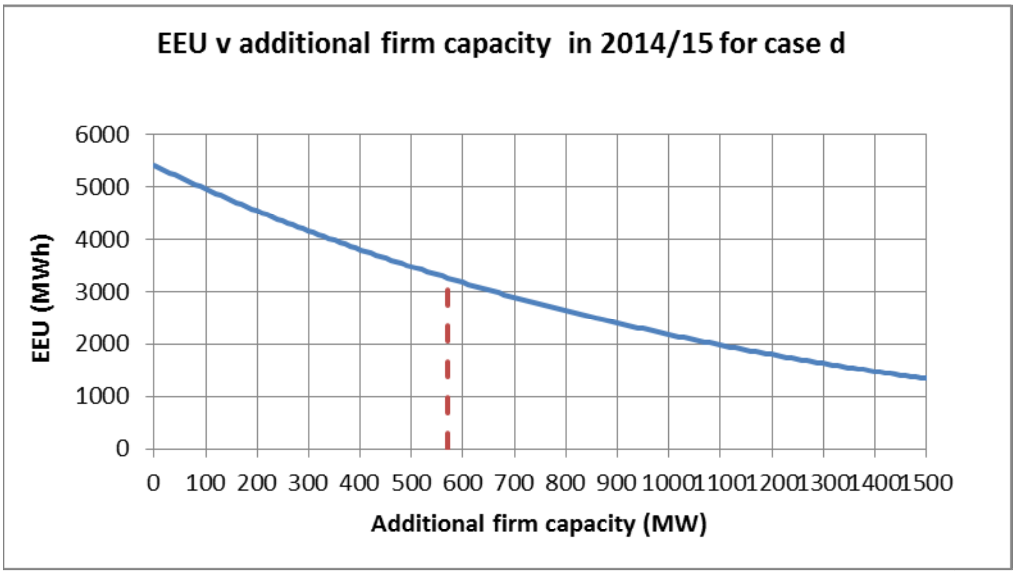
For example, the following LOLE curveplotted from the model output for one of the sensitivities (case “d”) illustrates this. In this illustrative example, additional firm capacity of 570 MW is required to reduce the LOLE to 3 hours in 2014/15.



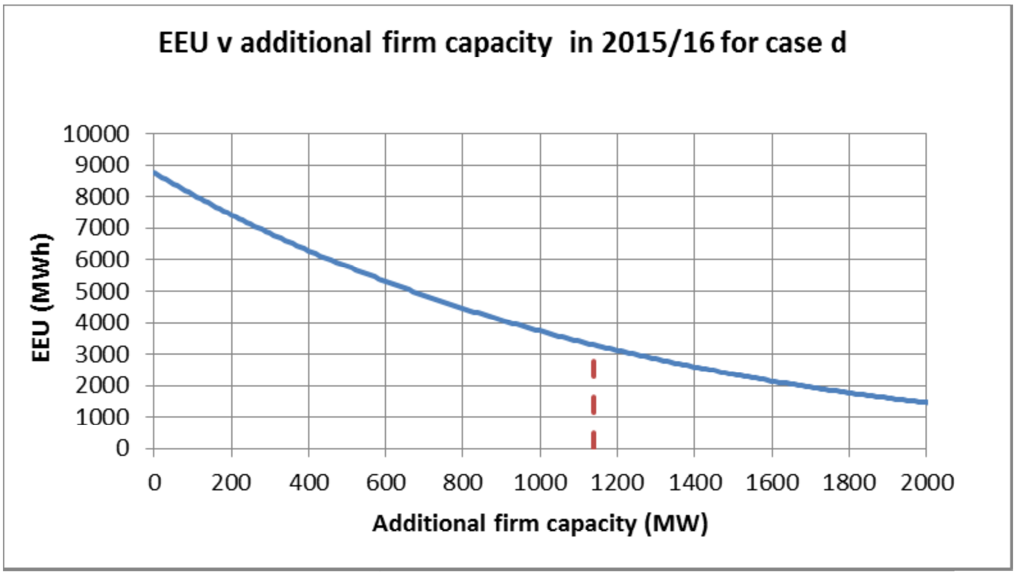
Another illustrative example below shows the LOLE curve plotted from the model output for case “d”. In this illustrative example, additional firm capacity of 1140 MW is required to reduce the LOLE to 3 hours in 2015/16.



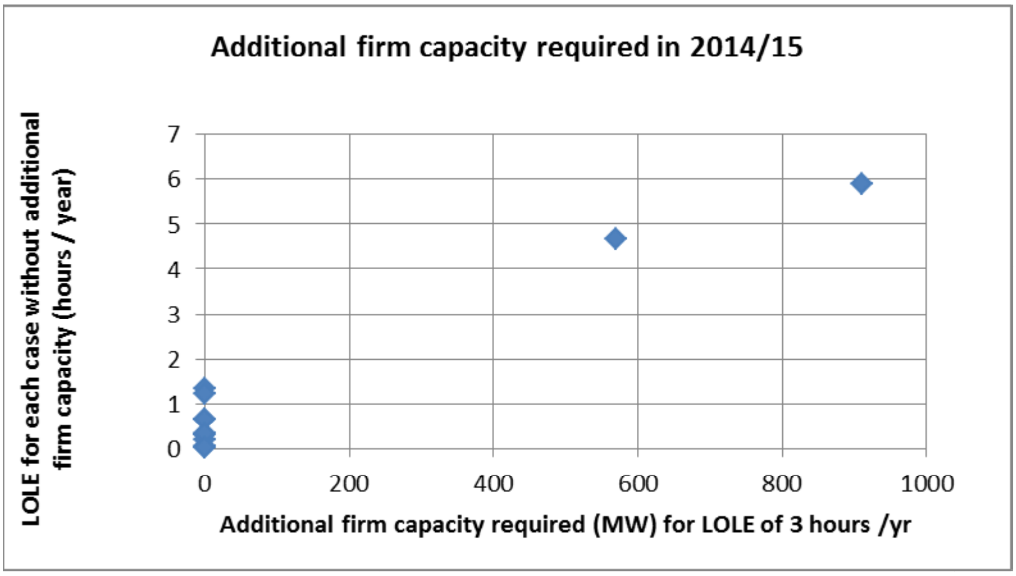
The model also outputs the EEU for different levels of additional firm capacity. For example, the following EEU curve plotted from the model output for case “d” illustrates this. In this illustrative example, an additional 570MW of firm capacity reduces the EEU from 5,411 MWh to 3,264 MWh in 2014/15.



