# National Electricity Transmission System Seven Year Statement

May 2011

Chapters

nationalgrid

THE POWER OF ACTION

# NATIONAL ELECTRICITY TRANSMISSION SYSTEM
# SEVEN YEAR STATEMENT
# MAY 2011

## National Grid

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# FOREWORD

The 2011 National Electricity Transmission System Seven Year Statement (NETS SYS) has been published by National Grid Electricity Transmission plc (NGET), acting in its role as National Electricity Transmission System Operator (NETSO) and in accordance with System Operator Standard Licence condition C11 of National Grid's Transmission Licence. The 2011 NETS SYS covers the period from 2010/11 to 2017/18 inclusive.

A key characteristic of the NETS SYS is that all of the analysis and data associated with the document is based around the *contracted* background over the study period. It is therefore prudent to bear in mind when studying the analysis that the position is likely to change and that this document should not be treated as a forecast or scenario of the future, it is intended to show users the contracted position as at the data freeze date.

The NETS SYS contains a wide range of technical and non technical information relating to the NETS, however the principle purpose of the document is to assist existing and prospective new users in assessing opportunities available to them for making new or additional use of the NETS in the competitive electricity market.

To aid users to recognise opportunities, the NETS SYS includes demand forecasts, various contracted generation capacity breakdowns, plant margins and boundary transfer analysis along with high level information on likely connection timescales in each geographical area. The document also gives an overview of some of the key commercial factors associated with obtaining access to the NETS.

I hope you find our 2011 NETS SYS both interesting and informative. Given the challenges facing the electricity industry over the coming seven years and for 2020 and beyond, I would particularly welcome any comments you may have on both the style and the content of the document so we can fully consider any improvements for the 2012 NETS SYS. An electronic questionnaire can be accessed by a link from the Seven Year Statement area of our website for this purpose:

http://www.nationalgrid.com/uk/Electricity/SYS/current/

I look forward to receiving your views on the Statement, including suggestions on how it may be further improved.

Richard Smith
Future Transmission Networks Manager
National Grid

May 2011

# National Electricity Transmission System Seven Year Statement
# May 2011

# Executive Summary

## Introduction

This 2011 National Electricity Transmission System Seven Year Statement (NETS SYS) is the sixth Statement to be published by National Grid Electricity Transmission plc (NGET) acting in its role as National Electricity Transmission System Operator (NETSO). The two Scottish transmission licensees are required to assist National Grid in preparing the Statement pursuant to their licence obligations.

The aim of the statement is to assist existing and prospective new users of the NETS in assessing opportunities available to them for making new or further use of the NETS in the competitive electricity market in Great Britain. The statement contains information on demand, generation, plant margins, system performance / capabilities and other related information.

## Scope, Responsibility and Delivery Considerations

It should be noted that the generation background, on which this document is based, **is not National Grid's forecast** of the most likely developments over the next seven years (due to commercial confidentiality we are unable to show this level of detail on future generation project developments, however this detail is shown in the ODIS scenarios). The generation background is a factual list of existing and proposed generation projects that have a signed connection agreement. Consequently, care must be taken when interpreting the results as there is a degree of uncertainty associated with the number of generation projects opening or closing.

On the other hand, the main demand forecasts included in this document are National Grid's own forecasts. Demand forecasts received from customers are also included for comparison purposes.

The data and results presented in this summary are correct as at 31 December 2010 (the data freeze date) and do not include changes in the contracted position since that date. Any subsequent changes to the contracted background will be published in the NETS SYS updates.

The NETS SYS updates have now been included within the Transmission Networks Quarterly Connections Update (TNQCU), which is published at the following location:

http://www.nationalgrid.com/uk/Electricity/GettingConnected/gb_agreements/

The latest update was issued in April 2011, and includes contractual changes that have occurred since the data freeze date.

## Demand

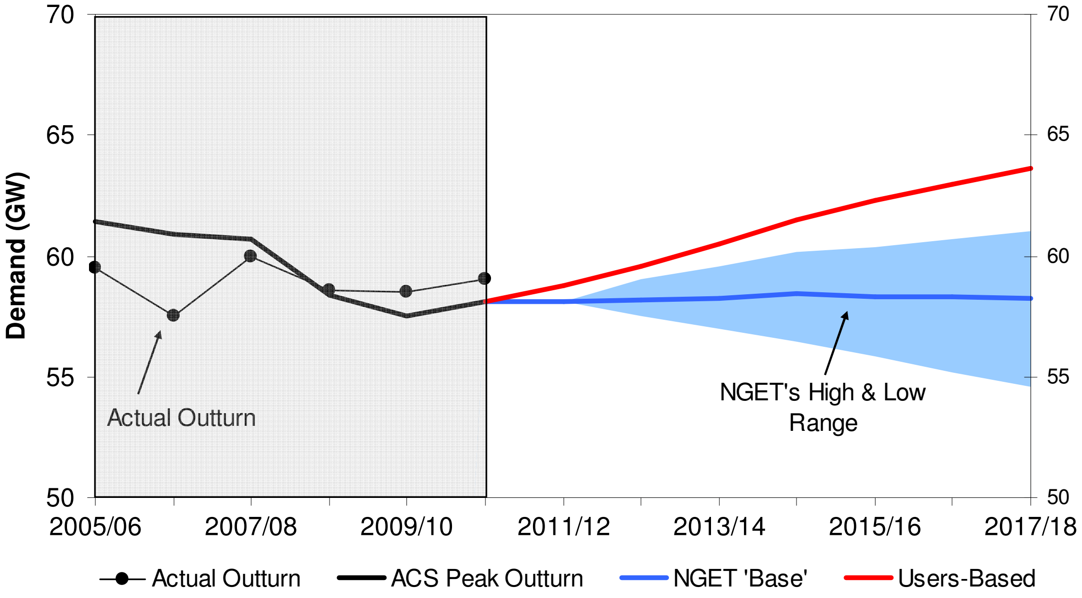
The main forecasts of electricity demand to be met from the NETS presented in this Statement are National Grid's own forecasts. These NGET forecasts are national projections for Great Britain. For comparison purposes, forecasts based on information submitted by Customers who take (or propose to take) electricity from the system are also presented. These 'User' based forecasts are based on the demand levels at individual Grid Supply Points.

Unless otherwise stated, all demand forecasts presented are in respect of the Average Cold Spell (ACS) winter peak and include transmission and distribution losses, but excludes station demand and exports. The forecasts are in respect of the time of simultaneous peak on the national electricity transmission system and are unrestricted (i.e. take no account of demand response/management by customers).

Correcting historical actual demands to ACS conditions eliminates the weather effects and gives a better indication of the underlying pattern of annual peak demand. Correcting winter weekday peak demands in 2010/11 to ACS conditions yields a provisional 'unrestricted' peak of 58.1GW.

Figure ES.1 includes recent outturns together with the current NGET 'Base' forecasts of ACS peak demand on the GB transmission system. Also as well as our own 'Base' forecast of peak demand and annual electricity requirements, we have also prepared 'High' and 'Low' transmission system demand scenarios. For the 'High' and 'Low' demand scenarios, combinations of favourable and adverse developments are assumed which yield high and low transmission system demands. These demand scenarios are then compared against User based forecasts.

**Figure ES.1** - ACS Peak Outturn and Forecasts



## Generation

This generation information reports on all sources of generation that are used to meet the ACS Peak Demand whether they are classified as Large, Medium or Small, all directly connected External Interconnections with External Systems and all Large Power Stations, which are embedded within a User System (e.g. distribution system).

In recognition of the uncertainties associated with the future, unless otherwise stated the information presented relates to existing generation projects and only those proposed new generation projects which are classified as "transmission contracted".

Consequently, care must be taken when interpreting the overall capacity figures as a number of stations will close due to the Large Combustion Plant Directive (LCPD) and many of the proposed projects will not progress to a connection. In addition there may be some non-contracted projects not included within the SYS that may proceed to a connection during the seven years.

**Figure ES.2** - Changes in Generation Capacity, 2011/12 to 2025/26

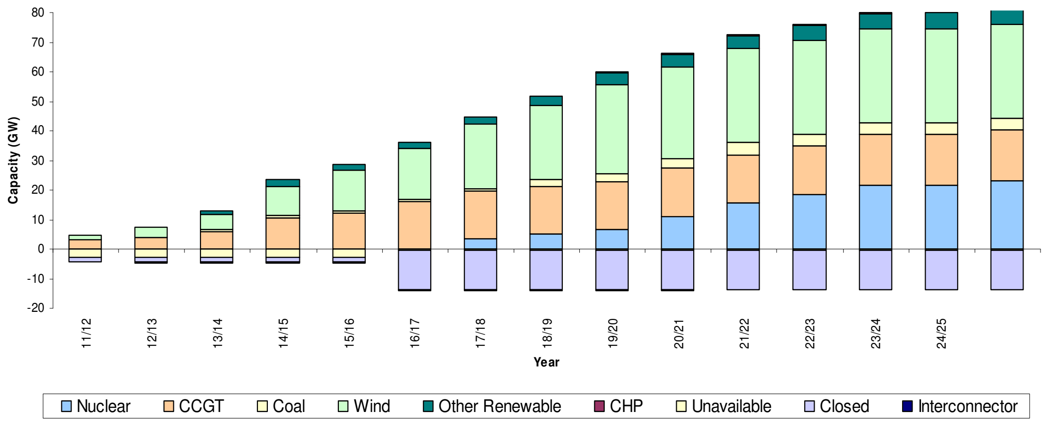


Figure ES.2 illustrates the reported increase in generation capacity from 2010/11 onwards. The capacity of stations that will close on or before 31st December 2015 due to opting out of the LCPD amounts to 12GW of coal and oil capacity. These stations have been retained in the generation background up to and including 2015/16 because of the uncertainty over closure date and the potential for them to be available at peak in 2015/16 if the peak is prior to Christmas. The affected stations have however, been shown as closed from 2016/17 onwards, and this accounts for the step change in closed capacity in 2016 shown in Figure ES.2.

Figure ES.3 shows that over the seven years of this statement, from 2010/11 to 2017/18, there is a reported rise in new capacity of 31.2GW.

**Figure ES.3 - Existing and Planned Transmission Contracted Generation**

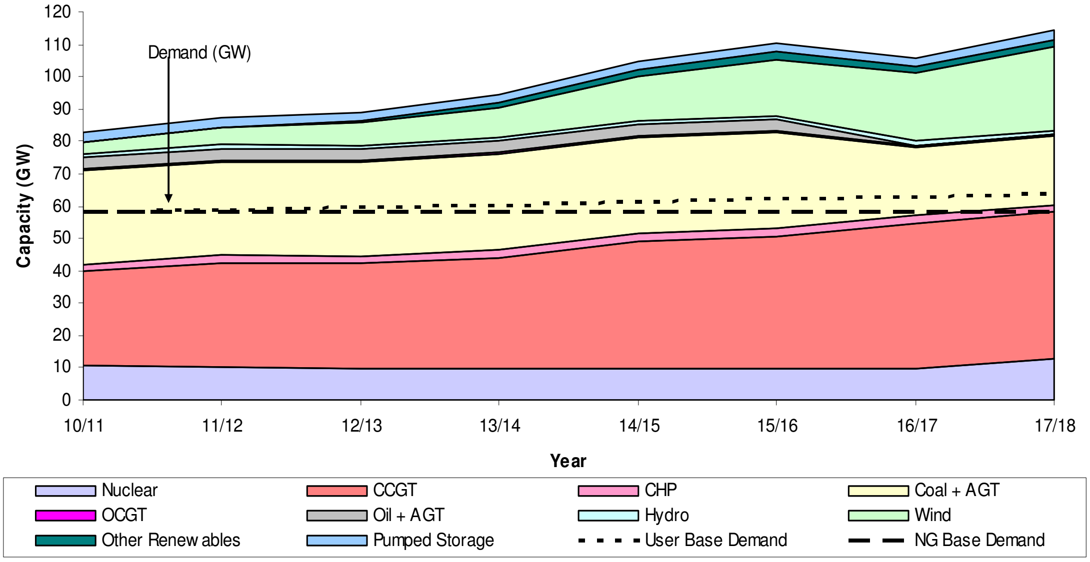


Figure ES.3 also illustrates the main plant types of the contracted generation background over the period from 2010/11 to 2017/18 and includes both existing and proposed new transmission contracted generation. The aggregate power station capacity (TEC and/or 'Size of Power Station') is reported to rise from 82.1GW in 2010/11 to 113.3GW by 2017/18, note that these figures do not include TEC for interconnectors as these are now shown in the ranking order as exporting and are therefore counted as negative generation. An overall increase in contracted generation of 31.2GW is reported, over the period from the 2010/11 winter peak to the 2017/18 winter peak.

The net increase is made up of the following:

- an increase of 16.2GW in CCGT capacity
- an increase of 22.4GW in wind capacity
- an increase of 2.0GW in nuclear capacity
- an increase of 2.1GW in other renewables capacity (mainly biomass, biopower and woodchip generation), this is shown collectively as Other Renewables in Figure ES.3
- an increase in exports of 0.4GW being classed as negative generation (not visible on ES.3)
- a decrease of 3.6GW in oil capacity;
- a decrease of 7.5GW in coal capacity.

The largest increase is wind capacity with an increase of 22.4GW. However at 2017/18 the predominant plant type in capacity terms is CCGT where the total capacity is reported to be 45.3GW and exceeds coal by a level of 21.7GW and account for 40.1% of the total transmission contracted installed generation capacity.

It should be remembered that the above figures reflect the current contracted position and take no account of future uncertainty.

Further details of individual projects can be found in Chapter 3 and Appendix F of this document.

## Plant Margin

**It is emphasised that none of the plant margins presented in this document is intended to represent our forecast or prediction of the future position.** The primary purpose is rather to provide sufficient information to enable the readers to make their own more informed judgements on the subject. The plant margins presented have been evaluated on the basis of a range of different backgrounds; Existing, Under Construction, Consents Granted and Without Consents as shown graphically in Figure ES.4.

Figure ES.4 Generation Backgrounds and Peak Demands

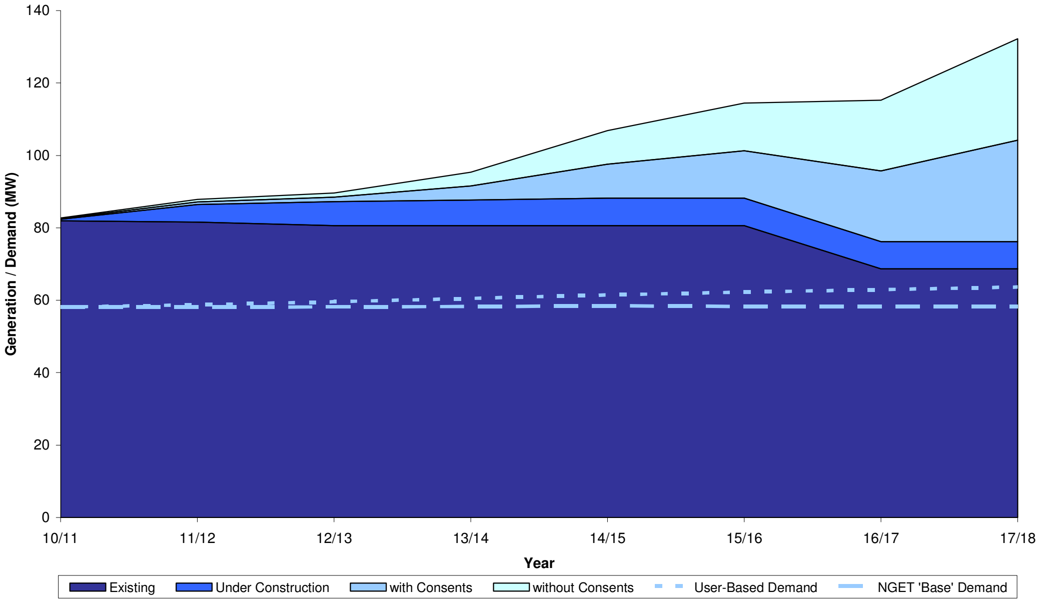
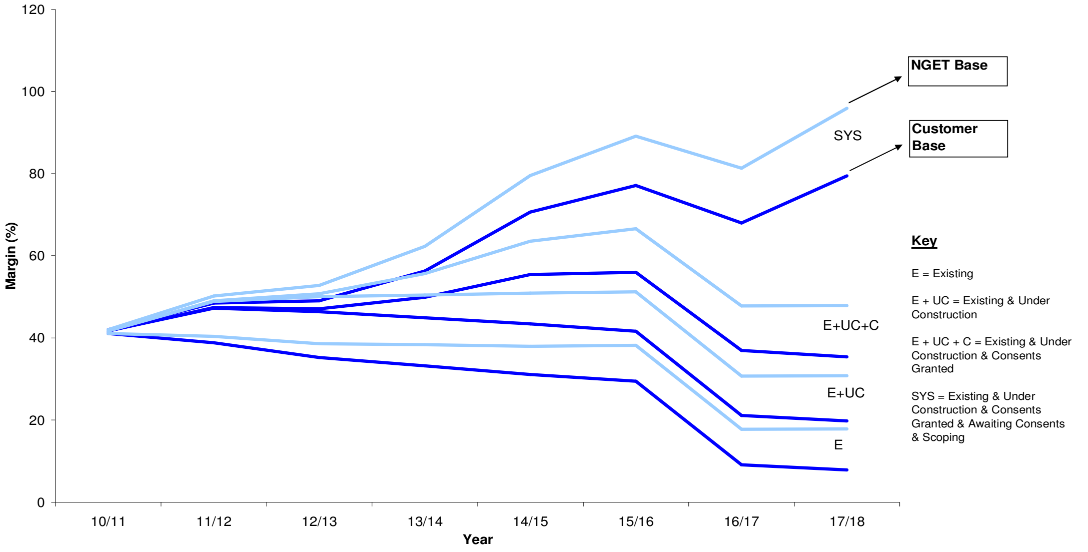


Figure ES.5 compares plant margins derived from the customer based demand forecast with those derived from our own base view of future demand growth for the above four backgrounds; giving eight sensitivities in all.

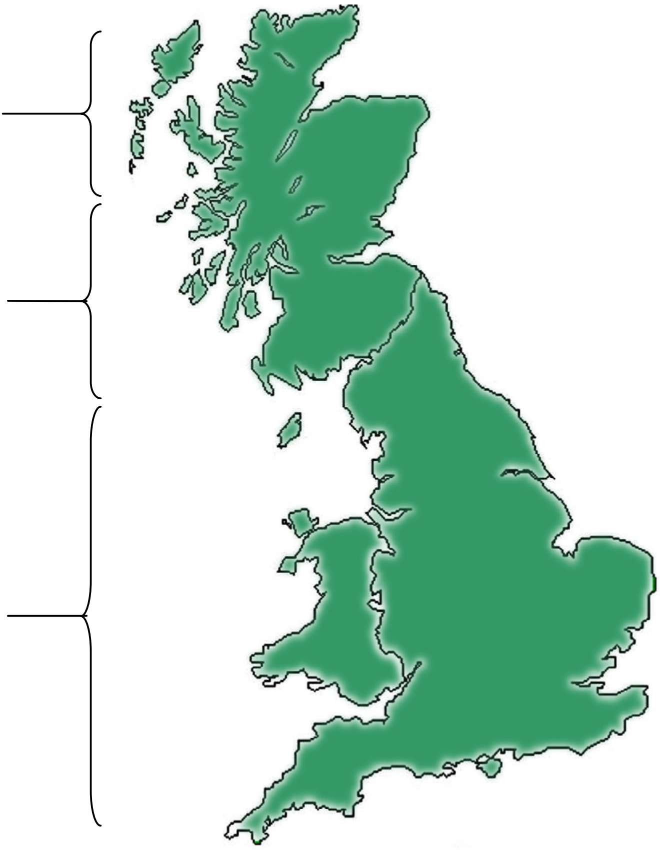
**Figure ES.5 Plant Margins for Various Generation Backgrounds**



## Generation Opportunities

ES.6 provides an indication of the likely connection dates that we would currently expect to offer to connection applications in various geographical locations around the country. These dates have been based around those that have been offered to projects that have recently been transitioned to the new Connect and Manage arrangements.

ES.6 – Illustrative Connection Timescales



**2016 - 2017**
Lots of embedded.
Often Grid Supply Point reinforcements

**2014 – 2016**
Dependant on size (smaller projects earlier).

Less connection applications than further north.

**2012 - 2016.**
Shorter timescales for embedded, dependant on local Grid Supply Point

**2015 / 2016.**
Larger new projects, possibly earlier in some areas

Please note that these are indicative only and are subject to confirmation on an individual case by case basis. We welcome the opportunity to discuss your aspirations for grid connections ahead of any formal application. To discuss an individual project please contact your Customer Agreement Manager or our Customer Services team. The contact details for the Electricity Customer Connections manager are julian.leslie@uk.ngrid.com or 01926 653350.

For more detailed information on connection opportunities and the likely lead times relating to certain geographical areas please refer to Chapter 9 of this document.

## Strategic Investment

The information contained in this year's SYS reflects the report delivered by the Energy Networks Strategy Group (ENSG) – Our Electricity Network – A Vision for 2020. The work carried out for ENSG identifies a set of transmission reinforcements that would facilitate the connection of renewable generation to help meet the Government's 2020 climate change targets. The majority of these works are now progressing and as the date for construction becomes closer clarity over developer projects is increasing and hence these works identified are anticipated to be completed (subject to achieving consents) in time to facilitate the connection of new contracted generation.

## The Offshore Development Information Statement

The Offshore Development Information Statement (ODIS) is produced in accordance with Special Condition C4, and is available at the following location.

https://www.nationalgrid.com/uk/Electricity/ODIS/

The main purpose of the Statement is to facilitate the achievement of the coordinated development of the offshore and onshore electricity grid in Great Britain. The network solutions identified in the Statement represent a vision of how the offshore and onshore reinforcements could be developed; it is the responsibility of individual onshore/offshore network owners to develop detailed designs. In developing these detailed designs it is envisaged that this Statement will provide guidance in determining the optimum solutions. However it should be borne in mind that the network analysis for the ODIS is based on a number of different scenario backgrounds whereas the NETS SYS is based on a contracted background, therefore it is possible that some network reinforcements may differ.

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# Chapter 1

# Introduction

## Introduction

The 2011 National Electricity Transmission System Seven Year Statement (NETS SYS) is published by National Grid Electricity Transmission plc (NGET), acting in its role as National Electricity Transmission System Operator (NETSO) and is published in accordance with the System Operator Standard Licence Condition C11 of National Grid’s Transmission Licence. The two Scottish transmission licensees, Scottish Power Transmission Ltd (SPT) and Scottish Hydro Electric Transmission Ltd (SHETL), are required to assist National Grid in preparing each NETS SYS pursuant to their licence obligations. National Grid Electricity Transmission plc is a member of the National Grid plc (National Grid) group of companies.

A key purpose of the document is to assist existing and prospective new Users of the National Electricity System (NETS), whether generators or suppliers of electricity, in assessing the opportunities available to them for making new or additional use of the transmission system in the competitive electricity market.

## The SYS Structure

For those readers who are unfamiliar with the current market structure, Chapter 10 (Market Overview) provides a high level summary of this and a number of related issues such as governance, institutional and contractual arrangements.

The chapter entitled Chapter 4 (Embedded and Renewable Generation) has been included in recognition of the current and potential future growth in embedded and renewable generation given the government’s targets for generation from combined heat and power (CHP) and renewable sources.

The Statement presents a wide range of technical and non-technical information relating to the NETS in a series of chapters and appendices.

## Confidentiality of Information

Much of the data included in this NETS SYS is provided by Users and potential new Users of the NETS other than National Grid and the two Scottish Transmission Licensees. There are certain obligations placed on ourselves (e.g. Clause 6.15 of the Connection and Use of System Code (CUSC)) regarding the use of such data with respect to ‘disclosure of commercial interests’.

In view of this, the customer demand and generation information listed in the Statement and used to produce the forecast power flows is generally restricted to that for which an appropriate Bilateral Agreement has been entered into between the relevant Transmission Licensee and the customer. Speculative new projects, potential closure of existing stations or other developments, which may have been discussed with the relevant customer, are not included without the agreement of the customer. In this Statement, present and future customer developments for which appropriate Bilateral Agreements have been entered into are generally referred to as ‘transmission contracted’.

Similarly, unless otherwise stated, the transmission network presented includes developments needed for the “transmission contracted” demand and generation projects and excludes transmission works that may be needed to accommodate prospective (i.e. not as yet the subject of an appropriate Bilateral Agreement) new or modified projects for demand or generation.

*The exception to this is the Western HDVC link where import and export flows have been taken into account during modelling, however the link itself is not represented in the technical diagrams or in the branch data as a physical part of the transmission network at this stage.*

It should be noted that some proposed transmission developments included in the background may also be subject to planning consent as may the transmission contracted demand and generation projects.

## The SYS Background

Unless otherwise stated, the network analyses (e.g. the illustrative power flows, the loading on each part of the NETS and the fault levels) presented in this NETS SYS is based on a system background referred to as the "NETS SYS Background", which is often shortened to “SYS background”. The SYS Background is made up of the following:

(i) Demand Background: The "NGET based" demand forecasts rather than the "customer-based" demand forecasts. Both sets of demand forecasts are reported in Chapter 2 (Electricity Demand);

(ii) Generation Background: Unless otherwise stated the existing generation and that proposed new generation for which an appropriate Bilateral Agreement (i.e. BCA, BEGA or BELLA) is in place. This is detailed in Chapter 3 (Generation Capacity); and

(iii) Network Background: The existing transmission network and those future transmission developments, which are considered ‘firm’ in that they are least likely to be varied or cancelled as the needs of the evolving system change. Such transmission developments will include, but will not be restricted to, those schemes, which have been technically and financially sanctioned by the relevant Transmission Owner.

Other schemes, which may not yet be financially sanctioned by the relevant Transmission Owner, but which are nevertheless considered ‘firm’, may also be included. Such transmission reinforcement schemes would, nevertheless, be associated with “Transmission Contracted” generation projects included in the generation background of (ii) above and may have an appropriate Transmission Owners Construction Agreement (TOCA) and Transmission Owners Reinforcement Instruction (TORI) in place.

Transmission network information is detailed in Chapter 6 (The Transmission System).

Please note that the terminology used in the above background descriptions is explained in the Glossary.

The "SYS background" is internally consistent. For example, the transmission background of item (iii) above includes all transmission connection developments cited in the relevant connection agreement as being necessary to connect the generation contained in the background of item (ii) above. The "SYS background" does not include any transmission development that may be needed to accommodate prospective projects of new generation or demand, which do not have an appropriate Bilateral Agreement in place on the Data Freeze Date of 31 December 2010, and which are therefore not reported under item (ii) above. The connection dates used, reflect the contracted position.

It is recognised that the above “SYS background” does not necessarily represent the most likely outturn. For example, it is reasonable to suppose that new applications for power station connections will be received, some power stations will close and some contracts for generation projects may be modified or terminated. This may lead to the need to vary the planned future development of the transmission system to meet changing system requirements. Whilst the main body of this Statement is based on the ”SYS background”, future uncertainties and their effect on system performance, the need for transmission reinforcement and resultant opportunities have also been considered in the relevant chapters.

In view of the previously mentioned uncertainty associated with the need for future developments, the timing of construction of reinforcements to the Main Interconnected Transmission System (MITS) is managed such that investments are made to well defined requirements. Accordingly, in some cases, reinforcement of the MITS may be deferred to the last moment to avoid the risk of undertaking investments which may, in the event, turn out to be unnecessary. In view of this, the "SYS background" may not necessarily contain all the MITS reinforcement schemes required for compliance with the Licence Standard. However, this Statement does include an indicative list of future reinforcement schemes, which could be used where necessary to maintain compliance with the Licence Standard.

## Further Information

The information provided in this Statement will, amongst other things, enable existing customers and potential new customers to identify general opportunities for new, continued and further use of the NETS. When a customer is considering a development at a specific site, certain additional technical information in relation to that site may be required which is of a level of detail that is inappropriate to include in a document of this nature.

In such circumstances the customer may contact the appropriate Transmission Licensee, initially the relevant technical contact, who will be pleased to arrange a confidential discussion, and the provision of such additional information relevant to the site under consideration as the customer may reasonably require.

Customers wishing to make an Application for an appropriate Bilateral Agreement to the CUSC and wishing to discuss the possible terms of such an agreement or obtain an application pack, should initially contact the relevant commercial contact.

Details for these contacts can be found by following the link below,

http://www.nationalgrid.com/uk/Electricity/SYS/Contact/

## Quarterly Updates

The main Statement is supplemented by a set of Updates. These updates are included in the Transmission Networks Quarterly Connections Update (TNQCU), which is available at the following location:

http://www.nationalgrid.com/uk/Electricity/GettingConnected/ContractedGenerationInformation/TNQuUpdate/

The first Update to this 2011 NETS SYS was published in April 2011, and includes the effect of any changes notified since the data freeze date. As in previous years, further Updates will be issued on a regular basis (approximately three month intervals). No new simulations are carried out for the Updates but an estimate is made of the effect of the changes on the various issues covered by the Statement.

## Data Freeze Date

The 'Data Freeze Date' for all information included in this Statement reflects, unless otherwise stated, the extant position on **31 December 2010**. Subsequent developments are reported in the Quarterly Updates.

## Offshore Transmission Owner Licensees

There is no information or data in the NETS 2011 SYS regarding licensed Offshore Transmission Operators (OFTOs), this is due to the fact that as of the data freeze on 31st December 2010 there were no OFTOs officially in place and therefore no obligation on them to provide analysis and data to NGET.

As and when perspective OFTOs are officially in place we will be contacting these parties to make them aware of what is required of them in terms of information provision for the NETS 2012 SYS.

## Contracted Position

Concerning the SYS background there are some instances where the contracted position, as published on the National Grid website in the TEC register, does not align with the generation data displayed in the Chapter 3 and Appendix F. The reason for this is that in a small number of cases users are partway through the commercial process of updating their TORIs and TOCAs in order for their contracted position to be changed, hence for the purposes of the SYS we have assumed that if a TORI has been adjusted that the affected/associated TOCA will also be adjusted to ensure consistency in the studies.

## Content Outline

The following gives an outline of the main sections of the NETS SYS, together with the main data items included within each section. The content outline is given in terms of main sections, which correspond broadly to the chapters and appendices in the SYS. There are a number of figures and tables in the NETS SYS that are generic in nature and provided for illustrative purposes. For the sake of conciseness they are not listed here.

The following definitions are used in the sections that follow:

- Year 0 is 2010/11
- Year 1 is 2011/12
- Year 2 is 2012/13
- Year 3 is 2013/14
- Year 4 is 2014/15
- Year 5 is 2015/16
- Year 6 is 2016/17
- Year 7 is 2017/18

Chapter 2 - Demand

This chapter presents the following data:

- historical outturns of actual and weather-corrected peak demand and energy supplied from 2005/06 to Year 0
- daily demand profiles for winter peak, typical winter, typical summer and summer minimum in Year 0
- weekly maximum and minimum demands in Year 0
- annual load duration curve for Year 0
- forecast of peak demand from Year 1 to Year 7 based on data submitted by Users, including interconnector, pumped storage and demand management assumptions
- National Grid forecast for demand and electricity requirements from Year 1 to Year 7 for Low, Base and High growth scenarios

The chapter also includes a discussion of the assumptions behind the National Grid Low, Base and High forecasts, and an explanation of demand terminology such as weather corrections.

Chapter 3 - Generation

This chapter provides data on historic, existing and planned generation connected to the transmission network. The data provided includes the following:

- total existing and planned capacities for year 1 to year 7
- planned capacity additions from year 1 to year 7, indicating the amount of capacity under construction and the amount that have consents granted
- planned generation closures from year 1 to year 7, including LCPD (Large Combustion Plants Directive) closures
- unavailable generating units up to year 7
- details of transmission contracted generation planned to connect beyond year 7

An explanation is also given of how generation capacities are defined and the different types of contract that customers have.

Appendix F shows more detailed breakdowns of the generation data shown in this chapter often broken down by Station and SYS Study Zone.

Chapter 4 - Embedded Generation

This section will present data on installed embedded generation according to the defined levels for large, medium and small power stations for each of the three transmission licensees. The data includes capacity and plant type. Data is also presented on the amount of generation netted off the demand by Distribution Network Operators (DNO) at the time of system peak.

Chapter 5 - Plant Margins

This chapter deals with the performance of transmission contracted generation in meeting the GB transmission system demand. The data provided includes the following:

- historic plant margins from 2005/06 to year 0, based on installed generation from the SYS January updates, and actual and weather-corrected peak demands
- generation capacity totals from Year 0 to Year 7, using the four generation backgrounds of existing, under construction, consents granted and all generation, together with the customer-based and NGET Base demands
- plant margins from Year 0 to Year 7, using the four generation backgrounds above, and the customer-based and NGET Base demands
- plant margins from Year 0 to Year 7, for varying levels of wind output, based on the customer-based peak demands

Chapter 6 - Transmission System

This chapter introduces the diagrams in Appendix A & Appendix C, and the data in Appendix B, and also contains the following:

- planned developments on the transmission network from Year 1 to Year 7, for SHETL, SPT and NGET areas
- planned developments on the transmission network that either take place beyond year 7 or are associated with future connections that take place beyond year 7

A brief discussion of how the power system is controlled and operated with reference to the main types of equipment installed on the system will be provided.

Chapter 7 - Transmission System Performance

This chapter introduces the power flow diagrams presented in Appendix C, and also presents data and analysis on the following:

- daily demand profiles for winter peak, typical winter, typical summer and summer minimum in Year 0, showing energy supplied by plant type
- ranking order of generation operation for Year 1 to Year 7
- zonal demand, studied generation and transfers, for SYS Study Zones Z1 to Z17, for Year 1 to Year 7 inclusive for winter peak
- boundary demand, studied generation and transfers, for transmission boundaries B1 to B17, for Year 1 to Year 7 inclusive for winter peak
- transmission losses by circuit type for Year 1 to Year 7 inclusive for winter peak
- zonal transmission losses for SYS Study Zones Z1 to Z17, based on year 1

This chapter also discusses the method used for the calculation of fault levels, and introduces the fault level results in Appendix D.

Chapter 8 - Transmission System Capability

This chapter presents the results of the boundary capability studies. For each boundary the following is given:

- planned transfer, required capability, actual capability for Year 1, Year 3, Year 5 and Year 7
- probabilistic transfers for Year 1 to Year 7 inclusive
- a commentary for each boundary

A table of additional construction schemes that are identified for network compliance as a result of the boundary capability studies is also provided, and a discussion of the ENSG (Electricity Networks Strategy Group) report.

Chapter 9 - Opportunities

The main purpose of this chapter is to provide a commentary on opportunities for connection to the transmission network for demand, generation and interconnector customers. Hence, the following is provided:

- zonal demand and studied generation for each SYS study zone
- a commentary on opportunities for the connection of generation in each SYS study zone
- reactive utilisation (metered output) from April 2005 to March 2011

A link to the Charging & Revenue web pages will be provided where the latest version of the geographic diagram of generation Use of System tariff zones can be viewed.

Chapter 10 – Market Overview

This chapter section provides a discussion on BETTA (British Electricity Trading and Transmission Arrangements), including market structure, key documents, the System Operator's role and obligations, and participants requirements.

Appendix A - Geographic & Schematic Diagrams

Geographical drawings of the national electricity transmission network will be provided, based on the existing transmission network. The maps will show the following:

- location of existing Large Power Stations
- DNO boundaries
- main system boundaries and SYS study zones
- existing National Parks

Each Licensee will produce schematic diagrams for their own networks. The following will be produced:

- existing transmission system as at the main SYS data freeze date (31 December 2010)
- reactive compensation equipment, with the Year 1 transmission network as background
- Generation Use of System Tariff Zones, with the Year 1 transmission network as background
- main system boundaries and SYS study zones, with the Year 7 transmission network as background

Appendix B - Technical Data

Technical data for the national electricity transmission network will be provided as follows:

- data for existing and planned substations, giving substation code, operating voltage, demand tariff zone, generation tariff zone and LV shunt susceptance
- tables of transmission circuits for winter Year 1, giving circuit type, circuit length, circuit parameters and circuit ratings
- planned changes to transmission circuits for Year 2 to Year 7, giving the type of change and the equivalent data supplied for existing circuits
- tables of grid supply transformers for winter Year 1, giving transformer parameters and rating
- planned changes to grid supply transformers for Year 2 to Year 7, giving the type of change and the equivalent data supplied for existing transformers
- typical parameters for transformers, QBs and SVCs

- reactive compensation equipment for winter Year 1, giving equipment type, operating voltage, and reactive ranges
- planned changes to reactive compensation equipment, for Year 2 to Year 7, giving the type of change and the equivalent data supplied for existing compensation equipment
- indicative switchgear ratings, including voltage level, breaker type nominal rating, three-phase and single-phase initial peak, RMS break and peak break ratings

Appendix C - Power Flow Diagrams

Each Licensee will produce power flow diagrams for their own network, and NGET will collate the three separate sets of diagrams into the NETS SYS document. The diagrams will show power flows on all transmission circuits for year 1 to year 7 inclusive.

Appendix D - Fault Levels

Each licensee will calculate fault levels on their networks for Year 1 to Year 7 inclusive for winter peak. The quantities calculated will be:

- node name
- voltage level (kV)
- three-phase initial peak current (kA)
- three-phase RMS break current (kA)
- three-phase DC break current (kA)
- three-phase peak break current (kA)
- single-phase initial peak current (kA)
- single-phase RMS break current (kA)
- single-phase DC break current (kA)
- single-phase peak break current (kA)

Appendix E - Supply Point Demands

This appendix presents the following data:

- supply point demands at time of supply point peak and system peak, power factor and generation for Year 0 to Year 7, for winter peak conditions, together with node name and customer name for each supply point
- supply point demands at time of system minimum, power factor and generation for Year 0, for summer minimum, together with node name and customer name for each supply point

Other Sections

Other sections of the NETS SYS document include:

- legal disclaimer
- foreword
- executive summary, which will discuss the main points together with headline figures from the main statement
- introduction
- contact details for the three transmission companies
- a list of references, useful documents and websites
- glossary

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# Chapter 2

# Electricity Demand

## Introduction

This chapter presents forecasts of electricity demand to be met from the National Electricity Transmission System (NETS). The main forecasts are based on NGET's own forecasts, which are used in conjunction with the generation and transmission backgrounds described in Chapter 3 and Chapter 6 respectively, to form the basis of the studies presented in this Statement.

Alternative 'High' and 'Low' scenario forecasts are also included as supplementary information and reflect our views on possible outcomes based on specific assumptions.

Information submitted by Customers (transmission system 'Users') who take, or propose to take, electricity from the high voltage system is also presented. The 'User'-based forecasts, includes details of individual Grid Supply Point demands.

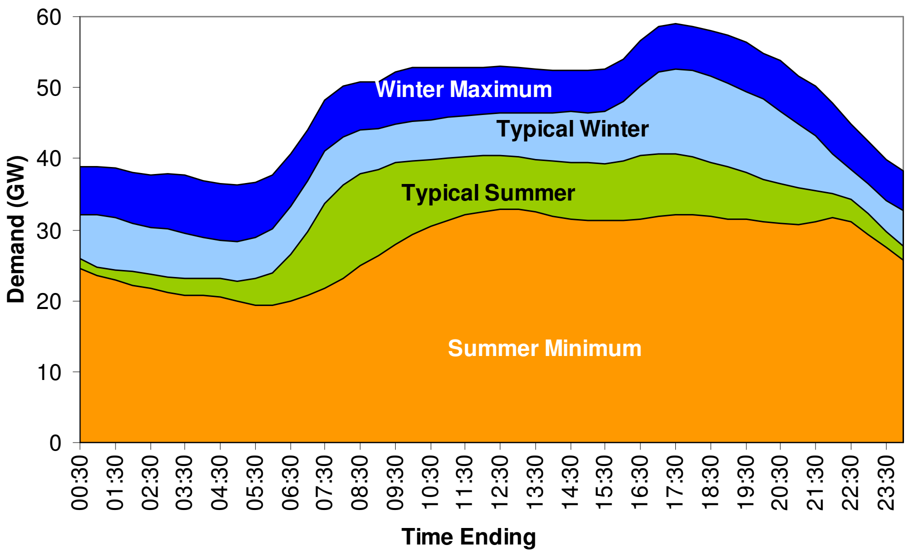
Other demand information such as winter and summer demand profiles, load duration curves, weekly maximum and minimum demands, and annual requirements for NGET's base, high and low cases are also presented in this Chapter to provide an overview of NETS electricity demands other than at the time of system peak.

Finally readers are advised that if they are not familiar with demand terminology that they read Appendix G before studying this chapter. Appendix G explains the terminology used in this chapter.

## Demand Outturn 2010/11

Figure 2.1 presents daily demand profiles for the days of maximum (07/12/10) and minimum (18/07/10) demand on the Transmission System in 2010/11 and for days of typical winter (17/11/10) and summer (10/06/10) weekday demand. Please note that these demands are shown exclusive of station transformer, pumping demand and interconnector exports.

**Figure 2.1 - Summer and Winter Daily Demand Profiles in 2010/11**



Key points of interest are:

(i) Maximum & Typical Winter Profiles (Weekday)

| | |
|---|---|
| 00:00h - 03:00h: | Operation of time-switched and radio tele-switched storage heating & water heating equipment. |
| 06:30h - 09:00h: | Build-up to start of working day. |
| 09:00h - 16:00h: | Plateau reflecting the working day (primarily commercial & industrial demand). |
| 16:30h - 17:30h: | Rise to peak due to lighting load and increased domestic demand outweighing fall-off in commercial and industrial demand. |

(ii) Typical Summer Profile (Weekday)
As (i) above without effects of storage heating demand and with the later onset of evening lighting load.

(iii) Minimum Summer Profile (Sunday)
As (ii) above with increased lunchtime cooking demand.

Whilst Figure 2.1 shows how demand varies through the day in summer and winter, Figure 2.2 plots weekly maximum and minimum demands in 2010/11 to indicate how demand varies over the year. Please note that week 1 shown below on Figure 2.2 refers to the first week in April 2010.

