Electricity Capacity Assessment Report 2014

Supplementary appendices

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Overview

This document sets out the supplementary appendices to the Electricity Capacity Assessment Report 2014.

Contents

Appendix 1 – Specific cases

1.1. This appendix contains details for specific cases which are not covered in the main part of the report. The cases described in the appendix are as follows:

1. Gas stress test
2. Transmission boundary constraint
3. Summer analysis
4. Demand confidence intervals

1. Gas stress test

1.2. The aim of the gas stress test is to analyse the impact of a drop in gas supplies to GB on generating de-rated margins. Two tests are considered: (i) the potential impact on de-rated margins during an "n-1" event[1]; and (ii) how much gas could be lost from peak day deliverability before de-rated margins are impacted.

1.3. Our analysis shows that an "n-1" outage event is unlikely to impact our calculated de-rated margins. These would only be impacted after a significant loss in gas peak supply availability.

1.4. To complete the gas stress test we compare demand for gas from the power and non-power sectors with peak day gas deliverability. If the potential demand for gas is higher than peak day deliverability, then de-rated margins may be affected. This is because such a result would suggest that some gas plant could not be utilised if called upon.

1.5. To undertake both stress tests, we have produced an estimate for total potential gas demand from the power sector. To estimate the gas use at existing plants, we use effective efficiency data from Mott MacDonald and National Grid. New CCGT plant is assumed to be 52% efficient. We assume that plants are running at a consistent load throughout the day. The results are presented in Table 1 together with an assumption on the total gas demand from the non-power sector.

[1] An "n-1" event is equivalent to the loss of the largest gas import facility in GB.

Table 1: Potential demand for gas, 1-in-20 peak day

Gas demand [MCM/day]	2014/15	2015/16	2016/17	2017/18	2018/19
Potential gas demand from power (Gone Green scenario 2014)	131.1	133.3	139.9	143.0	145.0
Total gas demand from non-power– Gone Green (National Grid Gas Ten Year Statement 2013[2])	422.3	414.0	409.1	403.6	397.9
Total potential gas demand (potential power plus non-power)	553.4	547.3	549.1	546.6	542.9

Test 1: Effect of "n–1" event on de-rated margins

1.6. In this test we compare the total potential gas demand against total peak supply availability during an "n-1" event. An "n-1" event is equivalent to the loss of the largest gas import facility in GB. In this test we assume the loss of the pipeline connecting Milford Haven to Felindre[3] (86 mcm per day). The second row in Table 2 shows the impact of an "n-1" event on peak supply availability (shown in first row).

Table 2: Gas supply surplus (n-1) and total potential gas demand

Variable [MCM/day]	2014/15	2015/16	2016/17	2017/18	2018/19
Peak supply availability – Gone Green 2013	728.4	741.0	742.1	737.4	734.8
Peak supply availability ("n-1" event)	642.4	655.0	656.1	651.4	648.8
Total potential gas demand	553.4	547.3	549.1	546.6	542.9
Supply surplus ("n-1" event)	89.0	107.8	107.0	104.8	105.9

1.7. Table 2 shows that under an "n-1" outage event, there is still a large surplus of gas capacity throughout the period of the analysis. Therefore, an "n-1" outage event is unlikely to impact our calculated de-rated margins.

Test 2: Potential gas losses before de-rated margins are affected

1.8. We extend the analysis to assess how much peak supply availability could be lost before the potential demand for gas from power could not be served. Table 3 presents the surplus supply by subtracting total potential demand for gas from peak supply capacity.

[2] National Grid Gas Ten Year Statement 2013 - Charts GTYS 2013 MASTER FINAL_2003 www2.nationalgrid.com/UK/Industry-information/Future-of-Energy/Gas-Ten-Year-Statement/.

[3] For more information see DECC's "UK Risk Assessment on Security of Gas Supply – Report completed for EU Regulation 994/2010", available here: www.gov.uk/government/publications/uk-risk-assessment-on-security-of-gas-supply.

Table 3: Gas supply surplus and total potential gas demand

Variable [MCM/day]	2014/15	2015/16	2016/17	2017/18	2018/19
Peak supply availability	728.4	741.0	742.1	737.4	734.8
Supply surplus	175.0	193.8	193.0	190.8	191.9

1.9. Table 3 shows that under our assumptions, and depending on the year, between 175 and 194 mcm per day of supply availability would have to be lost before de-rated margins were impacted. This is between 24% and 26% of total peak gas supply availability. This range represents a significant loss in gas supply availability. Therefore, the likelihood of occurrence is low.

1.10. In addition, it should be highlighted that we have assumed maximum CCGT output for 24 hours and as such the analysis provides an hypothetical maximum demand from CCGT generation (eg if it were required to run as a baseload source). We would expect gas-fired generators to run for fewer hours of the day.

2. Transmission boundary constraint

1.11. Our Capacity Assessment model considers GB as a single area, consistent with the operation of the market as a whole. A possible cause of system risk can arise from physical limitations in certain areas on the GB transmission network. For instance, a situation could arise where GB-wide there is enough generation to supply overall demand, but in a particular region demand 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 shortfall.