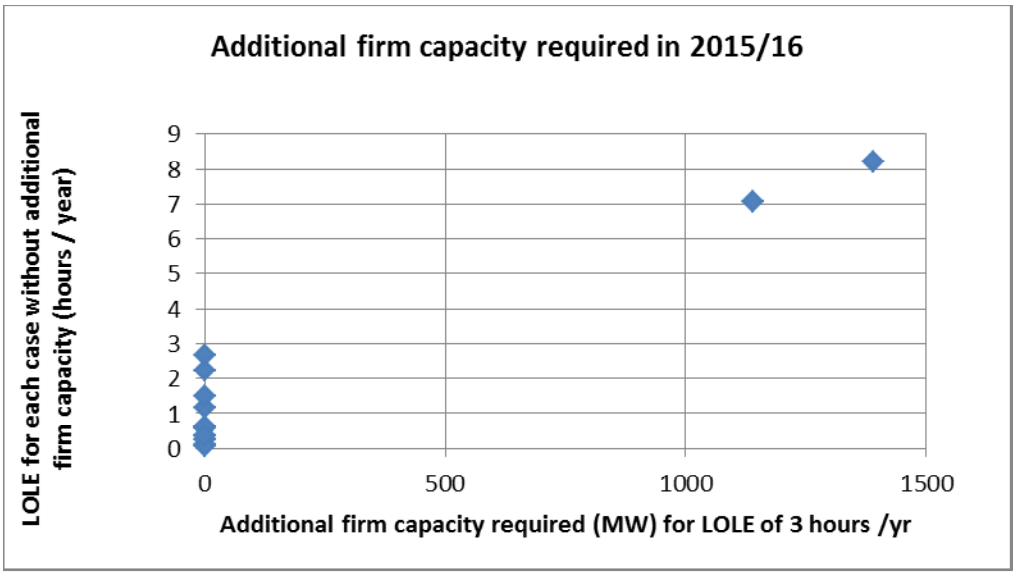
Another illustrative example below shows the EEU curve plotted from the model output for case “d” in 2015/16. In this illustrative example, an additional 1140MW of firm capacity reduces the EEU from 8,758 MWh to 3,411 MWh in 2015/16.



The additional firm capacity required to bring LOLE down to 3 hours in 2014/15 in the illustrative example for all 15cases is shown below plotted against the original LOLE values.An additional 570MW of additional firm capacity would ensure that 93% (14 out of 15) cases would have their LOLE at or below 3 hours in that year.



The following illustrative chart shows the additional firm capacity required to bring LOLE down to 3 hours in 2015/16for the illustrative example.An additional 1140MW of firm capacity would ensure that 93% (14 out of 15) cases would have their LOLE at or below 3 hours in that year.



The least regret analysis in Appendix 2 explains why in the illustrative example we would cover 93% of cases in 2014/15 and 2015/16.

In 2016/17 and 2017/18 there were no cases in the illustrative example with LOLE over 3 hours and hence there would be no volume requirement in the illustrative example for these years.

Appendix 2 – Least worst regret approach to narrow the choice of volume to a single value

When deciding betweenpotential options, a least worst regret approach (also known as robust optimisation) aims to minimise the cost implications of any decision made when there is uncertainty over the future. One benefit of this approach is that it is independent of the probabilities of the various potential future outcomes and therefore it can be used when the probabilities of these outcomes are unknown, providing that the cases considered cover a range of credible outcomes.

For each case and potential volume (de-rated) in a particular year, the total cost to consumers can be estimated based on an assumed unit costof de-rated capacity / demand reduction capability and an assumed unit cost of energy unserved of £17,000/MWh-DECC's central estimate of the Valueof Lost Load (VoLL)).

For example, the total cost of a case (scenario or sensitivity) is calculated as:

Total Cost = Cost of De-Rated Volume + Cost of EEU

where:

Cost of De-Rated Volume = De-Rated Volume (MW)
* Unit cost of De-Rated Volume (£/MW)

and:

Cost of EEU = EEU (MWh) * £17,000/MWh

For each case, a base cost is calculated as the total cost for the optimum level of additionalde-rated capability (i.e. the level required to bring LOLE down to 3 hours). For the other potential volume levelsfor that case, the regret cost is defined as the difference between the total cost and the base cost. The "worst regret" for a potential volume level is then defined as the highest of the regret costs across all cases i.e. the highest cost of under / over procurement. The "least worst regret" volume is then the potential volume level with the lowest "worst regret" value. This is the same principle used in NGET's National Development Policy to choose between potential transmission network reinforcement options.[12]

Using the illustrative example shown in Appendix 1, in 2014/15, the illustrative potential volume levels of additional de-rated capability equivalent to a LOLE of 3 hours are 0, 0, 570 and 910 MW derived from cases o, e, d and l respectively. (Note that there are other cases in addition to cases o and e that meet the reliability standard and have an additional volume required of 0 MW. The regret costs for these cases have been calculated, but since they lie within the range of the four cases, they have been excluded from the tables below to simplify the tables without changing the conclusion). These potential volumes are all below the proposed volume cap and hence there are no cases excluded for that reason. The EEU and cost of unserved energy are shown in the following tablefor each case and potential volume level.