**Figure 2.2 - Weekly Maximum and Minimum Demands in 2010/11**

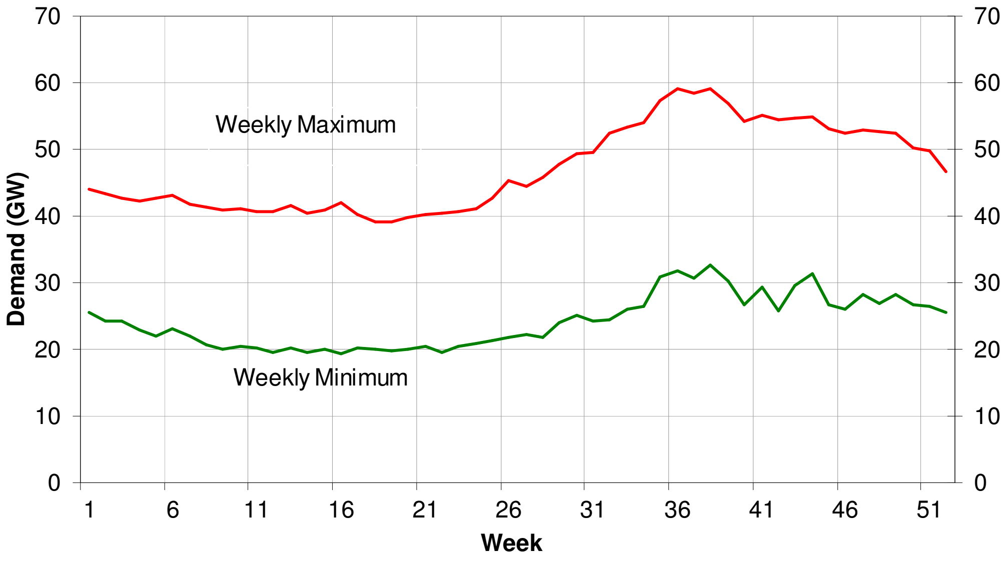
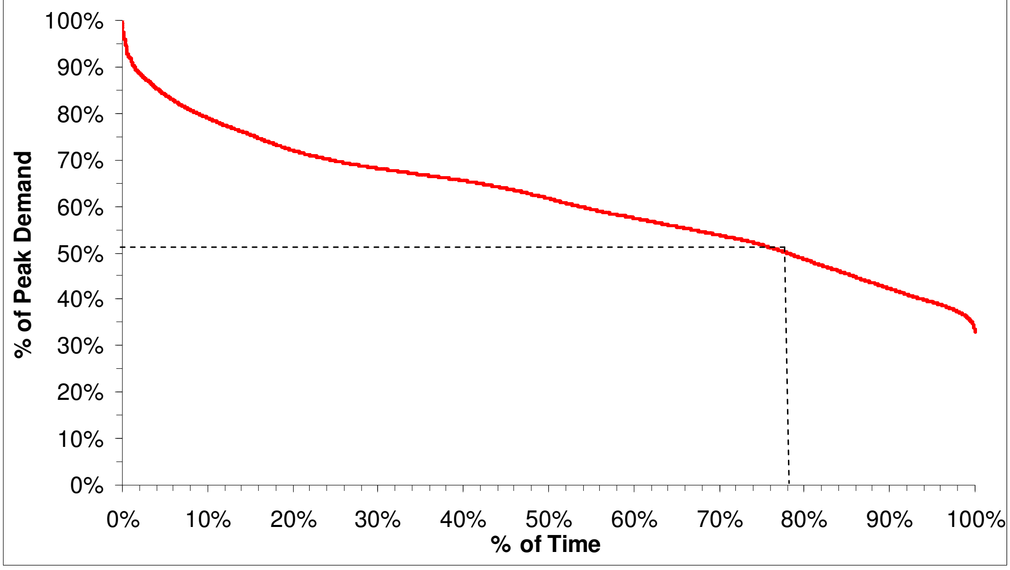


Figure 2.3 shows the annual load duration curve for 2010/11. Based on demand data for every half hour of the year, it shows the percentage of time in the year against the proportion of the year's peak. For example, demand exceeded 50% of the annual peak for 78% of the time.

**Figure 2.3 - Annual Load Duration Curve for 2010/11**



## ACS Peak Demand

ACS Peak Demand refers to the time of the simultaneous peak demand on NETS and accordingly takes account of any diversity between the individual peak demands on each of the systems of the three Onshore Transmission Licensees (i.e. NGET, SPT and SHETL).

For this Statement, ACS Peak Demand is defined as unrestricted peak demand including losses, excluding station demand and exports. No pumping demand at pumped storage stations is assumed to occur at peak times. Infrastructure planning for the transmission system continues to be based on ACS 'unrestricted' demands – a prudent approach to transmission planning made on the basis that demand control cannot be fully relied upon to be enacted at peak times.

Please note that other related documents may refer to 'restricted' demands rather than 'unrestricted' demands, e.g. National Grid's 'Winter Outlook Report'. Naturally, therefore, care should be exercised when making comparisons between demand forecasts on different bases.

As outlined earlier in this chapter, NGET's own forecasts are used in conjunction with generation and transmission backgrounds to form the basis of the studies presented in this Statement.

NGET's ACS peak demand forecast is derived from detailed analysis on the annual energy consumption. A historic relationship between annual energy consumption and system peak demand is used to form the basis for the future relationship between the annual and peak demands.

Annual energy consumption is derived from a number of key drivers:

- Historic annual energy consumption
- Economic growth (including fuel price)
- Growth in household numbers
- Growth in industrial and commercial sectors
- Embedded generation development
- Energy efficiency measures

- New emerging technology such as heat pumps and electric vehicles

Historical annual energy consumption forms the basis of our forecasts, with each of the other factors adding or reducing energy usage to it. Growth in the economy, household numbers, industrial and commercial sectors would tend to increase energy consumption (with a shrink in these factors having a reverse impact); whilst an increase in embedded generation (CHPs, wind, biomass and other renewable generation) and greater energy efficiency measures will reduce demand. Smart metering is anticipated to have a greater impact on system peak demand than on annual energy consumption, with the distribution of the demand load throughout the day anticipated to change. The introduction of heat pumps and electric vehicles will also contribute to the change in energy consumption.

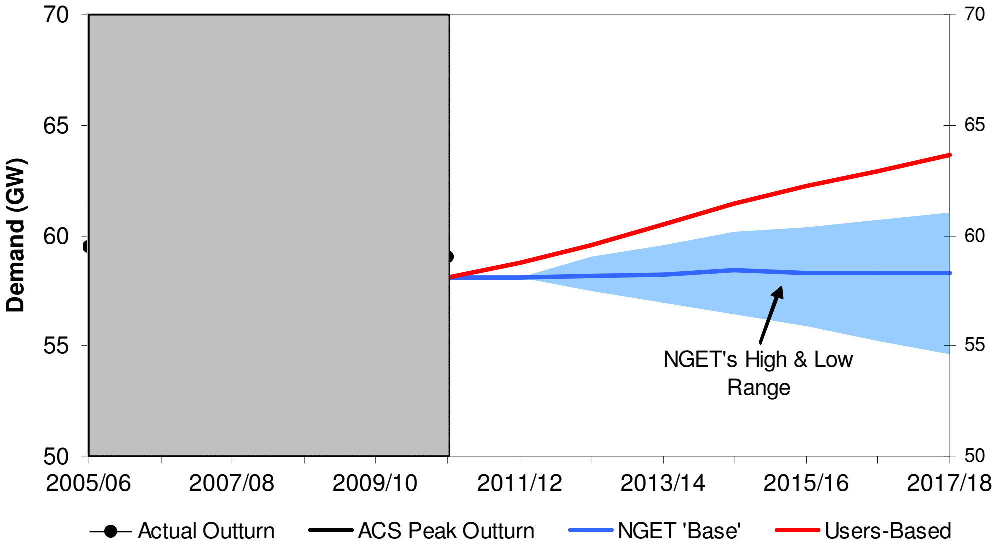
Details of NGET's peak demand and electricity requirements outturn and projections, and the main economic assumptions underlying them are given in Tables 2.1 – 2.5. (Please note that the central economic forecasts on which they are based have been provided by Experian Business Strategies).

For more information on ACS and Users-based demands, please see Appendix G.

## ACS Peak Demand Outturn and Forecasts

Figure 2.4 shows recent actual and ACS peak demands along with the latest NGET 'Base' forecasts of ACS peak demand on the Transmission System. Correcting historical peak demands to ACS conditions enables underlying peak demand patterns and trends to be more readily observed. NGET's high and low cases, together with Users'-based forecasts are also shown in the chart.

**Figure 2.4 - ACS Peak Outturn and Forecasts**



## NGET's 'Base' Forecast

In the 'Base' forecasts, peak demand is projected to increase by 0.3% over the study period. There are factors that drive this demand to increase whilst other factors drive the demand to decrease, giving a relative flat forecast over all.

The economic background is an important element of NGET's demand forecasts. The UK economy emerged weakly from an 18-month recession in the fourth quarter of 2009. GDP contracted by 4.9% over 2009. The economic recovery gained pace in early 2010, but reversed with a contraction in GDP in the final quarter of the year, partially attributed to poor weather. GDP grew by 1.3% over 2010. Economic recovery is expected to be moderate, with fiscal austerity acting as a drag on the positive impact of stronger exports. GDP is expected to grow by 1.7% in 2011, returning consistently to the historical trend rate of around 2.5% pa after 2016. Under these assumptions, annual GDP growth averages 2.0% over the period 2010 to 2016 inclusive.

Increasing end-user energy consumption driven by economic growth is forecast to be offset by forecast growth in embedded generation, thus reducing the growth in transmission electricity demand. Although the development of embedded generation, in particular CHP generation, has been weakened by the economic downturn, we forecast that total embedded generation will grow at about 2 – 3.5 % p.a. from current capacity of 8.8GW to 10.6GW by end of the study period  Nearly half of this would come from embedded CHP, approximately a quarter coming from embedded wind (full capacity) and the remaining embedded generation from biomass plants, solar PV, etc.  In addition, some solar thermal heating at homes could reduce direct electric water heating.

Another factor that could reduce energy consumption is energy efficiency measures. Our forecast assumes an increase in the level of energy efficiency over the period, with the change from incandescent light bulbs to CFLs (compact fluorescent light bulbs), more efficient household appliances and insulation (loft, cavity wall and solid wall) all having an effect on domestic demand.  Energy savings from CRC Energy Efficiency Scheme for non-domestic customers were also incorporated into our forecasts.

The UK government has a policy to roll-out smart metering to all residential gas and electricity customers by the end of 2020.  This policy would influence the demand daily profile, encouraging the charging of electric vehicles overnight, reducing the level of demand at peak and resulting in general behavioural changes affecting overall energy consumption.  It is assumed that 20% of domestic consumers would take up the time of use tariff, reducing energy consumption over the year by around 3% for these customers.

During this study period, the combined savings from energy efficiency measures and time of use tariffs/smart metering reduces energy consumption by 0.5 – 3% per annum.

This forecast also assumes the deployment of heat pumps and locally-connected electric heating and an increase in the ownership of electric vehicles.  Although these new technologies have minimal effect on peak demand and annual energy during this study period, both are expected to play a significant role beyond 2020.

For the duration of this forecast, it is assumed that there will be no exports to Continental Europe at the time of the system peak.  Exports of 400 – 500MW at peak are expected from the SPT system to Northern Ireland via the Moyle interconnector and across the planned 500MW interconnector between North Wales and the Irish Republic.  This change in forecast is due to the new exemption of TNUoS demand and generation charges on interconnectors.  Under the second and third package EU legislation, an interconnector is defined as a transmission line (thus the flows are considered as neither generation nor demand).  Please note that exports are not included in the definition of "ACS peak demand" and are consequently treated as negative generation.

### NGET's High Growth Scenario

In this scenario, peak demand increases by 5% over the study period compared with an increase 0.3% in the base case, and similar increase on annual energy.

This scenario (see Table 2.5) is based on the possibility that the economic recovery will gain strength due to strong exports and investment activity, enabling the private sector to outweigh the impact of fiscal tightening. Under this scenario, annual GDP growth averages 2.7% over the period 2010 to 2016 inclusive.

Other factors considered in this scenario are lower energy efficiency savings, lower demand reduction from the effects of smart metering/time of use tariffs and less embedded generation. Increase in demands from electric vehicles and demands from heat pumps were also considered, though these have minimal effect on peak and annual energy over the study period.

Total embedded generation will grow at a slightly slower pace of about 1.5 – 3% per annum, giving a total capacity of 9.8 GW at the end of the study period. Please note that these are full capacities and may be lower at the time of system peak.

### NGET's Low Growth Scenario

In this scenario, peak demand decreases by 6% over the study period compared with an increase of 0.3% in the base case and a decrease of 7.5% on annual energy over the study period.

This scenario (see Table 2.5) is based on the possibility that the recovery falters due to fading consumer confidence and rising unemployment as the fiscal squeeze takes hold, the impact being magnified by downward pressures on UK exports as recovery in the eurozone loses momentum. Under this scenario, annual GDP growth averages 1.4% over the period 2010 to 2016 inclusive.

Other factors considered in this scenario are greater energy efficiency savings, more demand reduction from the effects of smart metering/time of use tariffs, and a faster growth of embedded generation. Increase in demands from electric vehicles and demands from heat pumps were also considered, though these have minimal effect on peak and annual energy over the study period.

Total embedded generation will grow at a faster pace of 3 – 6% p.a., giving a total capacity of 12.1 GW at the end of the study period. Please note that these are full capacities and may be lower at the time of system peak.

## 'Users' Based Forecasts

As explained earlier in this chapter, the main forecasts are based on NGET's own forecasts rather than based on Users' forecasts. NGET's 'base' demand forecasts form part of the SYS background upon which most of the studies presented in this Statement are based. For comparison, 'User'-based peak demand forecasts are presented in this Statement. These are obtained from the aggregation of 'User' submissions (see Table 2.3).

In submitting their forecasts, 'Users' are not required to provide information on their background assumptions but possible reasons for the transmission system demand differences include alternative views on factors such as economic prospects and the growth of demand met by embedded generation. Furthermore, the User-based forecasts were submitted last June based on demand seen in 2009/10. NGET forecasts benefit from being based on provisional demand outturn seen in 2010/11.

Local peak demand is used for Grid Supply Point planning while the demand at the time of the system peak is used for infrastructure planning purposes. Transmission losses are added to User's demand submissions. The aggregation of these demands is then scaled to the provisional or, if known, final ACS corrected outturn for the winter. The resulting adjustment factor is applied to subsequent years, thus retaining customers' forecast aggregate annual growth rates.

## Demand on the Grid Supply Points (GSPs)

Grid Supply Points (GSPs) are the points of connection between the transmission system and the distribution networks and/or Large Power Stations. The times of individual GSP peak demands can vary from GSP to GSP and as such may not coincide with the time (or date) of the system peak. In Appendix E, tables E.1.0 to E.1.7 list the 'User'-based forecasts of maximum demand for each GSP, firstly in respect of the time of the GSP peak and secondly in respect of the projected time of the system peak. These demands are measured at the GSP and accordingly include distribution losses but do not include transmission losses.

The final column in Table E.1.1 gives Direct Current Load Flow (DCLF) Node information. This has been included to enable Users to identify the HV DCLF transport model node at which LV demand is mapped for the purpose of calculating Transmission Network Use of System (TNUoS) tariffs (please refer to Chapter 6 under "Use of System Tariff Zones") and producing the Condition 5 information paper which forecasts the future path of the locational element of the TNUoS tariffs. The additional column is included for information purposes, but it should be noted that the peak figures included in the table will not necessarily exactly match those demand figures contained in the DCLF transport model as adjustments to the data are made to allow for station demand and generation is treated as negative demand. Also in Appendix E, table E.2.0 provides GSP information at the projected time of the minimum system demand.

For grid supply point planning, demand at each GSP's peak is used and is scaled to GB demand, together with appropriate allowances for embedded Large Power Stations, in accordance with the Licence Standard. An allowance for generation by Medium and Small Power Stations and imports across embedded External Interconnections is already made in the customers' demand projections. For completeness, the tables in Appendix E also list Large Power Stations connected to GSPs or embedded in the distribution networks behind GSPs, together with demand power factors.

**Figure 2.5 - ACS Peak GB Demand**

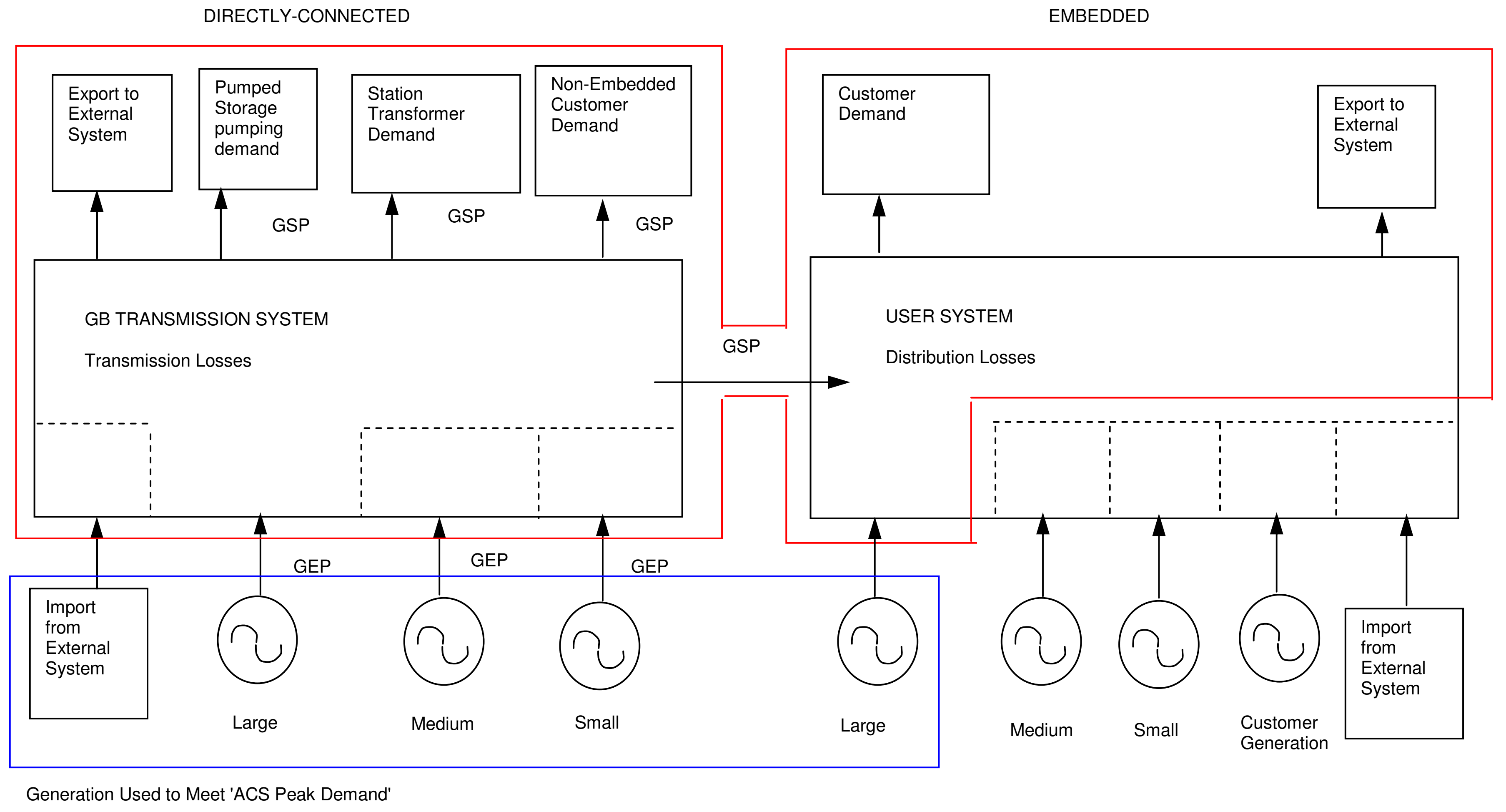


**Table 2.1 - NGET's 'Base' ACS Peak Demand Forecasts (GW)**

| Forecast | Description | 2010/11 | 2011/12 | 2012/13 | 2013/14 | 2014/15 | 2015/16 | 2016/17 | 2017/18 |
|---|---|---|---|---|---|---|---|---|---|
| 1 | ACS Peak incl Station Demand and Exports to External Systems | 59.1 | 59.2 | 59.7 | 59.9 | 60.0 | 59.7 | 59.7 | 59.7 |
| 2 | Station Demand | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 |
| 3 | ACS Peak excl Station Demand and Exports to External Systems (for plant margin evaluation) | 58.5 | 58.6 | 59.1 | 59.3 | 59.4 | 59.1 | 59.1 | 59.1 |
| 4 | Export to N Ireland via Moyle Interconnector | 0.4 | 0.5 | 0.5 | 0.5 | 0.5 | 0.4 | 0.4 | 0.4 |
| 5 | Export to Republic of Ireland via "East/West" Interconnector | N/A | N/A | 0.5 | 0.5 | 0.5 | 0.4 | 0.4 | 0.4 |
| 6 | Export to France via IFA | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 7 | Export to The Netherlands via Britned Interconnector | N/A | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 8 | ACS Peak excl Station Demand and Exports to External Systems (for ranking order & SQSS studies, where exports to External Systems are treated as negative generation) | 58.1 | 58.1 | 58.1 | 58.3 | 58.4 | 58.3 | 58.3 | 58.3 |

**Table 2.2 - Peak Demands and Annual Electricity Requirements: Historical Outturns**

| Year | Actual Peak Demand (GW) | ACS Corrected Peak Demand (GW) | Actual Electricity Requirements (TWh) | Weather Adjusted Electricity Requirements (TWh) |
|---|---|---|---|---|
| 2005/06 | 59.5 | 61.4 | 349.0 | 347.6 |
| 2006/07 | 57.5 | 60.9 | 339.8 | 343.0 |
| 2007/08 | 60.0 | 60.7 | 339.9 | 342.5 |
| 2008/09 | 58.6 | 58.4 | 333.3 | 329.3 |
| 2009/10 | 58.5 | 57.5 | 320.7 | 318.1 |
| 2010/11 | 59.1 | 58.1 | 319.2 | 314.7 |

**Table 2.3 - NGET's ACS Peak Demand Forecasts & Users' Peak Demand Forecast**

| Year | ACS Peak Demand (GW) Low Scenario | ACS Peak Demand (GW) Base Forecast | ACS Peak Demand (GW) High Scenario | Users' Peak Demand Forecast |
|---|---|---|---|---|
| 2010/11 | 58.1 | 58.1 | 58.1 | 58.1 |
| 2011/12 | 58.1 | 58.1 | 58.1 | 58.7 |
| 2012/13 | 57.5 | 58.1 | 59.0 | 59.6 |
| 2013/14 | 57.0 | 58.3 | 59.6 | 60.5 |
| 2014/15 | 56.4 | 58.4 | 60.2 | 61.5 |
| 2015/16 | 55.9 | 58.3 | 60.3 | 62.3 |
| 2016/17 | 55.2 | 58.3 | 60.7 | 62.9 |
| 2017/18 | 54.6 | 58.3 | 61.0 | 63.6 |

**Table 2.4 - NGET's Annual Electricity Requirement Base Forecast and Scenarios**

| Year | Annual Electricity Requirements (TWh) Low Scenario | Annual Electricity Requirements (TWh) Base Forecast | Annual Electricity Requirements (TWh) High Scenario |
|---|---|---|---|
| 2010/11 | 314.7 | 314.7 | 314.7 |
| 2011/12 | 312.0 | 314.4 | 316.9 |
| 2012/13 | 309.3 | 314.8 | 319.2 |
| 2013/14 | 305.7 | 315.1 | 321.9 |
| 2014/15 | 302.2 | 315.9 | 325.3 |
| 2015/16 | 298.7 | 315.2 | 326.3 |
| 2016/17 | 294.2 | 314.7 | 327.8 |
| 2017/18 | 290.9 | 314.5 | 329.9 |

**Table 2.5 - NGET's Base Forecast and Scenarios Economic Assumptions**

| Forecasts 2009/10 - 2016/17 (% p.a.) | GDP | Household Disposable Income | Manufacturing Output | Non-Manufacturing Output |
|---|---|---|---|---|
| Low Growth Scenario | 1.4% | -0.4% | 1.0% | 1.4% |
| NGET 'Base' Forecast | 2.0% | 1.1% | 2.2% | 2.0% |
| High Growth Scenario | 2.7% | 2.6% | 3.4% | 2.6% |

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# Chapter 3

# Generation

## Introduction

This chapter presents information on all sources of generation, which are used to meet the ACS Peak Demand as defined in the on line Glossary and presented in Chapter 2 (Electricity Demand).

Information provided in this chapter relates to those generators who are “Transmission Contracted” i.e. they have a contract for either an existing or a new connection, hence **the SYS Background is a factual list of contracted sites and is not a forecast** of which generators are expected to remain in operation or which proposed new generation projects are deemed most likely to proceed to completion. Consequently, care must be taken when interpreting the overall capacity figures as some stations may close, and some of the proposed projects may not progress to a connection. In addition there may be some non-contracted projects not included within the SYS that may proceed to a connection during the seven years. The “Transmission Contracted” generation capacities show a mix in terms of fuel type, geography and system disposition.

The “Transmission Contracted” SYS Background incorporates all existing and proposed projects with a signed bilateral agreement and only includes the closure of existing plant if we have been informed by the generator. Consequently, the Magnox plants at Oldbury and Wylfa, where closure dates have been published by BNFL Magnox Electric, are shown as closing over the period. It has also been assumed that plant that has opted out of the LCPD obligation will not generate from 2016 onwards.

An exception to the general rule of only including sites with bilateral agreements is Alcan's Lynemouth power station, which is embedded, Licence exempt and Large but currently has yet to sign a Bilateral Agreement. However, this power station does exist and is capable of spilling large amounts of power onto the system (circa 420MW). In consequence, it is subject to special treatment in this NETS SYS in that it is treated as "Transmission Contracted". Its capacity is not netted off the demand forecasts submitted by Users but, instead, is included as generation capacity used to meet the ACS Peak Demand.

Finally readers are advised that if they are not familiar with Generation terminology that they read Appendix H before studying this chapter. Appendix H explains the Generation terminology used in this chapter.

### The SYS Background

The generation background presented in this chapter and the transmission background described in Chapter 2 (Electricity Demand) and Chapter 6 (The Transmission System) respectively, form the basis of the SYS background upon which most of the studies and analyses presented in this Statement are based. These three elements of the SYS background (namely: demand; generation; and transmission) are internally consistent. For example, the transmission background of Chapter 6 includes all transmission connection developments cited explicitly in the relevant Bilateral Agreement as being necessary to permit the connection of the generation contained in the generation background presented in this chapter. It is worth repeating, however, that the SYS background does not include any transmission development that may be needed to accommodate prospective projects (with the exception of the Western HVDC link as mentioned in Chapter 1) of new generation or demand that did not have an appropriate Bilateral Agreement in place on the Data Freeze Date of 31 December 2010.

## Consents (S36 and S14) and Under Construction Status

The requirements for generation projects to obtain the necessary consents (i.e. under Section 36 of the Electricity Act 1989 and Section 14 of the Energy Act 1976) is explained in Chapter 10 (Market Overview). Many of the tables giving information on generation introduced later in this chapter and also in Appendix F include an indication of whether that plant has obtained section 36 and/or section 14 (where appropriate) consents or not. This information is useful when considering the relative likelihood of a project proceeding to completion.

From 1 March 2010, the Infrastructure Planning Commission (IPC) became responsible for processing new planning applications under the Planning Act 2008. Section 36 applications received before 1 March 2010 will remain as part of the previous process as described above with new applications for consents having to go through the IPC for examination and decision.

## Commissioning Dates

The commissioning year given will normally correspond to both the 'contract' date and the assumed date of actual full commercial output from the plant in question. However, in some cases full commercial output may slip into the years following the contract date. In such cases, the assumed generation commissioning dates given reflect the advice of the relevant generator.

Rather than strict adherence to a formal transmission contracted position, pragmatic assumptions relating to commissioning dates in the earlier years were, where considered appropriate, adopted in previous Seven Year Statements in order to enhance the relevance of the information provided. Such assumptions were made without prejudice and were intended to recognise the extant consent status of the plant in question and the progress towards completion of the project.

## Generation Capacity

### Power Station Capacities

Table F.1 in Appendix F presents details of all power stations falling within the scope of this chapter including the output capacity of each from 2010/11 to 2017/18.

Table 10.2 in Chapter 10 shows the relationship between the different types of agreements and capacities. In Table F.1, where the type of Bilateral Agreement is either a BCA or a BEGA, the capacity for that station is a TEC value. Where the type of Bilateral Agreement is given as a BELLA, the station is included by virtue of its size. The capacities of new generation projects are shown as zero up until the year in which the project is contracted to commission.

**The information is presented on the basis of Licensee then on power station type. For ease of reference, the SYS Study Zone, in which each Power Station is located, is also given. The SYS Study Zones are explained in Chapter 6 under "SYS Boundaries and SYS Study Zones". Charging Zones are also now included in Appendix F Table F.1.**

Please note that the External Interconnection between Scotland and Northern Ireland (Moyle Interconnector Ltd) normally operates in export mode and this is reflected in Appendix F Table F.1 showing values of -500MW and -400MW over the study period. For the purposes of the 2011 NETS SYS interconnectors to mainland Europe are being treated as float, whereas the Irish interconnectors that are assumed to be exporting at time of system peak are shown as negative generation.

Appendix F Table F.4 shows the Generation Ranking Order, this is also described in Chapter 7 (Transmission System Performance). There are a number of differences between Table F.1, which is intended to provide information on the formal contracted (TEC) position, and Table F.4, which includes a number of informed pragmatic assumptions designed to reflect the likely operation of generation sources at peak for the purpose of power flow analyses.

The capacities in Table F.1 do not include the embedded Medium and Small generation and embedded External Interconnections with External Systems. The capacity of such embedded generation sources is the subject of Chapter 4 (Embedded and Renewable Generation).

It should be remembered that Table F.1 reflects the current contracted position and takes no account of future uncertainty.

## Large Combustion Plant Directive

The introduction of the Large Combustion Plants Directive (LCPD) has required large electricity generators to meet more stringent air quality standards since 1 January 2008. Plant that has "opted out" of this obligation will have to close by the end of 2015 or after 20,000 hours of operation from 1 January 2008, whichever is the sooner. This affects some 12 GW of coal and oil-fired generating plant which will therefore now close by 1st January 2016. However, the exact timing of these closures is a commercial matter for plant owners, taking into account factors such as other environmental restrictions and the state of repair of the plants. Consequently, it is not possible to predict with certainty the precise timing of the impact of the LCPD on generation capacity, particularly if a replacement station is planned to be constructed on the same site.

For the 2011 NETS SYS, it has been assumed that plant that has opted out of the obligation will not generate from 2016 onwards. For more detail on the LCPD please refer to the following link

(Defra, UK – The Environment > Environmental quality and pollution > Industrial emissions > EU directives and international agreements > Large Combustion Plant Directive):

http://www.defra.gov.uk/environment/quality/industrial/eu-international/lcpd/

## Generating Unit Capacities

The power stations listed in Table F.1 are generally made up of individual generating units. The 'effective output' capacity of each Generating Unit is given in Table F.2 in Appendix F along with a range of additional data relevant to individual Generating Units or 'sets' within each power station. The 'effective output' is simply the Registered Capacity of each Generating Unit scaled down, where both appropriate and necessary, such that the aggregate output of all Generating Units at a power station is limited to the value of the relevant Power Station TEC. This would not be 'appropriate' for a generating unit covered by a Bilateral Embedded Licence Exemptible Large power station Agreement (BELLA), since a BELLA power station does not have a TEC. Nor would it be 'necessary' should the aggregate unit Registered Capacity at a power station be equal to or less than the station TEC. For ease of reference, the SYS Study Zone is again included. Table F.2 reflects the contracted position for the winter peak of 2010/11 as known at the data freeze date of 31 December 2010.

Three phase fault infeeds and reactive ranges are also given and these are at the interface between the Generating Unit and the National Electricity Transmission System (NETS) i.e. on the higher voltage side of the generator transformer. This information is supplied to us by Users as part of their Week 24 Grid Code submissions.

## Generation Capacity Additions

Table F.7 in Appendix F lists the changes in the contracted capacity of generation, which has either actually commissioned or is contracted to commission, over the period from the winter peak of 2005/06 to the winter peak of 2010/11. Please note that capacities up to and including the winter peak of 2002/03 were based on power station Registered Capacity (RC) while capacities for 2003/04 onwards are based on either power station Transmission Entry Capacity (TEC) or power station 'Size of Power station', as appropriate (TEC being appropriate for BCA and BEGA power stations and 'Size of Power Station' being appropriate for BELLA power stations).

Table F.7 does not include any subsequent increases or decreases in capacity of plant commissioned before 2005. Table F.7 also includes plant closures that have taken place from

2005/06 to 2010/11 inclusive. These closures are indicated by negative values of capacity, such as in the case of Dungeness A and Sizewell A. Both of these stations were actually closed on 31 December 2006, which is within the 2006/07 winter peak period.

However, as well as new (i.e. commissioned, or to be commissioned, from year 2005 onwards) transmission contracted generation, the table does also include increases due to plant being returned to service from reserve (or closure), increases in import capabilities from External Systems, and some minor proposed changes in TEC. For consistency between the various tables presented in this Statement, all generation expected to commission by the winter peak of 2010/11 is classified as either ‘existing’ or ‘under construction’.

The net total of capacity is included in the penultimate line of Table F.7. This may be used as an indicator as to the level of activity over the period.

## Disconnections

Disconnection is normally the irreversible closure of a power station and requires formal notification to be given to us at least six months prior to the event. Table 3.5 lists notified generation disconnections (closures) from the year 2010/11 to 2017/18 inclusive. Please note that capacities up to and including the winter peak of 2002/03 are based on power station Registered Capacity (RC) while capacities for 2003/04 onwards are based on power station Transmission Entry Capacity (TEC). The year indicated on the table is the year of closure and normally implies that the power station will not be generating over the subsequent winter peak.

Due to the Large Combustion Plant Directive opted-out plant, comprising of 8.5GW of coal and 3.5GW of oil, some 12GW of closures will take place by 1st January 2016; however, due to the uncertainty of the closure dates and whether any TEC would be terminated no allowance has been made for these closures up to and including the winter peak of 2015/16. The affected stations are however, shown as closed from 2016/17 onwards.

## Decommissioning

Decommissioning also requires six months formal notification but is not irreversible. Generating Units with a notified Registered Capacity of zero are, for the purpose of this Statement, in the same category as decommissioned plant.

A Generator may wish to decommission or mothball a Generating Unit for a relatively long period for commercial reasons. In such an event the Generator may also wish to affect a corresponding reduction in the power station TEC in order to reduce the Use of System charges. At a later date, the customer may choose to ‘re-commission’ the generating unit and return the Power Station TEC to its appropriate value.

As explained in PC.4.3.1 of the Grid Code, NGET use the TEC data (and CEC data for that matter) from the relevant Connection and Use of System Code (CUSC) Contract. The value of TEC is specified in Appendix C of the appropriate Bilateral Connection Agreement or Bilateral Embedded Generation Agreement. These are agreements entered into pursuant to paragraph 1.3.1 of the CUSC.

Paragraph 6.30 of the CUSC explains how revisions to the value of TEC may be made. TEC may be decreased provided that certain specified notice is given to National Grid. Generators are entitled to request an increase in TEC, up to a maximum of the relevant CEC, through the more protracted Modification Application process.

Where we have received notification from the Generator (in accordance with the CUSC requirements) that a particular generation source is to reduce its value of TEC, then the reduced value is accordingly attributed to that plant for the purpose of the power flow studies and analyses contained in this Statement. In the extreme, we may receive notification that a particular plant has reduced TEC to zero. This could, under certain circumstances, mean that additional transmission reinforcement work would be required before such plant is able to subsequently re-register TEC at a higher level and this may cause a delay. In view of this, the

Generator may choose to maintain the value of Power Station TEC throughout in order to avoid any subsequent delays. Increases in station TEC above the extant contracted value are not possible without an appropriate Modification Application from the generator to us to modify the site specific Bilateral Agreement.

Where the Generator has notified us that the Output Usable is zero (e.g. unavailable due to maintenance), the full value of station TEC is still attributed to that plant for the purpose of power flow and fault level studies. This ensures that no transmission reinforcement, and possible delay, will be necessary when the plant is repaired and returned to service.

Table 3.6 lists Generating Units which have either been formally notified by the owner as decommissioned (effectively RC=0) or simply notified zero Registered Capacity covering the seven year period of this Statement. In either event they may effectively be classed as unavailable. The year shown is the year in which the decommissioning took place. The capacity shown is the capacity prior to decommissioning. Please note that decommissioning is commonly on a generating unit basis for which the terms Registered Capacity or Connection Entry Capacity apply. Transmission Entry Capacity relates to the power station and does not exist on a unit basis. However, the values of RC given in Table 3.6 may be taken as an equivalent reduction in power station TEC.

To provide a more complete picture, Table 3.6 includes the effect of the LCPD closures detailed in Table 3.5. Closures are indicated by negative values in Table 3.6.

Table 3.6 shows that there is currently an overall reduction in potential power station capacity of some 2.9GW comprising: 534MW of OCGT plant; 2035MW of Oil plant; and 350MW of Coal plant. However, it is unlikely that all this capacity could be returned to service. Of the 2.9GW, perhaps some 500MW to 1GW has the greatest potential to return to service. Even then, it should also be borne in mind that, were individual plants to be re-commissioned/returned to service, the full previous capacities may not necessarily be realised.

## Interconnections with External Systems

The NETS currently has directly connected External Interconnections with the External Systems of France and Northern Ireland. The commissioning of an External Interconnection with the Netherlands system was completed in early 2011. The commissioning of an External Interconnection with the Republic of Ireland system is planned for 2011/12. The opportunities for making use of these External Interconnections are outlined in Chapter 9 (Opportunities). Appendix F Table F.13 sets out the notional import and export capabilities across each of the External Interconnections and the normal direction of flow.

### Cross-Channel Link

The cross-channel link with France is a DC link consisting of four pairs of cables connecting converter stations at Sellindge in Kent and Les Mandarins near Calais.

### Northern Ireland Link

The link between Scotland and Northern Ireland was commissioned in December 2001 with commercial operation commencing in January 2002. The interconnector is a DC link connecting converter stations at Auchencrosh in the 'South' zone of the SPT system, which corresponds to SYS Study Zone Z6, and Islandmagee in Northern Ireland. SYS Study Zones are explained under Chapter 6 under "SYS Boundaries and SYS Study Zones". The 500MW Auchencrosh converter station is supplied by a 275kV overhead line from Coylton substation.

Although this Interconnector can operate with power flows in either direction, the power flow has been predominantly from Scotland to Northern Ireland. While the link has both an export and import capability, it is normally used for export to Northern Ireland. An export (i.e. a demand) of 400MW may be assumed for the winter peak of each year for the purpose of power flow analyses. This transfer to Northern Ireland may be treated as being equivalent to demand and has been taken into account in the demand forecasts of Chapter 2.

### Netherlands Link

A DC link for interconnection with the Netherlands electricity system was commissioned in early 2011. The link has a capacity of 1000MW, capable of bi-directional flow, and will be connected at Grain 400kV substation.

### Republic of Ireland Link

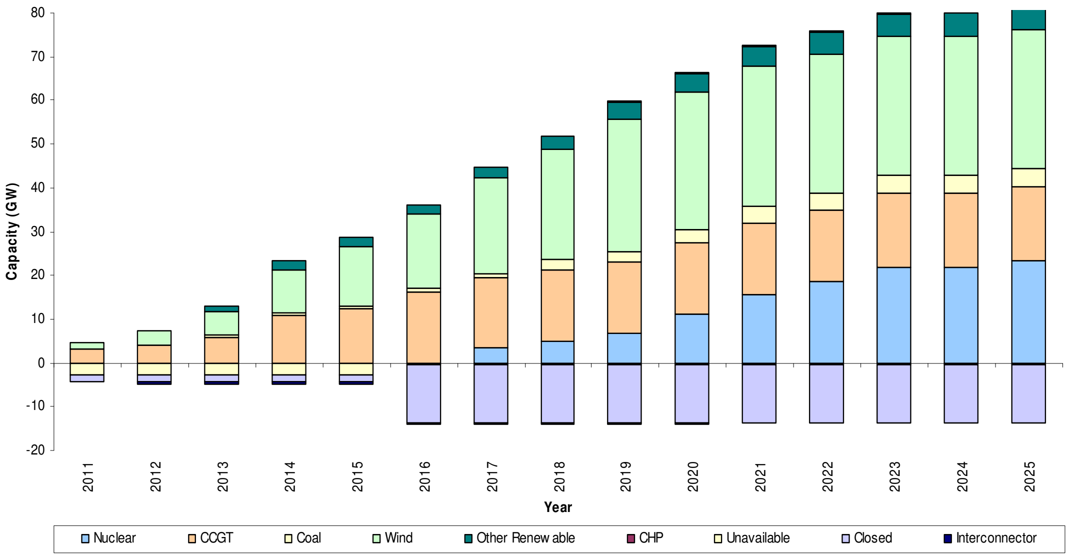
A DC link for interconnection with the Republic of Ireland electricity system is planned to commission by 2011. The link will be of capacity up to 500MW, capable of bi-directional flow, and will be connected at Deeside 400kV substation. At peak times it is expected that the link will normally be used for exports from the NETS.

## Generation Mix

Figure 3.1 illustrates the main changes, from 2010/11 onwards, in the generation capacity of transmission contracted plant. For the underlying detail please refer to appendix F, Table F.8 (New Power Station Capacity); Table 3.5 (closures); and Table 3.6 (unavailable plant). In including closures and unavailabilities, it should be noted that generators are not required to provide formal notification of disconnections or decommissioning until 6 months prior to the event.

An allowance has been included for those stations that will close on or before 31st December 2015 due to opting out of the LCPD.