1.12. Our analysis suggests that GB electricity security of supply is unlikely to be impacted by the most constrained link of the transmission network. We have updated our analysis of the transmission boundary constraint sensitivity from our 2013 report.[4] According to National Grid, the Cheviot boundary, between Scotland (SC) and England (E&W), is still expected to be the most constrained transmission network link in GB over the period of analysis.

1.13. The capacity of the Cheviot boundary is due to increase over the period. The existing line capacity is expected to increase between 2014/15 and 2015/16. The projected installation of a bootstrap HVDC link between England and Scotland in 2016/17 will see the capacity of the Cheviot boundary almost double.

1.14. Despite the expected surplus capacity in both E&W and SC being positive, the physical limitations (eg limited transfer capability and availability) of the Cheviot boundary could potentially impact our risk measures of security of supply. To test the impact of the presence of the boundary, we have run a sensitivity that treats the GB system as two interconnected regions, ie SC and E&W. We summarise in Table 4 the impact of the Cheviot boundary on our risk metrics, LOLE and EEU, for the No Progression scenario.

[4] Available here (page 63): https://www.ofgem.gov.uk/ofgem-publications/75232/electricity-capacity-assessment-report-2013.pdf. Details on the methodology can be found in appendix 3 of our 2013 report.

Table 4: Impact of the Cheviot boundary on the risk metrics for the No Progression scenario

Risk metric	2014/15	2015/16	2016/17	2017/18	2018/19
GB LOLE [hours per year]	0.5	3.8	1.4	0.8	2
Additional GB LOLE [hours per year]	0.0	0.0	0.0	0.0	0.0
GB EEU [MWh]	456	4,258	1,345	762	2,128
Additional GB EEU [MWh]	0.1	0.6	0.0	0.0	0.0
Cheviot Capacity [MW]	3300	4300	6400	6400	6400

1.15. Table 4 shows that before the installation of the bootstrap HVDC link between E&W and SC in 2016/17, there would be only a negligible increase in the risk measures resulting from the presence of the limited transfer capability of the Cheviot boundary. This suggests that the Cheviot boundary is unlikely to act as a constraint when electricity generated in SC is required to meet demand in E&W or vice versa. Following the capacity upgrade in 2015/16, our results suggest that the presence of the Cheviot boundary would have no impact on our risk measures. This implies that at no time during these years the new upgraded capacity on the boundary would act as a constraint to the flow of electricity between SC and E&W. The findings of the analysis are valid for all FES.

3. Summer Analysis

1.16. The summer season presents a low level of risk to security of supply compared with the winter season in GB. Peak demand is substantially lower in summer than in winter. The resulting summer margins are relatively high compared with winter meaning that planned maintenance outages historically occur in summer.

1.17. As in the 2013 report, we compare the trend in ACS peak demand and de-rated margins for winter compared with summer until 2018/19. Table 5 compares the assumptions from National Grid for ACS peak demand in the Gone Green 2014 scenario in winter with that of summer over the next five winters.

Table 5: ACS peak demand and summer peak demand for the Gone Green 2014 scenario

Peak demand [MW]	2014/15	2015/16	2016/17	2017/18	2018/19
Winter	54,200	53,855	53,338	52,737	52,263
Summer	38,400	38,156	37,789	37,363	37,028

1.18. Table 5 shows that the trend in summer peak demand is similar to that for ACS winter peak demand, and that summer peak demand is much lower. Given this difference, there is limited historical data on the way generators behave during periods of tight margins in the summer season. For this reason, we have used a deterministic stress test approach for the summer analysis as in the 2013 analysis.

1.19. To account for the higher levels of maintenance that occur in the summer, we have based our assumptions in this sensitivity on historical average summer maintenance by generator type. In doing so, we have also recognised that some plant may have the flexibility to reschedule their maintenance schedule in response to short term indications of low capacity margins. National Grid estimates this to be around 2.4GW. This capacity is then added back on to the supply side in the calculation of the de-rated margin.

1.20. Table 6 shows the estimated winter and summer de-rated margins for the next five winters for the Gone Green 2014 scenario.