[12]See http://www2.nationalgrid.com/UK/Industry-information/Future-of-Energy/Electricity-Ten-Year-Statement/

Case - 2014/15	EEU (MWh) with following de-rated capability added			Cost of unserved energy (£million) for added de-rated capability		
	0 MW	570MW	910MW	0 MW	570MW	910MW
o	12	6	4	0.21	0.10	0.06
e	1,341	746	517	22.80	12.68	8.80
d	5,411	3,264	2,381	91.99	55.49	40.47
l	7,307	4,551	3,388	124.22	77.36	57.60

The cost of SBR was estimated to be around £25/kW/year(based on the estimated revenue of STOR providers and validated against published O&M costs for CCGTs) as part of the final consultation on the DSBR/ SBR[13]. If we assume a de-rating factor for SBR of 85% this equates to a cost or de-rated capacity of around £30/kW/year. In the absence of bid tender information, we will use this is a central estimate of the de-rated volume cost per kW per year in the 2014 volume assessment. Using these assumptions[14], the cost of an additional volume (de-rated) of 570MW would be £17.1 million and the cost of an additional 910 MW would be £27.3 million. The de-rated volume cost in 2014/15 for each case and potential volume level is shown below.

Case - 2014/15	Cost of De-Rated Volume (£million)		
	0 MW	570 MW	910 MW
o	0	17.10	27.30
e	0	17.10	27.30
d	0	17.10	27.30
l	0	17.10	27.30

For each potential volume level (de-rated), the benefit to consumers from reducing the unserved energy is greater than the cost and hence no options are ruled out from this check. For example, the reduction in unserved energy costs for case “d” from a volume (de-rated) of 570 MW is £36.5million (£91.99m – £55.49m) – this is greater than the cost of the additional volume (£17.1 million).

The total costs to consumers (unserved energy cost plus cost of additional de-rated capacity) for each potential volume level and case would be as follows shown along with the base cost:

Case - 2014/15	Total cost to consumers (£million)			Base cost
	0 MW	570 MW	910 MW	
o	**0.21**	17.20	27.36	**0.21**
e	**22.80**	29.78	36.10	**22.80**
d	91.99	**72.59**	67.77	**72.59**
l	124.22	94.46	**84.90**	**84.90**

The regret cost (calculated from the absolute value of the difference between the total cost and the relevant base cost) for each case and potential volume is shown in the following table along with the worst regret for each potential volume:

[13]The final consultation on DSBR / SBR suggests a cost of around £25/kW/year for non de-rated capacity.DSBR was also estimated to have a similar cost - see pages 54 and 55 of http://www.nationalgrid.com/NR/rdonlyres/F3F35BA1-8FCA-4206-9234-85D59B2ADB66/62904/FinalProposalsConsultationDSBRSBR10thOctober2013Final1.pdf

[14]Note that any fixed costs of operating DSBR / SBR (not dependent on the total volume procured) have been excluded from this analysis - they are likely to be small in comparison with the assumed cost per kW.

Case - 2014/15	Regret Cost (£million) for volume cost of £30/kW/year		
	0 MW	570 MW	910 MW
o	0.00	**16.99**	**27.16**
e	0.00	6.98	13.29
d	19.40	0.00	4.82
l	**39.31**	9.56	0.00
Worst regret	**39.31**	**16.99**	**27.16**

In this illustrative example the least worst regret cost is £16.99 million corresponding to a volume (de-rated) of 570MW. To check how sensitive this result is to the assumed cost per kW (de-rated), the analysis was repeated with an assumed low and high volume (de-rated) cost of £20/kW/year and £47/kW/year respectively (see following tables). The low cost is estimated from generation costs for CCGTs analysed by PB Power and published by DECC[15]. This suggests a low figure for O&M (including insurance) of around £19/kW/yr which would equate to around £20/kW/year (de-rated) assuming a higher de-rating factor of 95%. The high cost is set to £47/kW, the central value of gross cost of new entry (CONE) published in DECC's EMR Delivery Plan[16]

Case - 2014/15	Regret Cost (£million) for volume cost of £20/kW/year		
	0 MW	570 MW	910 MW
o	0.00	11.29	**18.06**
e	0.00	1.28	4.19
d	25.10	0.00	8.22
l	**48.41**	**12.96**	0.00
Worst regret	**48.41**	**12.96**	**18.06**

Case - 2014/15	Regret Cost (£million) for volume cost of £47/kW/year		
	0 MW	570 MW	910 MW
o	0.00	**26.68**	**42.63**
e	0.00	16.67	28.76
d	9.71	0.00	0.96
l	**23.84**	3.78	0.00
Worst regret	**23.84**	**26.68**	**42.63**

In this illustrative example the least worst regret option is 570MW for an assumed cost of £20/kW/year and0 MW for an assumed cost of £47/kW/year. Hence for two out of three assumed cost values including the central cost, 570 MW is the least worst regret option - this is the option we would choose in this example. (Note that for an assumed cost per kW (de-rated) of £45.08/kW/year the 570MW and 0 MW volume options would have the same worst regret costs).