**Figure 3.1** - Changes in Generation Capacity, 2011/12 to 2025/26



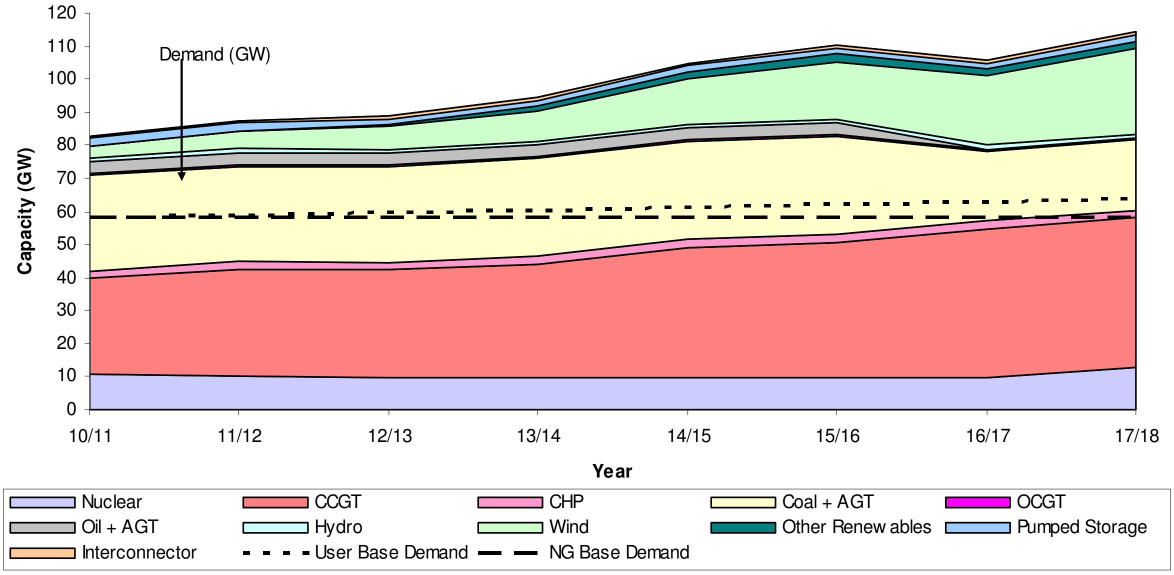
The effect of the LCPD closures can be seen in 2016, these closures are partially offset by three new coal plants namely Hatfield, Hunterston and Blythe.

The majority of the new capacity up to 2017/18 is made up of CCGT and wind generation. Due to the level of contracted activity beyond 2017/18, the capacities of new contracted generation projects up to 2025 have also been included. Details of individual projects can be found in Appendix F Table F.12, that lists generation projects for which an appropriate bilateral agreement is in place but which are scheduled to commission beyond the scope of this NETS SYS (i.e. after 2017/18).

As can be seen from Figure 3.1new nuclear and wind capacity make up the bulk of the new capacity from 2017/18 onwards.

Figure 3.2 illustrates the generation mix from 2010/11 to 2017/18 and includes all transmission contracted generation whether existing or planned (i.e. the 'SYS background') based on appendix Table F.1. In Figure 3.2, the different fuel types are given in an illustrative order of operation. Please note, however, that this is indicative only and no account has been taken, for instance, of generation availability. Nevertheless, the figure does imply a variation in the type of marginal plant used to meet the demand over the seven years considered.

**Figure 3.2 - Existing and Planned Transmission Contracted Generation**



As can be seen from Figure 3.2 a reduction in coal capacity used to meet the demand in 2016/17, due to the effect of the assumed LCPD closures. The closure of Magnox plant by 2011/12 can also be seen. These closures are offset by growth in CCGT, onshore and offshore wind, other renewables (mainly biomass, biopower and woodchip).

In considering the above information it is important to note the following points:

- the generation capacity estimates do not take account of the possibility of modification of existing connection agreements, additional new connection agreements being signed, possible future closures which have not yet been formally notified to us for which only 6 months notice of closure is required or the return to service of plant held in reserve;
- the additional contracted generation capacity due to connect from 2010/11 onwards includes those projects that are under construction and those that are not under construction;

Figure 3.2 also includes the peak demand forecasts for 2010/11 to 2017/18, both for the NGET 'Base' forecast and the customer-based demand forecast, superimposed on the generation mix. This gives an indication of the apparent surplus of generation over demand, which is discussed further in Chapter 5 (Plant Margin). The peak demands shown in Figure 3.2 exclude station demand and also exclude exports, making them compatible with Table F.1, which includes exports as negative generation.

As a point of interest, Figure 3.3(a), Figure 3.3(b), Figure 3.3(c) and Figure 3.3(d) indicate how generation was actually used to meet demand on each of the four days referred to in Figure 2.2 of Chapter 2. These are the winter maximum (Tuesday, 07/12/10), typical winter (Wednesday, 17/11/10), minimum summer (Sunday, 18/07/10) and typical summer (Thursday, 10/06/10) respectively.

## Generation Disposition

Figure A.1.1 in Appendix A gives the geographical location of all transmission contracted Large power stations, whether directly connected or embedded within a distribution system that are existing as at the data freeze date of 31 December 2010. Directly connected Medium and Small power stations are also shown as are directly connected External Interconnections with External Systems. These generation sources form the generation background contained within the ‘SYS background’. Large power stations which have been formally disconnected (closed) are not shown (see Table 3.5) but Large power stations with decommissioned Generating Units are shown (see Table 3.6). Embedded Medium and Small power stations and embedded External Interconnections are not shown.

The disposition of the above existing plant, and prospective future plant, in terms of its capacity and location around the system is particularly important when considering the performance (e.g. resultant power flows) of the transmission system, the need for transmission developments and the opportunities for connecting further generation (or demand) to the system. These topics are discussed further in Chapter 7 (Transmission System Performance), Chapter 8 (Transmission System Capability) and Chapter 9 (Opportunities), which present the results of the main system analysis undertaken for this statement.

When considering bulk transfers of power around the system it is often useful to regard the transmission system as being made up of a number of zones. Such zones and the transmission boundaries between them are described in detail in Chapter 6 (The Transmission System). For consistency and ease of explanation, the generation dispositions described in the following paragraphs are also presented on a similar zonal basis.

Figure 3.8 and Figure 3.9 show the changes in generation capacity by plant type from 2010/11 to 2017/18. The table details the capacity changes on the basis of the SYS Study Zone Number described in Chapter 6 (The Transmission System) and referred to in Table 6.2.

It is the generation actually used in meeting the demand on the day, which determines the power flows at any given time. The 'Generation Ranking Order', which is explained in Chapter 7 (Transmission System Performance), is used to determine which generation is operated for the study purposes of this Statement.

Additional information on generation location is given in Appendix F Tables F.9, F.10 and F.11 which show the detail behind Figures 3.8 and 3.9 and location of generation on the basis of SYS Study Zone and plant type for the years 2010/11 and 2017/18 respectively.

## Winter Maximum / Typical Demand Days

**Figure 3.3 (a) - Maximum Winter Demand: Tuesday 07 Dec 2010**

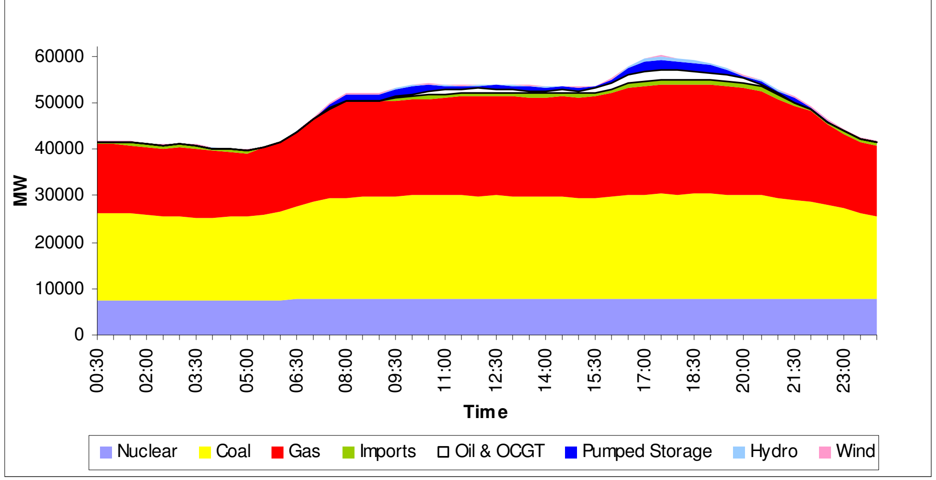


**Figure 3.3 (b) - Typical Winter Demand: Wednesday 17 Nov 2010**

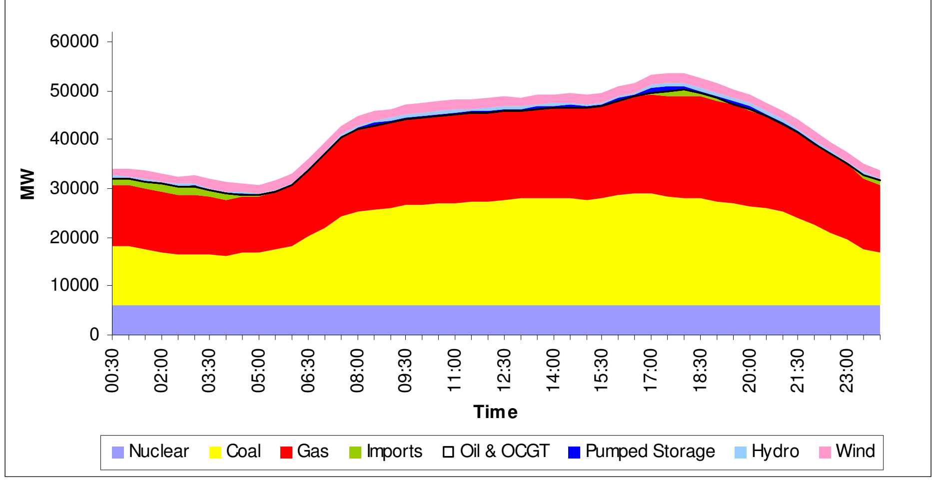


**Figure 3.4 (a) - Total Energy Supplied over Day of Maximum Winter Demand: Tuesday 07 Dec 2010**

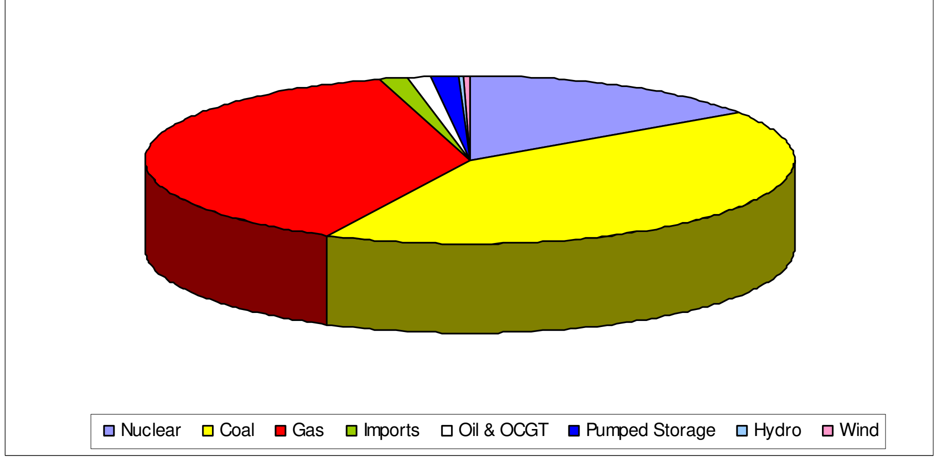
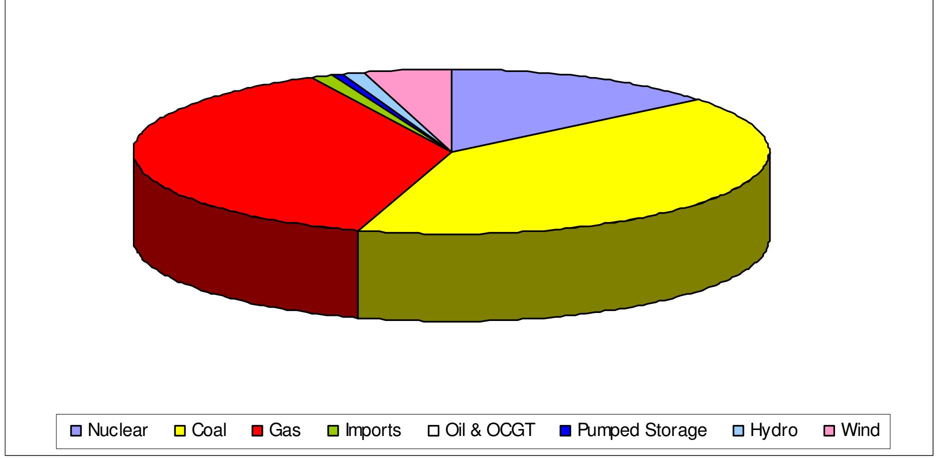


**Figure 3.4 (b) - Total Energy Supplied over Day of Typical Winter Demand: Wednesday 17 Nov 2010**



## Summer Minimum / Typical Demand Days

**Figure 3.3 (c) - Minimum Summer Demand: Sunday 18 Jul 2010**

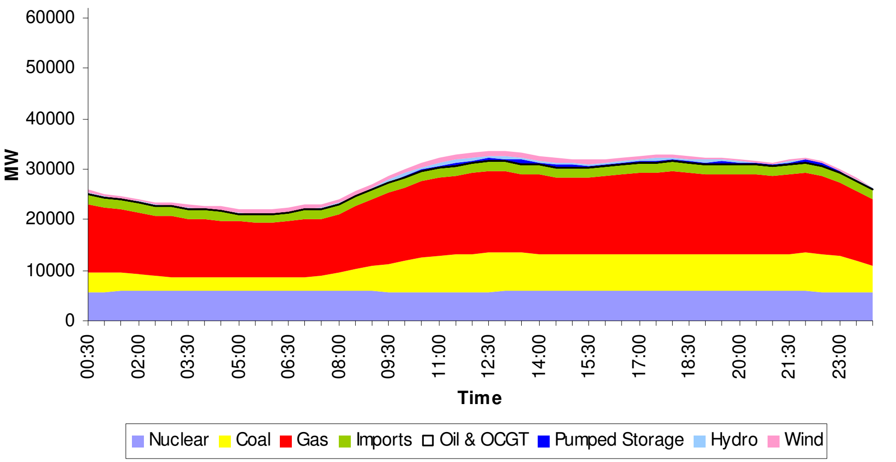


**Figure 3.3 (d) - Typical Summer Demand: Thursday 10 Jun 2010**

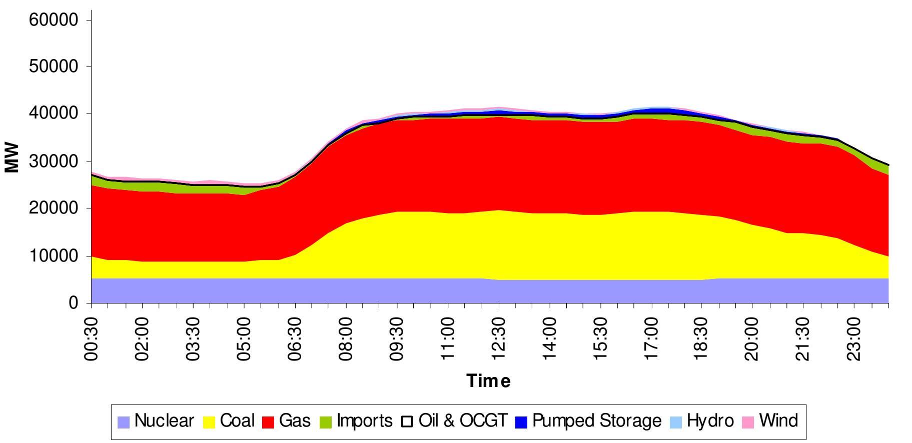


**Figure 3.4 (c) - Total Energy Supplied over Day of Minimum Summer Demand: Sunday 18 Jul 2010**

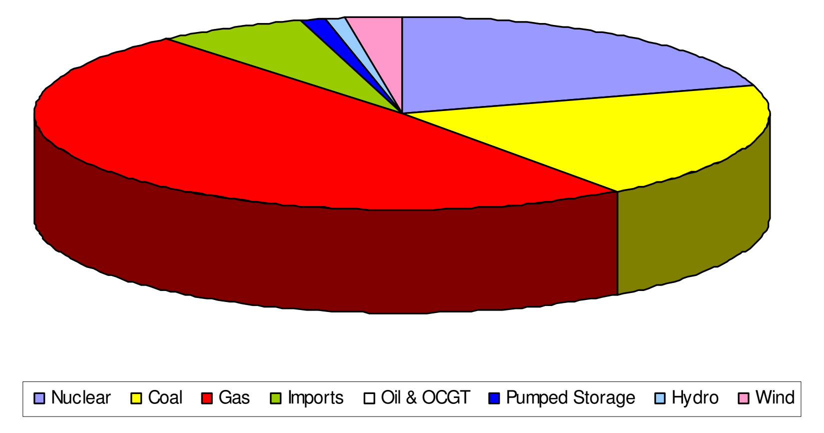
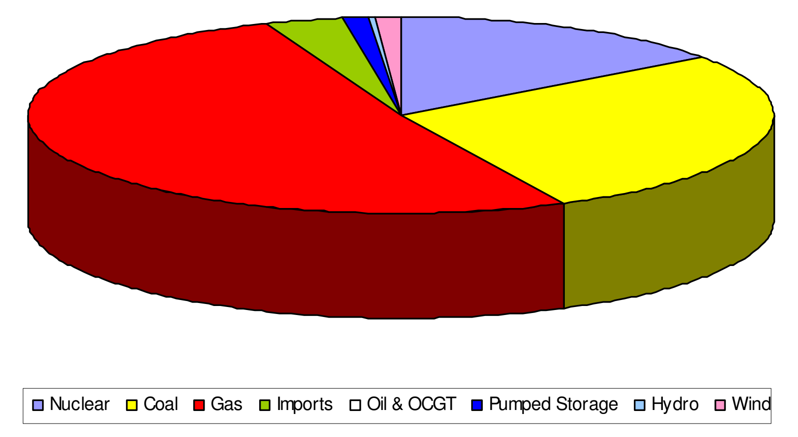


**Figure 3.4 (d) - Total Energy Supplied over Day of Typical Summer Demand: Thursday 10 Jun 2010**



# Generation Analysis

## Generation Projects under Construction

Table 3.1 lists power stations under construction, for which section 36 and/or section 14 consents have been given. The CCGT projects under construction in 2011 onwards are Grain Stage 3, Pembroke Stages 1 & 2, West Burton B and in 2012 onwards Pembroke Stage 3 totalling 3900MW in TEC. Table 3.2 lists power stations, not yet under construction, for which section 36 and/or section 14 consents have been given. The information in Table 3.1 and Table 3.2 is consistent with the TEC Register as at the main Data Freeze Date. The TEC Register can be viewed on the National Grid website:

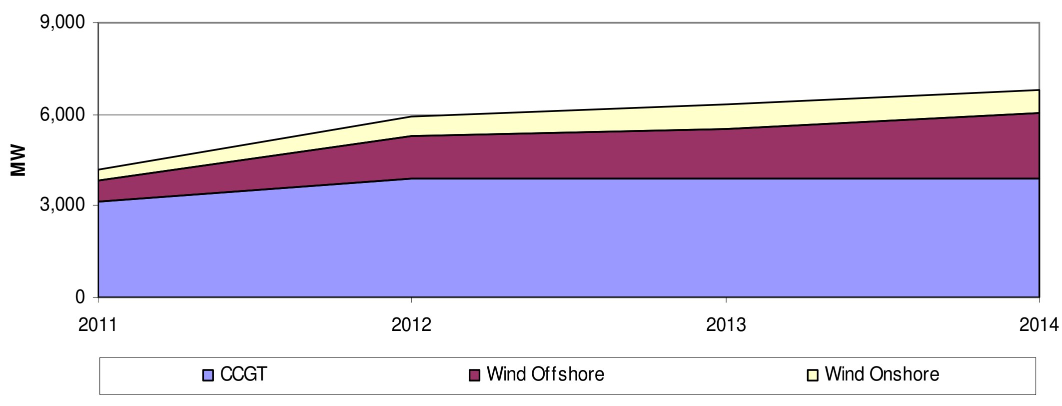
http://www.nationalgrid.com/uk/Electricity/GettingConnected/TEC+Register/

Figure A.1.4 shows the location of National Parks in England, Wales and Scotland. Consents may be easier to obtain outside these areas.

**Table 3.1 - Generation Projects Under Construction**

| Licensee | Plant Type | 2011 | 2012 | 2013 | 2014 |
|---|---|---|---|---|---|
| NGET | CCGT | 3,150 | 3,900 | 3,900 | 3,900 |
| NGET | Wind Offshore | 708 | 1,359 | 1,644 | 2,156 |
| SHETL | Wind Onshore | 322 | 368 | 492 | 492 |
| SPTL | Wind Onshore | - | 270 | 270 | 270 |

**Fig 3.5 - Generation Projects Under Construction**



**Please note that the data table previously included in this chapter which supports the above information and contains breakdown by Station Name and SYS Study Zone is now located in Appendix F, Table F.5**

## Generation Projects with Consents Granted

Please note that Table 3.2 and Figure 3.6 look only at projects within the NETS SYS 2011 study period, from 2011 to 2017.

**Table 3.2 - Generation Projects with Consents Granted**

| Licensee | Plant Type | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 |
|---|---|---|---|---|---|---|---|
| NGET | CCGT | - | - | 1,360 | 5,541 | 7,061 | 8,047 |
| NGET | Wind Offshore | - | - | 553 | 553 | 553 | 553 |
| NGET | Woodchip | - | - | 350 | 350 | 350 | 350 |
| SHETL | Wind Onshore | 45 | 185 | 350 | 412 | 412 | 426 |
| SPT | Biomass | 52 | 52 | 52 | 52 | 52 | 52 |
| SPT | Wind Onshore | - | 176 | 385 | 460 | 531 | 531 |

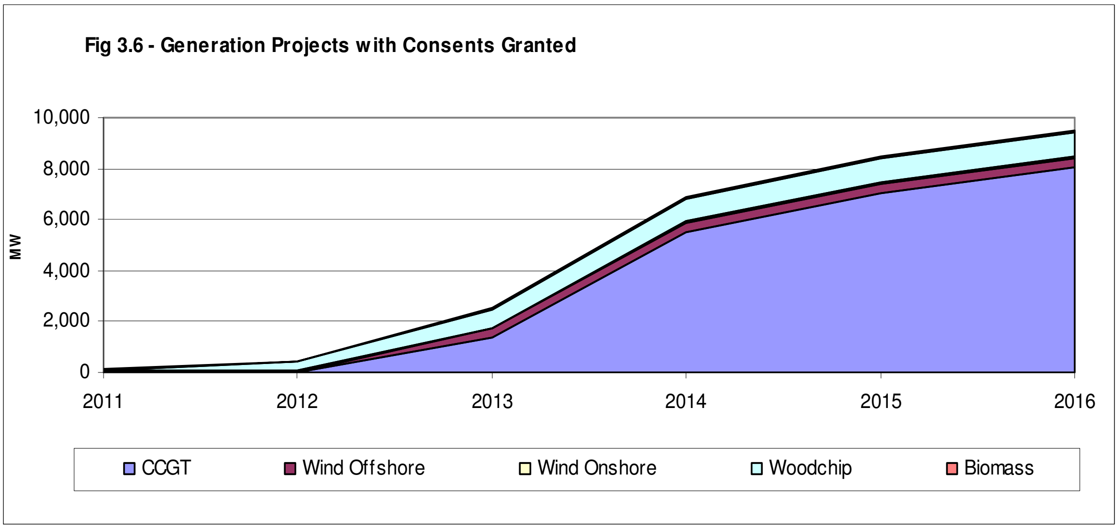


Fig 3.6 - Generation Projects with Consents Granted

P

**Please note that the data table previously included in this chapter which supports the above information and contains breakdown by Station Name and SYS Study Zone is now located in Appendix F, Table F.6**

## New Power Station Capacity

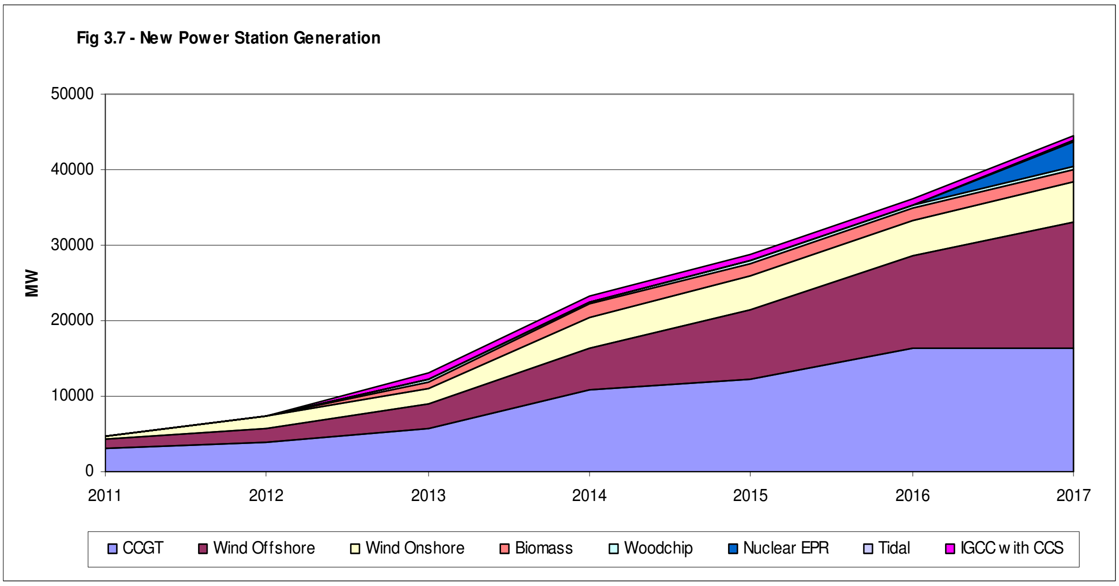
Table 3.3 lists the changes in the contracted capacity of generation, which are contracted to commission, over the period from the winter peaks of 2010/11 to 2017/18 inclusive.

**Table 3.3(a) - New Power Station Capacity (TEC (MW)), 2011 to 2017**

| Licensee | Plant Type | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 |
|---|---|---|---|---|---|---|---|---|
| NGET | CCGT | 3150 | 750 | 1795 | 5021 | 1520 | 4000 | - |
| NGET | IGCC with CCS | - | - | 800 | - | - | - | - |
| NGET | Wind Offshore | 1208 | 651 | 1338 | 1489 | 2204 | 2324 | 2105 |
| NGET | Wind Onshore |  | 299 |  |  | 176 | 184 | - |
| NGET | Biomass | - | - | 754 | 879 | - | - | - |
| NGET | Woodchip | - | - | 350 | - | - | - | - |
| NGET | Nuclear EPR | - | - | - | - | - | - | 3340 |
| NGET | Tidal | - | - | - | - | - | - | 100 |
| SHETL | Wind Onshore | 366 | 185 | 319 | 1316 | - | 44 | 114 |
| SHETL | Wind Offshore | - | - | - | 400 | 1375 | 420 | 300 |
| SHETL | Tidal | - | - | 10 | - | - | - | - |
| SPT | Wind Onshore | - | 649 | 359 | 782 | 113 |  | 274 |
| SPT | Wind Offshore | - | - | - | 450 | - | 400 | 2225 |
| SPT | Biomass | 52 | - | - | - | - | - | - |

**Table 3.3(b) - New Power Station Capacity (TEC (MW)), 2011 to 2017 (Cumulative)**

| Plant Type | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 |
|---|---|---|---|---|---|---|---|
| CCGT | 3150 | 3900 | 5695 | 10716 | 12236 | 16236 | 16236 |
| IGCC with CCS | 0 | 0 | 800 | 800 | 800 | 800 | 800 |
| Wind Offshore | 1208 | 1859 | 3197 | 5536 | 9115 | 12259 | 16889 |
| Wind Onshore | 366 | 1499 | 2177 | 4247 | 4564 | 4792 | 5180 |
| Biomass | 52 | 52 | 806 | 1685 | 1685 | 1685 | 1685 |
| Woodchip | 0 | 0 | 350 | 350 | 350 | 350 | 350 |
| Nuclear EPR | 0 | 0 | 0 | 0 | 0 | 0 | 3340 |
| Tidal | 0 | 0 | 10 | 10 | 10 | 10 | 110 |



## Overview of New Capacity

Table 3.4 complements Table 3.3 by providing an overview of the generation capacity additions over the period from 2010/11 to 2017/18 inclusive. Table 3.4 separately identifies the capacity of future plant by type and according to whether the necessary consents have been obtained.

**Table 3.4 - Overview of New Capacity, 2010/11 to 2017/18**

| Background | Plant Type | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 |
|---|---|---|---|---|---|---|---|---|
| Existing | - | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total (1)** | | **0** | **0** | **0** | **0** | **0** | **0** | **0** |
| Under Construction | CCGT | 3,150 | 3,900 | 3,900 | 3,900 | 3,900 | 3,900 | 3,900 |
| Under Construction | Wind Offshore | 708 | 1,359 | 1,644 | 2,156 | 2,156 | 2,156 | 2,156 |
| Under Construction | Wind Onshore | 322 | 638 | 762 | 762 | 762 | 762 | 762 |
| **Total (2)** | | **4,180** | **5,897** | **6,306** | **6,818** | **6,818** | **6,818** | **6,818** |
| With Consents | Biomass | 52 | 52 | 52 | 52 | 52 | 52 | 52 |
| With Consents | CCGT | 0 | 0 | 1,360 | 5,541 | 7,061 | 8,047 | 8,047 |
| With Consents | Wind Offshore | 0 | 0 | 553 | 553 | 553 | 553 | 553 |
| With Consents | Wind Onshore | 45 | 359 | 735 | 872 | 943 | 956 | 956 |
| With Consents | Woodchip | 0 | 0 | 350 | 350 | 350 | 350 | 350 |
| **Total (3)** | | **97** | **411** | **3,050** | **7,368** | **8,959** | **9,958** | **9,958** |
| Without Consents | Biomass | 0 | 0 | 754 | 1,633 | 1,633 | 1,633 | 1,633 |
| Without Consents | CCGT | 0 | 0 | 435 | 1,275 | 1,275 | 4,289 | 4,289 |
| Without Consents | Clean Coal | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Without Consents | IGCC with CCS | 0 | 0 | 800 | 800 | 800 | 800 | 800 |
| Without Consents | Nuclear EPR | 0 | 0 | 0 | 0 | 0 | 0 | 3,340 |
| Without Consents | Tidal | 0 | 0 | 10 | 10 | 10 | 10 | 110 |
| Without Consents | Wave | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Without Consents | Wind Offshore | 500 | 500 | 1,000 | 2,827 | 6,406 | 9,550 | 14,180 |
| Without Consents | Wind Onshore | 0 | 502 | 680 | 2,640 | 2,858 | 3,073 | 3,461 |
| **Total (4)** | | **500** | **1,002** | **3,679** | **9,185** | **12,982** | **19,355** | **27,813** |
| **Total (1,2,3,4)** | | **4,777** | **7,310** | **13,035** | **23,371** | **28,759** | **36,131** | **44,589** |

**Please note that the data table previously included in this chapter which supports the above information and contains breakdown by Station Name and SYS Study Zone is now located in Appendix F, Table F.8.**

**Table 3.5 - Generation Disconnections from 2010/11 to 2017/18 inclusive**

| Licensee | Closure Year | Plant Type | Station | Set(s) Disconnected | Capacity (MW) |
|---|---|---|---|---|---|
| NGET | 2011 | Nuclear Magnox | Oldbury | 1, 2 | 470 |
| NGET | 2011 | Nuclear Magnox | Wylfa | 1, 2, 3, 4 | 980 |
| SPT | 2016 | Medium Unit Coal | Cockenzie | 1, 2, 3, 4 | 1102 |
| NGET | 2016 | Large Unit Coal | Didcot A | 1, 2, 3, 4 | 2109 |
| NGET | 2016 | Large Unit Coal | Didcot A | G1, G2, G3, G4 | 100 |
| NGET | 2016 | Large Unit Coal + AGT | Ferrybridge C | 1, 2, G5, G6 | 993 |
| NGET | 2016 | Large Unit Coal + AGT | Ironbridge | 1, 2, G1, G2 | 964 |
| NGET | 2016 | Large Unit Coal + AGT | Kingsnorth | 1, 2, 3, 4, G1, G4 | 1966 |
| NGET | 2016 | Medium Unit Coal + AGT | Tilbury | 7, 8, 9, 10, G7, G8, G9, G10 | 1131 |
| NGET | 2016 | Oil | Fawley | 1, 3, G1, G2, G3, G4 | 1036 |
| NGET | 2016 | Oil | Grain | 1, 2, 3, 4, G1, G2, G3, G4 | 1355 |
| NGET | 2016 | Oil | Littlebrook | 1, 2, 3, G1, G2, G3 | 1245 |
|  |  |  |  | **Total** | **13451** |

**Table 3.6 - Unavailable Generating Units**

| Licensee | Year | Plant Type | Station Name | Unit(s) | Capacity (MW) | SYS Study Zone |
|---|---|---|---|---|---|---|
| NGET | 1991 | OCGT | Cottam | G2, G4 | 50 | Z10 |
| NGET | 1991 | OCGT | Ferrybridge C | G6, G7 | 34 | Z8 |
| NGET | 1991 | OCGT | Fiddlers Ferry | G1, G4 | 34 | Z9 |
| NGET | 1991 | OCGT | Kingsnorth | G2A, G3A | 44 | Z15 |
| NGET | 1991 | OCGT | Ratcliffe on Soar | G1, G3 | 34 | Z11 |
| NGET | 1994 | OCGT | Cottam | G1, G3 | 50 | Z10 |
| NGET | 1994 | OCGT | Drax | G7 | 25 | Z8 |
| NGET | 1994 | OCGT | Eggborough | G6, G7 | 34 | Z8 |
| NGET | 1994 | Oil | Grain | 2 | 675 | Z15 |
| NGET | 1994 | OCGT | Grain | G2A, G3A, G5A | 87 | Z15 |
| NGET | 1994 | OCGT | Ironbridge B | G1, G2 | 34 | Z11 |
| NGET | 1994 | OCGT | Tilbury B | G7A | 17 | Z15 |
| NGET | 1994 | OCGT | West Burton | G2, G3 | 40 | Z10 |
| NGET | 1995 | OCGT | Fawley | G2, G4 | 34 | Z16 |
| NGET | 1995 | Oil | Littlebrook D | 3 | 685 | Z14 |
| NGET | 1998 | Oil | Grain | 3 | 675 | Z15 |
| NGET | 1998 | OCGT | Tilbury B | G10A | 17 | Z15 |
| NGET | 1998 | Medium Unit Coal | Tilbury B | 7 | 350 | Z15 |
| NGET | 2016 | OCGT | Ferrybridge C | G6 | -17 | Z8 |
| NGET | 2016 | OCGT | Kingsnorth | G2A, G3A | -44 | Z15 |
| NGET | 2016 | Oil | Grain | 2 | -675 | Z15 |
| NGET | 2016 | OCGT | Grain | G2A, G3A, G5A | -87 | Z15 |
| NGET | 2016 | OCGT | Ironbridge B | G1, G2 | -34 | Z11 |
| NGET | 2016 | OCGT | Tilbury B | G7A | -17 | Z15 |
| NGET | 2016 | OCGT | Fawley | G2, G4 | -34 | Z16 |
| NGET | 2016 | Oil | Littlebrook D | 3 | -685 | Z14 |
| NGET | 2016 | Oil | Grain | 3 | -675 | Z15 |
| NGET | 2016 | OCGT | Tilbury B | G10A | -17 | Z15 |
| NGET | 2016 | Medium Unit Coal | Tilbury B | 7 | -350 | Z15 |
|  |  |  |  | **Total** | **284** |  |

## Growth and Generation Capacity (MW), 2010/11 to 2017/18

Figure 3.8 shows the increase or in some cases decrease in TEC by SYS Study Zone between Year 0 (2010/11) and Year 7 (2017/18). For example the largest TEC increase within this period is located in Study Zone Z12 and is a total of 6,151MW.

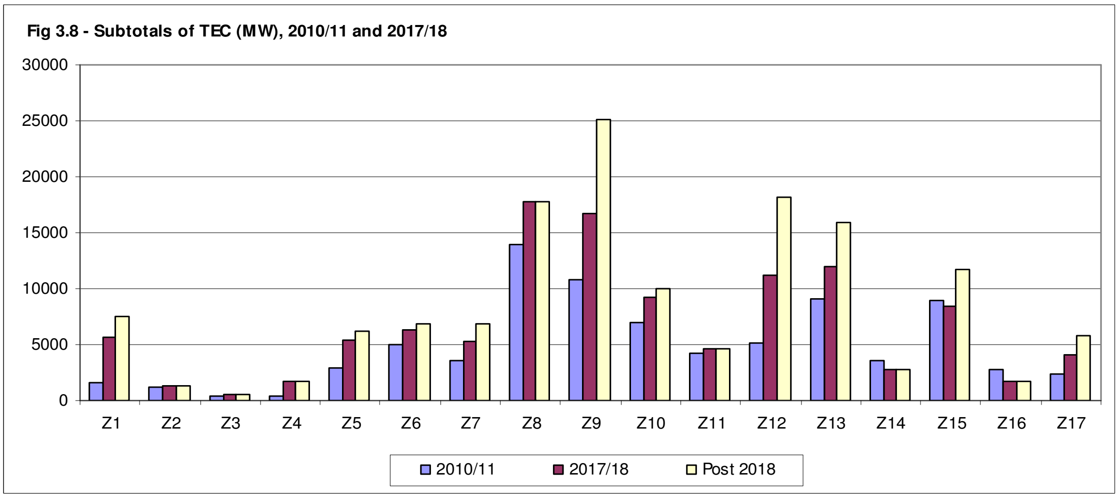
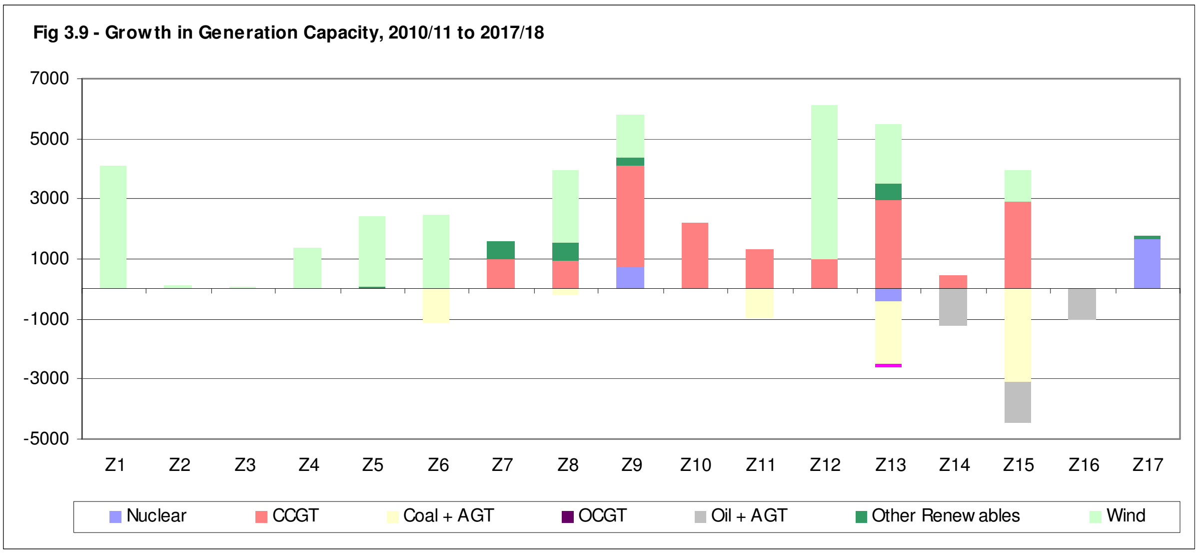


Figure 3.9 illustrates the split of the *net* total increase or decrease in TEC shown in Figure 3.8, for example the total increase shown for Study Zone Z6 is 1,355MW and Figure 3.9 shows that this is made up of an increase in wind of 2,457MW and a decrease in Coal + AGT of -1,102MW.



**Please note that the data table previously included in this chapter which supports the above information and contains breakdown by Plant Type and SYS Study Zone is now located in Appendix F, Tables F.9, F.10 and F.11.**

## Transmission Generation Contracted beyond 2017/18

Table 3.7 and Figure 3.10 show the contracted generation only from 2018/19 to 2025/26.

**Table 3.7 - Transmission Contracted Generation beyond 2017/18**

| **Plant Type** | **2018** | **2019** | **2020** | **2021** | **2022** | **2023** | **2024** | **2025** |
|---|---|---|---|---|---|---|---|---|
| CCGT | 0 | 0 | 0 | 0 | 0 | 824 | 824 | 824 |
| Clean Coal | 1600 | 1600 | 2400 | 3200 | 3200 | 3200 | 3200 | 3200 |
| Nuclear APR | 0 | 0 | 1200 | 2400 | 3600 | 3600 | 3600 | 3600 |
| Nuclear EPR | 1670 | 3320 | 6590 | 9930 | 11580 | 14780 | 14780 | 16380 |
| Tidal | 600 | 800 | 1100 | 1400 | 2000 | 2000 | 2300 | 2300 |
| Wind Offshore | 2160 | 5920 | 6680 | 7280 | 7280 | 7280 | 7280 | 7280 |
| CHP | 0 | 250 | 250 | 250 | 250 | 250 | 250 | 250 |
| Wave | 700 | 722 | 722 | 722 | 722 | 722 | 722 | 722 |
| Thermal | 0 | 250 | 250 | 250 | 250 | 250 | 250 | 250 |
| Wind Onshore | 803 | 1650 | 1650 | 1650 | 1650 | 1650 | 1650 | 1650 |
| Hydro | 0 | 6 | 6 | 6 | 6 | 6 | 6 | 6 |
| **Cumulative Total** | **7600** | **14519** | **20849** | **27089** | **30539** | **34563** | **34863** | **36463** |

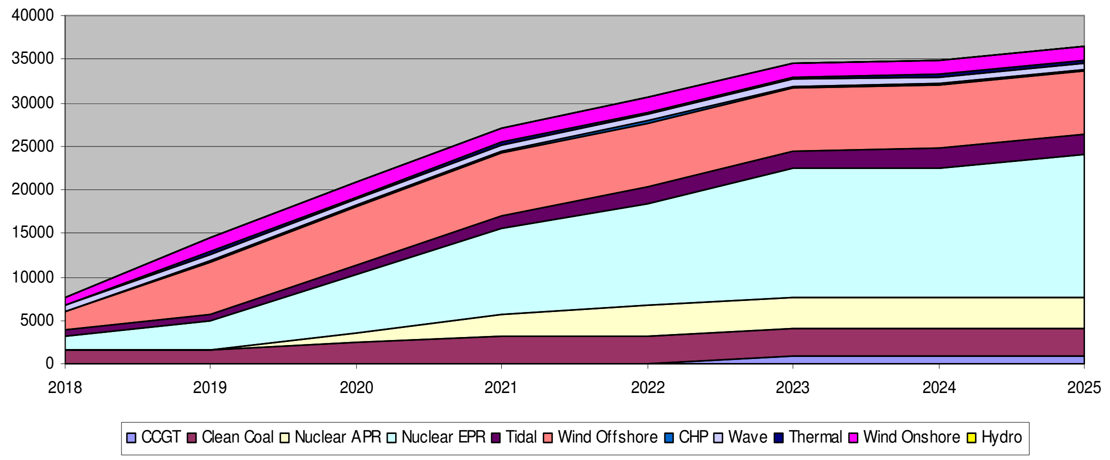


**Figure 3.10 - Transmission Contracted Generation beyond 2017/18**

**Please note that the data table previously included in this chapter which supports the above information and contains breakdown by Plant Type and SYS Study Zone is now located in Appendix F, Table F.12.**

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# Chapter 4

# Embedded and Renewable Generation

## Introduction

Chapter 3 (Generation) presents information on all the sources of generation which are used to meet the Average Cold Spell (ACS) Peak Demand as defined in the on line Glossary and Appendix G. Accordingly, Chapter 3 presents information on Large power stations (directly connected or embedded), Medium and Small power stations that are directly connected to the National Electricity Transmission System (NETS) and directly connected External Interconnections with External Systems.