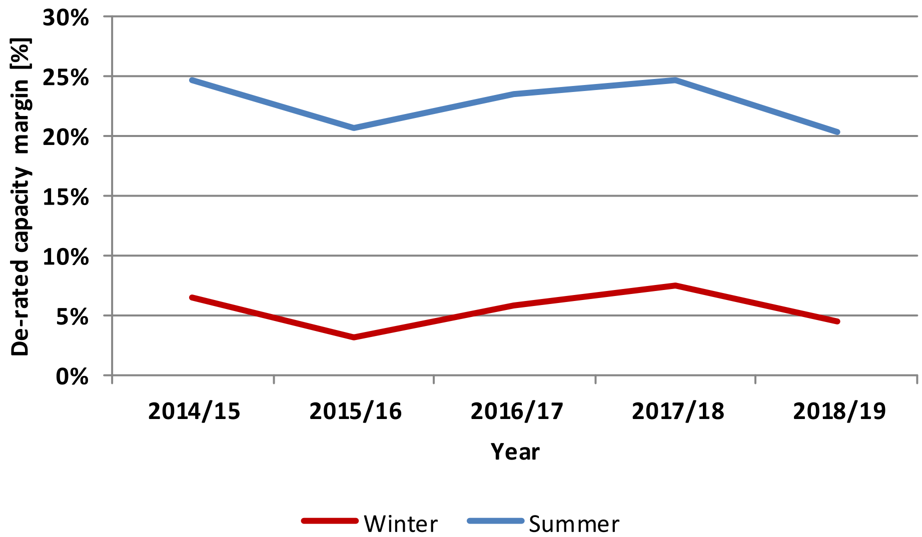
Table 6: Winter and summer de-rated margins for the Gone Green 2014 scenario

De-rated margin [MW]	2014/15	2015/16	2016/17	2017/18	2018/19
Winter	3,590	1,707	3,156	4,034	2,396
Summer	9,516	7,898	8,920	9,289	7,610

1.21. The estimated summer de-rated capacity margin is on average around 5.7GW higher than the winter de-rated margin over the period of the analysis. Both de-rated margins follow a similar trend, falling until winter 2015/16 and then rising up to winter 2017/18 before they drop again in winter 2018/19. The differential between the de-rated margins remains broadly constant throughout the period.

1.22. Figure 1 shows the estimated winter and summer de-rated margins for the next five winters expressed in percentage terms. It shows that summer margins are around four times higher than winter margins on average over the period. The findings of the analysis are valid for all FES.

Figure 1: Winter and summer de-rated margins for the Gone Green 2014 scenario

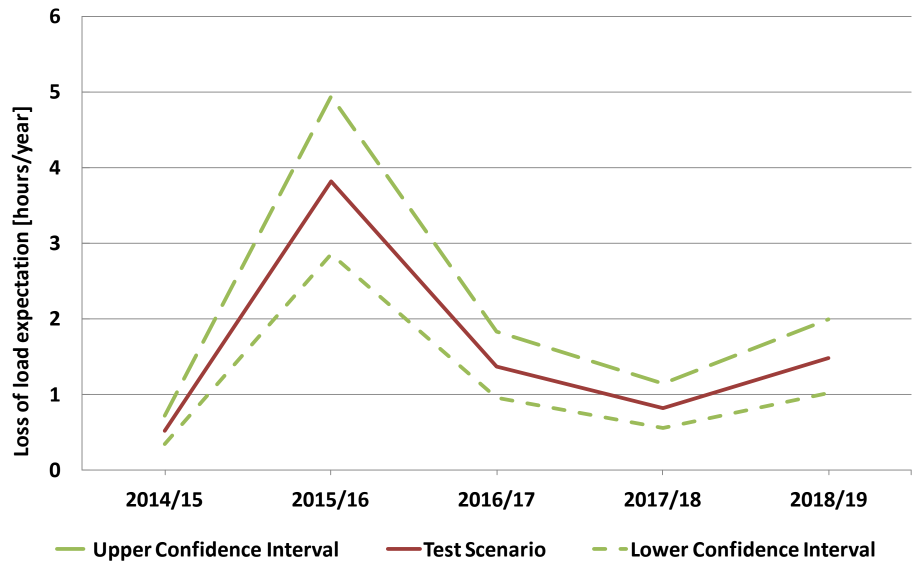


4. Demand confidence intervals

1.23. To estimate the risk measures, we combine input data assumptions with stochastic distributions (eg electricity demand, wind power output). We have examined the impact of uncertainty in the input data assumptions using sensitivity analysis. To do the same for the demand distribution, we use a standard statistical technique known as bootstrapping. We explain this technique in more detail in Appendix 3 of our 2013 report.

1.24. Figure 2 presents the estimated LOLE for a test scenario together with the 95% confidence intervals for LOLE over the next five winters.

Figure 2: Loss of load expectation for test scenario and associated confidence intervals



1.25. The figures show the range of the LOLE around a test scenario due to uncertainty in the distribution of demand. The estimates suggest that in winter 2015/16, the LOLE in the test scenario could range between around 3 hours per year and 5 hours per year because of this uncertainty. Importantly, the test carried out above investigates the uncertainty around the historical demand distribution used in the analysis, which is based on data from the past nine winters. It is not possible to assess how the demand distribution might change in the future.

Appendix 2 - Supporting information

1.1. This appendix provides supporting information in the following areas:

- our approach on interconnectors and the updated outlook in the relevant markets to GB;
- the changes in methodology for the 2014 analysis;
- the assumptions on the reserve for the largest infeed loss; and
- the mitigation actions available to the System Operator, including the new balancing services.

Interconnectors

Approach on interconnectors

1.2. GB currently has around 3.8GW of interconnected capacity in operation (as shown in Table 7). Several interconnectors are in various stages of development, however significant uncertainty exists over when each one will become fully operational.