Using the illustrative example shown in Appendix 1, in 2015/16, the potential volumes of additional de-rated capability equivalent to a LOLE of 3 hoursare 0, 0, 1140 and 1390 MW derived from cases m, j, d and l respectively. (Note that there are other cases in addition to cases m and j that meet the reliability standard and have an additional volume required of 0 MW. The regret costs for these cases have been calculated, but since they lie within the range of the four cases, they have been excluded from the tables below to simplify the tables). These potential volumes are all below the proposed volume cap and hence there are

[15] See https://www.gov.uk/government/organisations/department-of-energy-climate-change/series/energy-generation-cost-projections
[16] See https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/267613/Annex_C_-_reliability_standard_methodology.pdf

no cases excluded for that reason. The regrets costs for these potential volumes for the different assumed cost per kW (de-rated)options are shown below:

Case - 2015/16	Regret Cost (£million) for volume cost of £20/kW/year		
	0 MW	1140 MW	1390 MW
m	0.00	**22.17**	**27.12**
j	0.00	10.05	8.74
d	70.06	0.00	17.85
l	95.96	9.05	0.00
Worst regret	**95.96**	**22.17**	**27.12**

Case - 2015/16	Regret Cost (£million) for volume cost of £30/kW/year		
	0 MW	1140 MW	1390 MW
m	0.00	**33.57**	**41.02**
j	0.00	1.35	5.16
d	58.66	0.00	20.35
l	**82.06**	6.55	0.00
Worst regret	**82.06**	**33.57**	**41.02**

Case - 2015/16	Regret Cost (£million) for volume cost of £47/kW/year		
	0 MW	1140 MW	1390 MW
m	0.00	**52.95**	**64.65**
j	0.00	20.73	28.79
d	39.28	0.00	0.24
l	**58.43**	2.30	0.00
Worst regret	**58.43**	**52.95**	**64.65**

In this illustrative example the least worst regret option is a volume (de-rated) of 1140MW for all three assumed cost values including the central one - this is the option we would choose. (Note that for an assumed cost per kW (de-rated) of £49.17kW/year the 0 MW and 1140 MW volume options would have the same worst regret costs).

The assumed low, central and high cost per kW will be updated in future analysis to take account of updated information such as the range of bids received in previous tenders and updated analysis on generation costs.

Appendix 3 – Technical note explaining theory behind addition of additional capacity to a given scenario

Conversion between margin and LOLP/LOLE

Stan Zachary and Chris Dent

February 23, 2014

0. Introduction

This note describes the conversion between the various measures of capacity margin and LOLP or LOLE, in all cases with respect to a given supply-demand balance scenario. In particular it describes how to determine how much additional capacity (certain or uncertain) must be added to a system in order to achieve a given LOLP/LOLE target.

There are two methodologies involved, both of which involve the (cumulative) distribution function F_Z of the random variable Z modelling the existing supply – demand balance. This distribution function is assumed to be well tabulated and available, and indeed it is produced as an output of the present model.

The first methodology, which we describe in Section 1 below, concerns the actual conversion between margin and LOLP, and for maximum accuracy makes use of the known function F_Z itself, rather than any approximation to it.

The second methodology, which we describe in Section 2, concerns the calculation of equivalent firm capacities (EFCs) for uncertain additional generation (including conventional generation whose availability is not totally guaranteed). These EFCs are the margin shifts corresponding to the capacity addition, and it is necessary to ensure that the total margin shift is sufficient—as determined by the first methodology—to achieve the required LOLP/LOLE target. For the calculation of EFCs it is usually convenient to use an exponential approximation to the left tail of the distribution function F_Z, assuming this approximation to be sufficiently good (this needs to be checked).

Section 3 discusses practical implementation. Essentially this reduces to (a) determine the required margin shift required to produce a given target LOLP/LOLE, (b) calculate the EFCs of proposed capacity additions, and ensure their total is sufficient to achieve the required margin shift. We give a worked example in Section 4.

1. Conversion between margin and LOLP

In any given scenario, let F_Z be the (cumulative) distribution function of the time-collapsed or "snapshot" *margin*

$$Z = \text{supply} - \text{demand}.$$

Note that the distribution of Z, and hence F_Z, is an output of the time-collapsed model. Then the *loss-of-load probability* corresponding to the supply – demand bal-

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ance modelled by Z is given by

$$\mathrm{LOLP_{orig}} = F_Z(0). \tag{1}$$

If now the margin Z is increased by a *constant* (i.e. non-random) amount z' the new loss-of-load probability is given by

$$\mathrm{LOLP_{new}} = F_Z(-z'). \tag{2}$$

(Thus a particular target $\mathrm{LOLP_{new}}$ can be achieved by a pure-shift increase in the margin, i.e. addition of *completely* firm capacity, of $z' = -F_Z^{-1}(\mathrm{LOLP_{new}})$.)

More generally the *equivalent firm capacity* (EFC) of variable additional capacity, modelled by a random variable Y, is the solution EFC_Y of

$$\mathbf{P}(Z + \mathrm{EFC}_Y \leq 0) = \mathbf{P}(Z + Y \leq 0) \tag{3}$$

(where $\mathbf{P}$ denotes probability). Hence if the margin Z is increased by the addition of variable capacity Y the new loss-of-load probability is given by

$$\mathrm{LOLP_{new}} = F_Z(-\mathrm{EFC}_Y), \tag{4}$$

so that the equation (2) continues to hold where we now take $z' = \mathrm{EFC}_Y$. Thus if the capacity to be added to a system is not actually firm, but rather modelled by a random variable Y, we need to be able to calculate its equivalent firm capacity EFC_Y. This is typically a quick calculation—which we describe below—when Y is statistically *independent* of Z, as will usually be the case when the additional capacity is supplied by conventional generation. However, when Y is not independent of Z (as might be the case when the additional capacity is supplied by wind) then this has to be allowed for. This may be reasonably straightforward, as in the situation described in Section 3, while in other circumstances it may be necessary to rerun the original model generating Z with the new capacity in place.

2. Calculation of EFC_Y when Y is assumed independent of Z

We now consider the calculation of EFC_Y for a (possibly) variable capacity addition Y which is assumed to be **independent** of Z.