Embedded generation may be Large but is more likely to be either Medium or Small. Large embedded power stations are reported in Chapter 3 as explained above. Medium and Small embedded power stations and embedded External Interconnections with External Systems are reported in this chapter.

Much of the existing and future embedded generation is either in the form of combined heat and power (CHP) projects or in the form of renewable projects. This chapter considers these two types of generation source and, in so doing, also reports on non-embedded renewable sources of generation (e.g. Wind farms).

## Embedded Generation

### Types of Embedded Generation

The output of most embedded Medium and Small power stations falls into two main categories that are not mutually exclusive, namely that generated primarily for own use, normally in the form of CHP, and that generated for supply to third parties, mainly from renewable sources (e.g. wind).

A CHP plant is an installation where there is simultaneous generation of usable heat and electrical power in a single process. CHP schemes are generally fuelled by gas, coal or oil although some are also partially fuelled by fossil fuels and partially fuelled by renewable sources of energy (e.g. biofuels such as sewage gas). The latter are referred to as ‘Co-firing’ generating stations. CHP schemes tend to be located in close to customers (e.g. large industry) wishing to take the heat output.

Renewable generation technologies cover a range of energy sources including hydro, biofuels, wind, wave and solar. In output terms, the largest contributions currently come from biofuels, which include landfill gas, waste combustion, sewage sludge digestion and coppice wood and straw burning.

Further information can be found on the renewable energy statistics website:

http://www.restats.org.uk/

http://www.restats.org.uk/electricity.htm

### Embedded Small and Medium Power Stations

Chapter 2 (Electricity Demand) considers, amongst other things, the forecast peak demand on the NETS in ACS conditions, which is based on the projections provided by the system 'Users' and by National Grid.

Network operators are required under the Grid Code to net off their own allowances for the output from embedded Medium and Small power stations when submitting their forecasts of demand to be supplied at the Grid Supply Points. They are also required to net off their own allowances for any forecast imports across embedded External Interconnections from External Systems. Accordingly, the output of embedded Medium and Small power stations is taken into account when planning the development of the transmission system. However, this output is not directly seen by the National Electricity Transmission System Operator (NETSO), although its overall effect on the NETS and its operation is.

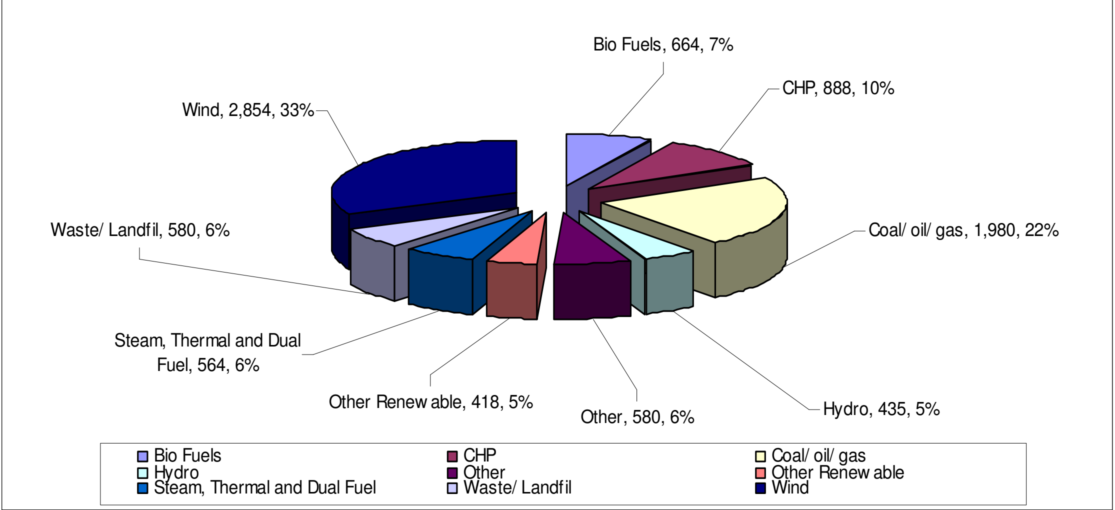
Figure 4.1 - Main Types of Embedded Generation (MW)

Table F.3 in Appendix F contains a range of information on Small and Medium power stations embedded within distribution networks. The information in this table is based on information originally provided by the relevant distribution network operators beyond their Week 24 Grid Code obligations.

Figure 4.1 summarises the main fuel and plant types in Table F.3 in pie-chart form. The main renewable types of generation shown are: wind, coal/oil/gas, CHP and biofuels. The capacity of wind generation includes both onshore and offshore wind. The waste and landfill plant types have been grouped together as “man-made” forms of renewable energy.

In Table F.3, the information in respect of the Scottish distribution companies (i.e. SHEPD and SP Distribution Ltd) has been updated this year. However, updated information in respect of the distribution companies in England and Wales has been sourced internally from our own data.

In view of the relatively high volume of data relating to the distribution systems in England and Wales, a cut-off point of 5MW was originally adopted to reduce the data collection burden on the distribution network operators (i.e. embedded plant of less than 5MW located in England and Wales was not included). The data for England & Wales has since been supplemented by embedded generation data of our own, which includes some generation projects with an installed capacity of less than 5MW. The information relating to the Scottish distribution systems provided by the Scottish network operators does not have a lower cut-off level. For some User Systems, the information is provided on an individual power station basis while for others the information is provided on a GSP basis.

There is a current Grid Code requirement (PC.A.3.1.4 of the Planning Code refers) for distribution network operators to inform NGET of the summated capacity of embedded Medium and Small power stations within their area and the allowances made for these in their demand forecasts projected for the time of the system peak. This information is summarised in Table 4.1. Please note that the ‘Zone Number’, referred to in Table 4.1, is the ‘Demand TNUoS Tariff

Zone' rather than the 'SYS Study Zone', both of which are introduced in "Use of System Tariff Zones" in Chapter 6.

For comparison purposes, Table 4.1 gives totals of installed capacity for each DNO summated from the data in Table F.3. These figures give an approximate indication of the proportion of installed capacity of embedded generation that the distribution network operators assume is considered to be contributing at the time of the system peak. The contribution assumed by network operators to be firm at other times, including the time of the local peak demand for which the Grid Supply Point is chiefly designed, rather than the time of peak demand, is not reported.

The information presented in Table F.3 and Table 4.1 may, in some respects, be incomplete, but does nevertheless provide an initial useful insight into the different types of embedded generation and into the total demand in the system (i.e. demand on the NETS plus embedded generation capacity 'netted off' in the distribution network operators' Grid Code demand submissions).

## Environmental Targets for Renewables & Emissions

The UK has two key environmental targets relating to renewable energy and greenhouse gas emissions (GHGs). The first of these targets is part of the European Union's (EU) integrated energy/climate change proposal that addresses the issues of energy supply and climate change and in doing so sets a target of 20% of European energy (including electricity, heat & transport) to come from renewable sources by 2020[1].

The UK's contribution to this target is 15% which is lower than the European wide average due to the UK's low starting point (2% compared to EU average of 9%). However, the UK has the largest increase of any country which was due to its low starting point, economic strength and its high potential for renewable generation i.e. significant wind, wave and tidal resources.

The Renewable Energy Strategy[2] (published in July 2009) identified that in order to meet this target approximately 30% of UK's electricity will have to come from renewable sources by 2020, with a corresponding 12% from heat and 10% from transport.

The second target, which also follows the principles of the overall EU 20/20/20 vision (20% of energy from renewable sources along with a 20% reduction in GHG emissions and 20% improvement in energy efficiency by 2020) but goes even further, has been incorporated in the Climate Change Act[3] and sets a target of 80% reduction in GHGs from the 1990 levels by 2050. This equates to a 34% reduction in GHGs emissions by 2020 as specified by the Climate Change Committee[4].

To see what potential power station developments and network reinforcements are required to enable these 2020 targets to be met please refer to the section on the Electricity Networks Strategy Group (ENSG) report under "Indicative Reinforcements required to meet Environmental Targets" in Chapter 8.

## Renewable Obligation

The Renewables Obligation (RO) scheme[5] obligates electricity suppliers to source an increasing proportion of their power from renewable generation. Accredited renewable generators are issued with Renewable Obligation Certificates (ROCs) for each megawatt hour (MWh) of eligible energy generated, multiplied by a factor that is dependant on the type of generation technology.

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[1] http://www.energy.eu/directives/com2008_0030en01.pdf

[2] http://www.decc.gov.uk/en/content/cms/what_we_do/uk_supply/energy_mix/renewable/res/res.aspx
http://www.decc.gov.uk/assets/decc/What%20we%20do/UK%20energy%20supply/Energy%20mix/Renewable%20energy/Renewable%20Energy%20Strategy/1_20090717120647_e_@@_TheUKRenewableEnergyStrategy2009.pdf

[3] http://www.opsi.gov.uk/acts/acts2008/ukpga_20080027_en_1

[4] http://www.theccc.org.uk/

[5] http://www.ofgem.gov.uk/Sustainability/Environment/RenewablObl/Pages/RenewablObl.aspx

The RO, the Renewables Obligation Scotland and the Northern Ireland Renewables Obligation have been designed to incentivise renewable generation into the electricity generation market. Renewable generators can sell ROCs that they have acquired to electricity suppliers. Each year, the Office of Gas and Electricity Markets (Ofgem) sets the percentage of electrical energy for which suppliers must obtain ROCs for and the buy-out price[6] that suppliers must pay for any deficit.

The RO was introduced in 2002[7] with an original end date of 2027. However, in light of the 2020 targets and the need to encourage investment in renewable energy up to 2020, the operational timeline of the RO has been recently extended to 2037[8]. A limit of 20 years support for accredited generating stations was also introduced in parallel (subject to the 2037 end date) to avoid overcompensation. More recent changed, applicable from April 2011, will allow operators of large offshore wind generating stations (accredited after 31st March 2013) to register for their ROCs in phases of operational capacity to account for long construction periods. The 20 years of support would apply to up to five phases starting from the date of full RO accreditation and then once a year for a maximum of five years[9].

Historically one ROC was issued for each MWh of eligible renewable output generated. However April 2009 introduced the concept of a banding system. The banding system used onshore wind power as a reference technology (reference band), with any technology which needed more support (post demonstration and emerging technologies band) being granted additional ROCs and similarly more commercially viable technologies (established bands) being granted less ROCs.

Renewable Obligation Certificates Allocation (England, Wales & Scotland) [10]

| **Developmental Category for Renewable Obligation Banding** | **Technologies** | **Level of Support ROCs per MWh** |
|---|---|---|
| Most Established | Landfill Gas | 0.25 |
| Established | Co-firing of Biomass<br>Sewage Gas | 0.5 |
| Reference | Co-firing of Biomass with CHP<br>Co-firing of Energy Crops<br>Energy from Waste with CHP<br>Geopressure<br>Hydro-electric<br>Onshore Wind | 1.0 |
| Post Demonstration | Co-firing of Energy Crops with CHP<br>Dedicated Biomass<br>Offshore Wind | 1.5 |
| Emerging Technologies | Anaerobic Digestion<br>Dedicated Biomass with CHP<br>Dedicated Energy Crops<br>Dedicated Energy Crops with CHP<br>Gasification<br>Geothermal<br>Pyrolysis<br>Solar Photovoltaic<br>Tidal Impoundment – Tidal Barrage<br>Tidal Impoundment – Tidal Lagoon<br>Tidal Stream<br>Wave | 2.0 |
| Enhanced Wave & Tidal Bands (Scotland Only)[11] | Wave and tidal projects located in Scottish waters and not receiving Government support. | Tidal 3.0<br>Wave 5.0 |

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[6] http://www.ofgem.gov.uk/Media/PressRel/Documents1/RO%20buy-out%20Info%20Note%204%20Feb.pdf

[7] Renewable Obligation (Scotland) Order came into effect in April 2002
Renewable Obligation (Northern Ireland) Order came into effect in April 2005

[8] http://www.ofgem.gov.uk/Sustainability/Environment/RenewablObl/Documents1/Annual%20Report%202008-09.pdf

[9] http://www.decc.gov.uk/assets/decc/consultations/renewables%20obligation/1059-gov-response-ro-order-2011-cons.pdf

[10] http://chp.defra.gov.uk/cms/roc-banding/

[11] http://www.scotland.gov.uk/Publications/2009/12/10134807/4

Under the banding scheme, offshore wind projects attracts 1.5 ROCs with tidal/wave projects attracting 2 ROCs for each MWh of eligible renewable output generated. To further stimulate the market, additional ROCs were to be made available to offshore wind projects which met a number of preconditions[12]. It has subsequently been announced that this additional support for offshore wind projects would be extended, with projects which have been fully accredited between 1st April 2010 and 31st March 2014 attracting 2 ROCs for each MWh of eligible renewable output generated[13].

## Feed-In-Tariffs

Feed-In-Tariffs were introduced in April 2010 to incentivise small scale, low carbon electricity generation by providing "clean energy cashback" for householders, communities and businesses – to allow them to become generators of electricity, as opposed to simply consumers. The feed-in tariffs (FITs) will work alongside the Renewables Obligation, which will remain the primary mechanism to incentivise deployment of large-scale renewable electricity generation, and the Renewable Heat Incentive (RHI) which will incentivise generation of heat from renewable sources at all scales.

The GB FITs will consist of two elements of payment, made to generators, and paid for, by licensed electricity suppliers. The largest suppliers (mandatory FITS suppliers) will be obliged to offer FITs, and smaller suppliers may participate if they wish. The first element is a **generation tariff** that differs by technology type and scale, and will be paid for every kilowatt hour (kWh) of electricity generated and metered by a generator. This generation tariff will be paid regardless of whether the electricity is used onsite or exported to the local electricity network. The second element is an **export tariff** which will either be metered and paid as a guaranteed amount that generators are eligible for, or will, in the case of very small generation, be assumed to be a proportion of the generation in any period without the requirement of additional metering.

Further information can be found on the DECC website:

http://www.decc.gov.uk/en/content/cms/consultations/elec_financial/elec_financial.aspx

## Climate Change Levy

Another instrument of the government's policy to reduce environmental emissions is the Climate Change Levy (CCL)[14]. This is an energy tax payable by all industrial and commercial businesses since April 2001. It is levied on energy supplies, the rate varying depending on the fuel. The CCL levy rate for electricity for 2011/12 is 0.485p/kWh. From April 2011, energy intensive businesses can receive up to 65% discount on the levy if they enter into agreements with the government to undertake significant energy efficiency improvements.

Electricity generated from renewables is exempt from the CCL, thus currently benefiting developers of renewable electricity by an extra 0.470p/kWh during 2010/11. As a result, developers of qualifying renewable schemes could receive a minimum support of 4.169p/kWh in 2010/11, (i.e. the buy-out price of 3.699p/kWh under the RO plus 0.470p/kWh under the CCL). This is in addition to the value of the share-out of the buy-out kitty among those suppliers who have bought green energy under the Renewables Obligation.

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http://www.scotland.gov.uk/News/Releases/2008/09/19111827
http://www.scotland.gov.uk/Resource/Doc/917/0065773.pdf

[12] Offshore wind projects which have government consent and have placed order for wind turbines in financial year 2009/10 will be eligible for 2 ROCs with 1.75 ROCs available in 2010/11.

[13] http://www.ofgem.gov.uk/Sustainability/Environment/RenewablObl/Documents1/Annual%20Report%202008-09.pdf

[14] http://customs.hmrc.gov.uk/channelsPortalWebApp/channelsPortalWebApp.portal?_nfpb=true&_pageLabel=pageExcise_InfoGuides&propertyType=document&id=HMCE_CL_001174#P27_1281

## Growth and Location of Wind Farms

There are clear indications of significant activity associated with the development of wind generation and, accordingly, future activity in this area is worthy of further consideration. Wind farms may, of course, be embedded or non-embedded and may be classified as Large, Medium or Small power stations. Accordingly, relevant information can be found from two sources of data within this Statement.

The first is Table F.3 in Appendix F, which presents information on embedded Medium and Small power stations. As explained previously, the information contained in Table F.3 is not necessarily complete and, as such, should not be relied up on. Much of the information contained in Table F.3 has been voluntarily sourced by the distribution network operators and NGET cannot therefore guarantee its accuracy. Nevertheless, the information it contains does provide a useful initial indicator to the types and capacity of embedded Medium and Small generation connected to distribution networks. The DNOs denoted “SHEPD” and “SPD” in zones 1 and 2 are in Scotland. The other DNOs are in England & Wales.

The second source is Table F.1 in Appendix F, which presents information on directly connected power stations and Large embedded power stations. Accordingly, Table F.1 includes information on all Large wind farms, whether directly connected or embedded, and Medium and Small wind farms, that are directly connected to the NETS. Table 5.4 in Chapter 5 shows the reported increase in onshore and offshore wind capacity from 2010/11 to 2017/18 inclusive.

## Effect on Power Transfers

### General Considerations

One effect of an increasing proportion of embedded generation will be to reduce the flow across the interface between the transmission and distribution networks. This will tend to delay the need for reinforcement of parts of the transmission network but it is unlikely to remove the need for the substations that exist at the interface between the transmission and distribution systems (i.e. the Grid Supply Points). These will continue to be required to balance the fluctuations between generation and demand in that specific part of the distribution network from minute to minute.

In a few areas it is possible that embedded generation may increase to a level where there could be electricity exports from distribution networks to the transmission system. Provided such transfers are within the capacity of the super grid transformers, this is not expected to lead to major technical difficulties. The general reduction in the power flow from the transmission to distribution networks does not necessarily lead to a similar reduction in the bulk power transfer across the transmission system. These bulk transfers, and therefore the need for system reinforcements, are a function of the size and geographical location of both generation and demand.

Power stations, particularly Large Power Stations, tend to be located in clusters near fuel sources. This, coupled with their size (i.e. capacity) relative to that of individual demands, means that generation developments (openings or closures) tend to exert the greater influence on the need for transmission reinforcements. Demand changes are normally less localised and are subject to a more even rate of change. Having said that, in some areas (e.g. where demand exceeds local generation) demand can exert the greater local influence and as such there remains a need for accurate demand forecasts in terms of both level and location.

The section in Chapter 7 on "Transmission System Performance" considers the performance of the NETS against the 'SYS background', includes two figures (Figure 7.1 and Figure 7.2) which provide an overview of the power flow pattern at the time of ACS peak demand for the years 2010/11 and 2017/18 respectively.

Power transfers across the system depend on the disposition of generation and demand regardless of whether it is directly connected to the NETS or embedded within a distribution system. To reduce bulk flows would require a general movement of economic generation (directly connected or embedded) nearer to the major load centres (e.g. the south). Even then it would not necessarily follow that the north to south power transfers would reduce. For instance, if new embedded generation were to be located in the south its operation could displace the operation of less economic plant also in the south, in which case transfers would be unchanged. Alternatively, if new embedded generation were to be located in the north of the system it is more likely that north to south transfers would increase.

## Transmission Network Use of System Charges (TNUoS)

The Balancing and Settlement Code (BSC) and TNUoS charges, including to whom they apply, are explained in Chapter 10 (Market Overview).

Generators that are not registered within the BSC are exempt from TNUoS charges and payments. Relevant power stations would be Licence exempt, embedded and registered within a Supplier BM Unit. The output of these power stations will have already been accounted for in the supplier's demand figures upon which TNUoS charges are based.

Under the above circumstances an embedded power station which is both licence exempt and not party to the BSC will not be charged TNUoS and may be able to reduce the TNUoS charges payable by the host supplier (i.e. the supplier in whose BM Unit the power station is registered) by generating on the Triad legs.

## Fluctuating Unpredictable Output and Standby Capacity

The output of some renewable technologies, such as wind, wave, solar and even some CHP, is naturally subject to fluctuation and, for some renewable technologies, unpredictable relative to the more traditional generation technologies. Analyses of the incidence and variation of wind speed, the expected intermittency of the national wind portfolio would not appear to pose a technical ceiling on the amount of wind generation that may be accommodated and adequately managed. However, increasing levels of such renewable generation on the system would increase the costs of balancing the system and managing system frequency.

It is a property of the interconnected transmission system that individual and local independent fluctuations in output are diversified and averaged out across the system. Moreover, the interconnected system permits frequency response and reserves to be carried on the most cost effective generation or demand side service provider at any particular time. These properties of the transmission network permit intermittent/variable generation to be used with lower standby and frequency control costs than would otherwise be the case.

Given the variable and unpredictable nature of some renewable technologies such as wind, the proportion of conventional generation needed to be retained in the electricity market so that current levels of security of supply are not eroded is the subject of recent research that has been recently published. The report "Growth Scenarios for the UK Renewable Generation and Implications for future Developments and Operation of electricity Networks" (BERR Publication URN 08/1021 June 2008) indicates that in the future "the probability of having low wind output at times of peak demand is considerable. There is a 10% probability that wind output will be below about 20% of installed capacity at times of peak demand in winter and a 5% probability of output being below about 15%."

This implies that, for larger wind penetrations, the wind capacity that can be taken as firm is not proportional to the expected wind energy production. It follows that the electricity market will need to maintain in service a larger proportion of conventional generation capacity despite reduced load factors. Such plant is often referred to as "standby plant".

## Balancing Mechanism Participation

Users registered within the BSC may volunteer to participate in the Balancing Mechanism (BM) regardless of whether they are directly connected to the transmission system or embedded within a distribution system. The minimum offer size in the BM is 1MW.

National Grid's responsibility in the BM is limited to balancing generation and demand and to resolving transmission constraints. This includes a duty and financial incentive under the System Operator Incentive Scheme to purchase Balancing Services economically. The Grid Code requires all embedded participants on the BM to ensure that their physical notifications, bids and offers are feasible with respect to their host network.

The persistence effect of wind (i.e. its output is naturally subject to fluctuation and unpredictability relative to the more traditional generation technologies) coupled with the expected significant diversity between regional variations in wind output means that, while the balancing task will become more onerous, the task should remain manageable. Provided that the necessary flexible generation and other balancing service providers remain available, there is no immediate technical reason why a large portfolio of wind generation cannot be managed in balancing timescales.

It is anticipated that balancing volumes and costs will increase as the wind portfolio increases. National Grid estimation of these volumes and costs will be highlighted via a separate consultation report on future system operations which was published in June 2009. Both the consultation document and the results of the consultation can be found at the following link,

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

In the longer term, we do not think it likely that there will be a technical limit on the amount of wind that may be accommodated as a result of short term balancing issues but economic and market factors will become increasingly important.

Further information on Balancing Services can be obtained on the National Grid website:

http://www.nationalgrid.com/uk/Electricity/Balancing/services/

A useful reference document on the management of constraints and incentives ("BSIS Reference Document - An introduction to National Grid Electricity Transmission System Operator (SO) Incentives") is available under "System Operator Incentives":

http://www.nationalgrid.com/uk/Electricity/soincentives/docs/

## Technical and Data Requirements

All Generators with Large power stations are obliged to sign onto the Connection and Use of System Code (CUSC). This includes signatories to the BSC. In addition parties who are not holders of a Licence but who have registered within the BSC are also required to sign the CUSC.

The CUSC places a number of obligations on signatories, which includes compliance with the Grid Code. Amongst other things, the Grid Code sets out technical requirements for the various classes of generation (e.g. Large, Medium, Small, embedded and directly connected External Interconnections) as well as requirements for data to be supplied to National Grid as NETSO.

Some of the earlier technologies used in wind turbines were very sensitive to voltage depressions, even where such depressions lasted for very short periods of time, such as the 140 milliseconds that protective equipment on the NETS typically take to remove a line fault caused by lightning. Such faults can result in voltage depressions over an extensive area of the system potentially causing a large number of wind turbines to trip as a result of a common cause. In recognition of this the Grid Code has now been revised to include revised minimum technical characteristics for such generation technologies.

Medium and Small embedded generation which is Licence exempt and which is not registered within the BSC, is not required to sign on to the CUSC and, in consequence, is not obliged to comply with the Grid Code. Nevertheless, it is recognised that such embedded generation does impact on the overall performance of the transmission system and its operation.

Embedded Medium power stations are most likely to have a material effect. Small power stations may also be important particularly if connected at the first voltage transformation level of the Grid Supply Point.

To enable the Transmission Owners to meet their obligations with regard to planning the transmission system and National Grid, acting as NETSO, to further meet its obligations with regard to operating the NETS it is important that Users submit sufficient and timely information on all embedded generation that may have a material effect on the transmission system. Amongst other things, the following are required:-

- technical and other information in respect of any new embedded generation which may be material to the design and operation of the transmission system in order that any necessary works can be evaluated and initiated in a timely fashion; and

- sufficient notification to enable any necessary works to be completed and ensure the transmission network is safe and secure before the embedded generation is energised.

## Summary

National Grid recognises the importance of climate change issues and that the government's targets for growth in CHP and renewable generation are likely to lead to continuing increases in embedded generation. It is important for National Grid to play its part in facilitating this by ensuring that any transmission issues arising are appropriately addressed. At present, no insurmountable transmission problems associated with accommodating new embedded generation projects are foreseen. Indeed, the properties of the interconnected transmission system are such as to facilitate embedded generation growth regardless of location.

Nevertheless, this does not preclude the potential need for reinforcements to the NETS, the extent of which would be a function of the system location of the new plant. For example, the extent, and therefore cost, of transmission reinforcement would be a function of the volume of offshore wind located off the England and Wales coast or onshore wind located in Scotland. There is considerable ongoing work in this area which is published by the Electricity Networks Strategy Group (ENSG):
http://www.ensg.gov.uk/index.php?article=126

The persistence effect of wind (i.e. its output is naturally subject to fluctuation and unpredictability relative to the more traditional generation technologies) coupled with the expected significant diversity between regional variations in wind output, means that, while the balancing task will become more onerous, the task should remain manageable. It is anticipated that balancing volumes and costs will increase as the wind portfolio increases. However, provided that the necessary flexible generation and other balancing service providers remain available, there is no immediate technical reason why a large portfolio of wind generation cannot be managed in balancing timescales.

Further information can be obtained from the National Grid website:
http://www.nationalgrid.com/uk/Electricity/Operating+in+2020/

**Table 4.1 - Embedded Medium and Small Generation Netted off Demand Forecast Submissions by DNOs**

| **DNO Network** | **Zone Number** | **Zone Name** | **Installed Capacity (MW) from Table F.3** | **Generation Netted Off at Time of System Peak (MW)** |
|---|---|---|---|---|
| Scottish & Southern Energy | 1 | North Scotland | 353 | 86 |
| Scottish & Southern Energy (Southern) | 2 | South England | 857 | 448 |
| CE Electric UK | 3 | North East England & Yorkshire | 1,458 | 632 |
| Electricity North West | 4 | North West England | 905 | 731 |
| E-on Central Networks | 5 | Central England | 1,116 | 219 |
| UK Power Networks | 6 | London & East England | 2,014 | 573 |
| Scottish Power Distribution | 7 | South Scotland | 567 | 179 |
| Western Power Distribution | 8 | South West England & South Wales | 702 | 61 |
| Scottish Power Distribution (North Wales) | 9 | North Wales | 992 | 30 |
| Other / Directly Connected | | | | 578 |
| **Totals (MW)** | | | **8,964** | **3,537** |

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# Chapter 5

# Plant Margin

## Introduction

This chapter brings together information on generation capacity from Chapter 3 (Generation Capacity) and forecast Average Cold Spell (ACS) unrestricted peak demand from Chapter 2 (Electricity Demand) and examines the overall plant/demand balance on the National Electricity Transmission System (NETS) by evaluating a range of potential future plant margins.

However, it is emphasised that **none of the plant margins presented in this chapter is intended to represent our forecast or prediction of the future position.** The primary purpose is rather to provide sufficient information to enable the readers to make their own more informed judgments on the subject. Indeed National Grid believes that the relatively high margins presented in the various tables and figures of this chapter are unlikely to occur in practice for a number of reasons that are discussed in the main text.

The plant margins presented have been evaluated on the basis of a range of different backgrounds. These backgrounds take some account of the uncertainties relating to future generation, which include: the relative likelihood of prospective new future generation projects proceeding to completion; as yet un-notified future generation disconnections (closures), e.g. LCPD closures; and the possible return to service of previously decommissioned plant (or the return to service of plant with TEC currently set at zero). The appropriate contribution towards the plant margin of generation output from wind farms is also considered, as is the potential effect on the plant margin of exports (rather than imports) across External interconnections and the sterilisation of generation capacity by virtue of its location behind a transmission constraint.

There are a number of definitions of plant margin in current usage; and each definition is appropriate to a particular purpose. Naturally, the calculated value of plant margin also varies along with the definition. A discussion of the plant margin definition for the purposes of the NETS SYS is included in Appendix I.

The chapter concludes with a brief report on the related issue of gas and electricity market interaction.

Finally readers are advised that if they are not familiar with Plant Margin terminology that they read Appendix I before studying this chapter. Appendix I explains the Plant Margin terminology used in this chapter.

## Plant Margins on Different Generation Backgrounds

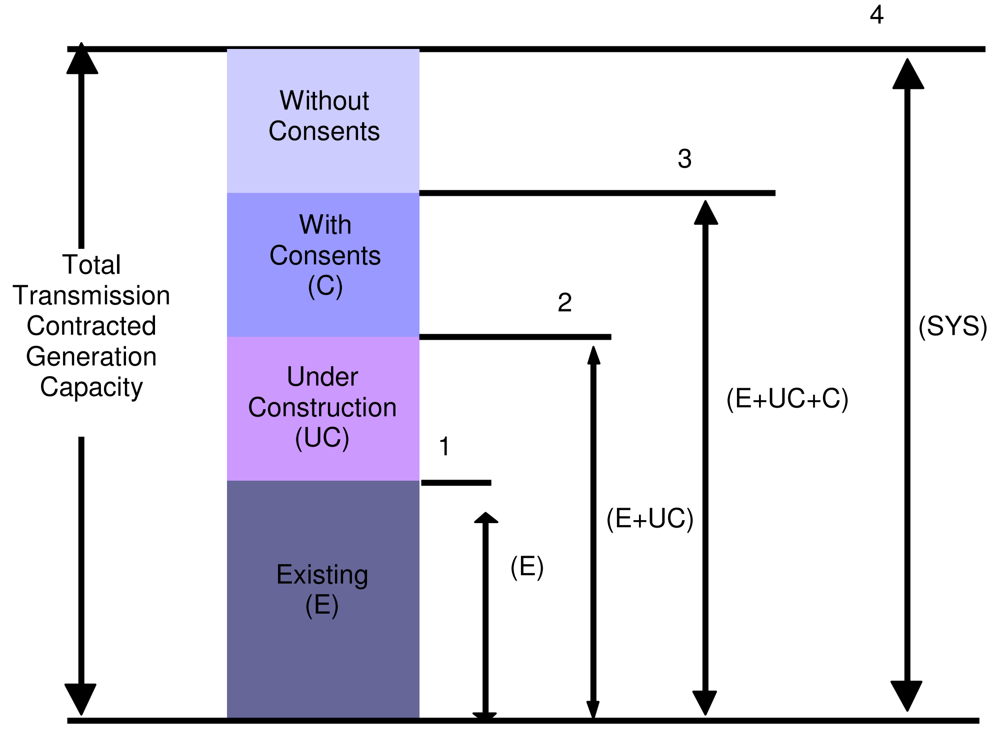
### Generation Commissioning Backgrounds

Unless otherwise stated the network analyses (e.g. the illustrative power flows, the loading on each part of the NETS and the fault levels) presented in this Statement are based on the SYS background. Amongst other things, the SYS background includes existing generation projects and those proposed new generation projects for which an appropriate Bilateral Agreement is in place. Accordingly, most of the studies and analyses presented assume that all of the generating plant planned for commissioning over the period from the 2011/12 winter peak to the 2017/18 winter peak, will commission.

However, unless plant is already under construction there can be only limited certainty that any particular project will proceed to completion and, accordingly, there are a number of areas of uncertainty relating to the future generation position and consequently the future plant/demand position. These include:

- the possibility of termination or modification of longer term connection agreements before construction or commissioning;
- additional new connection agreements being signed;
- as yet un-notified plant closures;
- possible retention of generation assets by the owner for commercial reasons or the return to service of plant currently held in reserve. Table 3.11 identifies plant which, on the face of it, has the potential to return to service. However, in practice, the majority of this plant belongs to stations that have opted-out of LCPD, and will therefore not generate beyond 2015; and
- the possibility that some transmission contracted generation may not in the event be granted Section 36 consent.

**Figure 5.1 - Generation Backgrounds**



In view of these uncertainties, four different generation backgrounds have been considered. Each has been selected in recognition of the different level of certainty relating to whether the proposed new transmission contracted plant will, in the event, proceed to completion. These are illustrated in Figure 5.1.

- Background 1: ‘Existing Background’ (E)
  This background includes all transmission contracted generation plant that is already constructed and connected to either the transmission network or a distribution network
- Background 2: ‘Existing or Under Construction Background’ (E, UC)
  This background includes all the generation included under background 1, plus all future generation plant under construction.
- Background 3: ‘Consents Background’ (C)
  A second useful indicator is whether plant has already been granted the necessary consents under Section 36 (S36) of the Electricity Act 1989 and Section 14 (S14) of the Energy Act 1976 (see Chapter 10: "Market Overview"). This background includes all existing plant, that portion of plant under construction that has obtained both S36 and S14 consent where relevant, and planned future plant that has obtained both S36 and S14

consent where relevant. Any 'contracted' generation not already existing that requires S36 and S14 consent but has not obtained both is excluded from this background.

- Background 4: ‘SYS Background’ (SYS)
  This background includes the existing generation and that proposed new generation for which an appropriate Bilateral Agreement is in place. The fact that a generation project may be classified as 'contracted’ does not mean that the particular project is bound to proceed to completion. Nevertheless, the existence of the appropriate signed Bilateral Agreement does provide a useful initial indicator to the likelihood of this occurring.

Table 5.1, Table 5.2, Table 5.3 and Table 5.4 provide subtotals by plant type for each of the four generation commissioning backgrounds for the years 2010/11 to 2017/18 inclusive. Table 5.5 provides totals for each of the four generation backgrounds for the years 2010/11 to 2017/18 inclusive. Table 5.5 also provides peak demands on the basis of the customer based unrestricted demand forecasts given in Chapter 2 (Electricity Demand), and also for the NGET ‘Base’ economic growth scenario. The forecast demand streams utilised in each of these tables exclude station demand as that element of demand is excluded from the station TEC. Figure 5.2 is a graphical version of the totals given in Table 5.5.

**Figure 5.2 Generation Backgrounds and Peak Demands**

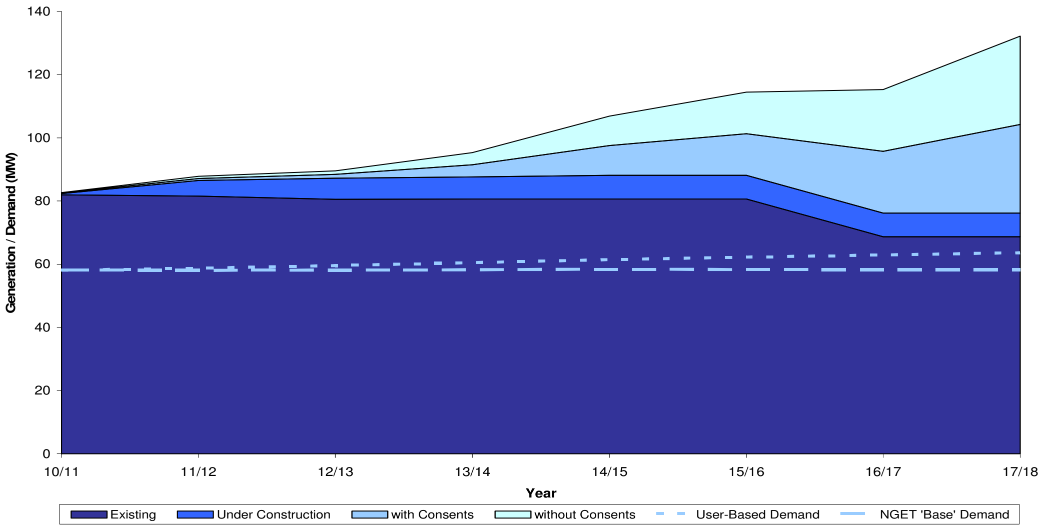
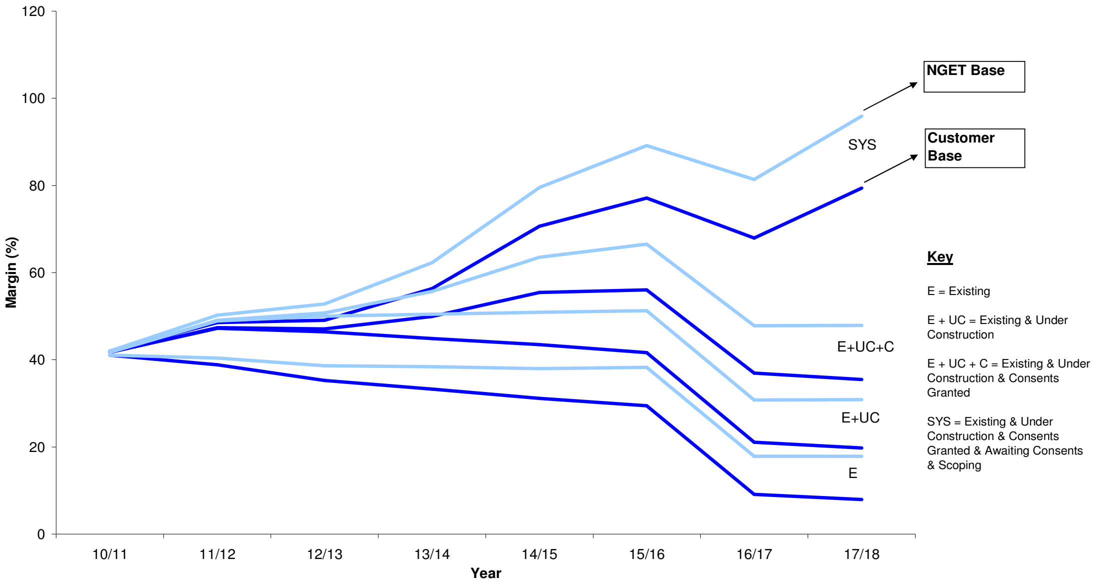


Table 3.3(a) and Table 3.3(b) of Chapter 3 identify, amongst other things, the amount of ‘transmission contracted’ generation planned to connect beyond 2010/11. For a more detailed view of this data showing how much of the remaining new ‘transmission contracted’ generation has, where relevant, obtained the necessary S36 and S14 consents, and how much has yet to obtain consent, please see table F.8 located in appendix F.

Table 5.6 and Figure 5.3 compare plant margins derived from the customer based demand forecast with those derived from our own base view of future demand growth given in Table 2.3. This is repeated for each of the above backgrounds to give six sensitivities in all, along with the SYS Background plant margins.

Figure 5.3 Plant Margins for Various Generation Backgrounds



## Generation Disconnection (Closure)

Generators are only required to give 6 months notice of closure of existing plant, which means that it is possible for us to receive formal notice of closure of plant within the first year of this Statement. It is important to read the Quarterly Updates to this Statement to identify any changes since the data was frozen for this NETS SYS on 31 December 2010.

The effect on the potential future plant margin of a particular assumption on future generating closure may, of course, be readily assessed. For example, if it were assumed that say 1GW of additional generating plant were to decommission (close) by the year 2017/18 (i.e. when the demand less station demand is some 58.4GW (as presented in Table 2.3**),** the Plant Margin in that year would be reduced by around 1.7 percentage points (i.e. 100*1GW/58.4GW = 1.7%) relative to the margins shown in Table 5.6 and the related figures.

## Decommissioning

Table 3.6 lists generating units, that have either been formally notified by the owner as decommissioned (effectively TEC=0) or simply notified zero TEC covering the seven year period of this Statement; the total capacity of this plant is just over 2.9GW. Some, or all, of this plant has been retained by its owners for commercial reasons (e.g. placed in reserve or mothballed) and may under certain circumstances be returned to service at some future date (see "Decommissionings" in Chapter 3).

However it is unlikely that all this capacity could be returned to service. Of the 2.9GW, perhaps some 500MW to 1GW has the greatest potential to return to service. Even then, it should also be borne in mind that, were individual plants to be re-commissioned/returned to service, the full previous capacities may not necessarily be realised.

The effect on the potential future plant margin of a particular assumption on re-commissioning generating units may again be readily assessed. For example, if it were assumed that say a 500MW unit were to re-commission by the 2017/18 winter peak**,** the plant margin in that year would be increased by around 0.9 of a percentage point (i.e. 100*0.5GW/58.40GW) relative to the margins shown in Table 5.6 and Figure 5.3.

The broad system effect of recommissioning mothballed plant is a function of the size and location of the particular plant or tranche of plant. The effects of returning any individual plant to service must necessarily be considered on a case by case basis both in terms of the overall system impact and on a site specific basis.