Table 7: Interconnected capacity between GB and its neighbouring markets.

Interconnector	Country	Capacity
IFA	France	2 GW
Britned	Netherlands	1 GW
Moyle[5]	Northern Ireland	0.25 GW
East West	Republic of Ireland	0.50 GW
Total		3.75 GW

What does the report consider?

1.3. As noted in Chapter 1 of our report, we believe interconnectors are beneficial to GB security of supply. DECC shares this view and published a report in December 2013 that describes the benefits of interconnection to GB in more detail.[6]

1.4. Our analysis considers the system under normal winter conditions, and not only at times of system stress. We cannot simply look at the total capacity of interconnection, but rather at what interconnector flows to and from GB could be on a winter day. This is a difficult exercise as flows are broadly price responsive in coupled markets, and behave differently from period to period and day to day.

[5] The capacity of Moyle was reduced last year from 450MW to 250MW due to a fault on a cable. It remains highly uncertain whether and when the full Moyle capacity will become available.

[6]www.gov.uk/government/uploads/system/uploads/attachment_data/file/266460/More_interconnection_-_improving_energy_security_and_lowering_bills.pdf.

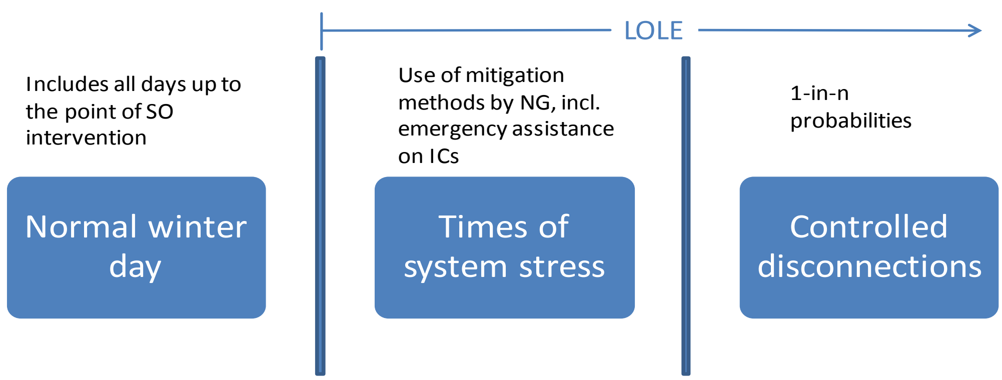
Qualitative approach to interconnectors

1.5. The market has recently undergone a number of changes. In February 2014, north-western European (NWE) price coupling was launched. This sees the formation of a single, interconnected price region for day-ahead electricity that encompasses a number of countries.[7] Market coupling ensures that interconnectors can be more efficiently used by removing the need to buy cross-border energy and cross-border capacity separately. Prices for each nation would also converge if there were unlimited transmission capacity between markets. We should ideally build a probability distribution of flows to be combined with the distributions of demand and supply used in our probabilistic model[8] but, given that interconnector dynamics are changing significantly all around Europe, there is no reliable and credible data to build such a distribution. The change of market structure makes the analysis of historical trends less useful to estimate future flows.

1.6. We therefore use a qualitative approach and concentrate on two points of the distribution to analyse potential level and direction of flows at these points: the average, which represents a typical winter day and helps us estimate the contribution of interconnector flows to the de-rated margin; and the tail, where loss of load events occur and interconnectors can contribute to decrease the probability of controlled disconnections of customers. This is illustrated in Figure 4 below. We consulted on the methodology in November 2013. Two respondents recommend some form of quantitative approach, while the majority agreed with a qualitative approach.

1.7. We recognise that interconnectors can behave in a different way on average compared to when margins are getting close to zero in a specific day. However, rather than making assumptions[9] about the shape of the relationship between the margin and level of interconnector flows, we evaluate a range of sensitivities to illustrate the impact of different levels of interconnector flows on the de-rated margin and LOLE.

Figure 3: Contribution of interconnectors to security of supply indicators



1.8. The direction of flow is difficult enough to calculate, but modelling the specific volume of flows requires looking at the available margin not only for GB, but for all interconnected markets. Such work is beyond the scope of the Capacity Assessment. In 2013 therefore, the decision was made to take a qualitative approach to the analysis. Specifically, the report detailed analysis of the structural similarities and interactions between GB and its interconnected neighbours to

[7] The NWE market coupled region includes the following countries: Austria, Belgium, Denmark, Estonia, Finland, France, Germany, Great Britain, Latvia, Lithuania, Luxemburg, The Netherlands, Norway, Poland, and Sweden.

[8] For more information see appendix 3 of our 2013 report.

[9] As no data is available for a proper statistical analysis

identify possible outcomes. Poyry was also commissioned to analyse the behaviour of interconnectors under a number of conditions to try and identify causality links. As noted above, historic analysis is not a good predictor of future flows, rather this was done to add further context to the structural analysis.