A general approach to this calculation would be to calculate first $\mathrm{LOLP_{new}} = \mathbf{P}(Z + Y \leq 0)$ (involving the typically numerical convolution of the distributions of Z and Y) and then obtain EFC_Y by the solution of (4). However, provided the left tail of the distribution of Z is well approximated by an *exponential* function, as, for good theoretical reasons, will usually be the case, then EFC_Y may be much more easily obtained directly and then (4) used to derive $\mathrm{LOLP_{new}}$.

We thus assume (in addition to the above independence assumption) that the distribution function F_Z is indeed well approximated in the region of interest—that corresponding to negative values of Z—by an exponential function, i.e. that

$$F_Z(z) = ce^{\lambda z}, \qquad z \leq 0, \tag{5}$$

for some constants $\lambda > 0$ and $0 < c < 1$. Note that, from (1), we have $c = \mathrm{LOLP_{orig}}$. Using this, and taking logs of both sides of (5), we have

$$\log F_Z(z) = \log \mathrm{LOLP_{orig}} + \lambda z \tag{6}$$

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(where here and subsequently "log" refers to the *natural* logarithm). Thus the quality of the exponential approximation may be tested by a plot of $\log F_Z(z)$ against z, and, provided the relationship is reasonably linear, λ may then be estimated as the associated slope.

Now suppose that it is proposed to add additional capacity whose contribution is modelled by a random variable Y, and that Y may reasonably be treated as *independent* of the existing supply – demand balance given by Z. Then it is easily shown (see [1]) that, under the above exponential approximation, the equivalent firm capacity EFC_Y of Y is given by

$$\mathrm{EFC}_Y = -\frac{1}{\lambda}\log \mathbf{E}e^{-\lambda Y}, \tag{7}$$

where $\mathbf{E}$ denotes expectation. The quantity EFC_Y given by (7) is something less than the mean $\mathbf{E}Y$ of Y (except when Y is constant, i.e. firm, in which case EFC_Y is simply this constant value).

Note also the following very important property which holds in this "exponential tail" case. If the random variables Y_1 and Y_2 represent two capacity additions which are **independent** of each other and of the existing supply-demand balance Z, then it follows easily from (7) that

$$\mathrm{EFC}_{Y_1+Y_2} = \mathrm{EFC}_{Y_1} + \mathrm{EFC}_{Y_2}. \tag{8}$$

Thus in this case the benefits, in terms of margin shift, of additional capacity $Y_1 + Y_2$ is the sum of their individual benefits. However, the independence requirements here are crucial.

We give some special cases where the quantity represented by (7) may be evaluated analytically.

1. *Independent binary addition.* Suppose that the additional capacity Y takes the value a with (availability) probability p and the value 0 with probability $1-p$. Then
$$\mathrm{EFC}_Y = -\frac{1}{\lambda}\log(1-p+pe^{-\lambda a}). \tag{9}$$
(This is the well-known Garver approximation.)
2. *Independent normal addition.* Suppose that the additional capacity Y has an $N(\mu, \sigma^2)$ distribution. Then
$$\mathrm{EFC}_Y = \mu - \frac{\lambda}{2}\sigma^2. \tag{10}$$
3. *Independent exponential addition.* Suppose that the additional capacity Y has an exponential distribution with mean μ (and hence standard deviation μ). Then
$$\mathrm{EFC}_Y = \frac{1}{\lambda}\log(1+\lambda\mu). \tag{11}$$
4. *Independent addition with small standard deviation.* Suppose that the additional capacity Y has a distribution with mean μ and standard deviation σ, and that $\lambda\sigma$ is very much less than one. Then we have the approximation
$$\mathrm{EFC}_Y \approx \mu - \frac{\lambda}{2}\sigma^2, \tag{12}$$
(the quality of this approximation improving as $\lambda\sigma$ becomes closer to zero). However, for additional capacity with a non-normal distribution, this approximation should be used with care. It is only good for sufficiently small values of $\lambda\sigma$—say $\lambda\sigma \leq 0.1$.

In the cases 1–3. above these results follow from (7) and the moment generating functions (or Laplace transforms) of the probability distributions concerned, while the final result follows from the expansion of (7) as a power series in λ. Note that in the cases 1. and 3. above, the result (12) may be verified directly for sufficiently small λ.

While the expression (7) may also be evaluated exactly for a few other standard distributions for Y, in general it may need to be evaluated numerically. (This is nevertheless a much simpler process than the convolution referred to above.)

The above methodology is useful for determining EFC_Y for variable additional capacity Y (subject as always to the above *independence* condition). Note however that, for maximum accuracy, once EFC_Y is determined as above, the LOLP resulting from the addition of Y should then be evaluated using the result (4) without the need to resort to further use of the approximation (5).

3. Practical implementation

Suppose that we wish to determine the additional capacity to be added to a given system in order to achieve a target LOLP/LOLE. In general we can proceed as follows.