## Wind Farm Contribution to Plant Margin

Within Appendix I referred to earlier in this chapter it is explained that the definition of Plant Margin, is such that no allowance is made within its calculation for the intermittent nature of the output and the level of output that, in consequence, can be relied upon from wind power plants at the time of system peak. This is unlike the assumptions on wind plant output underlying the system analyses, which are presented and discussed in "Modelling of the Planned Transfer" in Chapter 7 and in Chapter 8 (Transmission System Capability).

However, to enhance transparency and promote greater understanding within this chapter, additional plant margins have been calculated for a range of assumptions on the availability of wind generation capacity at the time of the winter peak as per customer based forecasts. Nevertheless, it should be remembered that such a range is quite arbitrary in the context of plant margin.

**Figure 5.4 - Plant Margins for various Wind Generation Availability Assumptions (relative to SYS Background)**

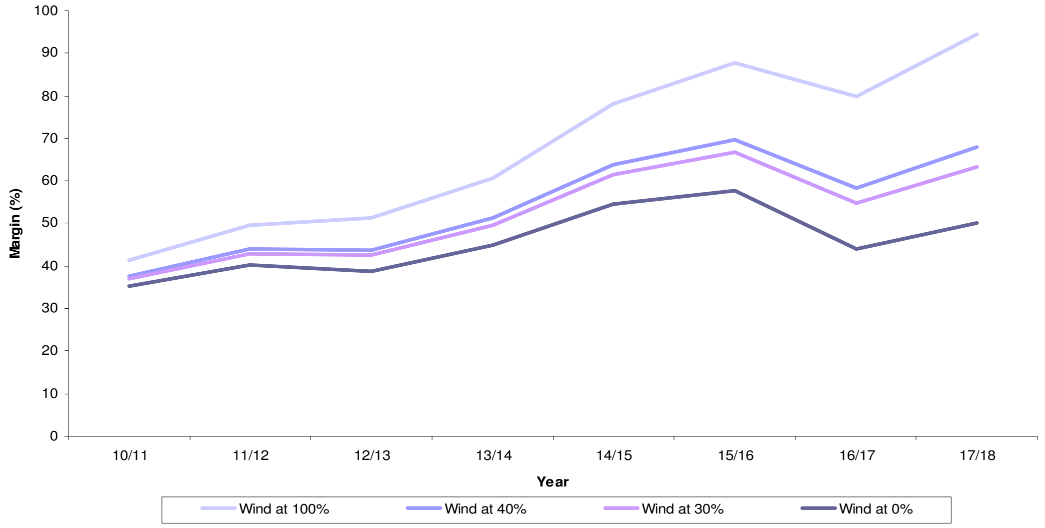


Table 5.7 and Figure 5.4 display plant margins for wind capacity availability assumptions of 40%, 30% and 0%. The SYS background (i.e. with an inherent 100% wind capacity assumption), as given in Figure 5.2 and Table 5.4, is also included for ease of comparison.

The effect of the LCPD closures in 2016/17 can be seen in Figure 5.3 and Figure 5.4.

## Import and Export Assumptions across Interconnections with External Systems

Appendix F Table F.13 sets out the notional import and export capabilities across the External Interconnections at the time of our ACS Peak Demand. The table shows that the IFA link provides a nominal import/export capability of 1988MW each way; although the link is normally used for imports. Similarly the Netherlands link will provide an import/export capability (from 2010/11 onwards) of 1320MW import and 1390MW export and again the link will normally be used for imports. The link to the Republic of Ireland will provide an import/export capability (from 2011/12 onwards) of 500MW import and 500MW export, and the link will normally be used for exports. The link with Northern Ireland has a nominal export/import capability of 500MW export and 80MW import. In this case the link will normally export. For the purpose of evaluating plant margins, import capabilities across External Interconnections are treated as float and exports are treated as negative generation.

### Transmission Congestion

Transmission congestion exists on certain parts of the NETS and this is considered in Chapter 8 (GB Transmission System Capability). Congestion occurs when the transfer capability of certain parts of the transmission system is insufficient to carry the power transfers arising from the unconstrained operation of generating plant. In such circumstances, generation is either constrained on or constrained off to avoid violation the Licence Standard in relation to system operation. Plant, which is constrained off, may be considered to be 'sterilised' in that it is unable to contribute to meeting the demand and may therefore be regarded as non contributory towards the overall GB plant margin.

Recent and forecast growth in generation in Scotland is significant, partly due to the high volume of new renewable generation seeking connection in the area. Transmission reinforcement works are in place to enhance transmission capability across the boundaries between the SHETL system, the SPT system and the NGET system. For timescales of likely connection dates in particular areas please refer to Chapter 9 Figure 9.1.

Amongst other things, Chapter 8 (Transmission System Capability) explains that the ‘planned transfer’ from Scotland to England exceeds the expected capability of that transmission boundary in some years even with the planned transmission reinforcements to enhance that capability. Accordingly, some of the generating capacity in Scotland will need to be constrained off and, consequently, may be regarded as ‘sterilised’. The level of plant required to be constrained off varies through the period. However, as a generalised illustration, if it were assumed that say 1GW of generating plant in Scotland were constrained off at, say, the time of the 2010/11 peak to limit the power flows from Scotland into England to within acceptable levels, then this would effectively reduce the overall plant margin, in that year, by around 1.7 percentage points (i.e. 100*1GW/57.6GW = 1.7%).

## Interpretation

### Broad Overview

It is worth repeating that, while plant margins based on several backgrounds have been considered, we do not attach any probability to the likelihood of occurrence of any particular background, including the SYS background. The range of backgrounds has been considered to enable readers to form their own view on potential future plant margins and do not represent our predictions of the future outcome.

Appendix I explains that a margin of installed generation capacity over peak demand is necessary for security of electricity supply and is not surplus or excess capacity. That section also explains that, for the purpose of calculating plant margins, power station TEC has been used. Power station TEC is net of station demand. Accordingly, the demand used in the calculation of plant margin also excludes station demand.

As a general observation, plant margins are generally numerically similar to the equivalent margins published in last year’s Statement. National Grid do not believe that the relatively high margins shown in Figure 5.3 and Table 5.6 will occur in practice; particularly in respect of the later years. Amongst other things, those margins do not assume any plant is removed from service through disconnection (other than that assumed for nuclear magnox and LCPD affected plant) or added through the return to service of currently unavailable (or decommissioned) plant. Nor do they take any account of additional new connection agreements being signed or the possibility that some transmission contracted plant may not, in the event, proceed to completion.

In particular the margins of Figure 5.3 and Table 5.5 take no account of wind farm intermittency. When reduced availability in wind farm output is taken into account, the apparent margins are naturally reduced significantly as illustrated in Figure 5.4 and Table 5.6. The potential for transmission congestion to ‘sterilize’ portions of installed generating capacity provides further scope for reduced margins.

The National Grid based forecast demands are lower than their equivalent User-based demands and this is reflected in the higher plant margins calculated using the National Grid based forecast demands.

The margins for 2010/11 should be viewed against the background of higher certainty (e.g. relating to demand forecasts and plant availability) associated with the earlier years. Thus, a lower margin in the earlier years may provide the same level of generation security as a higher apparently higher margin in later years.

Finally, it is stressed that none of the margins presented can, at this stage, be said to be ‘correct’. However, the most probable margins are considered to be captured by the wide range given. This range of backgrounds, qualified by the comments on the potential for closures, the possibility of terminations, the possible return to service of plant that is currently unavailable, and the potential sterilisation of generating plant, may assist readers in formulating their own views on the subject. Table 5.7 attempts to give an indication of margins that have actually occurred in recent years.

## Generation Market Drivers

As a result of the various uncertainties, not all of which have been reported in this chapter, there is the potential for a wide range of possible outcomes relating to generation. As a consequence, we have developed our own view of the likely developments into the future, which is considered alongside the SYS based backgrounds when undertaking our investment planning processes, but this is not detailed in this document.

In developing our own view of available generation capacity going forward, we have made an assessment of the potential impact of a number of physical, environmental and commercial drivers. The physical drivers include the ageing population of certain classes of generating plant. Environmental drivers include the impact of the introduction of the 2005 EU Emissions Trading Scheme (ETS) from 2008, the Large Combustion Plant Directive (LCPD) from 2008 and the development of offshore wind farms. Commercial factors, which are entwined with the drivers outlined above, include the impact of forward prices, generator rationalisations, mothballing of plant and ancillary services. In addition, developments in the commercial framework would influence the generation capacity available.

## Gas and Electricity Market Interaction

The interconnected electricity transmission system in Great Britain provides for the efficient bulk transfer of power from sources of electricity generation to the demand centres. The main benefits of the NETS are outlined in ”The Benefits of an Interconnected Transmission System" in Chapter 4. Amongst other things, the transmission system provides for power stations to be located remote from the demand centres. The choice of power station location would take account of a wide range of considerations including financing, environmental factors, land availability, fuel availability and cost, potential savings in fuel transportation costs and transmission access, as well as taking account of our Transmission Network Use of System (TNUoS) charges which we levy on our customers for making use of our transmission system. Transmission Network Use of System charges are described in Chapter 10 (Market Overview).

Table 5.4 shows that CCGT capacity has the potential to exceed coal capacity by 2017/18 as the major plant type.

Gas is transported from producer to gas consumer (e.g. CCGT power station) via National Grid’s gas transmission network for which transportation charges are levied. Thus, CCGT power stations could be viewed as a producer on the electricity transmission system and a consumer on the gas transmission network. This dual role gives rise to a degree of interaction between the electricity and gas markets. In particular, there are two elements in the gas market that have the potential to affect the level of available generation capacity: ‘interruptible gas services’ and ‘CCGT arbitrage’.

## Interruptible Gas Arrangements & Off Peak Capacity Product

The current interruptible arrangements apply until 30th September 2012. This is a service National Grid Gas offers to its customers which provides for lower gas transportation charges but, at times of high gas demand, allows it to shut off some or all of the gas supplied to the supply point for a specified maximum number of days within a year.

Gas supply could be interrupted by National Grid when there are transportation constraints on the National Gas Transmission network. In addition Shippers or Suppliers of gas can commercially interrupt their customers (e.g. CCGT station) either to balance their demand and supply portfolios or to sell gas onto the open market.

However, many of the power stations that would be affected (i.e. those with interruptible gas supplies) have back up supplies of distillate oil. Thus, providing there are no technical problems relating to switching to and from distillate oil, and providing adequate distillate capacity is available, then electricity generation can be maintained.

New market arrangements have been introduced which are effective from 1st October 2012 where the current National Transmission System (NTS) interruption arrangements are replaced by an off peak capacity product available via a day ahead pay-as-bid auction. National Grid NTS will be able to scale back such capacity holdings to manage constraints on the gas system.

## CCGT Arbitrage

Gas-fired stations have the potential to respond to market price signals, decreasing their gas consumption when the electricity price is lower than the price of burning gas. This ability to arbitrage between gas and power is not restricted to power stations with National Grid Gas interruptible contracts. In recent experience some firm CCGT power stations have self-interrupted over the winter for commercial reasons.

The willingness of the CCGTs to commercially interrupt themselves will be determined by the spark spread, which is itself influenced by the ability of the power generation sector to switch to other fuels and the level of electricity demand. Given the within-day profile of electricity demand, there is more scope for gas-fired generators to reduce their gas demand outside the peak half-hours of the day, as well as at other times of low electricity demand, such as at weekends and during holiday periods and either burn alternative fuel or switch generation to another station, burning coal or oil, within their portfolio of stations.

National Grid have carried out a detailed analysis to estimate the potential extent of CCGT arbitrage/demand side response within England and Wales, the results of which can be found in our 2010/11 Winter Outlook Report published in October 2010:

http://www.nationalgrid.com/uk/Gas/TYS/outlook/

Looking forward, we think that there is a strong case for all prospective new CCGTs to fit alternative fuel capability in order to provide additional flexibility to deal with periods of gas-electricity interactions, especially given the projected increase in gas’ share of the electricity generation market.

**Table 5.1 - Capacity by Plant Type (E)**

| **Plant Type** | **2010/11** | **2011/12** | **2012/13** | **2013/14** | **2014/15** | **2015/16** | **2016/17** | **2017/18** |
|---|---|---|---|---|---|---|---|---|
| Biomass | 45 | 45 | 45 | 45 | 45 | 45 | 45 | 45 |
| CCGT | 29022 | 29022 | 29022 | 29022 | 29022 | 29022 | 29022 | 29022 |
| CHP | 2069 | 2069 | 2069 | 2069 | 2069 | 2069 | 2069 | 2069 |
| Hydro | 1113 | 1113 | 1113 | 1113 | 1113 | 1113 | 1113 | 1113 |
| Large Unit Coal | 4342 | 4342 | 4342 | 4342 | 4342 | 4342 | 2284 | 2284 |
| Large Unit Coal + AGT | 21440 | 21440 | 21440 | 21440 | 21440 | 21440 | 17517 | 17517 |
| Medium Unit Coal | 1102 | 1102 | 1102 | 1102 | 1102 | 1102 | 0 | 0 |
| Medium Unit Coal + AGT | 1131 | 1131 | 1131 | 1131 | 1131 | 1131 | 0 | 0 |
| Nuclear AGR | 8246 | 8246 | 8246 | 8246 | 8246 | 8246 | 8246 | 8246 |
| Nuclear Magnox | 1390 | 960 | 0 | 0 | 0 | 0 | 0 | 0 |
| Nuclear PWR | 1207 | 1207 | 1207 | 1207 | 1207 | 1207 | 1207 | 1207 |
| OCGT | 578 | 578 | 578 | 578 | 578 | 578 | 478 | 478 |
| Oil + AGT | 3636 | 3636 | 3636 | 3636 | 3636 | 3636 | 0 | 0 |
| Pumped Storage | 2744 | 2744 | 2744 | 2744 | 2744 | 2744 | 2744 | 2744 |
| Small Unit Coal | 783 | 783 | 783 | 783 | 783 | 783 | 783 | 783 |
| Wind Offshore | 997 | 997 | 997 | 997 | 997 | 997 | 997 | 997 |
| Wind Onshore | 2093 | 2128 | 2128 | 2135 | 2135 | 2135 | 2135 | 2135 |
| **Total Capacity (MW)** | **81938** | **81543** | **80583** | **80590** | **80590** | **80590** | **68640** | **68640** |

**Table 5.2 - Capacity by Plant Type (E+UC)**

| **Plant Type** | **2010/11** | **2011/12** | **2012/13** | **2013/14** | **2014/15** | **2015/16** | **2016/17** | **2017/18** |
|---|---|---|---|---|---|---|---|---|
| Biomass | 45 | 45 | 45 | 45 | 45 | 45 | 45 | 45 |
| CCGT | 29022 | 32172 | 32922 | 32922 | 32922 | 32922 | 32922 | 32922 |
| CHP | 2069 | 2069 | 2069 | 2069 | 2069 | 2069 | 2069 | 2069 |
| Hydro | 1113 | 1113 | 1113 | 1113 | 1113 | 1113 | 1113 | 1113 |
| Large Unit Coal | 4342 | 4342 | 4342 | 4342 | 4342 | 4342 | 2284 | 2284 |
| Large Unit Coal + AGT | 21440 | 21440 | 21440 | 21440 | 21440 | 21440 | 17517 | 17517 |
| Medium Unit Coal | 1102 | 1102 | 1102 | 1102 | 1102 | 1102 | 0 | 0 |
| Medium Unit Coal + AGT | 1131 | 1131 | 1131 | 1131 | 1131 | 1131 | 0 | 0 |
| Nuclear AGR | 8246 | 8246 | 8246 | 8246 | 8246 | 8246 | 8246 | 8246 |
| Nuclear Magnox | 1390 | 960 | 0 | 0 | 0 | 0 | 0 | 0 |
| Nuclear PWR | 1207 | 1207 | 1207 | 1207 | 1207 | 1207 | 1207 | 1207 |
| OCGT | 578 | 578 | 578 | 578 | 578 | 578 | 478 | 478 |
| Oil + AGT | 3636 | 3636 | 3636 | 3636 | 3636 | 3636 | 0 | 0 |
| Pumped Storage | 2744 | 2744 | 2744 | 2744 | 2744 | 2744 | 2744 | 2744 |
| Small Unit Coal | 783 | 783 | 783 | 783 | 783 | 783 | 783 | 783 |
| Wind Offshore | 1198 | 1906 | 2557 | 2842 | 3354 | 3354 | 3354 | 3354 |
| Wind Onshore | 2281 | 2989 | 3305 | 3436 | 3436 | 3436 | 3436 | 3436 |
| **Total Capacity (MW)** | **82327** | **86463** | **87220** | **87636** | **88148** | **88148** | **76198** | **76198** |

**Table 5.3 - Capacity by Plant Type (E+UC+C)**

| **Plant Type** | **2010/11** | **2011/12** | **2012/13** | **2013/14** | **2014/15** | **2015/16** | **2016/17** | **2017/18** |
|---|---|---|---|---|---|---|---|---|
| Biomass | 45 | 97 | 97 | 97 | 97 | 97 | 97 | 97 |
| CCGT | 29022 | 32172 | 32922 | 34282 | 38463 | 39983 | 40969 | 40969 |
| CHP | 2069 | 2069 | 2069 | 2069 | 2069 | 2069 | 2069 | 2069 |
| Hydro | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| IGCC with CCS | 1113 | 1113 | 1113 | 1113 | 1113 | 1113 | 1113 | 1113 |
| Large Unit Coal | 4342 | 4342 | 4342 | 4342 | 4342 | 4342 | 2284 | 2284 |
| Large Unit Coal + AGT | 21440 | 21440 | 21440 | 21440 | 21440 | 21440 | 17517 | 17517 |
| Medium Unit Coal | 1102 | 1102 | 1102 | 1102 | 1102 | 1102 | 0 | 0 |
| Medium Unit Coal + AGT | 1131 | 1131 | 1131 | 1131 | 1131 | 1131 | 0 | 0 |
| Nuclear AGR | 8246 | 8246 | 8246 | 8246 | 8246 | 8246 | 8246 | 8246 |
| Nuclear Magnox | 1390 | 960 | 0 | 0 | 0 | 0 | 0 | 0 |
| Nuclear PWR | 1207 | 1207 | 1207 | 1207 | 1207 | 1207 | 1207 | 1207 |
| OCGT | 578 | 578 | 578 | 578 | 578 | 578 | 478 | 478 |
| Oil + AGT | 3636 | 3636 | 3636 | 3636 | 3636 | 3636 | 0 | 0 |
| Pumped Storage | 2744 | 2744 | 2744 | 2744 | 2744 | 2744 | 2744 | 2744 |
| Small Unit Coal | 783 | 783 | 783 | 783 | 783 | 783 | 783 | 783 |
| Wind Offshore | 1198 | 1906 | 2557 | 3395 | 3907 | 3907 | 3907 | 3907 |
| Wind Onshore | 2281 | 3033 | 3664 | 4168 | 4305 | 4376 | 4389 | 4389 |
| Woodchip | 0 | 0 | 0 | 350 | 350 | 350 | 350 | 350 |
| **Total Capacity (MW)** | **82327** | **86559** | **87631** | **90683** | **95513** | **97104** | **86153** | **86153** |

**Table 5.4 - Capacity by Plant Type (SYS)**

| **Plant Type** | **2010/11** | **2011/12** | **2012/13** | **2013/14** | **2014/15** | **2015/16** | **2016/17** | **2017/18** |
|---|---|---|---|---|---|---|---|---|
| Biomass | 45 | 97 | 97 | 851 | 1730 | 1730 | 1730 | 1730 |
| CCGT | 29022 | 32172 | 32922 | 34717 | 39738 | 41258 | 45258 | 45258 |
| CHP | 2240 | 2240 | 2240 | 2240 | 2240 | 2240 | 2240 | 2240 |
| Hydro | 1113 | 1113 | 1113 | 1113 | 1113 | 1113 | 1113 | 1113 |
| IGCC with CCS | 0 | 0 | 0 | 800 | 800 | 800 | 800 | 800 |
| Large Unit Coal | 4342 | 4342 | 4342 | 4342 | 4342 | 4342 | 2284 | 2284 |
| Large Unit Coal + AGT | 21440 | 21440 | 21440 | 21440 | 21440 | 21440 | 17517 | 17517 |
| Medium Unit Coal | 1102 | 1102 | 1102 | 1102 | 1102 | 1102 | 0 | 0 |
| Medium Unit Coal + AGT | 1131 | 1131 | 1131 | 1131 | 1131 | 1131 | 0 | 0 |
| Nuclear AGR | 8246 | 8246 | 8246 | 8246 | 8246 | 8246 | 8246 | 8246 |
| Nuclear EPR | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 3340 |
| Nuclear Magnox | 1390 | 960 | 0 | 0 | 0 | 0 | 0 | 0 |
| Nuclear PWR | 1207 | 1207 | 1207 | 1207 | 1207 | 1207 | 1207 | 1207 |
| OCGT | 578 | 578 | 578 | 578 | 578 | 578 | 478 | 478 |
| Oil + AGT | 3636 | 3636 | 3636 | 3636 | 3636 | 3636 | 0 | 0 |
| Pumped Storage | 2744 | 2744 | 2744 | 2744 | 2744 | 2744 | 2744 | 2744 |
| Small Unit Coal | 783 | 783 | 783 | 783 | 783 | 783 | 783 | 783 |
| Tidal | 0 | 0 | 0 | 10 | 10 | 10 | 10 | 110 |
| Wind Offshore | 1198 | 2406 | 3057 | 4395 | 6734 | 10313 | 13457 | 18087 |
| Wind Onshore | 2281 | 3033 | 4166 | 4850 | 6945 | 7234 | 7461 | 7849 |
| Woodchip | 0 | 0 | 0 | 350 | 350 | 350 | 350 | 350 |
| **Total Capacity (MW)** | **82498** | **87230** | **88804** | **94535** | **104869** | **110257** | **105678** | **114136** |

**Table 5.5 - Capacity Totals and Peak Demands (MW)**

| Background | Generation / Demand (MW) | 2010/11 | 2011/12 | 2012/13 | 2013/14 | 2014/15 | 2015/16 | 2016/17 | 2017/18 |
|---|---|---|---|---|---|---|---|---|---|
| 1 | Existing Generation | 81938 | 81543 | 80583 | 80590 | 80590 | 80590 | 68640 | 68640 |
| 2 | Generation Under Construction | 389 | 4920 | 6637 | 7046 | 7558 | 7558 | 7558 | 7558 |
| 3 | Subtotal (1+2) | 82327 | 86463 | 87220 | 87636 | 88148 | 88148 | 76198 | 76198 |
| 4 | Generation with Consents | 0 | 96 | 411 | 3047 | 7365 | 8956 | 9955 | 9955 |
| 5 | Subtotal (3+4) | 82327 | 86559 | 87631 | 90683 | 95513 | 97104 | 86153 | 86153 |
| 6 | Generation without Consents | 171 | 671 | 1173 | 3852 | 9356 | 13153 | 19525 | 27983 |
| 7 | Total (5+6) | 82498 | 87230 | 88804 | 94535 | 104869 | 110257 | 105678 | 114136 |
| 8 | Customer-Based Peak Demand | 58100 | 58744 | 59594 | 60493 | 61462 | 62260 | 62933 | 63630 |
| 9 | NG 'Base' Peak Demand | 58100 | 58085 | 58141 | 58258 | 58422 | 58306 | 58285 | 58265 |

**Table 5.6 - Plant Margins (%)**

| Demand Forecast | Generation Background | 2010/11 | 2011/12 | 2012/13 | 2013/14 | 2014/15 | 2015/16 | 2016/17 | 2017/18 |
|---|---|---|---|---|---|---|---|---|---|
| Customer-Based | Existing | 41.0 | 38.8 | 35.2 | 33.2 | 31.1 | 29.5 | 9.1 | 7.9 |
| Customer-Based | Existing and Under Construction | 41.7 | 47.2 | 46.4 | 44.9 | 43.4 | 41.6 | 21.1 | 19.8 |
| Customer-Based | Existing and Under Construction and with Consents | 41.7 | 47.4 | 47.1 | 49.9 | 55.4 | 56.0 | 36.9 | 35.4 |
| Customer-Based | All Generation | 42.0 | 48.5 | 49.0 | 56.3 | 70.7 | 77.1 | 68.0 | 79.4 |
| NGET 'Base' | Existing | 41.0 | 40.4 | 38.6 | 38.4 | 38.0 | 38.2 | 17.8 | 17.8 |
| NGET 'Base' | Existing and Under Construction | 41.7 | 48.9 | 50.0 | 50.4 | 50.9 | 51.2 | 30.8 | 30.8 |
| NGET 'Base' | Existing and Under Construction and with Consents | 41.7 | 49.0 | 50.7 | 55.7 | 63.5 | 66.6 | 47.8 | 47.9 |
| NGET 'Base' | All Generation | 42.0 | 50.2 | 52.8 | 62.3 | 79.5 | 89.1 | 81.3 | 95.9 |

**Table 5.7 - Plant Margins (%) for Various Wind Generation Availability Assumptions (relative to SYS Background)**

| Generation Background | 2010/11 | 2011/12 | 2012/13 | 2013/14 | 2014/15 | 2015/16 | 2016/17 | 2017/18 |
|---|---|---|---|---|---|---|---|---|
| SYS (Wind at 100%) | 42.0 | 50.2 | 52.8 | 62.3 | 79.5 | 89.1 | 81.3 | 95.9 |
| SYS (Wind at 40%) | 38.4 | 44.6 | 45.3 | 52.8 | 65.5 | 71.1 | 59.8 | 69.2 |
| SYS (Wind at 30%) | 37.8 | 43.6 | 44.1 | 51.2 | 63.1 | 68.1 | 56.2 | 64.7 |
| SYS (Wind at 0%) | 36.0 | 40.8 | 40.3 | 46.4 | 56.1 | 59.0 | 45.4 | 51.4 |

**Table 5.8 - Plant Margins: Historical Outturns**

| Year | Total Capacity - January Update (MW) | ACS Corrected Peak Demand, excluding Station Demand (MW) | Plant Margin based on ACS Corrected Peak Demand (%) | Actual Peak Demand, excluding Station Demand (MW) | Plant Margin based on Actual Peak Demand (%) |
|---|---|---|---|---|---|
| 2005/06 | 75064 | 61600 | 21.9 | 59600 | 25.9 |
| 2006/07 | 76955 | 61200 | 25.7 | 57800 | 33.1 |
| 2007/08 | 76867 | 60800 | 26.4 | 60100 | 27.9 |
| 2008/09 | 79459 | 58400 | 36.1 | 58600 | 35.6 |
| 2009/10 | 82559 | 57649 | 43.2 | 58710 | 40.6 |
| 2010/11 | 90582 | 58100 | 55.9 | 59100 | 53.3 |

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# Chapter 6

# The Transmission System

## Introduction

This chapter describes the existing and planned National Electricity Transmission System (NETS) in terms of the electrical parameters of its components, its electrical and geographical structure and its planned development over the period to 2017/18. The chapter provides information on and references to locations of the generation and demand tariff zones, which are used in the Transmission Network Use of System (TNUoS) charging process. Finally the chapter also reports on the main system boundaries which are used to illustrate the overall capability of the transmission system to transmit power and on the associated study zones used in the various technical analyses contained in this Statement.

In view of the volume of transmission system data presented in this chapter, most of the figures and tables are presented in Appendix A (System Maps) and Appendix B (System Data) and only referenced in the text. Such figures and tables have accordingly been prefixed with the letter 'A' or 'B' as appropriate (e.g. Figure A.1.2).

The latter part of this chapter includes some basic introductory material relating to the NETS to assist readers, unfamiliar with power systems, in gaining a better understanding of the material contained in the Statement.

### The SYS Background

The existing and planned NETS described in this chapter, together with the demand forecasts described in Chapter 2 and the existing and planned generation background described in Chapter 3, form the basis of the SYS background upon which most of the studies and analyses presented in this Statement are based.

These three elements of the SYS background (namely: demand, generation and transmission) are internally consistent. For example, the transmission background of this chapter includes all transmission connection developments cited explicitly in the relevant Bilateral Connection Agreements as being necessary to permit the connection of the generation contained in the generation background of Chapter 3 (and Appendix F).

The transmission background includes all transmission connection developments cited in the relevant connection agreement as being necessary to connect the generation contained in the generation background. The "SYS background" does not include any transmission development that may be needed to accommodate prospective projects of new generation or demand (with the exception of the HVDC link as explained in Chapter 1) which do not have an appropriate Bilateral Agreement in place on the Data Freeze Date of 31 December 2010.

### Scope

Accordingly, this chapter provides information on the existing transmission network and on those future transmission developments, which are considered ‘firm’ in that they are least likely to be varied or cancelled as the needs of the evolving system change. Such transmission developments include, but are not restricted to, those schemes, which have been technically and financially sanctioned by the relevant Transmission Owner.

Other schemes, which may not yet be financially sanctioned by the relevant Transmission Owner, but which are however considered ‘firm’, are also included. Such transmission reinforcement schemes are, nevertheless, associated with “Transmission Contracted” generation projects included in the generation background and may have an appropriate Transmission Owners Construction Agreement (TOCA) and Transmission Owners

Reinforcement Instruction (TORI) in place. The meaning of the terms TORI and TOCA are explained in Appendix H – Generation Terminology.

In view of the uncertainty associated with future developments (particularly that relating to future transmission contracted generation), the timing of construction of infrastructure reinforcements is managed such that investments are made to well defined requirements. This means that in some cases construction is deferred to the last moment to avoid the risk of undertaking investments which may turn out to be unnecessary (e.g. where transmission contracted generation does not in the event proceed to completion), while at the same time ensuring that an efficient, co-ordinated and economic system, compliant with the Licence Standard is provided as required by the Transmission Licences.

Accordingly, the SYS background, upon which the bulk of this Statement is based, does not necessarily contain all the transmission reinforcement schemes that may in the event be required for compliance with the Licence Standard. This chapter focuses on the transmission network of the ‘SYS background’ which comprises the existing network together with those planned future transmission developments which are considered least likely to be varied to meet the changing needs of the system as it evolves.

Planned transmission developments may include:

- developments needed for 'transmission contracted' generation and demand cited in relevant bilateral agreements as being necessary precursors to the connection. These can include reinforcements to the infrastructure of the transmission system remote from the connection site as well as reinforcements local to the connection site; and
- infrastructure developments required to meet the general needs of the system as it evolves rather than the needs of any specific user (generation or demand).

## The Existing and Planned Network

### Network Parameters

The NETS for the winter of 2010/11 (as at the data freeze date of 31 December 2010) is shown geographically in Figure A.1.2. Table B.7a, Table B.7b and Table B.7c in Appendix B list the main planned developments to the transmission system in each year up to 2017/18 for each of the three transmission Licensee’s areas (SHETL, SPT and NGET).

Please note that in a change to the method used previously, the calculation method for the 2011 NETS SYS relating to R, X and B values contained within appendix B tables is now based on tower geometry, conductor type and circuit length from GPS data rather than on pre-defined standard construction types and original surveyed circuit length. There will therefore be some small differences in outturn impedance.

Network parameter values for the existing and planned 400kV, 275kV and 132kV transmission system are included in Appendix B which details the following for each of the three transmission Licensee areas:

- Index of Substation Codes
- Circuit Parameters / Circuit Parameter Changes
- Grid Supply Transformers / Changes in Grid Supply Transformers
- Transformer, Static Var Compensator and Quadrature Booster Parameters
- Reactive Plant Compensation
- Circuit Breaker Ratings
- Planned Transmission Developments

Also held within Appendix B is a description and explanation of the data held in the above tables.

## Network Diagrams

The existing 2010/11 NETS is shown schematically in Figure A.2.1 for SHETL, Figure A.3.1 for SPT and Figure A.4.1 for NGET. Looking forward, the NETS as projected for the 2017/18 peak, including planned main extensions, is shown schematically in Figure A.2.4 for SHETL, Figure A.3.4 for SPT and Figure A.4.4 for NGET.

The above schematic figures are complemented by the schematic power flow diagrams, which cover each winter peak from 2011/12 to 2017/18 inclusive and are presented in Appendix C. The power flow diagrams also highlight planned developments in each year over the period. However, such planned developments are only shown in so far as they affect the figures. In addition, please note that the substation 'running arrangements' reflected in this series of figures are subject to variation (see Table B.2.1a, Table B.2.1b and Table B.2.1c). Table B.7a, Table B.7b and Table B.7c provides a more complete description of developments some of which may not be reflected in the power flow diagrams in Appendix C.

As mentioned previously, the system location of reactive compensation plant as at 2011/12, is shown schematically in Figure A.2.3 for SHETL, Figure A.3.3 for SPT and Figure A.4.3 for NGET. For details of additional reinforcement schemes, not forming part of the 'SYS background', which may be necessary for full compliance with the Transmission Licence security standards, please refer to Table 8.2 and "Indicative Reinforcements for Licence Compliance" in Chapter 8.

## Use of System Tariff Zones

Transmission Network Use of System (TNUoS) charges reflect the cost of installing, operating and maintaining the NETS (see Chapter 10: Market Overview). The basis of TNUoS charging is the Investment Cost Related Pricing (ICRP) methodology introduced in 1993/94.

### Generation TNUoS Tariff Zones

The generation TNUoS tariff zones are defined in such a way as to meet the criteria for defining zones set out in the ICRP methodology. These criteria broadly require that, zones should contain nodes whose marginal costs fall within a specified narrow band and also that nodes within zones should be both geographically and electrically proximate. The generation TNUoS tariff zones are depicted geographically on the "Charging" web pages:

http://www.nationalgrid.com/uk/Electricity/Charges/chargingstatementsapproval/

The geographic picture is complemented by Figure A.2.2 for SHETL, Figure A.3.2 for SPT and Figure A.4.2 for NGET, which present the generation tariff zones against the 2011/12 schematic/electrical backgrounds of each Transmission Area.

### Demand TNUoS Tariff Zones

The demand TNUoS tariff zones correspond to the original Regional Electricity Company (REC) franchise areas in England and Wales, and the geographical areas of the two Scottish electricity companies. These are depicted geographically in Figure A.1.3 against a backdrop of the 2010/11 NETS and also shown in Chapter 9 Table 9.1.

General Interpretation

The geographic diagrams of the Use of System tariff zones provide an approximate indication of the geographical area of the tariff zones. Formally, it is only the transmission substations that are allocated to zones and the figures should not therefore be used to establish the zone of any particular town or village. A demand customer's zone is effectively determined by the Grid Supply Point (GSP) Group to which the customer is deemed to be connected. In the case of a directly-connected power station, the generation tariff zone applicable relates to the geographical location of the transmission substation (connection site) to which the station is connected. In the case of an embedded power station, the generation tariff zone applicable relates to the transmission substation to which that station is deemed connected. This would depend on the operating arrangements of the lower voltage distribution networks under the control of the local distribution Network Operator.

Table E.1.0 lists the 2010/11 maximum demand for each GSP and was introduced in Chapter 2 (Electricity Demand). The final column in the table also gives DCLF (Direct Current Load flow) Node information. This has been included to increase the transparency, particularly with regard to the use of NETS SYS data in the DCLF Transport model, which is used for calculating TNUoS tariffs. Whilst the information provided allows Users to identify the DCLF nodes at which LV demand is mapped, it is important to note that this additional information will not enable Users to replicate the demand data used in the DCLF model exactly. This is due to the treatment of Large embedded generation and station demand, which is not included in these figures.

## SYS Boundaries and SYS Study Zones

### SYS Boundaries

For the purpose of illustrating system performance, the need or otherwise for transmission reinforcement and for describing opportunities, it is useful to divide the system up and consider power transfers across certain critical boundaries. 17 such boundaries are used in this Statement (11 for England & Wales and 6 for Scotland).

The 17 boundaries are shown schematically/electrically in Figure A.2.4 for SHETL, Figure A.3.4 for SPT and Figure A.4.4 for NGET against the backdrop of the 2017/18 system and are listed in Table 6.1. The 17 boundaries are also shown in Figure A.1.5 against a geographic backdrop, which includes the 2010/11 system. These boundaries are used, amongst other things, to provide a clearer picture of the overall capability of the transmission system to transmit power, as described in Chapter 8 (Transmission System Capability).

### SYS Study Zones

The areas of the system described by and/or encompassed by the 17 SYS boundaries are referred to as the SYS Study Zones. There are 17 such SYS Study Zones and these are listed in Table 6.2 and shown in Figure A.1.5 against a geographic backdrop, which also depicts the 2010/11 system.

## Introduction to the National Electricity Transmission System

### System Overview

By the end of 2010/11 the power system in Great Britain will be made up of all Large power stations, the 400kV and 275kV transmission system (and 132kV transmission system in Scotland) and 14 distribution systems.

The location of Large power stations is shown against a backdrop of the 2010/11 transmission system in Figure A.1.1. The 2010/11 NETS is again depicted in Figure A.1.2, with the 400kV system shown in blue, the 275kV system in red and the 132kV system in black.

The NETS includes:

- Overhead Lines
- Underground Cables
- Substations, i.e. transmission system facilities where voltage transformation or switching takes place
- Power transformers and Quadrature Boosters (QBs)
- Grid Supply Points, i.e. points where electrical supplies are provided to Users (Note: 132kV & 66kV are assumed to be Supply Voltages in England & Wales, but not in Scotland.)

The majority of Large power stations are directly connected to the NETS. However, several Large power stations are embedded within the lower voltage distribution networks. Medium and Small power stations are currently all embedded within the distribution networks. Table F.1 in Appendix F lists the capacities of Large power stations by fuel type as at the winter peak of 2010/11. The capacity of Auxiliary Gas Turbines associated with the Large power stations are included in the station capacities.

Currently there are three HVDC External Interconnections linking the NETS with External Systems. These are:

- Connecting converter stations at Sellindge in Kent and Les Mandarins near Calais in France; and
- Connecting converter stations at Auchencrosh in the south of the SPT system and Islandmagee in Northern Ireland; and
- Connecting converter stations at the Isle of Grain in Kent and Maasvlakte in the Netherlands.

Grid Supply transformers connect the NETS with the distribution systems at 'Grid Supply Points', where bulk supplies of electricity are delivered to the Distribution Companies and Non-Embedded Customers. Electricity is then usually supplied to domestic, commercial and industrial customers through the distribution systems.

## Benefits of an Interconnected Power System

Until the 1930's electricity supply in Great Britain was the responsibility of a multiplicity of private and municipally owned utilities, each operating largely in isolation. The Electricity Supply Act (1926) recognised that this was a wasteful duplication of resources. In particular, each authority had to install enough generating plant to cover the breakdown and maintenance of its generation. Once installed, it was necessary to run more plant than the expected demand to allow for possible sudden plant failure.

By interconnecting separate utilities with the high voltage transmission system, it is possible to pool both generation and demand, providing a number of economic and other benefits, including:

- An interconnected transmission system providing a more efficient bulk transfer of power from generation to demand centres.
- The interconnected transmission system, by linking together all participants across the transmission system, makes it is possible to select the cheapest generation available.
- Transmission circuits tend to be far more reliable than individual generating units, and enhanced security of supply is achieved because the transmission system is better able to exploit the diversity between individual generation sources and demand.

- An interconnected transmission system enables surplus generation capacity in one area to be used to cover shortfalls elsewhere on the system, resulting in lower requirements for additional installed generation capacity, to provide sufficient generation security for the whole system.
- Without transmission interconnection, each separate system would need to carry its own frequency response to meet demand variations, but with interconnection the net response requirement only needs to match the highest of the individual system requirements to cover for the largest potential loss of power (generation) rather than the sum of them all.

## Transmission System Capability

Three factors can limit the capability of the transmission system to transfer power across a system boundary

- Thermal capability is the maximum amount of power that can be transferred across a boundary on the system without exceeding the thermal rating of any one of the individual circuits; it depends to a large degree on the way in which the power transfer is shared between them
- Voltage capability, because it is sometimes necessary to restrict power transfers to a level lower than the firm thermal capability to ensure satisfactory voltage levels in the importing area.
- Stability limits, because the power transfer between two areas or between a major generating station and the system can also be limited by considerations of electro-mechanical stability. Two stability regimes are usually defined:
  - Transient, after a severe disturbance, like a network fault.
  - Steady state, which concerns the response to small disturbances such as the normal random load fluctuations.

## Transmission System Losses

The flow of power across the transmission system causes power losses in the various elements of the system. Most of these power losses are a function of the square of the current flowing through the circuit or transformer windings ($I^2R$) and cause unwanted but inevitable heating of transmission lines, cables and transformers. Since such losses are variable they are often referred to as the ‘variable’ power losses.

In addition there are unavoidable ‘fixed’ losses associated with overhead lines and transformers. The term ‘fixed’ losses however, is something of a misnomer. Relative to the ‘variable’ losses they are reasonably static, but they can and do vary. ‘Fixed’ losses on overhead transmission lines take the form of corona losses that are a function of voltage levels and weather conditions. Corona loss is the loss of power to the air and insulation surrounding high-voltage equipment and is generally visible in the dark as a luminous glow surrounding high-voltage conductors.

‘Fixed’ losses in a transformer take the form of iron losses. Iron losses occur in the iron core of the transformer when subjected to an alternating magnetic field and as such vary with the frequency of the power flow producing the alternating magnetic field. Iron losses are further sub divided into hysteresis and eddy current losses. It may be noted that the ‘variable’ transformer heating losses mentioned above are sometimes referred to as ‘copper’ losses in recognition of the material used for transformer windings. Thus transformers have ‘variable’ copper losses and ‘fixed’ iron losses.

An estimated breakdown of transmission power losses at the time of ACS peak demand is given under "Power Losses" in Chapter 7.

## Impact of Generation Site

Users can directly influence the need for major transmission reinforcements by their choice of where to site their new generating stations. For example, if a User sites a new station in an exporting area (i.e. where the amount of generation already exceeds the demand), the maximum power flow will increase and may exceed the firm transmission capacity of the existing system, thus precipitating the need for transmission reinforcement. The converse is, of course, also true.