1.9. For the 2014 report, we have maintained the qualitative approach. We updated the analysis, specifically the market outlook in the relevant markets to GB, to identify if any new information in the past year has made the likely future direction and volume of flows more predictable. The full details of this analysis can be found below.

1.10. At a high level, the analysis shows that uncertainty has increased, rather than decreased. The margins that are likely to be available in interconnected countries have broadly declined. This further increases the uncertainty as to the direction and size of flows from and to GB.

1.11. We do not have sufficient evidence to say with confidence that one direction or level of flow is more likely than another. From an analytical perspective they are all equally uncertain. As we lack a compelling counterfactual, we have developed sensitivity analysis around the plausible flows on interconnectors in the future.

Review of market outlook in relevant markets

1.12. This section presents the market outlook for our directly interconnected markets, ie Ireland, France and the Netherlands. It also considers the outlook for two other relevant markets that may indirectly impact GB's interconnector flows, namely Belgium and Germany.

1.13. Governments in Ireland, France, the Netherlands and Belgium have determined the acceptable level of risks to security of supply by deciding on a reliability standard, which are all expressed in the number of hours of LOLE per year. It represents a trade-off between the level of security of supply and the required cost (eg for new plant) to achieve that level. It is important to note that each country may use different methodologies and assumptions to derive the reliability standard, so the numbers may not be directly comparable.

Table 8: Reliability standard in interconnected markets

Reliability Standard	LOLE [hours/year]
Northern Ireland	4.9
Republic of Ireland	8.0
France	3.0
Netherlands	4.0
Belgium	18.0
GB	3.0

1.14. From our analysis of the national reports from each market, we conclude that generation adequacy is expected to get tighter in the French, Belgian and German markets. The Netherlands and SEM (Ireland)[10] are currently experiencing a surplus of capacity, though this is forecast to decline at the end of the decade (while still remaining within the bounds of the respective reliability standards in the 'best estimate' cases). Below we present the market outlook for each of the relevant markets.

[10] There is surplus capacity in the All Island system but transmission constraints make the outlook for Northern Ireland less optimistic. Imports from GB are required for NI to maintain the Reliabilty Standard.

Ireland

1.15. GB has historically been an exporter to Ireland. The Transmission System Operators for Northern Ireland (NI) and the Republic of Ireland (ROI) publish a joint generation capacity assessment report[11] where they present the outlook for security of supply in the all-island market, as well as in each market separately, for the next 10 years. On an all-island basis they are expecting the risks to remain below their reliability standard of 8 hours of LOLE per year in the future. However, in addition to the all-island, each jurisdiction has defined their own reliability standard. This is 4.9 hours of LOLE per year for NI and 8 hours of LOLE per year for ROI. The effects of environmental policies as well as delays in building further transmission capacity have created a dependency on imports from GB in order to meet demand demand and hit the 4.9 hours LOLE in Northern Ireland from 2016 onwards. This relative tightness compared with ROI is also due to a lack of significant new capacity expected to come online in this period.

1.16. The transmission system operators' (TSOs') Base Case assumes full exports from GB to Ireland through the East-West and Moyle interconnectors, including at peak times of electricity demand in GB. In all analysis it is assumed that the Moyle interconnector import capacity remains reduced to 250 MW.[12] The TSOs have also assessed a number of sensitivities, for example, the impact of the loss of interconnection with GB. In this sensitivity, Northern Ireland would face a capacity deficit in 2016 if no interconnector flows from GB were available.

France

1.17. The French TSO publishes a capacity assessment report where they present the outlook for the market in the medium and long term.[13] Its analysis indicates that the French market is facing an increasingly tighter situation over the period 2014-2018, with a significant decline in margin between 2015 and 2016. This decline is primarily driven by the retirement of LCPD opted-out plant along with the scheduled closure of two nuclear reactors at the end of 2016. On the other hand, the French TSO has revised its demand projections downwards, driven primarily by a reduction in forecast demand from the industrial sector.

1.18. In its 2013 report, the French TSO expects no capacity deficit (relative to their LOLE target), however this conclusion includes the assumption of around 7 GW of imports. The 2013 report's conclusion is an improvement on the 2012 outlook in which there was a capacity deficit of 1.2 GW in 2016 and 2.1 GW in 2017, corresponding to an LOLE of 2.5 and 3 hours per year in the two years respectively. This is greater than and just equal to, respectively, the reliability standard of 3 hours per year set by the French government. If imports from neighbouring markets are unavailable, France would face a capacity deficit of 6.5 GW and 7.5 GW in 2016 and 2017 respectively.