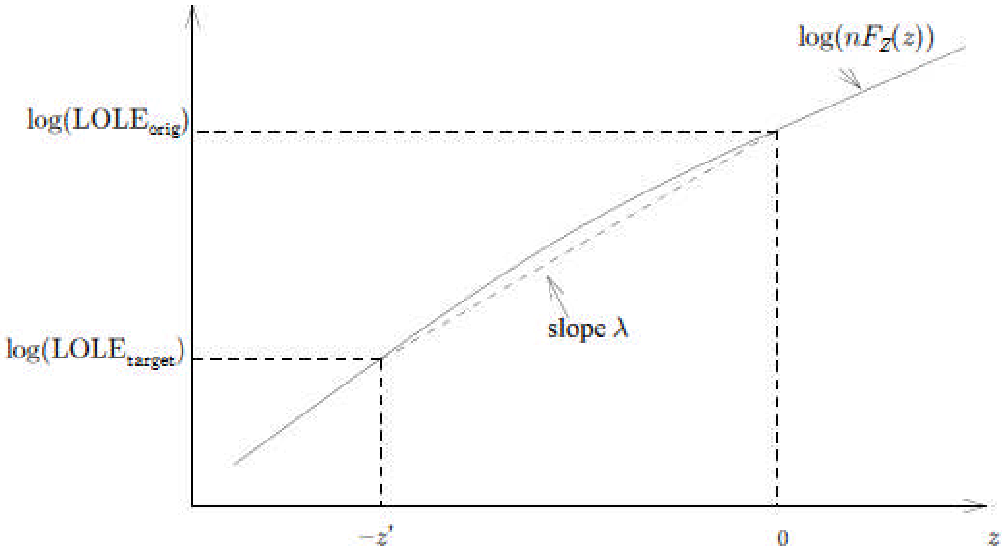

Figure 1: Plot of $\log nF_Z(z)$ against z, where $F_Z(z)$ is the cumulative distribution function of the existing supply − demand balance. Here z' is the margin shift required to achieve the target LOLE.

1. Calculate the margin shift z' necessary to achieve the target LOLE. From (2), this is the solution of

$$\mathrm{LOLE}_{\mathrm{target}} = nF_Z(-z'), \tag{13}$$

where, as before, $F_Z(z)$ is the cumulative distribution function of the existing supply − demand balance, represented by the random variable Z, and where n is the number of half-hour periods in the peak season, i.e. the LOLP to LOLE conversion factor. See Figure 1, which shows a plot of $\log nF_Z(z)$ against z. (A tabulation of $nF_Z(z)$ is available from the output of the model applied to the existing scenario.)

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2. Check that the plot of $\log nF_Z(z)$ against z is tolerably linear. (That shown in Figure 1 would be acceptable in this regard.) Estimate its approximate slope λ by
$$\lambda = \frac{1}{z'}[\log(\mathrm{LOLE_{target}}) - \log(\mathrm{LOLE_{orig}})] \tag{14}$$
where $\mathrm{LOLE_{orig}} = nF_Z(0)$ (again see Figure 1).
3. For each proposed capacity addition, **other than the wind**, modelled by a random variable Y, calculate its EFC via (7), i.e.
$$\mathrm{EFC}_Y = -\frac{1}{\lambda}\log \mathbf{E}e^{-\lambda Y} = -\frac{1}{\lambda}\log \sum_{\text{all possible } y} e^{-\lambda y}\,\mathbf{P}(Y = y). \tag{15}$$
Under the assumption that capacity additions are statistically **independent** of each other and of the existing capacity, the EFC of a number of capacity additions is, to a very good approximation (which is exact when the existing capacity distribution has an exponential left tail—see (8)), the sum of the EFCs of the individual capacity additions. It is therefore only necessary to choose capacities whose EFCs total to the margin shift z' identified in 1. above as being necessary to achieve the target LOLE.
4. In the case of **wind**, matter are more complex since new wind will almost certainly not be statistically independent of existing wind. If the random variables W_{orig}, W_{new}, and W_{total} model respectively all *existing* wind, all *new* wind, and *total* wind (i.e. *existing* plus *new*), it is necessary to calculate to calculate the EFC of W_{new} as
$$\begin{aligned}\mathrm{EFC}_{W_{\text{new}}} &= -\frac{1}{\lambda}\log \mathbf{E}e^{-\lambda W_{\text{total}}} + \frac{1}{\lambda}\log \mathbf{E}e^{-\lambda W_{\text{orig}}} \\ &= -\frac{1}{\lambda}\log \sum_{\text{all possible } w} e^{-\lambda w}\,\mathbf{P}(W_{\text{total}} = w) \\ &\qquad + \frac{1}{\lambda}\log \sum_{\text{all possible } w} e^{-\lambda w}\,\mathbf{P}(W_{\text{orig}} = w),\end{aligned} \tag{16}$$
that is, the EFC of the new wind is calculated as the EFC of the total wind less the EFC of the originally existing wind, the latter two quantities being calculated as in 3. (Note that calculating the EFC of the new wind *directly* as in 3., i.e. using equation (15), will give a considerably exaggerated answer, as the contribution of new wind is significantly decreased by the presence of existing wind.)
If the EFC of the total new wind is calculated via (16), then, as before, it is only necessary to choose capacities whose EFCs total to the margin shift z' identified in 1. above as being necessary to achieve the target LOLE.
We remark also that in the case where the *total* wind (*existing* plus *new*) is simply the *existing* wind scaled by a factor $k > 1$, i.e. $W_{\text{total}} = kW_{\text{orig}}$, as might well be reasonable when the geographical diversity of the total wind fleet is no greater than that of the original, then the expression (16) simplifies (slightly) to
$$\begin{aligned}\mathrm{EFC}_{W_{\text{new}}} &= -\frac{1}{\lambda}\log \sum_{\text{all possible } w} e^{-\lambda k w}\,\mathbf{P}(W_{\text{orig}} = w) \\ &\qquad + \frac{1}{\lambda}\log \sum_{\text{all possible } w} e^{-\lambda w}\,\mathbf{P}(W_{\text{orig}} = w).\end{aligned} \tag{17}$$

4. Example

Data from a realistic current GB scenario tabulate z and $nF_Z(z)$ (where F_Z is the distribution function of Z) for values z of Z in the region $-8000 \leq z \leq 8000$ (all units in MW). Figure 2 shows a plot of $\log[nF_Z(z)]$ against z for values z of Z in the region $-4000 \leq z \leq 4000$ where n is the number of half-hours periods in the season, i.e. the LOLP to LOLE (in half-hour periods) conversion factor.