**Table 6.1 - SYS Boundaries**

| Boundary Number | Boundary Name | Licensee |
|---|---|---|
| B1 | North West Export | SHETL |
| B2 | North-South | SHETL |
| B3 | Sloy Export | SHETL |
| B4 | SHETL-SPT | SHETL/SPT |
| B5 | North-South | SPT |
| B6 | SPT-NGET | SPT/NGET |
| B7 | Upper North-North | NGET |
| B8 | North to Midlands | NGET |
| B9 | Midlands to South | NGET |
| B10 | South Coast | NGET |
| B11 | North East & Yorkshire | NGET |
| B12 | South & South West | NGET |
| B13 | South West | NGET |
| B14 | London | NGET |
| B15 | Thames Estuary | NGET |
| B16 | North East, Trent & Yorkshire | NGET |
| B17 | West Midlands | NGET |

**Table 6.2 - SYS Study Zones**

| Zone Number | Zone Name | Licensee |
|---|---|---|
| Z1 | North West (SHETL) | SHETL |
| Z2 | North (SHETL) | SHETL |
| Z3 | Sloy (SHETL) | SHETL |
| Z4 | South (SHETL) | SHETL |
| Z5 | North (SPT) | SPT |
| Z6 | South (SPT) | SPT |
| Z7 | North & NE England | NGET |
| Z8 | Yorkshire | NGET |
| Z9 | NW England & N Wales | NGET |
| Z10 | Trent | NGET |
| Z11 | Midlands | NGET |
| Z12 | Anglia & Bucks | NGET |
| Z13 | S Wales & Central England | NGET |
| Z14 | London | NGET |
| Z15 | Thames Estuary | NGET |
| Z16 | Central S Coast | NGET |
| Z17 | South West England | NGET |

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# Chapter 7

# Transmission System Performance

## Introduction

Chapter 6 (The Transmission System) described the existing and planned transmission network in terms of its components and structure. This chapter describes the performance of the existing and planned transmission network in terms of:

(i) circuit capacities;

(ii) system power flows;

(iii) grid supply point loadings;

(iv) short circuit currents (single - phase and three - phase); and

(v) system and zonal power losses.

The reader is reminded that, as explained under "Scope" in Chapter 6 on the National Electricity Transmission System (NETS), the 'SYS background' does not necessarily contain all transmission reinforcement schemes which may in the event be required for compliance with the Licence Standard. Chapter 8 (Transmission System Capability) identifies only those reinforcement schemes judged to be necessary to ensure that the transmission system is compliant for the SYS background (see Table 8.2). Additional reinforcements to those in Table 8.2 may in the event also be required.

It is useful at this point to explain, in simple terms, the difference between circuit capacity, loading and boundary capability.

The capacity or rating of a circuit is the maximum loading which may be permitted to flow on that circuit under specific conditions (e.g. ambient/seasonal temperature).

The loading on a circuit is the actual or forecast power flow on that circuit resulting from a given set of conditions (e.g. the demand level and the generating plant used in meeting the demand).

The capability of a boundary is the maximum transfer across the boundary that can be tolerated for the particular background of demand and generation under consideration without breaching security criteria. This means that following 'secured events' such as fault outages of transmission circuits, there are, inter alia, no overloaded items of transmission equipment or unacceptable voltages, and all demand is supplied (save as permitted by specific demand connection criteria). The precise criteria are defined in Licence Standard, which is more fully referred to as the NETS Security and Quality of Supply Standard (NETS SQSS). Compliance with the standard is a condition of the Transmission Licence.

Circuit capacities and loadings are reported in this chapter. Boundary capabilities are reported in Chapter 8 (Transmission System Capability).

Again, as with the previous chapter, many of the figures discussed in this chapter have been included in Appendix A (Figures) and only referenced in the text.

## Circuit Capacities

Table B.2.1a for SHETL, Table B.2.1b for SPT and Table B.2.1c for NGET in Appendix B show, amongst other things, the post fault continuous ratings (in MVA) of all the circuits of the main interconnected transmission system for each season of the year.

## Bases of Power Flow Analyses

### Overview

The power flows presented in this chapter are based on the SYS background and the Planned Transfer Condition.

The SYS background includes:

(a) the NGET ‘Base’ forecast unrestricted ACS Peak Demand on the NETS, which is given in Table 2.1 (row 7);

(b) generation selected from a ranking order based on the existing and proposed new generation for which an appropriate Bilateral Agreement is in place. This generation is presented and discussed in Chapter 3. The techniques for selecting which generation is used to meet the demand are described below; and

(c) the existing transmission network and those planned future transmission developments which have been technically and financially sanctioned by the relevant Transmission Licensee. This is described in Chapter 6.

The demand forecasts used in the power flow analyses include transmission losses (see "ACS Peak Demand" in Chapter 2). For the purpose of illustrating the general power flows throughout the system, these losses are effectively apportioned uniformly across Grid Supply Points through the application of the correction factor described under "Customer Demand Data" in Appendix G. However, where greater accuracy is required for determining the need for local transmission reinforcements, we would more accurately calculate the losses particular to that local zone.

The forecast unrestricted ACS Peak Demand given in Table 2.1 is presented on several bases and it is clearly important that the appropriate basis is selected for use in power flow analyses. The demand stream given in row 3 treats exports via external interconnectors as demand and is also net of station demand. This latter point recognises that the value of power station TEC is used for power system analyses. TEC is net of any auxiliary demand supplied through the station transformers (station demand) and, consequently, the ACS Peak Demand used is also net of station demand.

Please note, however, that for the presentational purposes of the generation ranking order of operation given in Table F.4 in Appendix F, which is presented and discussed later in this chapter, exports across the Moyle interconnector and the East West link have been treated as negative generation. This is compatible with the demand stream given in row 8 of Table 2.1, which also is net of station demand.

For illustrative purposes, a useful reference system condition on which to base studies is the Planned Transfer Condition. The Planned Transfer Condition is defined in the Licence Standard. The following paragraphs outline how the techniques for modelling the Planned Transfer, which are set out in the Licence Standard, have been applied for the purposes of this Statement.

## Modelling of the Planned Transfer Condition

Appendix C of the Licence Standard sets out how the Planned Transfer Condition should be modelled. For this purpose, two techniques are described, namely: the Ranking Order Technique (to be applied when the plant margin exceeds 20%); and the Straight Scaling Technique (to be applied when the plant margin is 20% or less).

The overall process for modelling the planned transfer may be regarded as being made up of the following three parts, the first two of which concern the ranking order technique and the third is obviously concerned with the straight scaling technique. The three parts are:

- Ranking the relevant generating units in order of their relative likelihood of operation at peak;
- Identifying which plant is most likely to be contributing towards meeting the peak demand; and finally
- Applying the straight scaling technique.

### Ranking Plant in Order of Likelihood of Operation at Peak

This part of the process can be further subdivided into:

- treatment of imports and exports across External Interconnections;
- ordering (i.e. placing the generating units into a ranking order of likely operation); and

External Interconnections:

Please note that the External Interconnection between Scotland and Northern Ireland (Moyle Interconnector Ltd) normally operates in export mode and this is reflected in Appendix F Table F.1 showing values of -500MW and -400MW over the study period. For the purposes of the ranking order and evaluating plant margins, imports across external interconnections to mainland Europe are being treated as float, whereas the Moyle Interconnector and the East West link are assumed to be exporting at time of system peak and are shown as negative generation.

Ordering:

A list is compiled of all relevant generating units in the "SYS Background".

The term Transmission Entry Capacity (TEC) is defined and used solely on a power station basis and does not exist on a generating unit basis. In view of this, each generating unit on the list is attributed with the appropriate Registered Capacity (RC) and each power station is attributed with the appropriate TEC, correct as at the "data freeze date".

All generating units, imports and/or exports are then arranged in order of their perceived likelihood of operation at the time of the ACS Peak Demand.

Future plant is likely to achieve a relatively high ranking given that it is likely to be modern and efficient unless the particular plant is designed to operate at base load only. New generation is ranked according to plant type, with offshore wind at the highest rank, followed by wave/tidal, and nuclear above existing plants. Other new plants are onshore wind, biomass plants and new CCGTs, all of which are ranked relatively high, in between tranches of existing hydro generation, wind and nuclear.

For existing generation, this is achieved by inspection of the unit operation experienced over previous winter periods, which are taken as being from the beginning of December to the end of January. In general, if the unit operated at the daily peak, it is attribute a score of "1" whether operated at full or part load. If the unit did not operate, it is attributed a score of "0". Scores for each unit are then aggregated to give the "probability of running" for each unit. A high probability of running would mean that the relevant unit is ranked as having a high likelihood of operation over the coming winter peaks and vice versa for low probability of running.

However, the above represents a general rule and, rather than strict adherence, the rule is applied in a pragmatic way. That is, the results of its application are tempered by judgement based market intelligence. Accordingly, a particular plant with a low score may be moved up the ranking if market intelligence suggests this to be the more likely outcome or vice versa.

## Identification of Contributory and Non - Contributory Plant

This part of the process is concerned with identifying which generating plant is most likely to operate at the time of system peak in a climate where plant margins exceed 20%.

For analysing the performance of the transmission system at the time of winter peak, the load factor over the winter peak period becomes relevant. Experience shows that this is in the region of 90% and 36% for conventional and wind based generation respectively. These figures translate into assumed winter peak availabilities of 100% and 40% for conventional and wind based generation capacity respectively.

Accordingly, in establishing which plant, in the ranking order of Table F.4, is to be regarded in this Statement as contributory and which is to be regarded as non-contributory, the cumulative system generation capacity to be compared with demand in the calculation of plant margin has been taken as 100% of the capacity of each conventional generator and 40% of that of each wind farm.

The lower ranking plant in the ranking order is then progressively removed and treated as non-contributory, until a Plant Margin of just 20% is achieved.

The result of the above ranking order technique, which is used only if the plant margin exceeds 20%, is a list of contributory plant, with unit outputs, which sum to equal 120% of unrestricted ACS Peak Demand excluding station demand). The full capacities of all the contributory generation is used as the initial basis for system studies.

## Application of the Straight Scaling Technique

The straight scaling technique is applied when the plant margin, as defined in the Licence Standard, is equal to or less than (although still positive) 20%. Accordingly, the straight scaling technique is applied following application of the ranking order technique or otherwise straight away when the plant margin is already 20% or less.

The straight scaling technique, which is set out in the Licence Standard, involves the application of scaling factors ‘A’ and ‘S’. The ‘A factors’ relate to the expected availability of each generating plant type at the time of the peak. The ‘S factors’ relate to the ratio between the system demand to be met and the total generation capacity available. Under the technique, the generation output, for study purposes, of all contributory plant is calculated for the ‘planned transfer condition’ by applying 'A' and 'S' scaling factors to their capacities such that the aggregate effective generation of all contributory plant is equal to the forecast peak demand plus transmission losses less imports from external systems.

In recognition of their different characteristics and use, specific values of the ‘A factors’, which relate to expected generating plant availability, defined in the Licence Standard may be used for thermal, hydro and wind generation. The values are chosen in order that the ‘required transfer capability’ , which is simply the sum of the ‘planned transfer’ and the appropriate ‘interconnection allowance’, will represent approximately the same percentile of the actual distribution of power transfers at time of peak demand whether the background includes wind or hydro generation or not. In the power system analyses, which underlie the power flows and capabilities presented in this Statement, the following values were used: 100% for thermal; 100% for hydro; and 72% for wind.

## Overview of Main Power Flows at Peak

Power flows on the SHETL network for each of the seven years from 2011/12 to 2017/18 are illustrated in Appendix C from Figure C.1.1 to Figure C.1.7.

Power flows on the SPT network for each of the seven years from 2011/12 to 2017/18 are illustrated in Appendix C from Figure C.2.1 to Figure C.2.7.

Power flows on the NGET network for each of the seven years from 2011/12 to 2017/18 are illustrated in Appendix C from Figure C.3.1 to Figure C.3.7.

While the complex power flow program used to compute nodal voltage, phase angles and both real and reactive power flows on the system, only the real (MW) power flows have been displayed on the figures, both for ease of presentation and for clarity.

The requirements placed on the transmission system depend on the size and geographical/ system location of generation and demand.

The section on "SYS Boundaries and SYS Study Zones" in Chapter 6 introduced the 17 SYS boundaries, which are used for the purpose of illustrating system performance, illustrate the need or otherwise for transmission system reinforcement and for describing opportunities. These boundaries encompass the 17 SYS Study Zones.

Table 7.1 and Table 7.2 summarise the Planned Transfers, under the SYS background, for each of the 17 SYS Study Zones and across each of the 17 SYS boundaries respectively. Please note that, unlike the generation ranking order of Table F.4 which treats the exports from Scotland to Northern Ireland across the Moyle interconnector and flows across the East West link as negative generation, Table 7.1 and Table 7.2 treat such exports as demand.

There is a slight difference in the values of summated demand, which appear towards the foot of Table 7.1 compared with the demand forecast of row 8 of Table 2.1. This is due to the fact that the system losses included in the forecasts of Table 2.1 reflect estimates made at the time of formulating the forecasts whereas Tables 7.1 and 7.2 (and the power flow analyses presented in this chapter) include calculated system losses derived from the system analyses.
In general terms, the disposition of demand and generation across the NETS is such that much of the generation capacity is located in or towards the northern parts of the system while much of the demand is located in the southern parts of the system. As a consequence, the resultant power broadly flows from the northern parts to the southern parts of the system, particularly at times of the system peak.

The capacity of transmission contracted generation is reported to rise over the period 2010/11 to 2017/18. Amongst other things, "Generation Disposition" in Chapter 3 described the disposition of this future plant. However, these figures do not include the prospective growth of embedded generation; particularly in wind farms. This receives some consideration in Chapter 4 (Embedded and Renewable Generation).

The year on year fluctuations in planned transfer, displayed in Table 7.1 and Table 7.2, are not only a function of changes in demand and installed generation disposition, but also of the changing contributory plant disposition. The section on "Generation Disposition" in Chapter 3 reports that, the forecast disposition of contributory generation and ACS demand across the system is such that, against the SYS background, the high power transfers at times of peak demand from the, northern parts of the system to the southern parts, are expected to persist.

The Thames Estuary boundary transfer appears relatively small, however this is due to much of the local generation supplying the continental export. In the case of continental import, the local generation and import combine to give a significant export out of the Thames estuary.

Figure 7.1 and Figure 7.2 illustrate the broad power flow pattern for 2011/12 and 2017/18 respectively. The capability of the NETS to transport these levels of power transfer across system boundaries is the subject of Chapter 8 (Transmission System Capability). Amongst other things, that chapter explains that in considering boundary transfers and capabilities and the possible need for additional reinforcement, it is important to take account of the requirements of the planning criteria in the Licence Standard.

The outturn power flows at the peak of any year may differ from those given in Table 7.1, Table 7.2, Figure 7.1, Figure 7.2, and the series of figures included in Appendix C for a number of reasons. These include:

- the generation capacity and location may easily differ due to the decommissioning of plant, the addition of new plant, transmission contracted plant not being constructed, the non availability of particular generating units and of course a different ranking order of operation being used;
- the demand level and disposition may differ from that forecast. The level may easily differ by ± 1GW (± 2%) due to the temperature on the day of peak differing from that of Average Cold Spell;
- the unplanned (fault) outage of transmission circuits. A number of supergrid circuits may be out of service at any given time due to fault breakdown. Power flows in the neighbourhood of such circuit outages may be markedly affected; and
- the planned outage of transmission circuits for urgent maintenance, although such outages are more likely to be arranged for the summer months when demand and circuit loadings are lower.

There are clearly a great number of variables, which will influence the outturn power flow. However, whilst the power flows displayed in the various tables and figures of this chapter may not be experienced in practice, they are nevertheless indicative of the flows to be expected under the SYS background. Power flows, transmission capabilities and the possible need for further transmission reinforcement based on our current view of a more likely outturn than the SYS background are discussed in Chapter 8 (Transmission System Capability).

**Figure 7.1 - ACS Power Flow Pattern for 2011/12**

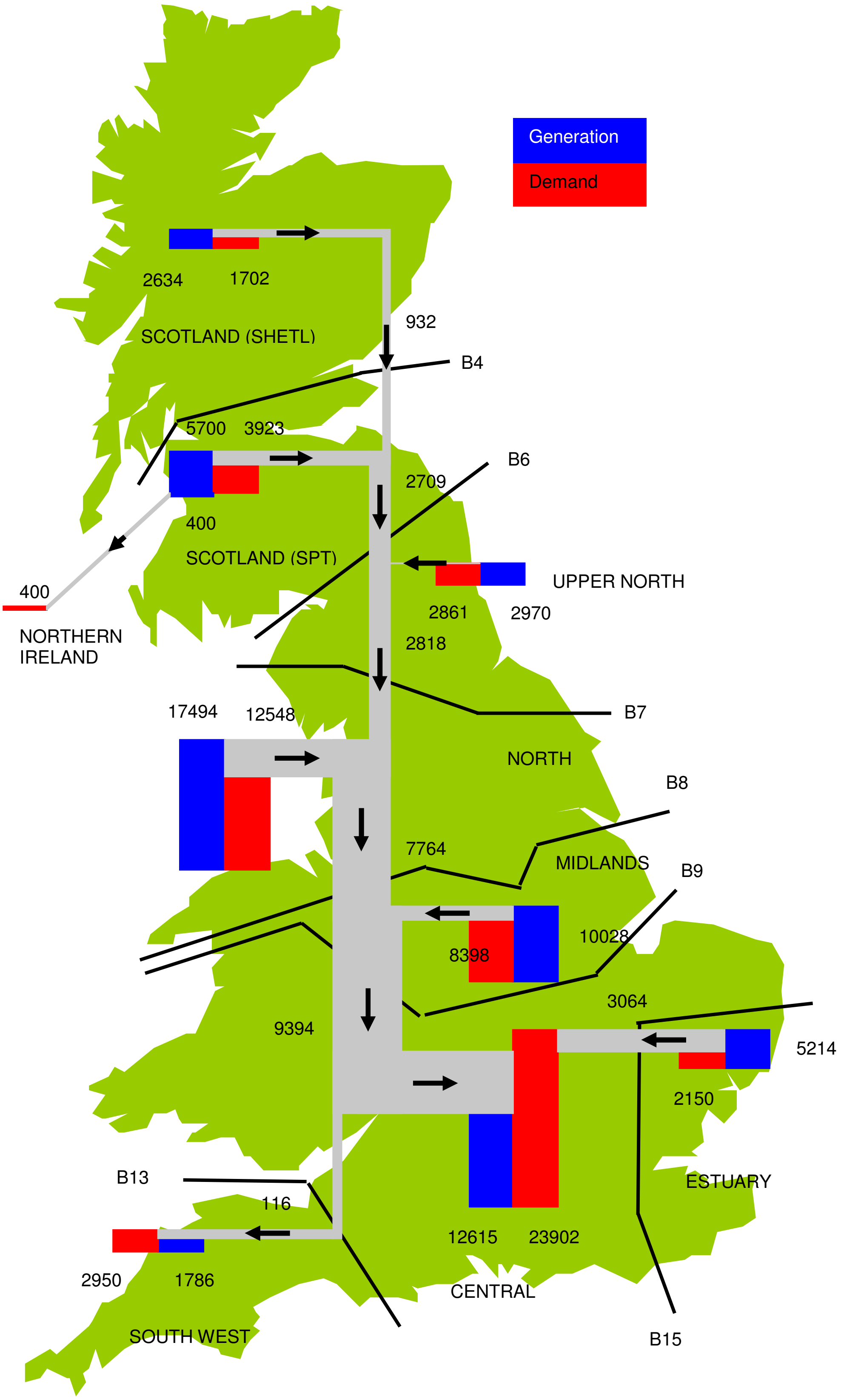
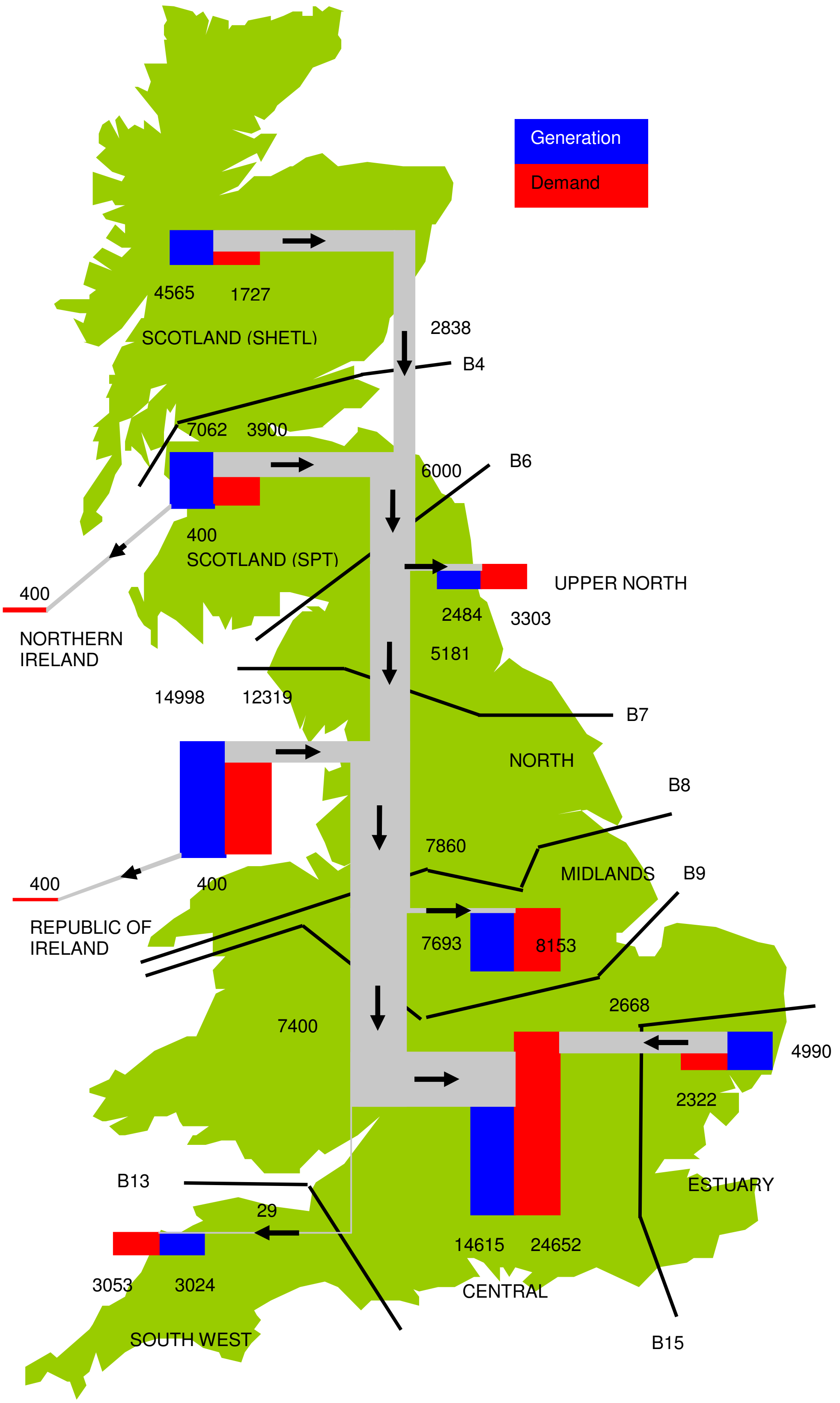


**Figure 7.2 - ACS Power Flow Pattern for 2017/18**



## Off-Peak Power Flows

At off-peak times less generation capacity is needed to meet the reduced demand and only the higher plant in the ranking order is used within the limits of system constraints. Thus the power flows around the system and circuit loadings not only change as a result of the lower demand levels but also because of the changes in the contributory generation disposition.

Transmission circuit thermal ratings reduce outside the winter period and, in addition, the system may become depleted due to transmission circuits and generation units being taken out of service for planned maintenance and other reasons. Maintenance practices on our system generally results in a boundary made up of about eight circuits being continuously depleted by one or other of its circuits between the months of April and October.

The net result is that both circuit loadings and boundary capabilities will vary at off-peak times according to prevailing conditions. They may be either higher or lower relative to the peak period. In view of the many variables associated with the real-time operation of the system, it is not a worthwhile exercise to present a rigorous analysis of possible future off-peak power flows and capabilities in this Statement.

In the real – time phase of operation the system is managed such that it complies with the operational criteria in our Licence Standard. In applying this standard, which is aimed at ensuring the required level of security and quality of supply, prevailing conditions are taken into account. Power transfers around the system are managed such that, amongst other things, circuit loadings would remain within their rating and boundary transfers within their capability and no unacceptable conditions will arise even with specified circuit fault outages on top of any maintenance outages.

## Grid Supply Point Loading

It was explained in "Demand on the Grid Supply Points" in Chapter 2 that Grid Supply Points (GSPs) are the points of connection between the NETS, distribution networks, Large power stations and other Non-Embedded Customers where we deliver electricity.

The loading on a GSP is the demand on the lower voltage (LV) side less the output of any Large power station connected to the LV side or embedded within the distribution system fed from that point. An allowance for the output from embedded Medium and Small power stations is already included in the users' demand estimates as explained under "Customer Demand Data" in Appendix G.

For the SYS background, the GSP net loading is the difference between the flows into and out of that GSP. Such power flows are shown in the series of power flow figures included in Appendix C. This GSP loading is net of any generation at that point. A more direct and detailed indication of GSP loading at maximum demand is given in the series of tables presented in Appendix E.

It is also explained under "Customer Demand Data" in Appendix G that, for infrastructure planning, the demand at the time of the system peak is used. For GSP planning, the demand at the GSP peak is more appropriate. This demand is used, together with appropriate allowances for embedded Large Power Stations, in the application of the criteria for design of demand connections in the Licence Standard.

## Short Circuit Currents

Engineering Recommendation G74 defines a computer based method for the calculation of short circuit currents and has been registered under the Restrictive Trade Practices Act (1976) by the Energy Networks Association (ENA), formerly the Electricity Association, and the associated Statutory Instrument has been signed to this effect.

Three phase to earth and single phase to earth short circuit current analyses have been conducted by each Transmission Licensee (SHETL, SPT and NGET), in respect of their own Transmission Areas, in accordance with ER G74. The series of tables presented in Appendix D, list the results of these analyses. To assist the reader in understanding the results, the next section of this chapter explains some of the salient points relating to the short circuit calculations including assumptions made and terminology used.

Tables B.6a to B.6c list the types of circuit breakers currently found at SHETL, SPT and NGET substations respectively together with their ratings (the NGET ratings are given for 400kV and 275kV voltage levels only). From this list it can be seen that several substations have a mixture of circuit breakers installed and this results in a range of ratings for those substations. Generally the substation infrastructure will have a similar rating to the associated circuit breaker.

The listed ratings should be regarded as indicative and therefore used as a general guide only. If customers require more detailed information relating to specific sites they may contact us as described in "Further Information" in Chapter 1.

Furthermore, although the short circuit duties at a node may at times exceed the rating of the installed switchgear, the switchgear may still not be overstressed for one or more of the following reasons:

- the topology of the substation is such that the switchgear is not subjected to the full fault current from all of the infeeds connected to that node. This is the case for feeder/transformer circuit breakers and mesh circuit breakers under normal operating conditions;
- switchgear is only subjected to excessive fault current when sections of busbar are unselected. This is the case for busbar coupler/section circuit breakers. On these occasions the substation can usually be temporarily re-switched or segregated to reduce the fault level; or
- re-certification of switchgear or modifications to its system is already in hand that will remove the overstressing.

Finally, please also note that, as explained in "Network Parameters" in Chapter 6, substation running arrangements are subject to variation. The running arrangements used for determining the short circuit currents presented in Appendix D may, in some cases, differ slightly from those presented elsewhere in this Statement.

### Engineering Recommendation G74

International Standard IEC909, "Short-Circuit Current Calculation In Three Phase AC Systems" was issued in 1988 and has subsequently been published as British Standard BS7639. When IEC909 was issued the Electricity Supply Industry had no standard method or uniform methodology for fault level calculation. The hand calculation methodology detailed in IEC909 was considered conservative for the UK supply system and it was believed that its application could lead to excessive investment. In consideration of this potential excessive investment, an industry wide working group was established in 1990 to define "good industry practice" for the calculation of short circuit currents.

The resulting document, Engineering Recommendation G74 (ER G74), defines a computer based method for calculation of short circuit currents which is more accurate than the methodology detailed in IEC909 and, as a consequence, potential capital investment is more accurately identified. As previously mentioned, ER G74 has been registered under the Restrictive Trade Practices Act (1976) by the ENA and the associated Statutory Instrument has been signed to this effect.

## Short Circuit Current Calculation

Sophisticated computer programs are used for the purpose of conducting short circuit current analyses. Each analysis is based on an initial condition from an AC load flow and is carried out in accordance with ER G74. The broad calculation methodology is summarised in the following paragraphs.

When assessing the duties associated with busbars, bus section/coupler circuit breakers and elements of mesh infrastructure, it is assumed that all connected circuits contribute to the fault. When assessing the duties associated with individual feeder/transformer circuits it is assumed that the fault occurs on the circuit side of the circuit breaker with the remote ends of the circuit open. These represent the most onerous conditions.

Short-circuit currents are calculated using a full representation of the national electricity transmission network. Directly-connected and Large embedded generating units are also discretely represented with their electrical parameters based on data provided by the owner of the generating unit. Other Network Operators' networks are represented by network equivalents at the interface between the NETS and the Network Operator's network. For example, a DNO network connected to a 132kV busbar supplied by SGTs will usually be represented by a single network equivalent in the positive phase sequence (PPS) and zero phase sequence (ZPS) networks. The use of network equivalents allows short-circuit currents in the NETS to be calculated with acceptable accuracy and provides a good indication of the magnitude of the short-circuit currents at interface substations. Short-circuit currents quoted in Tables D.1.1 to D.3.7 for interface substations are not, however, suitable for specifying short-circuit requirements for new switchgear at the interface substations. These will need to be agreed between the relevant Transmission Licensee and the Network Operator on a site specific basis.

## Short Circuit Current Terminology

The short circuit current is made up of an AC component with a relatively slow decay rate as shown in Figure 7.5 and a DC component with a faster decay rate as shown in Figure 7.6. These combine into the waveform shown in Figure 7.7. The waveform in Figure 7.7 represents worst case asymmetry and as such will be infrequently realised in practice.

**Figure 7.5 - AC Component of Short Circuit Current**

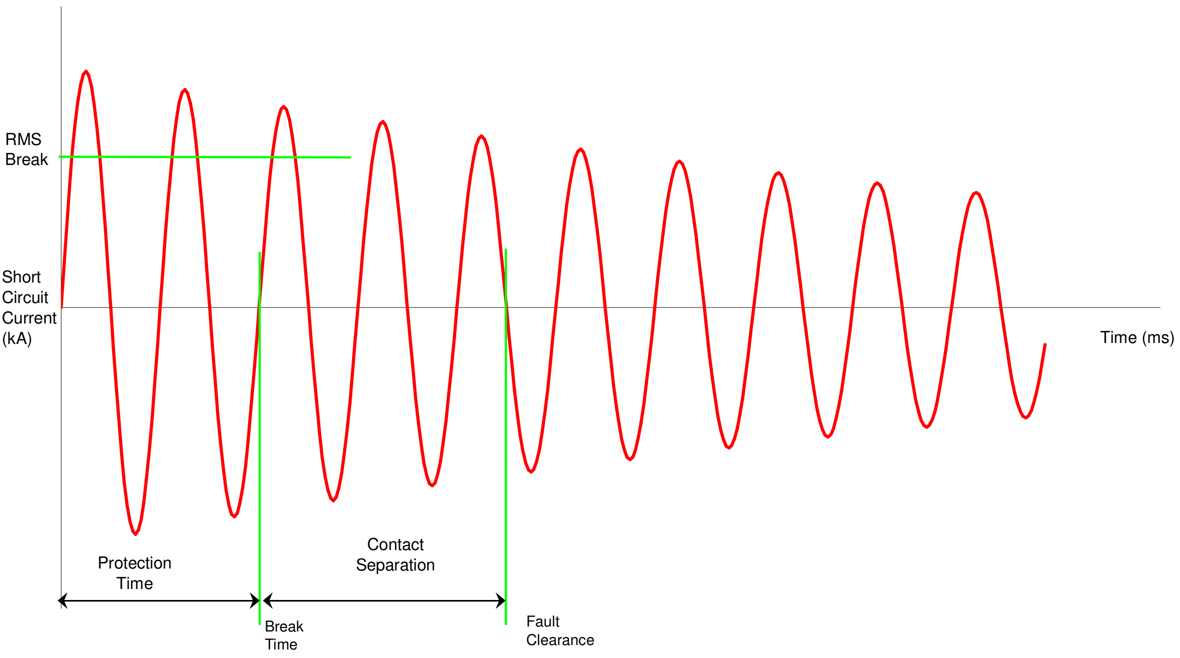
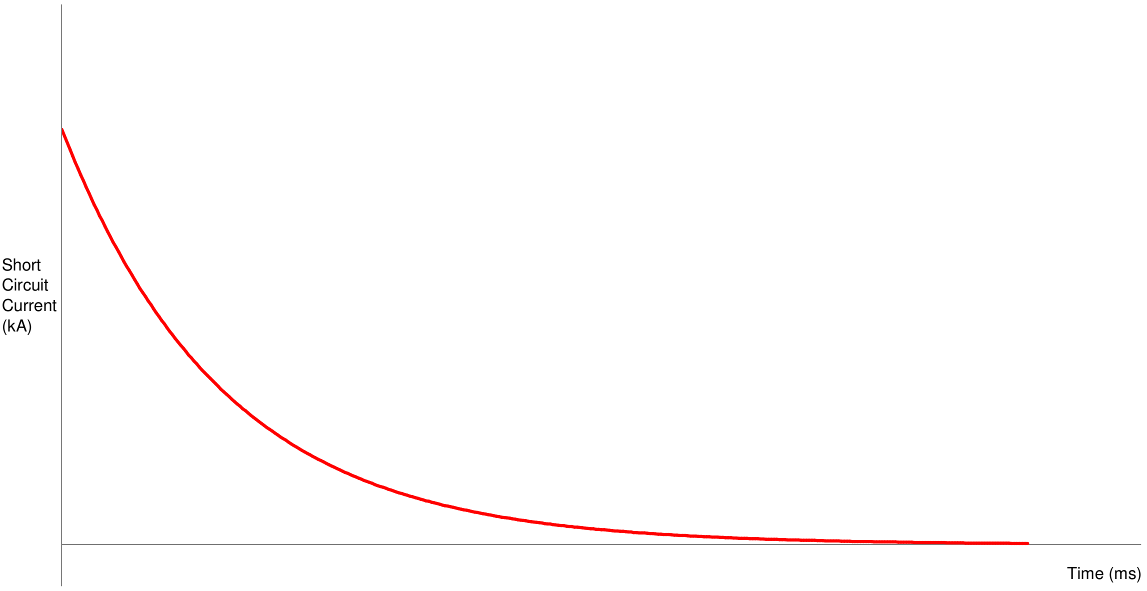


**Figure 7.6 - DC Component of Short Circuit Current**



## X/R Ratio

The DC component decays exponentially according to a time constant which is a function of the X/R ratio. This is the ratio of reactances to resistances in the current paths feeding the fault. High X/R ratios mean that the DC component decays more slowly.

## DC Component

The DC component of the peak make and peak break short-circuit currents are calculated from two equivalent system X/R ratios. An initial X/R ratio is used to calculate the peak make current, and a break X/R ratio is used to calculate the peak break current. Calculation of the initial and break X/R ratios is undertaken in accordance with IEC 60909-0 (2001-07) Method C (also known as the equivalent frequency method). We consider the equivalent frequency method to be the most appropriate general purpose method for calculating DC short-circuit currents in the national electricity transmission network.

The DC component of short-circuit current is calculated on the basis that full asymmetry occurs on the faulted phase for a single phase to earth fault or on one of the phases for a three phase to earth fault.

## Making Duties

The making duty on bus section/bus coupler breakers is that imposed when they are used to energise an unselected section of busbar which is either faulted or earthed for maintenance. Substation infrastructure such as busbars, supporting structures, flexible connections, conductors, current transformers, wall bushings and disconnectors must also be capable of withstanding this duty.

The making duty on individual circuits is that imposed when they are used to energise a circuit which is either faulted or earthed for maintenance. This encompasses the persistent fault condition associated with Delayed Auto-Reclose (DAR) operation.

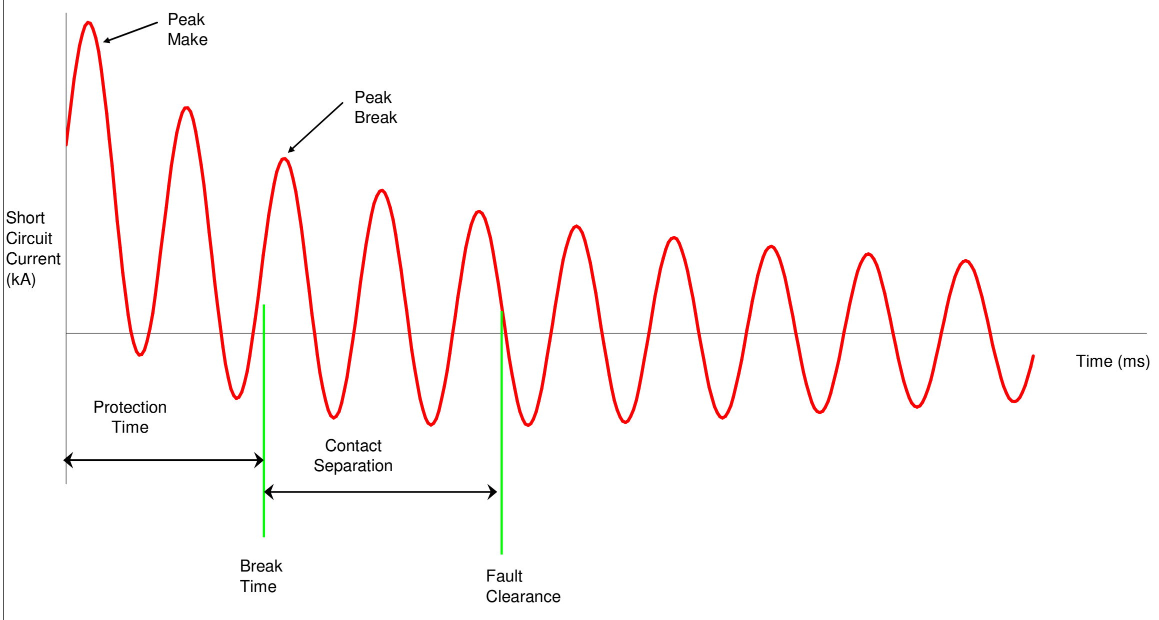
## Breaking Duties

Bus section/coupler breakers are required to break the fault current associated with infeeds from all connected circuits if a fault occurs on an uncommitted section of busbar. Circuit breakers associated with a feeder/transformer or a mesh corner are required to break the fault current on the basis that the circuit breaker is the last circuit breaker to open clearing the fault. Circuit breakers associated with faulted circuits are required to interrupt fault current in order to safeguard system stability, prevent damage to plant and maintain security and quality of supply.

## Initial Peak Current

In Figure 7.7, both the AC and DC components are decaying and the first peak will be the largest and occurs at about 10ms after the fault occurrence. This is the short circuit current that circuit breakers must be able to close onto in the event that they are used to energise a fault, hence this duty is known as the Peak Make. However, this name is slightly misleading because this peak also occurs during spontaneous faults. All equipment in the fault current path will be subjected to the Peak Make duty during faults and should therefore be rated to withstand this current. The Peak Make duty is an instantaneous value.

**Figure 7.7 - Resultant Short Circuit Current**



## RMS Break Current

This is the RMS value of the AC component of the short circuit current at the time the circuit breaker contacts separate (see Figure 7.5), and does not include the effect of the DC component of the short circuit current.

## DC Break Current

This is the value of the DC component of the short-circuit current at the time the circuit breaker contacts separate (see Figure 7.6).

## Peak Break

As both the AC and DC components are decaying, the first peak after contact separation will be the largest during the arcing period. This is the highest instantaneous short circuit current that the circuit breaker has to extinguish, hence this duty is known as the Peak Break. This duty will be considerably higher than the RMS Break because, like the Peak Make duty, it is an instantaneous value (therefore multiplied by the square-root of 2) and also includes the DC component.

## Choice of Break Time

The RMS Break and Peak Break will of course be dependent on the break time. The slower the protection, the later the break time and the more the AC and DC components will have decayed. For the purposes of this Statement a uniform break time of 50ms has been applied at all sites. For the majority of our circuit breakers, this is a fair or pessimistic assumption. In this context it should be noted that the break time of 50ms is the time to the first major peak in the arcing period, rather than the time to arc extinction.

## Data Requirements

### Generator Infeed Data

All generating units of directly connected Large power stations are individually modelled together with the associated generator transformers. Units are represented in terms of their Positive Phase Sequence (PPS) sub transient and transient reactances (submitted under the provision of Grid Code), as well as the DC stator resistances and Negative Phase Sequence (NPS) reactances (neither of these data items are submitted under the Grid Code but the stator resistance value is currently derived or assumed from historic records and the NPS reactance is calculated as the average of the relevant PPS sub transient reactances ($(X_d'' + X_q'')/2$). Fault level studies for planning purposes are carried out under maximum plant conditions (i.e. with all Large power stations included whether contributory or not) to simulate the most onerous possible scenario for a future generation pattern.

### Auxiliary System Infeed Data

The induction motor fault infeed from the station board is modelled at the busbar associated with the station transformer connection. Where sufficient information is not available, it has been assumed that Auxiliary Gas Turbines are connected to the station boards as well as to the main generating units in order to simulate the most onerous condition. Where the X/R Ratio has not been provided, a value of 10 has been assumed.

Where the information is available, the fault infeed from the unit board, due to induction motors and auxiliary gas turbines, is modelled as an adjustment to the main genset substransient reactance. A more detailed model of the power station system may have to be used to assess fault levels when station and unit boards are interconnected.

### GSP Infeed Data

Infeed data for induction motors and synchronous machines at GSPs is submitted by Users under the provision of the Grid Code. Infeeds from induction motors and synchronous machines are modelled as equivalent lumped impedances at the GSP.

Where the information is not available, 1MVA of fault infeed per MVA of substation demand, with an X/R ratio of 2.76 is assumed for all induction motors in the absence of more detailed data. This is in line with the requirements of ER G74.

Where more detailed fault level studies are required at 132kV or below, the associated system should be modelled in detail down to individual Bulk Supply Points (BSP's). Induction motor infeeds should then be modelled at these BSP busbars.

### LV System Modelling

Where interconnections exist between GSPs, these equivalents take the form of PPS impedances between those GSPs. The ZPS networks take the form of minimum ZPS values modelled as shunts at the GSP busbars.