[11] "All-Island Generation Capacity Statement – 2014-2022" by SONI and Eirgrid available at: http://www.eirgrid.com/media/Generation%20Capacity%20Statement%202014.pdf
[12] It is not clear when or if the Moyle interconnector will resume full capacity (450 MW Nov-Mar, 410 MW Apr-Oct)
[13] The updated capacity assessment for 2013 as well as past assessments are available at: http://www.rte-france.com/en/mediatheque/documents/operational-data-16-en/annual-publications-98-en/generation-adequacy-reports-100-en and in French at: http://www.rte-france.com/uploads/media/pdf_zip/marche_capacite/Rapport_accompagnement_des_regles_mecanisme_de_capacite.pdf

Netherlands

1.19. The Dutch TSO, TenneT, produces a capacity assessment report that covers the next 16 years.[14] The Dutch TSO expects the risk to remain comfortably below their reliability standard of 4 hours of LOLE per year over the entire assessment period. The most recent report presents an increasing surplus of available capacity above electricity demand. This is despite a reduction in the level of planned new thermal capacity projects compared to that used in the previous report. The increasing surplus of supply capacity over demand is also attributed to a reduction in their demand growth forecast compared to that used in their previous adequacy assessment.

Belgium

1.20. Belgium is not currently directly interconnected with GB (although it might become so with the development of the NEMO interconnector), but it is directly connected with the Netherlands and thus could have an indirect impact on interconnector flows to GB. Belgium is anticipated to face increasingly tight margins for the remainder of the decade in the face of increasing adequacy and flexibility issues[15]. This is driven by a number of structural changes taking place in their market, including the decision to phase out nuclear power completely by 2025.[16]

1.21. In any of the ENTSO-E scenarios, Belgium would be dependent on electricity imports to meet domestic demand. It has been assumed that the two nuclear reactors that faced problems in 2012/13[17] are available in all subsequent winters. Were these stations to experience any further issues, the generation adequacy situation would come under increasing stress in the period 2014-2016.

Germany

1.22. The generation adequacy at a market-wide level is forecast to remain positive overall until at least 2019 before beginning to tighten.[18] Despite this, two regions are currently forecasting negative or near-negative regional capacity margins.[19] In Southern Germany for example, there is currently a structural shortfall, which along with the regional transmission network constraints, requires approximately 2 GW of additional reserve capacity to be procured from Austria and Switzerland to maintain security of supply. Later in the decade, a tightening German system is anticipated, driven by a combination of the planned phase out of nuclear power by 2022, and the retirement of older conventional plant which is not to be replaced until the 2020s. German interconnector flows are highly dynamic, and Germany is interconnected to a number of neighbouring regions. The direction of this interconnector flow typically depends on the level of renewable output in Germany, which is inherently more variable and therefore heavily de-rated in

[14] This report has been updated in 2012 in Dutch and is available at : http://www.tennet.eu/nl/fileadmin/downloads/News/Rapport_Monitoring_2012-2028.pdf

[15] For more information on the market outlook in Belgium, see the "Scenario outlook and adequacy forecast" by ENTSO-E: https://www.entsoe.eu/about-entso-e/system-development/system-adequacy-and-market-modeling/soaf-2013-2030/

[16] Nuclear power meets more than one third of Belgian demand at present, with an installed capacity of just less than 6000 MW.

[17] Belgium was structurally dependent on imports during most part of winter 2012/13.

[18] For further information refer to: http://www.bmwi.de/BMWi/Redaktion/PDF/J-L/leistungsbilanzbericht-2013,property=pdf,bereich=bmwi2012,sprache=de,rwb=true.pdf

[19] The German electricity market is divided into 4 transmission network regions each operated by a separate TSO. Each year the TSOs produce a joint report on the generation adequacy in each of the regions and overall for the coming years in Germany. Two of the TSOs have forecasted negative or almost negative regional capacity margins.

terms of calculating capacity adequacy. Germany's transmission issues, as well as its growing proportion of renewable generation, translates into the possibility that interconnector flows are diverted to the Continent instead of to GB.

Changes to methodology

1.23. Below we present the changes in our methodology for the Capacity Assessment 2014 analysis compared with the 2013 analysis, namely on estimating the de-rating factors for gas plant and the 1 in n probabilities of disconnections.

De-rating factors for generation technologies

1.24. In order to estimate the available generation capacity we need to de-rate the installed capacity by the corresponding de-rating (or availability) factors that represent the availability of different generation technology types.

1.25. We broadly use the same methodology with last year to assess the de-rating factors for each type of generation. These are based on the analysis of the historical availability performance of the different generating technologies during the winter peak period, over the winters from 2006/07 to 2012/13. We define winter peak period as the days in winter where demand is greater than the median of daily demands during this period.

1.26. This year, for gas plant (CCGT and CHP) we derive the de-rating factors using the highest 10% of demand days for each winter, instead of the median. Analysis undertaken by Arup in the context of the Capacity Market modelling showed that gas plant availability in GB has been relatively low for international standards.[20] A potential reason for this is the relatively low spark spreads for part of the historic period under study. Considering periods when demand was relatively high, provides a more realistic availability level for gas plant and is more appropriate given the low profitability of gas plants over the past few years.[21] This results in a de-rating factor of 87%, instead of 85% if we were using the median of daily demands.