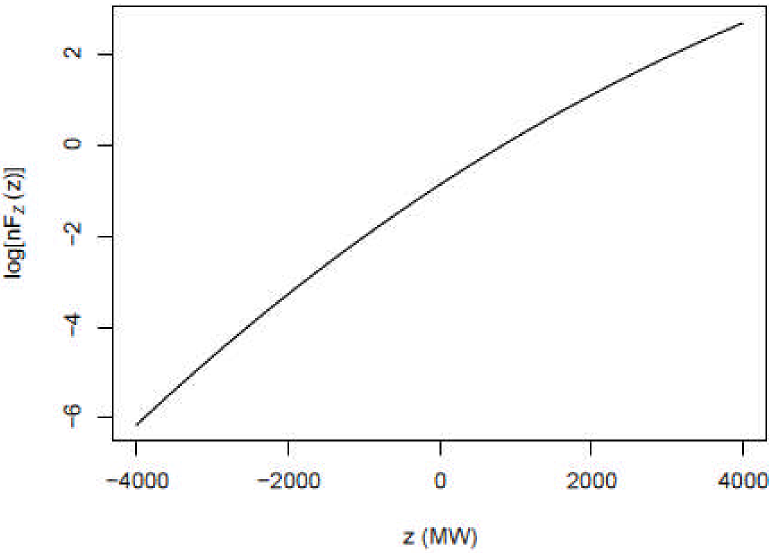

Figure 2: Plot of $\log[nF_Z(z)]$ against z.

Evaluating at $z = 0$ we have $nF_Z(0) = 0.417$ which is the LOLE in half-hour periods for the scenario concerned. If firm capacity z' MW is added to the system, then, from (2), the LOLE becomes $nF_Z(-z')$. For example the addition of 1000 MW of firm capacity changes the LOLE to 0.133 half-hours. (This may be read from the original tabulated data, or from the plot, which gives that $\log nF_Z(-1000) = -2.018$ and so $nF_Z(-1000) = 0.133$.)

We now take this LOLE of 0.133 half-hours as a target value. (While this is not a realistic figure by current standards, current targets are already more than achieved by this scenario.) To meet this target we need to shift the margin by 1000 MW of firm capacity. Since the plotted relationship is at least approximately linear it will be sufficient to identify units of additional capacity, statistically independent of each other and of the existing capacity, whose EFCs—calculated as in Section 3—sum to the required 1000 MW.

The value of λ, determined as in (14), is 0.00114 (Values of λ very close to this will be typical for most current GB scenarios).

Thus, if we wished to meet the required shift of 1000 MW of equivalent firm capacity from the addition of a single new unit (operating independently of existing units) which had capacity a and binary availability with availability probability p, then

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from (9) it would be necessary to solve the equation

$$1000 = -\frac{1}{\lambda}\log(1 - p + pe^{-\lambda a}). \qquad (18)$$

For an availability probability $p = 0.85$ this would require the unit to have capacity $a = 1414$ MW, or derated capacity $ap = 1202$ MW.

Wind The current GB wind fleet has an installed capacity of approximately 10.120 GW (3.960 GW offshore and 6.160 GW onshore). The mean of its predicted power output is 4.135 GW and the corresponding standard deviation is 2.334 GW. For $\lambda = 0.00114$ as above, its EFC is calculated via (7) as 2.225 GW.

Suppose now that the existing wind fleet is simply scaled up by a factor of 2, doubling the size of each farm, and doubling the installed capacity. With λ as above, the EFC of the total wind fleet is calculated via (7) as 3.225 GW. Thus the EFC of this additional wind is only 1.000 GW. This situation would be improved if the additional wind increased the geographical diversity of the wind fleet.

References

[1] C. J. Dent and S. Zachary, "Capacity value of additional generation: Probability theory and sampling uncertainty," in *PMAPS, Istanbul*, 2012. Available also at http://arxiv.org/abs/1305.6479.

Appendix 4 – Analysis supporting the sensitivity modelling reduced availability of wind at times of higher demand

The model requires as one of its inputs a specification of the joint distribution of demand D (scaled as a fraction of ACS peak) and available wind generation W. While marginal distributions of these two quantities may reasonably be estimated from the available data, the latter on its own is insufficient to estimate reliably their joint distribution in the region of extreme demand which is most important for determining the model outputs. For the scenarios(and most sensitivities) we assume that demand and available wind generation may reasonably be treated as statistically independent of each other. The available data are in general consistent with this assumption.

However there is a widespread belief thatthe wind stops blowing when there is a severecold spell, resulting in lower wind availability at the time of extreme demand forelectricity. We will therefore model a sensitivity in which there is aninverse relationship between wind availability and extreme demand.

For this sensitivity, we make the assumption that, at the times of highest demand (where the peak daily demand is above 92% of the ACS peak); the distribution of available wind generation gradually declines to 50% of its usual value. The relevant data justifying this choice of sensitivity and the details of the analysis are shown in the following paper.

Analysis of the wind-demand relationship

Matthew Roberts and Stan Zachary

April 8, 2013

The model requires as one of its inputs a specification of the joint distribution of demand D (scaled as a fraction of ACS peak) and available wind generation W.

While marginal distributions of these two quantities may reasonably be estimated from the available data, the latter on its own is insufficient to estimate reliably the joint distribution in the region of extreme demand which is most important for determining the model outputs. It is thus necessary to make further assumptions.