Where interconnections to other GSPs do not exist, the equivalents take the form of equivalent LV susceptances modelled as shunts at the GSP busbar. The ZPS networks are modelled as shunt minimum ZPS values at the GSP busbars.

The values of PPS impedances between GSPs shunt LV susceptances and shunt ZPS minimum impedances are as submitted by the Users under the provision of the Grid Code.

## Power Losses

The following information on system power losses and zonal power losses is indicative only and is included to provide an insight into the level and type of power loss which may be expected around the system at the time of system ACS peak and against the SYS background only. At other times and/or against other backgrounds different levels of power loss may arise.

### System Power Losses

An estimate of the level of system power loss occurring at the time of the ACS Peak Demand for the years 2011/12 to 2017/18 against the SYS background is given in Table 7.3. The losses shown are those incurred on the system between the power station generating unit and the grid supply points and are made up of:

- 'Variable' ($I^2R$) transmission heating losses in the overhead lines, underground cables and other equipment on our transmission system but excluding grid supply transformers at the GSPs;
- 'Fixed' losses made up of corona losses on outdoor transmission equipment and iron losses in transformers;
- 'Variable' ($I^2R$) heating losses (copper losses) in grid supply transformers at the GSPs; and
- 'Variable' ($I^2R$) heating losses (copper losses) in generator transformers.

It is stressed that the losses shown in Table 7.3 are indicative only. They correspond to the time of ACS Peak Demand and have been evaluated against the 'SYS background'. The 'fixed' losses, like the 'variable' losses, can also vary to a certain extent. Accordingly, the exact losses on the day can vary for a number of reasons including:

- the outturn demand and/or in-merit generation pattern being different resulting in changed power flows and consequential changes to the variable losses which are a function of the square of the power flow ($I^2R$); and
- weather conditions being more or less adverse than forecast. For example if 'heavy rain' or 'wet snow' prevails across Great Britain then the so called 'fixed' losses (e.g. corona) could be some 100MW or more higher.

Total system power losses are shown in line 4 of Table 7.3 and these have also been expressed as a percentage (line 6) of the NGET 'Base' forecast ACS peak demand stream given in Table 2.1, less station demand, transmission losses and exports to external systems. The NGET 'Base' demand forecast given in Chapter 2 reflects the demand seen at the metering points at the power stations and accordingly includes both transmission and distribution system losses. As some metering is on the high voltage side of the generator transformers and some on the low voltage side, generator transformer copper losses are only partially taken into account.

Please note that there is a slight difference between the value of forecast ACS peak demand including losses given in Table 7.3 (i.e. row 4 plus row 5) and that given in row 8 of Table 2.1. This is due to the fact that the system losses included in the forecasts of Table 2.1 reflect estimates made at the time of formulating the forecasts whereas Table 7.3 includes calculated system losses derived from system analyses.

The transmission heating losses (line 1) are a function of the power flow pattern around the system. Fixed losses (line 2) are fairly constant over the period. Please note that values provided for fixed losses are estimated based on reasonable growth from last year's values. Grid Supply transformer heating losses (line 3) display a modest increase over the period in step with the growth in forecast ACS Peak Demand (line 5).

Less significant perturbations, perhaps not obvious in the results displayed in the table, are caused by a number of factors including: increased transmission capacity (through reinforcement rather than reprofiling) which reduces transmission heating losses; or embedded large power stations closing, decommissioning or otherwise becoming non-contributory which can increase grid supply transformer heating losses.

The heating losses on generator transformers are also given in line 7 of Table 7.3. Although not included in the total for transmission losses, they are provided for information. It can be ssen from Table 7.3, that Generator Transformers heating losses display a modest increase over the period.

## Zonal Power Losses

Amongst other things, the commissioning and operation of a new power station will have an effect on transmission losses and this will be a function of its system location and the prevailing power flows at the time.

Clearly, if a new power station were to be located in the north, and this were to displace the operation of southern generation, then the north to south power flows would increase, transmission losses would increase and some of the output of the new station would, in effect, be 'lost' to the system. However, if the new power station were to be located in the south and this displaced northern generation, the converse would be true; north to south power flows would decrease, system losses would decrease and the relative net effect would be as if a larger station had been installed.

Table 7.4 demonstrates this by showing the relative effect on transmission losses of locating 100MW of new generating plant in each zone consecutively. For this purpose, the 17 SYS Study Zones introduced in Chapter 6 under "SYS Boundaries and SYS Study Zones" have been used.

Please note, however, that the power flows presented in this Statement are based around a winter peak demand case using an average plant availability which tends to give rise to a general north to south power transfer. At other times of the year, when plant availability and market conditions may modify the generation patterns, zonal losses can change dramatically. For example, if Scotland becomes an importing area during the summer period then siting generation in Scotland is likely to have a beneficial effect on transmission losses.

The analysis was carried out against the SYS background for the 2011/12 winter peak. The installation of new generation was represented by a 100MW reduction in demand spread across the nodes within the relevant zone. The computer program used in the analysis requires that the total generation matches total demand (including losses) and scales generation capacity accordingly. The studies were arranged such that the effective 100MW of new generation was compensated for by a slight reduction in the output of all other generation in the study. That is no plant was displaced from operating. This was repeated for each of the 17 zones and the change in losses, relative to a reference case where no 100MW of new generation was introduced, was calculated.

Table 7.4 is based on the calculations conducted as described above and lists the effectiveness of placing 100MW of additional generation in each zone. The effectiveness has been expressed in percentage terms. For example, an effectiveness of 92% means that for generation increase of 100MW in the zone in question, 92MW would meet demand, while 8MW would be lost to increased losses. The effectiveness expressed in percentage terms provides an indication of the effectiveness of the installation of levels of generation greater than 100MW.

The change in losses is, of course, due to the overall increase or decrease in transfers across the NETS rather than due to a local change in the zone in which the additional generation is located. The absolute values of effectiveness should not be relied upon, given the simplicity of the underlying studies. However, arranging the zones in order of effectiveness, as in Table 7.4, does provide a useful, and reasonably robust, indicator of the relative merits of locating generation in each of the 17 SYS Study Zones across the system on the basis of optimising (i.e. minimising) overall transmission system losses.

Table 7.4 shows that a small increase in generation in the zones north of zone 5 has an effectiveness of less than 90% in meeting demand across the system at the time of winter peak. In contrast to this, a small increase in generation in the South West (zone 17) has an effectiveness of 111% in meeting demand by virtue of reducing transmission power losses. Whilst these results are very broad brush and absolute percentages should not be relied upon, the relative order is considered reasonably robust. Please note that the generation effectiveness in zones 1 to 6 is likely to be understated due to the non-compliance of Boundary 6.

Finally, whilst the results may hold for the addition of 100MW of new generation, it does not follow that they would hold for say 1000MW of new generation. The aim of the above exercise was to provide an insight into the general effect of generation location on the overall NETS transmission losses. The capacity of 100MW of new generation was selected as, in itself, it has a relatively small system impact. The choice of a larger capacity (say 1000MW) would be more likely to incur heavy local loading of transmission circuits creating increased local transmission losses. Depending on the location, this may increase or decrease the overall NETS losses. It is also more likely that a generator of this size would require network reinforcement to ensure compliance with the Licence Standard. Consequently, it would not be appropriate to calculate zonal losses until that reinforcement had been included in the study. The effect of a smaller generator capacity (say 1MW) would not be seen.

**Table 7.1 - SYS Study Zones, Studied Zonal Generation, Demand and Transfer**

| Zone | Zone Name | Quantity (MW) | 2011/12 | 2012/13 | 2013/14 | 2014/15 | 2015/16 | 2016/17 | 2017/18 |
|---|---|---|---|---|---|---|---|---|---|
| Z1 | North West (SHETL) | Effective Generation | 915 | 992 | 1100 | 1675 | 1655 | 1646 | 1638 |
| Z1 | North West (SHETL) | Demand | 511 | 515 | 520 | 509 | 507 | 506 | 506 |
| Z1 | North West (SHETL) | Planned Transfer | 404 | 477 | 580 | 1166 | 1148 | 1140 | 1132 |
| Z2 | North (SHETL) | Effective Generation | 990 | 985 | 1019 | 1286 | 1440 | 1643 | 1775 |
| Z2 | North (SHETL) | Demand | 609 | 611 | 616 | 618 | 610 | 609 | 609 |
| Z2 | North (SHETL) | Planned Transfer | 381 | 374 | 403 | 668 | 830 | 1034 | 1166 |
| Z3 | Sloy | Effective Generation | 273 | 299 | 333 | 325 | 322 | 316 | 177 |
| Z3 | Sloy | Demand | 65 | 66 | 67 | 66 | 68 | 70 | 67 |
| Z3 | Sloy | Planned Transfer | 208 | 233 | 266 | 259 | 254 | 246 | 110 |
| Z4 | South (SHETL) | Effective Generation | 456 | 453 | 449 | 474 | 1071 | 1050 | 975 |
| Z4 | South (SHETL) | Demand | 517 | 520 | 527 | 540 | 541 | 548 | 545 |
| Z4 | South (SHETL) | Planned Transfer | -61 | -67 | -78 | -66 | 530 | 502 | 430 |
| Z5 | North (SPT) | Effective Generation | 2158 | 2164 | 1914 | 1950 | 1915 | 2110 | 2289 |
| Z5 | North (SPT) | Demand | 1193 | 1183 | 1170 | 1170 | 1175 | 1167 | 1169 |
| Z5 | North (SPT) | Planned Transfer | 965 | 981 | 744 | 780 | 740 | 944 | 1120 |
| Z6 | South (SPT) | Effective Generation | 3942 | 4283 | 4417 | 4611 | 4167 | 4114 | 5173 |
| Z6 | South (SPT) | Demand | 3130 | 3133 | 3136 | 3141 | 3135 | 3133 | 3131 |
| Z6 | South (SPT) | Planned Transfer | 812 | 1150 | 1281 | 1470 | 1032 | 981 | 2042 |
| Z7 | North & NE England | Effective Generation | 2970 | 2961 | 2976 | 3181 | 3446 | 2993 | 2484 |
| Z7 | North & NE England | Demand | 2861 | 2964 | 3067 | 3078 | 3091 | 3196 | 3303 |
| Z7 | North & NE England | Planned Transfer | 109 | -3 | -91 | 103 | 355 | -204 | -819 |
| Z8 | Yorkshire | Effective Generation | 10137 | 9732 | 9405 | 9008 | 8768 | 8395 | 7880 |
| Z8 | Yorkshire | Demand | 5291 | 5283 | 5276 | 5200 | 5127 | 5111 | 5094 |
| Z8 | Yorkshire | Planned Transfer | 4846 | 4449 | 4130 | 3808 | 3641 | 3284 | 2786 |
| Z9 | NW England & N Wales | Effective Generation | 7357 | 7480 | 7660 | 7269 | 7004 | 7319 | 7518 |
| Z9 | NW England & N Wales | Demand | 7257 | 7070 | 6882 | 6918 | 6956 | 7288 | 7625 |
| Z9 | NW England & N Wales | Planned Transfer | 100 | 409 | 778 | 351 | 48 | 31 | -107 |
| Z10 | Trent | Effective Generation | 6542 | 6628 | 6765 | 6781 | 6920 | 6182 | 5334 |
| Z10 | Trent | Demand | 957 | 966 | 974 | 986 | 999 | 914 | 828 |
| Z10 | Trent | Planned Transfer | 5585 | 5662 | 5790 | 5795 | 5921 | 5268 | 4506 |
| Z11 | Midlands | Effective Generation | 3486 | 3241 | 3023 | 3092 | 3217 | 2814 | 2359 |

**Table 7.1 - SYS Study Zones, Studied Zonal Generation, Demand and Transfer**

| Zone | Zone Name | Quantity (MW) | 2011/12 | 2012/13 | 2013/14 | 2014/15 | 2015/16 | 2016/17 | 2017/18 |
|---|---|---|---|---|---|---|---|---|---|
| Z11 | Midlands | Demand | 7441 | 7330 | 7217 | 7227 | 7240 | 7282 | 7325 |
| Z11 | Midlands | Planned Transfer | -3955 | -4089 | -4195 | -4135 | -4023 | -4469 | -4966 |
| Z12 | Anglia & Bucks | Effective Generation | 3773 | 3863 | 3983 | 4648 | 5405 | 6106 | 6715 |
| Z12 | Anglia & Bucks | Demand | 4744 | 4820 | 4897 | 4959 | 5023 | 5075 | 5127 |
| Z12 | Anglia & Bucks | Planned Transfer | -970 | -957 | -914 | -311 | 382 | 1031 | 1589 |
| Z13 | S Wales & Central England | Effective Generation | 5833 | 6095 | 6404 | 5516 | 4717 | 4926 | 5057 |
| Z13 | S Wales & Central England | Demand | 5221 | 5216 | 5211 | 5206 | 5203 | 5144 | 5083 |
| Z13 | S Wales & Central England | Planned Transfer | 611 | 879 | 1193 | 310 | -486 | -217 | -25 |
| Z14 | London | Effective Generation | 1750 | 1724 | 1712 | 1861 | 2044 | 2035 | 1992 |
| Z14 | London | Demand | 9504 | 9791 | 10078 | 10234 | 10395 | 10301 | 10205 |
| Z14 | London | Planned Transfer | -7755 | -8067 | -8366 | -8373 | -8351 | -8267 | -8214 |
| Z15 | Thames Estuary | Effective Generation | 5214 | 5285 | 5395 | 5189 | 5073 | 5073 | 4990 |
| Z15 | Thames Estuary | Demand | 2150 | 2155 | 2161 | 2193 | 2226 | 2273 | 2322 |
| Z15 | Thames Estuary | Planned Transfer | 3065 | 3130 | 3235 | 2997 | 2848 | 2800 | 2669 |
| Z16 | Central S Coast | Effective Generation | 1259 | 1072 | 893 | 876 | 873 | 869 | 851 |
| Z16 | Central S Coast | Demand | 4433 | 4443 | 4452 | 4458 | 4466 | 4353 | 4237 |
| Z16 | Central S Coast | Planned Transfer | -3174 | -3371 | -3558 | -3583 | -3593 | -3483 | -3386 |
| Z17 | South West England | Effective Generation | 1786 | 1760 | 1748 | 1713 | 1708 | 2382 | 3024 |
| Z17 | South West England | Demand | 2950 | 2944 | 2937 | 2944 | 2951 | 3002 | 3053 |
| Z17 | South West England | Planned Transfer | -1164 | -1184 | -1190 | -1231 | -1243 | -620 | -29 |
| All | Total | Effective Generation | 58834 | 59011 | 59187 | 59448 | 59708 | 59968 | 60229 |
| All | Total | Demand | 58834 | 59011 | 59187 | 59448 | 59708 | 59968 | 60229 |
| All | Total | Planned Transfer | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

**Table 7.2 - Studied Boundary Generation, Demand and Transfer (MW)**

| Boundary | Boundary Name | Quantity (MW) | 2011/12 | 2012/13 | 2013/14 | 2014/15 | 2015/16 | 2016/17 | 2017/18 |
|---|---|---|---|---|---|---|---|---|---|
| B1 | SHETL North West | Effective Generation | 915 | 992 | 1100 | 1675 | 1655 | 1646 | 1638 |
| B1 | SHETL North West | Demand | 511 | 515 | 520 | 509 | 507 | 506 | 506 |
| B1 | SHETL North West | Planned Transfer | 404 | 477 | 580 | 1166 | 1148 | 1140 | 1132 |
| B2 | SHETL North - South | Effective Generation | 1905 | 1977 | 2119 | 2961 | 3095 | 3289 | 3413 |
| B2 | SHETL North - South | Demand | 1120 | 1126 | 1136 | 1127 | 1117 | 1115 | 1115 |
| B2 | SHETL North - South | Planned Transfer | 785 | 851 | 983 | 1834 | 1978 | 2174 | 2298 |
| B3 | Sloy | Effective Generation | 273 | 299 | 333 | 325 | 322 | 316 | 177 |
| B3 | Sloy | Demand | 65 | 66 | 67 | 66 | 68 | 70 | 67 |
| B3 | Sloy | Planned Transfer | 208 | 233 | 266 | 259 | 254 | 246 | 110 |
| B4 | SHETL - SPT | Effective Generation | 2634 | 2729 | 2901 | 3760 | 4488 | 4655 | 4565 |
| B4 | SHETL - SPT | Demand | 1702 | 1712 | 1730 | 1733 | 1726 | 1733 | 1727 |
| B4 | SHETL - SPT | Planned Transfer | 932 | 1017 | 1171 | 2027 | 2762 | 2922 | 2838 |
| B5 | SPT North - South | Effective Generation | 5033 | 4884 | 4937 | 5929 | 6654 | 7156 | 6971 |
| B5 | SPT North - South | Demand | 2778 | 2803 | 2801 | 2783 | 2797 | 2790 | 2786 |
| B5 | SPT North - South | Planned Transfer | 2134 | 1961 | 1992 | 2989 | 3695 | 4178 | 4025 |
| B6 | SPT - NGET | Effective Generation | 8954 | 9060 | 9143 | 10104 | 10573 | 11424 | 12132 |
| B6 | SPT - NGET | Demand | 5486 | 5490 | 5497 | 5470 | 5504 | 5487 | 5484 |
| B6 | SPT - NGET | Planned Transfer | 2882 | 2984 | 3034 | 3962 | 4764 | 5228 | 5999 |
| B7 | Upper North | Effective Generation | 11698 | 12131 | 12200 | 13494 | 13978 | 13868 | 14507 |
| B7 | Upper North | Demand | 8886 | 8993 | 9102 | 9122 | 9123 | 9225 | 9329 |
| B7 | Upper North | Planned Transfer | 2812 | 3138 | 3098 | 4372 | 4855 | 4642 | 5178 |
| B8 | North - Midlands | Effective Generation | 29192 | 29343 | 29265 | 29772 | 29750 | 29582 | 29906 |
| B8 | North - Midlands | Demand | 21434 | 21346 | 21260 | 21240 | 21206 | 21624 | 22049 |
| B8 | North - Midlands | Planned Transfer | 7758 | 7997 | 8005 | 8531 | 8545 | 7958 | 7857 |
| B9E | Midlands - South (Export) | Effective Generation | 39219 | 39212 | 39052 | 39645 | 39887 | 38577 | 37599 |
| B9E | Midlands - South (Export) | Demand | 29832 | 29642 | 29452 | 29454 | 29444 | 29821 | 30202 |
| B9E | Midlands - South (Export) | Planned Transfer | 9387 | 9570 | 9600 | 10191 | 10443 | 8757 | 7397 |
| B9I | Midlands - South (Import) | Effective Generation | 19615 | 19622 | 19782 | 19189 | 18947 | 20257 | 21235 |
| B9I | Midlands - South (Import) | Demand | 29002 | 29192 | 29382 | 29380 | 29390 | 29013 | 28632 |
| B9I | Midlands - South (Import) | Planned Transfer | -9387 | -9570 | -9600 | -10191 | -10443 | -8757 | -7397 |
| B10 | South Coast | Effective Generation | 3045 | 2831 | 2641 | 2589 | 2582 | 3251 | 3875 |

**Table 7.2 - Studied Boundary Generation, Demand and Transfer (MW)**

| Boundary | Boundary Name | Quantity (MW) | 2011/12 | 2012/13 | 2013/14 | 2014/15 | 2015/16 | 2016/17 | 2017/18 |
|---|---|---|---|---|---|---|---|---|---|
| B10 | South Coast | Demand | 7384 | 7387 | 7389 | 7402 | 7418 | 7355 | 7290 |
| B10 | South Coast | Planned Transfer | -4339 | -4555 | -4748 | -4813 | -4836 | -4104 | -3415 |
| B11 | North East & Yorkshire | Effective Generation | 21835 | 21863 | 21605 | 22503 | 22746 | 22263 | 22387 |
| B11 | North East & Yorkshire | Demand | 14176 | 14276 | 14378 | 14323 | 14249 | 14336 | 14423 |
| B11 | North East & Yorkshire | Planned Transfer | 7658 | 7587 | 7227 | 8180 | 8497 | 7927 | 7964 |
| B12 | South & South West | Effective Generation | 8877 | 8927 | 9045 | 8105 | 7298 | 8177 | 8933 |
| B12 | South & South West | Demand | 12605 | 12603 | 12600 | 12608 | 12620 | 12498 | 12373 |
| B12 | South & South West | Planned Transfer | -3727 | -3676 | -3555 | -4503 | -5322 | -4321 | -3440 |
| B13 | South West | Effective Generation | 1786 | 1760 | 1748 | 1713 | 1708 | 2382 | 3024 |
| B13 | South West | Demand | 2950 | 2944 | 2937 | 2944 | 2951 | 3002 | 3053 |
| B13 | South West | Planned Transfer | -1164 | -1184 | -1190 | -1231 | -1243 | -620 | -29 |
| B14 | London | Effective Generation | 1750 | 1724 | 1712 | 1861 | 2044 | 2035 | 1992 |
| B14 | London | Demand | 9504 | 9791 | 10078 | 10234 | 10395 | 10301 | 10205 |
| B14 | London | Planned Transfer | -7755 | -8067 | -8366 | -8373 | -8351 | -8267 | -8214 |
| B15 | Thames Estuary | Effective Generation | 5214 | 5285 | 5395 | 5189 | 5073 | 5073 | 4990 |
| B15 | Thames Estuary | Demand | 2150 | 2155 | 2161 | 2193 | 2226 | 2273 | 2322 |
| B15 | Thames Estuary | Planned Transfer | 3065 | 3130 | 3235 | 2997 | 2848 | 2800 | 2669 |
| B16 | North East, Trent & Yorkshire | Effective Generation | 28376 | 28491 | 28370 | 29284 | 29666 | 28445 | 27721 |
| B16 | North East, Trent & Yorkshire | Demand | 15133 | 15242 | 15352 | 15309 | 15248 | 15250 | 15252 |
| B16 | North East, Trent & Yorkshire | Planned Transfer | 13243 | 13249 | 13018 | 13975 | 14418 | 13194 | 12469 |
| B17 | West Midlands | Effective Generation | 3486 | 3241 | 3023 | 3092 | 3217 | 2814 | 2359 |
| B17 | West Midlands | Demand | 7441 | 7330 | 7217 | 7227 | 7240 | 7282 | 7325 |
| B17 | West Midlands | Planned Transfer | -3955 | -4089 | -4195 | -4135 | -4023 | -4469 | -4966 |

**Table 7.3 - System Power Losses at Peak**

| **Category** | **2010/11** | **2011/12** | **2012/13** | **2013/14** | **2014/15** | **2015/16** | **2016/17** |
|---|---|---|---|---|---|---|---|
| Transmission Heating Losses excluding GSP Transformers (MW) | 682 | 779 | 904 | 1137 | 1031 | 954 | 829 |
| Fixed Losses (MW) | 276 | 276 | 276 | 282 | 284 | 288 | 288 |
| GSP Transformer Heating Losses (MW) | 152 | 151 | 155 | 161 | 161 | 165 | 166 |
| Total Transmission Losses | 1110 | 1206 | 1336 | 1580 | 1475 | 1407 | 1283 |
| ACS Peak Demand (MW) excluding Losses and Station Demand | 57388 | 57428 | 57628 | 57628 | 59566 | 59313 | 60310 |
| Total Transmission Losses as percentage of Demand | 1.93% | 2.10% | 2.32% | 2.74% | 2.48% | 2.37% | 2.13% |
| Generator Transformer Heating Losses (MW) | 101 | 99 | 108 | 113 | 119 | 121 | 105 |

**Table 7.4 - Effectiveness of Marginal Generation due to Transmission Losses**

| **Zone Number** | **Zone Name** | **Licensee** | **Effectiveness (%)** |
|---|---|---|---|
| Z1 | North West (SHETL) | SHETL | <90 |
| Z2 | North (SHETL) | SHETL | <90 |
| Z3 | South (SHETL) | SHETL | <90 |
| Z4 | Sloy (SHETL) | SHETL | <90 |
| Z5 | North (SPT) | SPT | 92 |
| Z6 | South (SPT) | SPT | 93 |
| Z7 | North & NE England | NGET | 96 |
| Z8 | Yorkshire | NGET | 100 |
| Z9 | NW England & N Wales | NGET | 101 |
| Z10 | Trent | NGET | 102 |
| Z11 | Midlands | NGET | 103 |
| Z12 | Anglia & Bucks | NGET | 109 |
| Z13 | S Wales & Central England | NGET | 108 |
| Z14 | London | NGET | 108 |
| Z15 | Thames Estuary | NGET | 107 |
| Z16 | Central S Coast | NGET | 109 |
| Z17 | South West England | NGET | 111 |

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# Chapter 8

# GB Transmission System Capability

## Introduction

This chapter describes the capability of the GB transmission system to transport power at the time of the system ACS peak. The power system analyses underlying many of the results discussed in this chapter have been conducted on the basis of the deterministic SYS background. The deterministic SYS background comprises the customer based demand forecasts of Chapter 2 (Electricity Demand), the existing and future transmission contracted generation of Chapter 3 (Generation) and the existing and planned transmission network described in Chapter 6 (GB Transmission System).

It should be noted that calculated system capabilities are a function of the generation, demand and transmission background against which they are assessed. Accordingly, the computed capabilities reported in this chapter are those which would arise should the SYS background be realised at the time of system peak. At other times and/or against other backgrounds different transmission capabilities may arise.

As explained in previous chapters, there is uncertainty associated with the demand forecasts and with future generation developments. Thus, it should be recognised that the SYS background does not necessarily represent the most likely outcome, nor should it be regarded as a 'forecast' of the outcome. Uncertainties in demand and generation developments will affect future power transfers, transmission system capabilities, the need or otherwise for transmission system reinforcements and the opportunities for making new or further use of the transmission system.

In view of this, the transfers and capabilities arising from the deterministic SYS background have been presented against the backdrop of a range of probabilistic transfers. These probabilistic transfers reflect, in part, our current views on a range of criteria, which influence the likely future outcome given the various generation and demand uncertainties. This presentation is intended to provide a more meaningful view of future transfers, promote a better appreciation of the future uncertainty we face in planning the system and enable the reader to make more informed judgements on the opportunities for making new or further use of the transmission system.

The chapter also identifies those reinforcements which could be required, in addition to the planned reinforcements presented in Chapter 6 (GB Transmission System), to achieve compliance with the Licence Standard on the basis of the SYS background. These additional reinforcements are subject to variation and should be regarded as indicative only.

In addition, a new section has been incorporated that refers to the work undertaken by the ENSG (Electricity Networks Strategy Group) in analysing what reinforcements would be required to meet the UK environmental targets, but in particular the electricity share of the renewable 2020 target.

The probabilistic range of transfers, which are presented in this chapter, have been derived using a National Grid program called the Generation Uncertainty Model (GUM). To provide a greater understanding of the probabilistic results presented and how they should be interpreted, the chapter includes a high level description of GUM.

## System Boundaries

An understanding of the capability of the GB transmission system to transport power leads to an understanding of the ability of the GB transmission system to accommodate further generation and demand in different zones across the system. When considering the capability of the system, it is useful to consider the limits on the bulk transfer of power across certain system boundaries.

Accordingly, this chapter reports on a number of key boundary capabilities and, for this purpose, the 17 SYS boundaries described in "SYS Boundaries and SYS Study Zones" in Chapter 6 and shown graphically in Figure A.1.5. These boundaries are also shown in Figure A.2.3 for SHETL, Figure A.3.3 for SPT and Figure A.4.3 for NGET. These 17 boundaries have historically reflected some of the main weaknesses on the interconnected system. Such weaknesses can lead to the need to restrict power flows across the system; possibly through the potentially uneconomic constrained operation of generating plant. Alternatively, weaknesses in transmission may be removed by transmission reinforcement. Although the most critical boundaries may not be precisely the same as those studied, the 17 boundaries which have been used remain relevant for illustrating system trends and limitations.

Consideration of the range of possible future transfers across each of the 17 boundaries enables us to describe the type of reinforcement schemes, which may be required in order to ensure continued compliance with the Licence Standard.

## Boundary Capabilities and Required Capabilities

Two types of system limitation, relating to the transfer of power across a boundary, have been considered. The first relates to thermal capability and the second to voltage capability. The boundary capabilities have been evaluated for the time of the system winter peak demand in 2011/12, 2013/14, 2015/16 and 2017/18 and are on the basis of the SYS background. These capabilities will, of course, potentially change at off-peak times but, as explained in "Off-Peak Power Flows" in Chapter 7, in the ‘real time’ operational time-phase, the system is managed such that it complies at all times with operational criteria of the Licence Standard.

As mentioned above, the Licence Standard defines certain unacceptable conditions, which shall not occur as a result of specific secured events. The unacceptable conditions referred to include:

- loss of supply capacity (except as permitted by specific demand connection criteria);
- unacceptable overloading of any primary transmission equipment;
- unacceptable voltage conditions or insufficient voltage performance margins; and
- system instability.

For example, in the case of planning the development of the Main Interconnected Transmission System, a boundary in which a single circuit is out of service due to a fault, must be capable of transferring the Planned Transfer (as defined in the Licence Standard) plus an allowance (also specified in the Licence Standard) to take account of non-average conditions (e.g. relating to power station availability, weather and demand) without any of the above unacceptable conditions arising. The allowance, referred to, is calculated by an empirical method described in the Licence Standard and is called the "Interconnection Allowance".

Similarly, the Licence Standard also requires that a boundary, in which two circuits are out of service (i.e. N-2 or N-D as appropriate), must be able to transfer the Planned Transfer plus half the calculated Interconnection Allowance without any unacceptable conditions arising.

The boundary thermal capability is the power flow that can be transferred across the boundary without causing any unacceptable conditions following the outage of two circuits (i.e. N-2 or N-D) as defined in the Licence Standard. The overall boundary capability is the lower of the thermal and voltage capabilities. Known stability limitations are also reported in the Boundary Commentary section which is presented later in this chapter. The required capability is simply the Planned Transfer plus half the Interconnection Allowance.

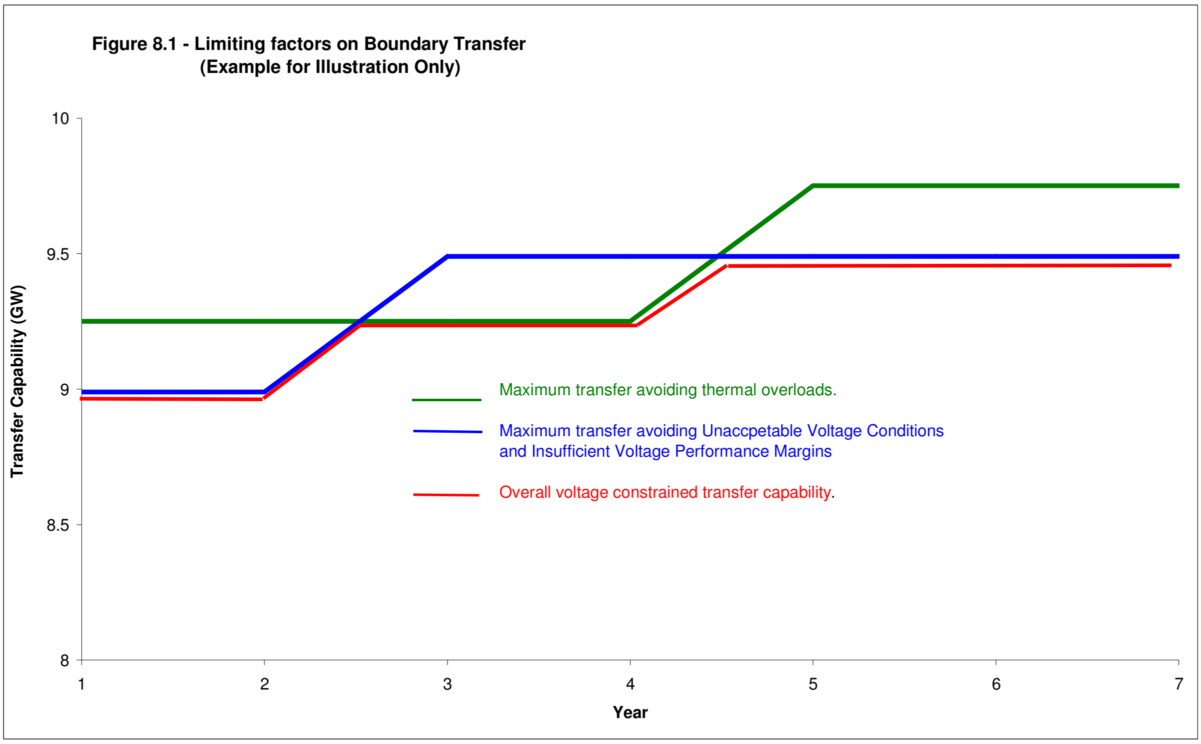
Please note, however, that application of the Interconnection Allowance (or part thereof) relates only to those boundaries, which divide the system into two contiguous parts, the smaller of which contains more than 1500MW of demand. In the case of the boundaries, which have been defined for the NGET and SPT systems, this is always the case. However, for a number of boundaries in the SHETL system (namely: boundaries B1, B2 and B3), this is not the case and, in these instances, the required capability quoted is simply the Planned Transfer.

The boundary capabilities reported in this chapter give an indication of the maximum boundary transfer that can be supported without contravening any of the above unacceptable conditions following a secured event. A boundary capability that is less than the required capability indicates a need for transmission reinforcement. A boundary capability that is greater than the required capability shows only that the security criteria are satisfied for the particular transfer conditions and background studied.

While not identical (particularly for voltage control and fault levels), in terms of flows on the system, the withdrawal of generation will have a broadly similar effect to the addition of demand and vice versa. The amount by which a boundary capability exceeds the required capability gives an indication of the approximate extent of 'spare' transfer capacity on that boundary. However, this does not necessarily mean that an equivalent volume of additional generation on the exporting side of the boundary (or an equivalent volume of additional demand on the importing side) can be readily accommodated. This can be due to a number of reasons including:

- there may be a need for 'local' reinforcements not directly related to the boundary;
- as additional generation or demand is connected to the system, the background against which both the required capability and boundary capability are assessed changes; and
- the security criteria must be satisfied for all system boundaries indicated by the Licence Standard, i.e. while a particular connection may satisfy conditions for one boundary, it may fail to do so for another.

The nature of a boundary capability can be illustrated by separately establishing the voltage capability and the thermal capability. The way in which voltage or thermal considerations might be the limiting factor in different years is illustrated in Figure 8.1. The voltage capability is shown as a blue line (this may arise either because of unacceptable voltage conditions or insufficient voltage performance margin, whichever limit arises first), and the thermal capability as a green line. The net boundary capability is shown by the red line.



## Deterministic Transfers

The power flows presented in this chapter are based on the deterministic SYS background. There is inherent uncertainty associated with the assumptions underlying any deterministic background. For example demand and generation may, in the event, deviate from any of the deterministic assumptions underlying the background. Uncertainty must also therefore be attributed to both the resultant deterministic power flows and any consequent perceived need for transmission reinforcement. The SYS background is no exception and, while it has been selected as the most reasonable deterministic background for the purposes of Chapter 7, it should not be assumed that it represents the most likely future outcome.

For ease of explanation, the boundary commentaries presented later in this chapter include a series of figures from Figure 8.B1 to Figure 8.B17. Amongst other things, each of these figures shows the planned transfer, the required capability and the actual calculated capability for the relevant boundary. These values are all calculated on the basis of the deterministic SYS background and, in view of this, they are often referred to as the “SYS Transfer”, the “SYS Required Transfer" and the "SYS Capability" respectively.

As specified by the Licence Standard, for a particular generation and demand background, the required capability is simply the planned transfer enhanced by the appropriate Interconnection Allowance for a boundary. Where the required capability is less than the actual boundary capability, there is no need for further reinforcement in respect of that particular boundary. An example of this is given in Figure 8.2, which illustrates that the required capability exceeds the actual capability from around year 3 onwards indicating a potential need for further reinforcement on the basis of the SYS background.

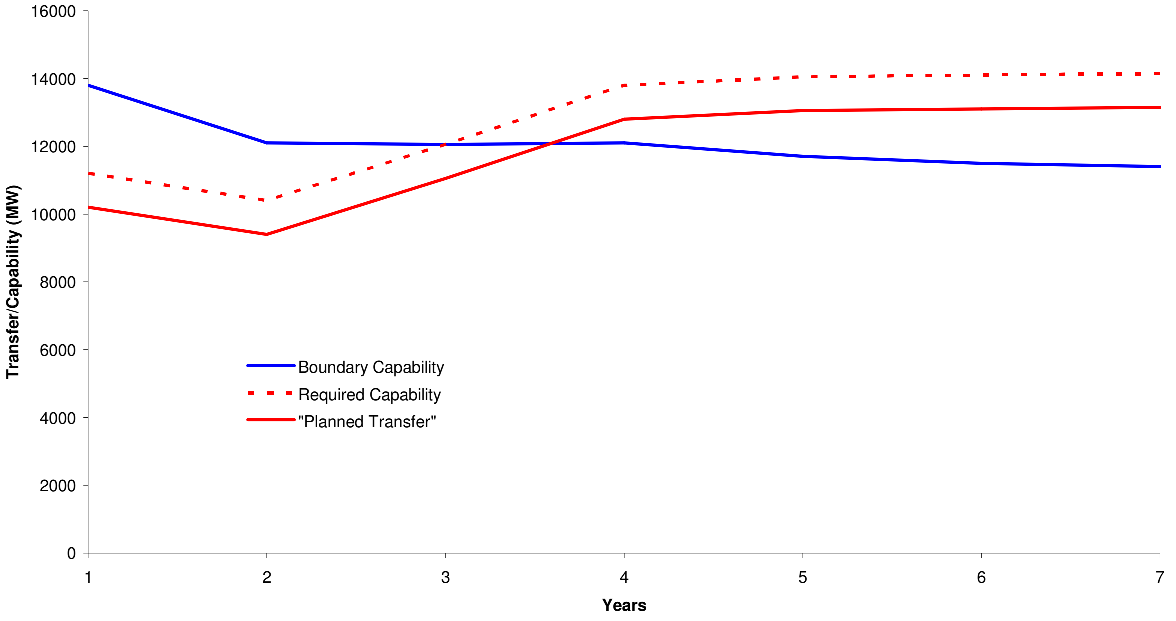


**Figure 8.2 - Constraints on Boundary Transfer (Example for Illustration Only)**

The boundary capabilities quoted in this chapter relate to planning the medium to long term future development of the system and are not necessarily appropriate to the real time operation of the system. Operational boundary capabilities are a function of the real time transfer, which can be achieved within operational timescales for a given pattern of system outages, demand and generation availability. In operational timescales each of these factors is known with a relatively high degree of certainty, unlike in the planning time phase where there is a need to consider a great many more uncertainties.

The boundary capabilities reported in this chapter do, nevertheless, provide a good broad appreciation of the overall capability of the GB transmission system to transport power. An apparent surplus of boundary capability over the required capability generally shows the exporting side to have at least some potential for additional generation and the importing side to have some potential for additional demand. A deficit of boundary capability against the required capability provides an indication that, were the SYS background to be realised, either investment to reinforce the system and thereby enhance the capability may be appropriate, or alternatively constrained operation of generation is required in order to limit the boundary transfers to within acceptable levels.

The possible need, or otherwise, for transmission reinforcement is discussed under "Boundary Commentary" later in this chapter.

Finally, for the purpose of providing the power flow information reported in this chapter and in Chapter 7, it is first necessary to be able to obtain a converged AC power flow study at least for the intact system and for the Planned Transfer Condition. Under the SYS background there are a number of boundaries for which the boundary capability is substantially lower than the planned transfer in a number of years. In those cases where such deficits are large, convergence of the AC power flow program may be inhibited. In such cases it may be necessary to add a minimum number of indicative system reinforcements solely for the purpose of obtaining convergence of the Planned Transfer Condition. These ‘indicative convergence works’ (e.g. reactive compensation to achieve acceptable voltage conditions) are not necessarily sufficient for compliance with the Licence Standard, and the boundary capabilities have been quoted with them included.

# Probabilistic Transfers

## The Generation Uncertainty Model (GUM)

Deterministically derived boundary transfers are useful but have limited value since they do not consider the uncertainties associated with projected future demand and generation developments. It is important to take account of the potential impact of these uncertainties on power transfers across key transmission boundaries when considering the merits of transmission reinforcements.

For a given set of assumptions relating to demand and generation, the Generation Uncertainty Model (GUM) provides a probabilistic representation of the electricity market. GUM employs a Monte Carlo model in which openings of new generating stations and closures of existing stations are randomly selected (subject to the influence of the input assumptions) against a background of uncertain demand growth. The resultant probabilistic transfers reflect our current view of how the planned transfers across each of the 17 boundaries at the time of system peak are likely to develop over the next seven years.

Factors which have been taken into account in compiling the input data for GUM include but are not limited to the possible:

- variations in demand growth;
- variations in Plant Margin;
- generation closure and placing in reserve (station CEC=TEC=0 or TEC < station CEC). Within GUM these are referred to as "closures";
- return to service of plant currently held in reserve. Within GUM these are referred to as "re-openings";
- new power stations, which have received approval, proceeding to completion. Within GUM these are referred to as "openings";
- additional proposed new power stations receiving approval and proceeding to completion. Within GUM these are again referred to as "openings";
- termination or modification to current generation connection agreements; and
- variations (including exports) in transfers over the External Interconnections with External Utilities.

It is not possible to provide the detail of the input assumptions we have made since this would breach our obligations on commercial confidentiality. The probabilistic transfer information is provided without prejudice and reflects our current view of future uncertainty. Clearly, this view may change as developments in the electricity market in Great Britain unfold, but nevertheless it should prove a useful complement to the simple deterministic SYS background approach.

The purpose of presenting this additional information is to:

- provide a more meaningful view of the possible range of future boundary transfers given an unconstrained transmission system;
- place the deterministic SYS background based boundary transfers and capabilities in the context of what we currently believe to be the likely range of future transfers;
- promote an appreciation of the future uncertainty in relation to planning the development of the transmission system; and
- enable the reader to make more informed judgements on the opportunities for making new or further use of the transmission system without incurring the need for major inter-zonal transmission reinforcement.

## Overview of GUM Analyses

For each year within the period of study, GUM models the system at the time of peak demand on the GB transmission system. This is consistent with the deterministic boundary transfer and capability analyses. The program does not simulate the system year-round; its purpose is to model the generating capacity that might be available to meet the likely peak demand.

The input information provided to GUM reflects our current views on the various generation and demand uncertainties. Our market intelligence in this area is largely based on material in the public domain. In compiling the input assumptions we have tried to avoid introducing any bias. Clearly, our views may change as developments in the electricity market in Great Britain unfold. Nevertheless, the results obtained from GUM analyses should prove more stable than a simple deterministic approach.