1 in n probability of disconnections

1.27. In the 2014 Capacity Assessment we have adjusted the method used to estimate the likely frequency and duration of shortfalls in supply. These changes have been made in order to more accurately fit the estimated outages to the specific characteristics of the tails of the combined supply-demand distribution derived by the LOLE risk calculation rather than the whole of the distribution. We have also updated the demand profile used to estimate the duration of outages (of a given maximum severity).

1.28. The probabilistic model used in the current and previous analyses does not produce the frequency and duration of outages directly because the model does not account for the chronological ordering of the time periods – it is a time collapsed model. The duration and number and frequency of outages are therefore estimated rather than modelled directly using a demand profile for the typical peak demand day. Previously, the frequency of each outage was matched to

[20] For more information see National Grid's EMR Electricity Capacity Report, available here: www2.nationalgrid.com/WorkArea/DownloadAsset.aspx?id=34154.

[21] Coal generation has been more economic than gas since the end of 2011, pushing gas plant higher in the merit order.

be consistent with the probabilistic model. In the 2014 Capacity Assessment a two-step process is used to estimate the frequency of outage types.

1.29. Specifically, frequency estimates for loss of load event sizes of 1 GW (coarse events, ie 0 to 1 GW, 1 to 2 GW, etc.) are calculated so that the relative probability of these events matches the shape of the tail of the half-hourly de-rated margin distribution, estimated for the key risk calculation. The frequencies of supply shortfalls are then scaled so that the corresponding LOLE matches the LOLE calculated by the probabilistic model. The frequencies of the shortfalls are summed and converted to an 1 in n value.

1.30. Additionally, regarding the demand profile change, the per minute demand is measured against a half-hourly peak value rather than the minute peak as in the 2013 Capacity Assessment. This is appropriate given that the probabilistic model uses half-hourly time periods to model the de-rated margin distribution.

1.31. To compare the impacts of these changes, the 2013 and 2014 capacity assessment methods were used with the same scenarios to generate two sets of results. This updated method results in more frequent severe shortfalls compared with short minor shortfalls. Furthermore, the frequency of small shortfall events is lower. The absolute frequency of "controlled disconnections" appears not to have changed significantly. However, it is important to note insufficient empirical data of controlled disconnections exist to determine which of the two sets of results is correct.

1.32. As in previous reports 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.

Largest infeed loss reserve

1.33. National Grid reserves power to maintain system frequency within statutory limits in the event of the loss of the largest generator (the largest infeed loss).[22] Its importance is such that National Grid would curtail demand before using this reserve. The generation capacity required for this reserve will therefore not be available under normal market operation and this is reflected within the assumptions of our analysis. We do this by including it as additional demand in our analysis.

1.34. For this year's analysis, National Grid has updated its assessment of the reserve requirement for the largest infeed loss. It estimates that the requirement is 0.9GW and remains constant throughout our analysis period or until the credible level of the largest generation loss in the system increases[23]. This represents a small increase from last year's analysis, which assumed a reserve of 0.7GW. This is primarily due to a reduction in the expected response that can be delivered by the demand side leading to an increase of the reserve requirement from the supply side.

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[22] Currently the National Electricity Transmission System Security Quality of Supply Standards, which is approved by Ofgem, limits the largest infeed loss reserve to 1.8GW, as of April 2014. For further information refer to:
www.nationalgrid.com/uk/Electricity/Codes/gbsqsscode/.

[23] The reserve requirement increases to 2.1GW in 2018/19 for the Slow Progression and No Progression scenarios, as National Grid assumes that new plant connect behind existing plant, thus increasing the credible level of the largest generation loss in the system.

1.35. Specifically, this is due to National Grid's expectation that less static frequency response can be provided by demand side participants and the projected lower peak demand levels compared to historical peak demand. Lower demand side frequency response provision increases the reserve requirement from generators. Lower peak demand means an increase of the reserve requirement from generators because the impact of the largest infeed loss becomes higher as a proportion of total demand.

Mitigation actions available to National Grid

1.36. Most of the time, when available supply is not sufficient to meet demand, National Grid can implement mitigation actions to solve the problem without disconnecting any customers. However, the system should be planned to avoid the use of mitigation actions, as frequent use of them would lower the resilience of the system, reducing security of supply in the longer term and increasing overall costs.

1.37. In addition to the mitigation actions, the recently introduced new balancing services provide National Grid with a further tool to balance the system in the event of tightening margins thus improving its ability to respond to the security of supply risks in the next two winters. These services will be held outside the market and hence they do not impact either the LOLE or the de-rated margins calculations.

1.38. For these reasons we measure LOLE ahead of any mitigation actions being used, including the new balancing services.