The underlying rationale is that those meteorological conditions which lead to extremes of demand may also associated with less wind availability than is usually the case. Because demand varies cyclically over the day regardless of meteorological conditions (which typically change on a slower timescale) it seems most natural to condition the distribution of wind at any given time, not on the demand D at that specific time but rather on the peak demand D' occurring in the same day. Thus we factor the joint distribution of wind generation and daily peak demand (represented by its density function $f_{D',W}$) as

$$f_{D',W}(d',w) = f_{D'}(d')f_{W|D'}(w|d') \tag{1}$$

where $f_{D'}$ is the marginal density of daily peak demand D' and $f_{W|D'}$ is the conditional density of wind generation W given daily peak demand. We assume that the conditional density $f_{W|D'}$ of wind generation is reasonably modelled as some scaled version of its marginal distribution, i.e. that

$$f_{W|D'}(w|d') = \lambda(d')f_W(w) \tag{2}$$

where f_W is the marginal density of wind generation W and $\lambda(d')$ is some function of the value d' of daily peak demand D', so that we assume

$$f_{D',W}(d',w) = \lambda(d')f_{D'}(d')f_W(w). \tag{3}$$

Here for consistency we require

$$\int_0^\infty \lambda(d')f_{D'}(d')\,\mathrm{d}d' = 1. \tag{4}$$

The base model assumes that D' and W are *independent*, i.e. that $\lambda(d') = 1$ for all d'.

To carry out an appropriate sensitivity analysis we reduce the available wind at times of extreme daily peak demand by reducing the scale factor $\lambda(d')$ for extreme values of the daily peak demand $D' = d'$. The only way to sensibly estimate $\lambda(d')$ is via scatterplots, for the available data, of wind generation versus daily peak demand at times of high daily peak

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demand. Such plots strongly suggest that it is perfectly reasonable to assume $\lambda(d') = 1$ for values of daily peak demand d' less than 90% of ACS peak, and that appropriate sensitivity analyses should consist of gradually reducing $\lambda(d')$ as d' increases above 90% of ACS peak—with a reasonable lower bound on the available wind generation given by taking $\lambda(d') = 0.5$ for the most extreme values of d'. (With this approach the integral on the left side of (4) is very slightly less than 1; while this might be compensated for, the density of D' in its extreme regions is sufficiently small that there is little need for this, and in any case the failure to make the correction is very slightly conservative with respect to the assumption of available wind generation.)

Figure 1 shows a scatterplot of available wind generation (based on a 2013–14 installed capacity scenario and expressed as a load factor) versus daily peak demand, corresponding to simultaneous MERRA data and demand data for half-hourly periods from 2006–12. For clarity the plot is restricted to those periods when the level of daily peak demand was in excess of 90% of ACS peak and to the wind load factors at the times of the daily peak demands themselves. The plotted line shows a estimate of the mean wind load factor conditional on the daily peak demand. This is fitted using a locally weighted least squares smoothing technique (LOWESS), and some experimentation shows that the fit is robust against varying choices of the width of the smoothing window.

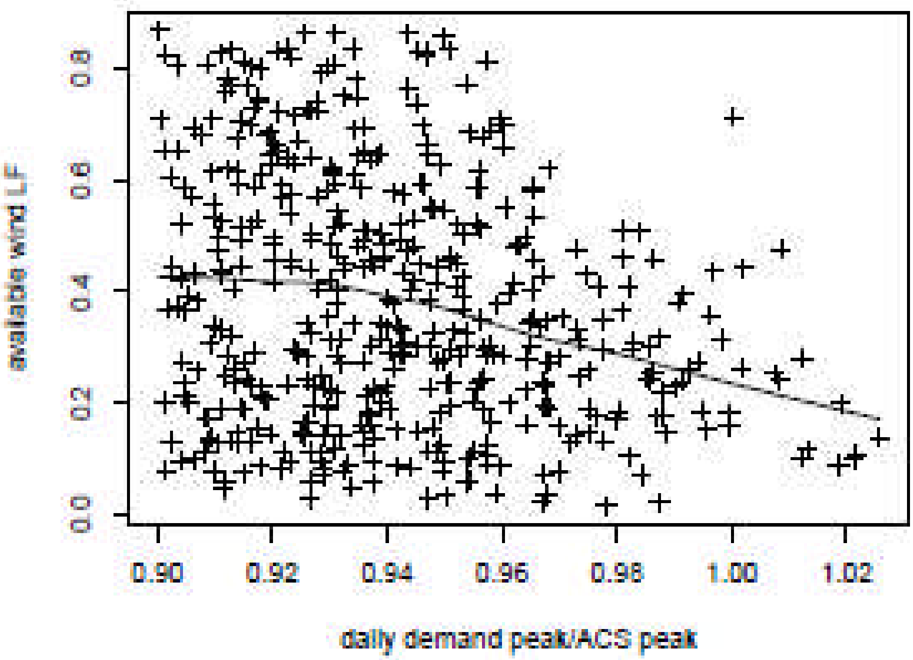

Figure 1: Plot of wind generation against daily peak demand for high levels of daily peak demand.

This suggests the following sensitivity analyses. For chosen levels of daily peak demand d'_1 (in excess of 90% 0f ACS peak) and $d'_2 > d'_1$, and for chosen values l_1 and l_2 of the scale factor λ, we take

$$\lambda(d^r) = \begin{cases} l_1, & d^r \le d_1, \\ l_1 + \dfrac{d^r - d^r_1}{d^r_2 - d^r_1}(l_2 - l_1), & d^r_1 < d^r < d^r_2, \\ l_2, & d^r \ge d^r_2 \end{cases} \tag{5}$$

i.e. $\lambda(d^r)$ is constant for values of d^r below d^r_1 and' above d^r_2 and varies linearly between these values.

From the above discussion, it seems reasonable to take $l_1 = 1$ and $l_2 = 0.5$. We consider appropriate pairs of values of d^r_1 and d^r_2 as suggested by the above plot. Plausible values corresponding to a lower bound on available wind generation look like $d^r_1 = 0.92$ and $d^r_2 = 1.02$.