1.39. As part of the mitigations actions, National Grid can take actions to reduce demand (through voltage reduction) and increase available supplies (eg emergency assistance on interconnectors). National Grid assesses the availability of these tools based on recent operational experience, which has been limited due to the lack of adequacy related incidents. Hence, the figures used in our analysis should be considered illustrative and not precise. Below, we briefly[24] describe these tools in the sequence it is expected they would be used by National Grid, if the need arises.[25]

- **New Balancing Services**: These are tools that will be used by National Grid in the event of tightening margins to balance supply and demand. DSBR is a demand-side service that offers payments to half-hourly metered non-domestic consumers if they reduce their demand between 4pm and 8pm on winter weekdays. SBR is a supply-based balancing service that is available between 6am and 8pm on winter weekdays.[26] National Grid will hold these services outside the market and would only use them after the Balancing Mechanism. It has expressed its intention to procure a maximum of around 0.3GW and 1.8GW of these services in 2014/15 and 2015/16 respectively.[27]

- **Voltage reduction:** For small events, in terms of both energy and duration, the SO can manage the system by reducing the voltage level and hence the level of

[24] For a full description of these tools and how they can be applied in practice see our 2013 report (Chapter 2).

[25] A different sequence of use of these tools might be applied by National Grid, due to the specific conditions of a supply shortfall event.

[26] For more information see: www.nationalgrid.com/uk/electricity/additionalmeasures.

[27] For more information see: www2.nationalgrid.com/Media/UK-Press-releases/2014/National-Grid-to-contract-for-new-balancing-services/

consumption. National Grid assesses that a maximum of 500MW demand reduction can be achieved through this measure.[28]

- **Maximum generation:** This service involves generators operating at above 100% of their rated output.[29] National Grid estimates that a maximum of 250MW of extra supply can be achieved through this measure.

- **Emergency services from interconnectors:**[30] Emergency services from interconnectors are used as a last resort solution before initiating controlled disconnections of GB customers. In the event of a supply shortfall and after all other measures have been exhausted, the SO can request assistance from the SOs of the interconnected markets. Specifically, the SO-SO agreements in place enable the SO to request the reduction of exports from GB or the increase of imports from the neighbouring markets. The available volume through emergency services from interconnectors depends on the level of imports and exports prior to requesting emergency services.[31] In National Grid's FES, we assume that GB can receive 2GW of assistance from the emergency services from interconnectors.

What would happen if the mitigation actions are not sufficient to balance supply and demand?

1.40. If all mitigation actions were exhausted and demand was still not met, the System Operator would proceed with the controlled disconnection of customers by asking the Distribution Network Operators (DNOs) to disconnect load. In addition, information would be provided to the market to reduce demand (rather than disconnect) by asking customers to reduce demand and to avoid turning on appliances at peak times.[32]

[28] This is based on National Grid's operational experience. Section OC6.5.3. of the Grid Code outlines the obligations for demand control for the DNOs.

[29] This mode of operation causes significant wear and tear to the generator and as a result this measure can only be applied rarely.

[30] For further information refer to:
www.nationalgrid.com/uk/Electricity/Balancing/services/balanceserv/systemsecurity/sotoso/.

[31] For example, if GB imports fully from mainland Europe the potential emergency assistance is reduced.

[32] Note that the explanation presented in this document is for illustration purposes only and it is not intended to provide precise information. This process is accurately documented in the appropriate provisions of the Grid Code, as described in OC6 (Demand Control), OC7 (Operational Liaison) and BC1 (Balancing Code).

Appendix 3 – Detailed results tables

1.1. Below we present the results of our analysis on the probability of controlled disconnections as measured by the 1 in n metric.[33] Table 9 shows the results of our analysis for the scenarios and sensitivities considered in Chapter 1 of our main report for the next two winters, including the potential impact of the new balancing services. The results, including the new balancing services, take into account the maximum volume that National Grid has indicated it is planning to procure. The volume to be procured by National Grid will depend on the actual cost of the bids it will receive for these services. The methodology designed by National Grid is intended to deliver the best value to customers, by balancing the cost of procuring these services against the value of lost load.[34]

1.2. The 1 in n metric is an approximation as there are significant uncertainties about the availability and size of the mitigation actions. We present it in this report for illustration of the potential impact on customers. The uncertainties about the size of the mitigation actions available to National Grid increases further out in the future. For example, it is uncertain how much demand reduction can be achieved through voltage control as the nature of the load in the system changes (eg with more electronic devices). Hence, we show the probability of customer disconnections in the next two winters only.

Table 9: Probability of customer disconnections including the potential impact of the new balancing services

1 in n years	2014/15		2015/16	
Including/excluding the new balancing services (NBS)	**Excl. NBS**	**Incl. NBS**	**Excl. NBS**	**Incl. NBS**
Gone Green 2014	72	107	6	49
Slow Progression 2014	81	121	8	73
Low Carbon Life 2014	83	124	4	31
No progression 2014	81	121	6	47
High supply	139	212	58	755
Low supply	22	31	2	12
Low demand	227	351	19	206
High demand	32	46	2	13
Full imports	221	347	19	203
No imports	32	46	2	13

[33] For more information on the 1 in n metric, see pages 23-24 and 28-29 of the main report.

[34] For more information see: www.nationalgrid.com/NR/rdonlyres/D63DC28A-ACC9-496E-A39C-1682CF25EE08/63428/VolumeRequirementOpenLetter.pdf.