There are currently more generation projects proposed than are essential to meet forecast demand. From experience, we consider it unlikely that all of these projects will be completed as planned. Some may slip from their planned commissioning dates while others will be terminated. At the same time, some existing plant can be expected to close down due to age alone while some may close due to competitive pressure from more efficient new market entrants or due to increasing pressure due to environmental constraints. We are not attempting to predict specific generation openings and closures, yet we need to know their probable effects on the power flows on the transmission system. GUM can be used to provide us with this information.

To estimate the probable ranges of power transfer, GUM randomly selects generator openings and closures, balancing the probable generation capacity against probable peak demand and probable plant margin. The random selections are weighted according to a range of input information and criteria, which influence the likelihood of the station opening or closing. Weightings for station openings consider, but are not limited to, the stage of development activity for the stations (which includes issues such as consents status), environmental impact, thermal efficiency, fuel type, and availability of fuel, water, and transmission. Weightings for station closure include, but are not limited to, age, thermal efficiency, fuel delivery, fuel type, availability and environmental impact.

By making random selections of demand and generation according to the given probability functions and weightings, GUM generates up to 10,000 demand/generation permutations or backgrounds. Each single background represents a time sequence of demand growth, plant openings and plant closures running from 2010/11 to 2017/18.

However, a typical GUM analysis does not model every possible future; rather it represents a possible range of variations around the overall demand growth forecast and range of possibilities within the current list of generation projects. Changing the underlying assumptions (for example, a major change in relative fuel costs, or changes in the location and timing of new generation projects) would have some effect on the power transfer ranges.

## GUM Boundaries and Zones

For each of the 10,000 backgrounds, GUM calculates the net generation capacity surplus or deficit for each specified GUM zone or group of GUM zones. This surplus or deficit then permits the calculation of the range of possible transfers out of or into each specified zone or group of zones for each sampled generation background. By calculating the net transfer for each of the 10,000 backgrounds within each year of the study period, it is possible to show probabilistic ranges of net transfers into or out of each specified zone, or group of zones, year by year. The program only considers net transfers. Since GUM does not incorporate a network model, it does not in itself calculate power flows across individual circuits.

As with the deterministic analyses, it is useful to consider probabilistic power transfers across certain critical boundaries. The GUM analyses presented in this chapter are based around the SYS Boundaries and SYS Study Zones introduced in Chapter "6_8","SYS Boundaries and SYS Study Zones". Since GUM calculates net imports and exports for zones and groups of zones, all

GUM boundaries are defined in terms of the complete boundary surrounding specified single zones or groups of zones.

Accordingly, each boundary under study is defined in terms of the zones on one side of that boundary. Table 8.1 lists the defining zones on one side of each of the main SYS boundaries. For boundaries B10 & B12 the defining zones are south of the boundary. For boundaries B1, B3, B13, B14, B15 & B17 the defining zones are those encompassed by the boundary. For all other boundaries, the defining zones are north of the boundary.

## Presentation of Results

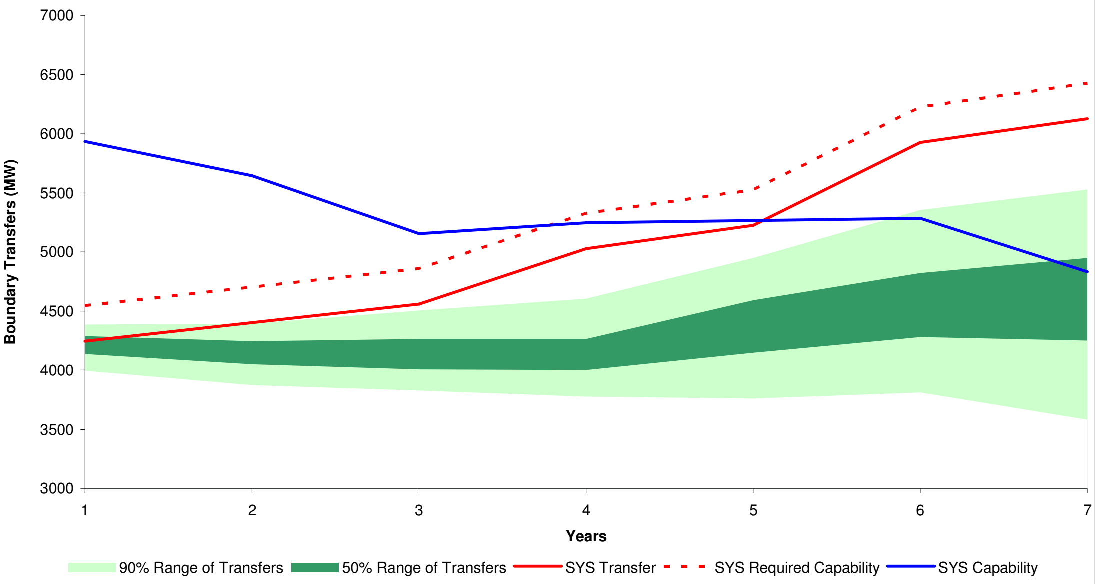
### The Fan Diagram

A key output of GUM is the probabilistic range of transfers over a given period for each defined boundary. For each year of the study, GUM calculates probabilistic distributions of power transfers for each boundary under peak load conditions. These distributions could be plotted as separate charts for each boundary for each year. However, a concise and convenient method of presenting the results is to plot percentiles of the distributions to show how the range of probable transfers varies year by year for each boundary.

The resultant plots typically display a narrower range of transfers in the earlier years than in the later years, since there is greater certainty associated with the earlier years. The characteristic shape is therefore generally in the form of a fan and, in view of this, the diagrams are often referred to as "fan diagrams".

An illustrative example is given in Figure 8.3. The green shaded area shows the range of probabilistically derived transfers arising out of the GUM analyses. The deterministic SYS planned transfer, the deterministic SYS required capability and the deterministic SYS capability have been superimposed on top of the fan of probabilistic transfers for comparison.

**Figure 8.3 Boundary Transfers and Capability (Illustrative Example)**



In Figure 8.3, the darker shaded central band extends (on the vertical axis) from the 25th to the 75th percentiles of the range of probabilistically derived transfers, and thus includes 50% of all such transfers across the boundary at the time of system peak. The wider area, encompassed by the lighter shaded bands runs from the 5th to the 95th percentile and thus, together with the dark band, includes 90% of transfers. The remaining 10% lie outside the shaded range.

The fan of probabilistically derived transfers can be compared with the deterministic planned transfer for the single deterministic SYS background.

It does not follow that the probabilistic transfer arising from a background considered to be likely will necessarily be captured within the envelope range shown on the diagram. Nor does it follow that all the most commonly occurring transfers have highly probable backgrounds. In GUM, all backgrounds are equally probable. Nevertheless, the range of transfers displayed in the fan diagram does provide a very useful indicator of the most probable future planned transfer across the boundary given the possible combined effects of the various sources of generation and demand uncertainty. GUM can then be interrogated to reveal the details of any background underlying any transfer (point on the fan diagram) for further detailed analysis.

GUM takes as its starting point the existing pattern of zonal demand and generation at the time of the 2010/11 winter peak. Conditions in the following year should be fairly predictable; nevertheless there are uncertainties that are represented in GUM's probabilistic analysis. For example, a power station may be scheduled to commission by the 2011/12 winter peak, but construction may slip such that it is unable to contribute to the system peak demand until 2012/13. Variations and uncertainties relating to transfers across the external interconnections with external systems are included in the probabilistic analyses. This can account for a significant part of the range of uncertainty displayed in the fan diagrams.

## Interpretation

In the arbitrary example given in Figure 8.3 the deterministic SYS required capability exceeds the SYS boundary capability by year four, which implies that there are no opportunities for additional generation on the exporting side of the boundary from that year without reinforcement. The probabilistic transfers, indicated by the fan, imply that the need for reinforcement is unlikely until the later years, if at all. Any reinforcement can therefore be delayed until the later years when the need becomes more certain.

However, as noted previously, these kinds of conclusions must be qualified by recognition that the boundary capability is dependent on the exact disposition of generation and demand in the background against which it is assessed. For example, interactions of generation openings and closures and changes in demand all on the same side of a boundary, or on opposite sides, can lead to little or no change in the ‘Planned’ boundary transfer but, nevertheless could give rise to a need for significant reinforcements in order to maintain system security. Nor would two backgrounds, which, result in similar transfers across a particular boundary necessarily, give rise to the need for the same transmission reinforcement across that boundary since the boundary capability is a function of how the boundary transfer is shared between the boundary circuits, which is in turn a function of the particular background under consideration.

An important message is that the requirement for transmission system reinforcement does not simply correspond to a given boundary transfer. The need for system reinforcement can still arise at transfers below the ‘SYS capability’ levels displayed in the series of figures (i.e. Figure 8.B1 to Figure 8.B17) included in the next section of this chapter.

# Boundary Commentary

## Background

For a better understanding of the results presented in this section the reader is advised to first read the previous sections of this chapter. In particular the format of the figures used is as presented in Figure 8.3. The SYS background transfers presented are consistent with the power flow studies discussed in Chapter 7 (GB Transmission System Performance) which were also based on the generation ranking order of operation given in Table 7.1.

Please note that the transfers displayed in the series of figures which follow (i.e. Figure 8.B1 to Figure 8.B17) relate to the time of system peak demand. The capabilities shown are the transfer levels beyond which either thermal or voltage limitations become apparent on the Main Interconnected Transmission System. These SYS capabilities have been evaluated for the spot years 2011/12, 2013/14, 2015/16 and 2017/18 only. It is stressed that the SYS capabilities are appropriate for the SYS background and do not necessarily correspond to any of the many backgrounds appropriate to the probabilistic transfer range. The SYS capability does nevertheless provide a useful reference and initial indicator of overall capability.

The probabilistic transfer ranges shown are considered to be a more realistic representation of the likely transfer range than the single deterministic SYS background transfers and naturally receive attention in the commentary that follows. However, apart from a high level comparison, it is not possible to provide a detailed commentary on the probabilistic ranges since to do so could breach our obligations to our customers on commercial confidentiality. For the single deterministic SYS background transfers this is not a concern and accordingly greater detail has been included in the commentary.

In considering each of the following boundary commentaries it is useful to cross reference a number of tables presented elsewhere which are relevant to the SYS background transfers. Table 7.3 presents the SYS background studied generation, demand and transfer for each boundary. For ease of reference, each of the following boundary commentaries includes the relevant extract of Table 7.3. Please refer to the tables shown in Appendix F for details of generation capacity changes under the SYS background over the period from 2011/12 to 2017/18 inclusive and also chapter 3 Table 3.5 and Table 3.6 for generation disconnections and generating units declared unavailable.

## Overview

As explained in Chapter 3, access to the GB transmission system is provided through arrangements with National Grid, acting as GBSO, under the Connection and Use of System Code (CUSC). The CUSC sets out the contractual framework for connection to, and use of, the GB transmission system. The CUSC has applied across the whole of Great Britain since BETTA "go-live" (1 April 2005).

The removal, under BETTA, of the previous commercial arrangements for the use of the circuits connecting Scotland and England has given wider rights of GB system access than previously was the case. However, the volume of requirements for connection to and use the GB transmission system has meant that:

- there is a potential shortage of transmission system capacity, and
- transmission reinforcement is required to maintain compliance with the Licence Standard.

The results reported in this chapter demonstrate this potential transmission capacity shortage under the SYS background. As a consequence, there is a potential need for significant reinforcement of the system in addition to those identified in Table 6.2.

After the introduction of BETTA an extensive reinforcement programme is required to accommodate the required capabilities determined by the SYS background for boundaries in the border area. The projected commissioning of more than 2GW of new transmission contracted generation in Scotland, substantially made up of wind farms, is dependent on the completion of the schemes which make up the planned Beauly/Denny transmission reinforcement and strategic reinforcements as planned through ENSG. The Beauly/Denny reinforcements are included as part of the SYS background for commissioning by 2013/14. In addition the first stages of the strategic ENSG reinforcements are also included.

Examination of the boundary transfer levels over the seven year period for the SYS background indicates that:

- The major Northern boundaries B1 (SHETL North West Export), B2 (North to South SHETL), B4 (SHETL to SPT), B5 (North to South SPT), B6 (SPT – NGET), B7 (Upper North) all show steady growth in power transfers over the SYS period due primarily to contracted renewable energy developments throughout Scotland. A sudden drop in power flow to the South happens in 2016 when some LCPD closures are expected. Further increase in new renewable generation in the North will push the boundary transfers higher.

- Boundaries B8 (North to Midlands) and B9 (Midlands to South), B11 (Northeast & Yorkshire), B12 (South & Southwest import), B16 (Northeast, Trent & Yorkshire) and B17 (West Midlands import) show mostly constant power flows with some fluctuation due to new generation connections and older generation closures.

- B14 (Central London import) shows a trend of a steady increase in transfers reflecting gradually increasing demands and the lack of new generation projects within this zone;

- There is a general trend with reducing transfers across the B10 (South Coast import), and B13 (South West import) reflecting new plant that might be expected to commission in the South and Southwest in line with present contractual positions.

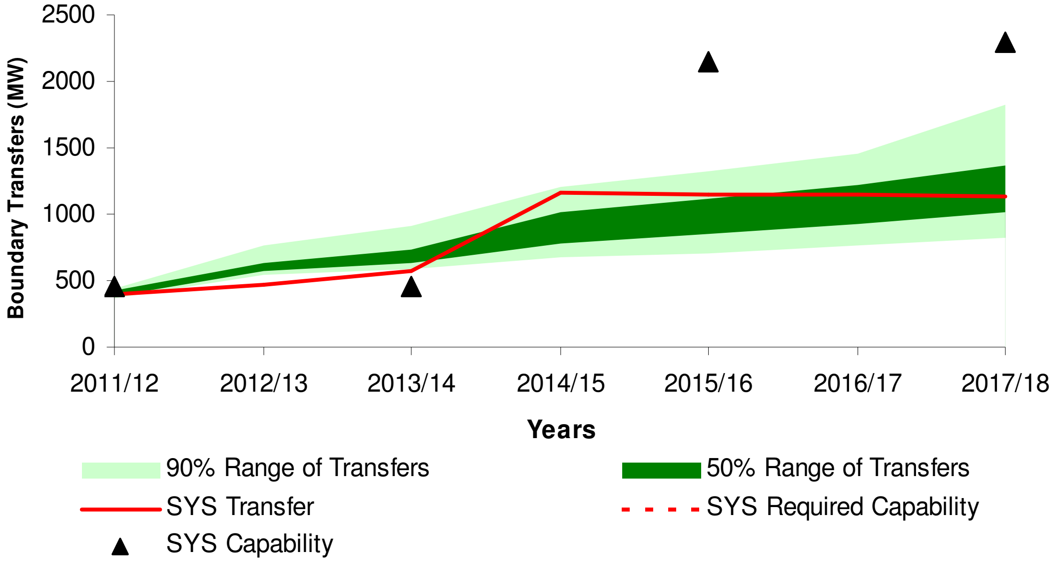
Comparison of the SYS Planned Transfers with the probabilistic ranges reveals that for most boundaries the SYS transfers lie very close the probabilistic range with only limited deviation which can be explained by the effect of some large individual generators pushing the transfer points.

Examination of Figures 8.B1 to Figure 8.B17 reveals a wide range in the width of the probabilistic transfer envelope across the various boundaries. For boundaries cutting large importing or exporting areas such as B8 (North to Midlands) and B9 (Midlands to South), the width of the probabilistic transfer envelope reflects, inter alia, the higher uncertainty associated with the larger tranche of generating plant on the exporting side. For other boundaries, such as B14 (London) which is an importing boundary dominated by a large demand with little generation, the width of the probabilistic transfer envelope is relatively narrow reflecting a higher degree of certainty.

The planned contracted and strategic reinforcements listed in Table 8.2 provide the transmission capability to cover the majority of the system boundary requirements. Some non-compliance for the major northern boundaries may be experienced for the early years until the necessary reinforcements are constructed or the power flow decreases enough to lie within capability.

## Boundary 1: SHETL North West

**Figure 8.B1** Boundary Transfers and Capability
Boundary 1: North West Export



| Table 8-T1 - Boundary B1 SHETL North West | | | | | | | |
|---|---|---|---|---|---|---|---|
| **Quantity (MW)** | **2011/12** | **2012/13** | **2013/14** | **2014/15** | **2015/16** | **2016/17** | **2017/18** |
| **B6E - EXPORT** | | | | | | | |
| Effective Generation | 915 | 992 | 1100 | 1675 | 1655 | 1646 | 1638 |
| Demand | 511 | 515 | 520 | 509 | 507 | 506 | 506 |
| Required Transfer | 404 | 477 | 580 | 1166 | 1148 | 1140 | 1132 |
| **B6I - IMPORT** | | | | | | | |
| Effective Generation | 57927 | 57850 | 57742 | 57167 | 57197 | 57193 | 57202 |
| Demand | 58321 | 58318 | 58313 | 58312 | 58315 | 58313 | 58314 |
| Required Transfer | -404 | -477 | -580 | -116 | -1148 | -1140 | -1132 |

Generation to the north of this boundary is increasing at a significant rate due to the high volume of contracted wind based generation seeking connection to the grid in the area. Consequently, the boundary transfers are also increasing at a similar rate. Further renewable generation is expected in this area as a result of onshore and offshore wind and marine generation in the waters around Orkney and in the Pentland Firth.

It should be noted that application of the Interconnection Allowance (or part thereof) relates only to those boundaries which divide the system into two contiguous parts, the smaller of which contains more than 1500MW of demand. For this boundary (as with boundaries B2 and B3), this is not the case and accordingly the Required Transfer capability is equal to the Planned Transfer.

The first of the proposed reinforcements for this boundary is scheduled for completion by 2011/2012 and comprises the creation of a new 275/132kV substation at Knocknagael. This is located to the south of Inverness at the existing Foyers connection tee point on the Beauly-Blackhillock line. The existing Inverness demand is relocated onto this new substation using new 132kV cable circuits, thus reducing the load on the Beauly-Keith 132kV circuits and thereby increasing the B1 capacity to around 450MW.

The second proposed reinforcement is the Beauly-Denny project comprising the replacement of the existing 132kV double circuit tower line between Beauly, Fort Augustus, Errochty and Bonnybridge by a new 400kV double circuit tower line terminating at Denny near Bonnybridge. The Beauly-Denny project was the subject of an extensive Public Inquiry which started in January 2007 and concluded successfully in January 2010 with consent from the Scottish Government to build the line, subject to mitigation measures being undertaken. Currently the project completion date is predicted to be the end of 2014. The completion of Beauly-Denny will increase this boundary capability from 450MW to around 1300MW.

The additional generation connecting to the north of this boundary means that further reinforcement of this boundary will be required. The next proposed reinforcement is strengthening of the transmission infrastructure between Beauly (near Inverness), Keith/Blackhillock and Kintore. The boundary capability can be raised to around 1600MW by replacing the conductor on the existing 275kV transmission line between Beauly, Blackhillock and Kintore with a new conductor of higher capacity. SHETL obtained regulatory approval to proceed to the construction phase of this reinforcement in March 2010.

Within the B1 North West boundary, additional transmission reinforcement is required to connect the contracted and expected new generation. For example, to the north of Beauly additional works between Beauly and Dounreay will be required. The first phase of this work comprises installation of a new conductor on the spare side of the existing 275kV double circuit line between Beauly and Dounreay, installation of a 275kV busbar and a second 275/132kV transformer at Dounreay. Phase shifting transformers will also be required on the 132kV lines between Beauly and Shin. SHETL obtained regulatory approval to proceed to the construction phase of this reinforcement in March 2010 and the work is expected to be completed by the end of 2012.

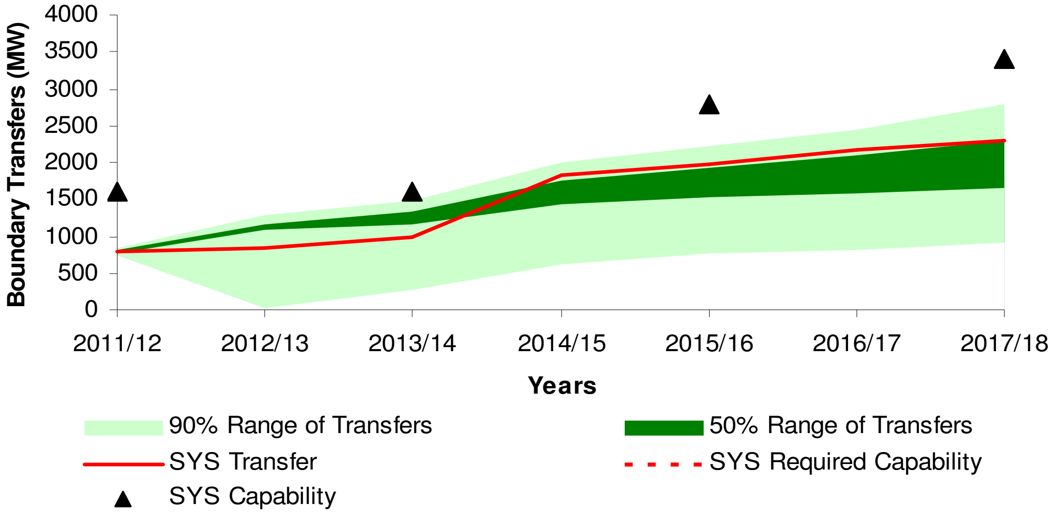
A second phase of reinforcement for the Caithness area will also be required as a result of contracted generation north of Beauly. The proposed reinforcement, due to complete by spring 2016, comprises the installation of an HVDC link between Caithness and the Moray coast and some associated works on the mainland network. This has the effect of providing an additional circuit across B1 and therefore increases the capacity of the boundary. The installation of an offshore HVDC switching Hub within the proposed HVDC link is being investigated with the aim to provide economic connection options for the generation on Shetland and the offshore windfarms in the Moray Firth.

The significant interest from generation developers on the large island groups of the Western Isles, Orkney and Shetland means that new transmission infrastructure will be required to connect these to the mainland transmission network. Current proposals are for the Western Isles to be connected using an HVDC transmission link to Beauly substation. It is also proposed to use an HVDC link to connect Shetland to the mainland at Blackhillock or to the offshore Hub mentioned above. The growth of onshore renewable generation on mainland Orkney is more gradual, however significant growth in marine generation around Orkney and the Pentland Firth is likely following the announcement by the Crown Estate to grant exclusive development rights to companies in these areas. Consequently, the extent to which reinforcement to Orkney is required is under review.

The proposed routes for new transmission tower lines and subsea cables will undergo detailed environmental impact assessment and will be subject to consents and planning approval**.**

## Boundary 2: SHETL North – South

**Figure 8.B2** Boundary Transfers and Capability
Boundary 2: North to South SHETL



| Table 8-T2 - Boundary B2 SHETL North–South | | | | | | | |
|---|---|---|---|---|---|---|---|
| **Quantity (MW)** | **2011/12** | **2012/13** | **2013/14** | **2014/15** | **2015/16** | **2016/17** | **2017/18** |
| **B6E - EXPORT** | | | | | | | |
| Effective Generation | 1905 | 1977 | 2119 | 2961 | 3095 | 3289 | 3413 |
| Demand | 1120 | 1126 | 1136 | 1127 | 1117 | 1115 | 1115 |
| Required Transfer | 785 | 851 | 983 | 1834 | 1978 | 2174 | 2298 |
| **B6I - IMPORT** | | | | | | | |
| Effective Generation | 56926 | 56854 | 56712 | 55870 | 55756 | 55539 | 55415 |
| Demand | 57722 | 57715 | 57704 | 57701 | 57708 | 57704 | 57706 |
| Required Transfer | -785 | -851 | -983 | -1834 | -1978 | -2174 | -2298 |

Generation to the north of this boundary is increasing at a significant rate due to the high volume of contracted renewable generation seeking connection to the north of this boundary. Consequently, the boundary transfers are also increasing at a similar rate. It should be noted that application of the Interconnection Allowance (or part thereof) relates only to those boundaries, which divide the system into two contiguous parts, the smaller of which contains more than 1500MW of demand. For this boundary (as with boundaries B1 and B3), this is not the case and accordingly the required transfer capability is equal to the Planned Transfer.

The increase in required transfer capability of this boundary over the seven year period indicates the need to reinforce the transmission system in this location. The proposed Beauly to Denny reinforcement required for the North West boundary also provides the necessary increased capacity for this boundary. The reinforcement comprises the replacement of the existing 132kV double circuit tower line between Beauly, Fort Augustus, Errochty and Bonnybridge, by a new 400kV double circuit tower line terminating at Denny near Bonnybridge. The Beauly-Denny reinforcement is due to be completed by the end of 2014 and will increase the North South boundary capability from 1600MW to 2650MW in 2014/15.

It is expected that additional reinforcement of this boundary will be required based on the contracted generation volumes. This is likely to comprise an upgrade of the existing east coast route, between Blackhillock and Kincardine, to 400kV using existing infrastructure that is currently operated at 275kV but which is constructed at 400kV. Currently SHETL are undertaking pre-construction design and engineering of the 400kV east coast project with a view to completion in 2015 subject to regulatory approval.

## Boundary 3: SHETL Sloy

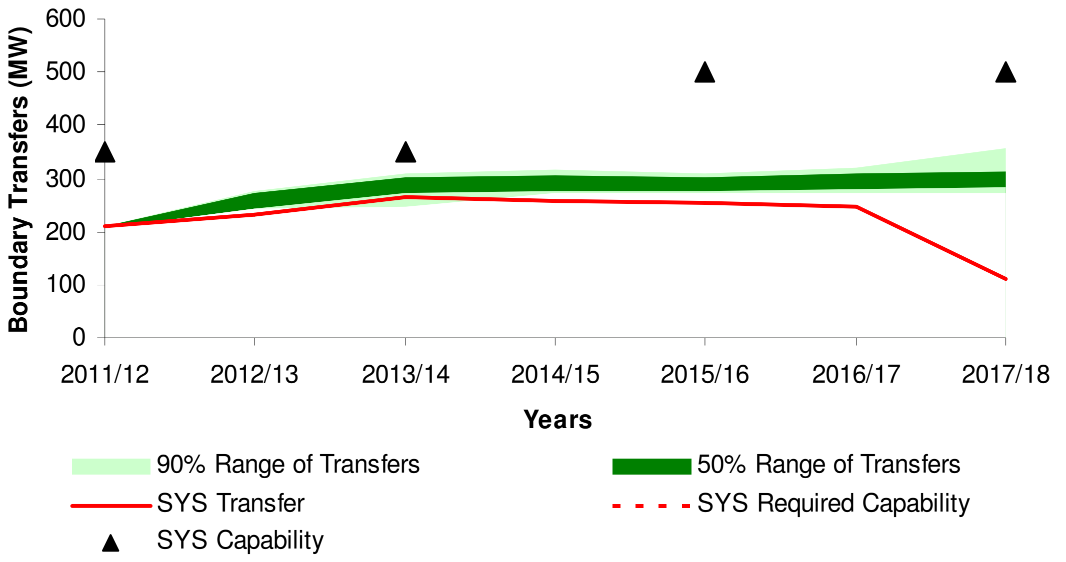


**Figure 8.B3** Boundary Transfers and Capability
Boundary 3: Sloy Export

**Table 8-T3 - Boundary B3 SHETL Sloy**

| Quantity (MW) | 2011/12 | 2012/13 | 2013/14 | 2014/15 | 2015/16 | 2016/17 | 2017/18 |
|---|---|---|---|---|---|---|---|
| **B6E - EXPORT** | | | | | | | |
| Effective Generation | 273 | 299 | 333 | 325 | 322 | 316 | 177 |
| Demand | 65 | 66 | 67 | 66 | 68 | 70 | 67 |
| Required Transfer | 208 | 233 | 266 | 259 | 254 | 246 | 110 |
| **B6I - IMPORT** | | | | | | | |
| Effective Generation | 58560 | 58535 | 58503 | 58511 | 58516 | 58520 | 58659 |
| Demand | 58782 | 58782 | 58781 | 58781 | 58782 | 58781 | 58782 |
| Required Transfer | -208 | -233 | -266 | -259 | -254 | -246 | -110 |

The application of the Interconnection Allowance (or part thereof) relates only to those boundaries, which divide the system into two contiguous parts, the smaller of which contains more than 1500MW of demand. For this boundary (as with boundaries B1 and B2), this is not the case and accordingly the required transfer capability is equal to the Planned Transfer. The new 275/132kV Inverarnan substation, which links the existing Killin to Sloy 132kV line with the existing 275kV line between Windyhill and Dalmally, was completed in 2010/11 and the increase in boundary capability is reflected in the above table.

The sudden decrease in Planned Transfer across B3 in 2017/18 is a result of Sloy hydro generation falling out of merit in the Seven Year Statement ranking order and is not representative. The removal of generation at Sloy has a significant impact on B3 transfers which is a very small boundary in the GB context. For this boundary, the range of transfers indicated in the Fan diagram gives a better indication of the required transfer levels for this region.

Renewable generation continues to increase in the Kintyre and Argyll area and further reinforcement will be required to address both the Zonal boundary capacity and the capability of the internal network, particularly between Carradale and Inveraray. The proposed reinforcement for this area is the installation of two subsea cable links from Crossaig, north of Carradale, to Hunterston in Ayrshire. Currently SHETL are undertaking pre-construction design and engineering of the subsea link with a view to completion in 2015/16 subject to regulatory approval.

## Boundary 4: SHETL – SPT

**Figure 8.B4** Boundary Transfers and Capability
Boundary 4: SHETL to SPT

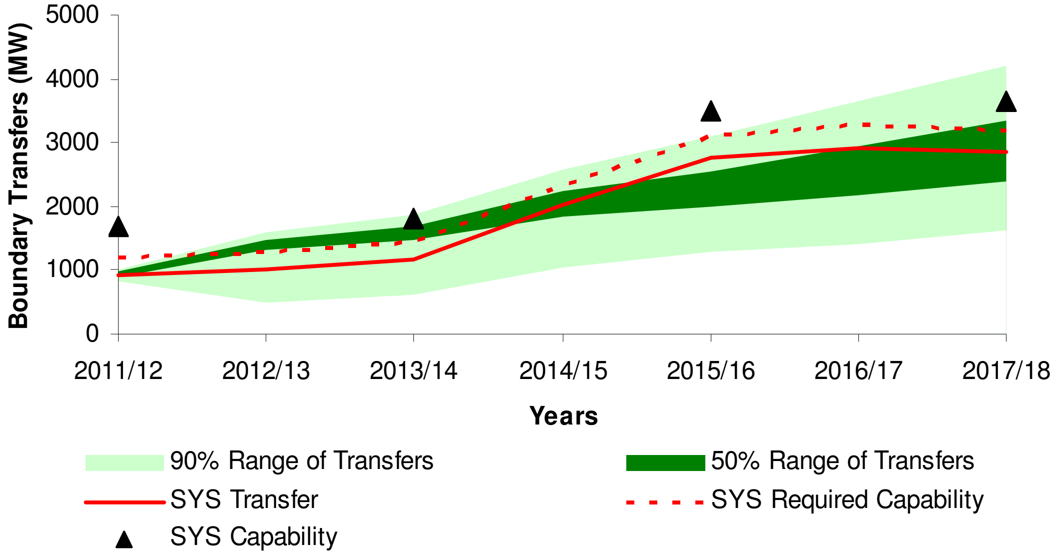


**Table 8-T4 - Boundary B4 SHETL – SPT**

| **Quantity (MW)** | **2011/12** | **2012/13** | **2013/14** | **2014/15** | **2015/16** | **2016/17** | **2017/18** |
|---|---|---|---|---|---|---|---|
| **B6E - EXPORT** | | | | | | | |
| Effective Generation | 2634 | 2729 | 2901 | 3760 | 4488 | 4655 | 4565 |
| Demand | 1702 | 1712 | 1730 | 1733 | 1726 | 1733 | 1727 |
| Required Transfer | 1192 | 1283 | 1446 | 2343 | 3107 | 3275 | 3187 |
| **B6I - IMPORT** | | | | | | | |
| Effective Generation | 56206 | 56111 | 55941 | 55082 | 54384 | 54183 | 54273 |
| Demand | 57132 | 57121 | 57105 | 57101 | 57112 | 57105 | 57108 |
| Required Transfer | -1192 | -1283 | -1446 | -2343 | -3107 | -3275 | -3187 |

The SHETL to SPT boundary defines the asset ownership boundary between SHETL and SPT and runs from the Firth of Tay in the east to near the head of Loch Long in the west. This boundary encompasses all the generation and demand (except for Dunoon and Strathleven) in the SHETL area and is normally an exporting boundary.

Generation to the north of this boundary is increasing over time due to the high volume of new contracted renewable generation seeking connection in the SHETL area. Consequently, the boundary transfers are also increasing with time.

The application of the Interconnection Allowance (or part thereof) relates only to those boundaries which divide the system into two contiguous parts, the smaller of which contains more than 1500MW of demand. For this boundary, Interconnection allowance is applicable and is added to the Planned Transfer to give the required transfer capability for the boundary.

The increase in the required transfer capability over the seven year period clearly indicates the need to reinforce the transmission system across Boundary 4. The proposed Beauly to Denny reinforcement, due to be completed by the end of 2014, will increase the capacity of the B4 boundary significantly from 1700MW to around 3000MW by the end of 2014. The Beauly to Denny reinforcement comprises the replacement of the existing 132kV double circuit tower line between Beauly, Fort Augustus, Errochty and Bonnybridge, by a new 400kV double circuit tower line terminating at Denny near Bonnybridge.

It is expected that additional reinforcement of this boundary will be required based on the contracted generation volumes. This is likely to comprise an upgrade of the existing east coast route, between Blackhillock and Kincardine, to 400kV using existing infrastructure that is currently operated at 275kV but which is constructed at 400kV. This reinforcement will increase the B4 boundary capability from 3000MW to around 3500MW in 2015/16. Currently SHETL are undertaking pre-construction design and engineering of the 400kV east coast project with a view to completion in 2015/16 subject to regulatory approval.

Smaller upgrades to the SHETL network including the installation of Quadrature Boosters at Blackhillock in 2016/17 and the split of the Errochty 132kV busbar in 2017/18 allow optimisation of power flows though the network and provide small but very cost effective increases in B1, B2 and B4 boundary capacities.

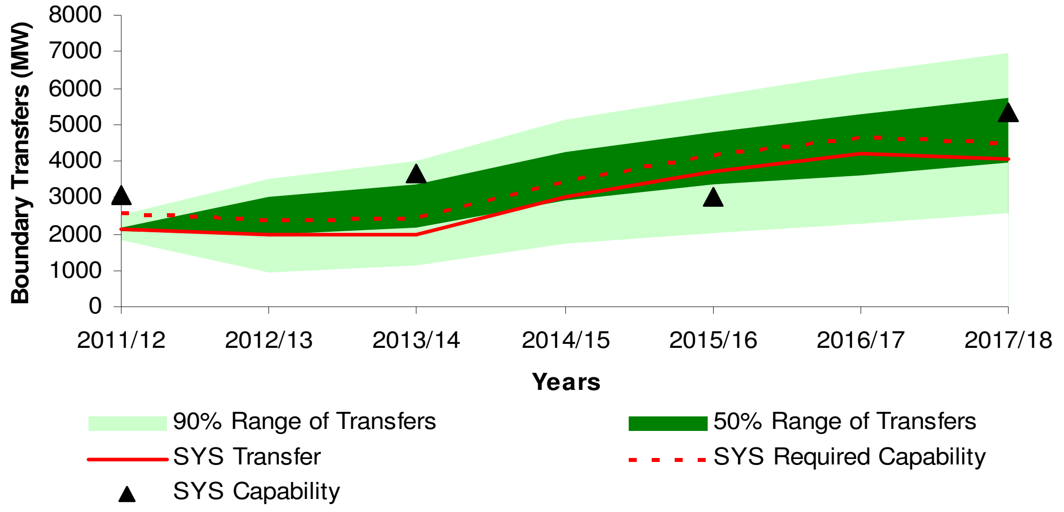
Boundary B4 capability from 2015/16 onwards is restricted by the thermal rating of two short sections of 275kV cable at Longannet on the circuits east to Westfield. Increasing the rating of these cables, together with the removal of protection limitations, may further increase boundary capability in these years by up to 300MW.

Beyond this, taking account of the potential generation in the period up to and beyond 2020, SHETL, SPT and NGET are carrying out pre-construction design and engineering of an offshore multi-terminal HVDC link between Peterhead, Torness and the north of England. An estimated completion date for this scheme is 2018, subject to regulatory approval.

The undertaking of pre-construction design and engineering work positions the delivery of a project such that construction can commence at the appropriate time when there is confidence that the reinforcement will be required.

## Boundary 5: SPT North – South

**Figure 8.B5** Boundary Transfers and Capability
Boundary 5: North to South SPT



| Table 8-T5 - Boundary B5 SPT North – South | | | | | | | |
|---|---|---|---|---|---|---|---|
| **Quantity (MW)** | **2011/12** | **2012/13** | **2013/14** | **2014/15** | **2015/16** | **2016/17** | **2017/18** |
| **B6E - EXPORT** | | | | | | | |
| Effective Generation | 5033 | 4884 | 4937 | 5929 | 6654 | 7156 | 6971 |
| Demand | 2778 | 2803 | 2801 | 2783 | 2797 | 2790 | 2786 |
| Required Transfer | 2546 | 2370 | 2404 | 3434 | 4171 | 4664 | 4505 |
| **B6I - IMPORT** | | | | | | | |
| Effective Generation | 54048 | 53947 | 54027 | 53132 | 52469 | 52073 | 51984 |
| Demand | 55939 | 55938 | 55935 | 55931 | 55937 | 55938 | 55939 |
| Required Transfer | -2546 | -2370 | -2404 | -3434 | -4171 | -4664 | -4505 |

The north to south transfer across this boundary in the central belt of Scotland rises through the years of this statement due to contracted renewable energy developments in the north of Scotland.

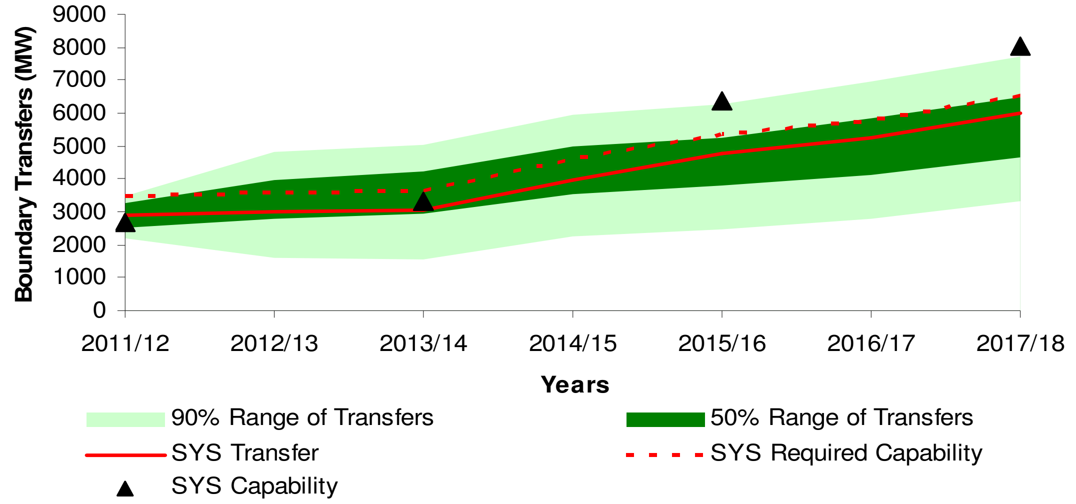
The base boundary capability is adversely impacted by the increased transfer assumption on the Moyle Interconnector in all years compared to that in the 2010 GB SYS. The installation of a second 400/275kV transformer at Strathaven, together with reactive compensation equipment in the SPT area, will enhance B5 capability to approximately 3650MW by winter 2012/13.

Taking into account the significant changes anticipated in the generation mix in the period to 2020 and beyond, SPT is undertaking pre-construction design and engineering work on further upgrades to Boundary B5. Undertaking pre-construction engineering work positions the delivery of any project such that construction can commence when there is sufficient confidence that the reinforcement will be required. The commissioning of a significant volume of generation in the south east of the SHETL area in 2015/16 has the effect of reducing the boundary capability due to the redistribution of power flows. Boundary capability may be restored by modifying connections at Denny North 275kV Substation, increasing the thermal rating of the 275kV circuits west from Denny and / or modifying the transfer level on the Western HVDC Link.

Indicative reinforcement, included in SYS Year 7, delivers a boundary capability approaching 5350MW.

## Boundary 6: SPT – NGET

**Figure 8.B6** Boundary Transfers and Capability
Boundary 6: SPT to NGET



| Table 8-T6 - Boundary B6 SPT – NGET | | | | | | | |
|---|---|---|---|---|---|---|---|
| **Quantity (MW)** | **2011/12** | **2012/13** | **2013/14** | **2014/15** | **2015/16** | **2016/17** | **2017/18** |
| **B6E - EXPORT** | | | | | | | |
| Effective Generation | 8954 | 9060 | 9143 | 10104 | 10573 | 11424 | 12132 |
| Demand | 5486 | 5490 | 5497 | 5470 | 5504 | 5487 | 5484 |
| Required Transfer | 3496 | 3602 | 3656 | 4611 | 5340 | 5806 | 6526 |
| **B6I - IMPORT** | | | | | | | |
| Effective Generation | 50106 | 49664 | 49610 | 48521 | 48302 | 47959 | 46811 |
| Demand | 52809 | 52805 | 52799 | 52790 | 52802 | 52805 | 52808 |
| Required Transfer | -3496 | -3602 | -3656 | -4611 | -5340 | -5806 | -6526 |

The north to south transfer across the boundary between SPT and NGET rises through the years of this statement, due to contracted renewable energy developments throughout Scotland. As a consequence, the required capability is significantly in excess of the current capability, indicating a strong need for reinforcement.

Due to the fact that the required capability currently exceeds the actual capability, SPT and NGET have been granted relief from Licence Condition D3 in respect of the circuits connecting the SPT system to that of NGET.

To achieve a capability of approximately 3,300MW by 2012/13, SPT and NGET are undertaking an extensive reinforcement programme. Upon completion of these works, this boundary continues to show insufficient transfer capability for the given SYS Background, indicating further reinforcement is required.

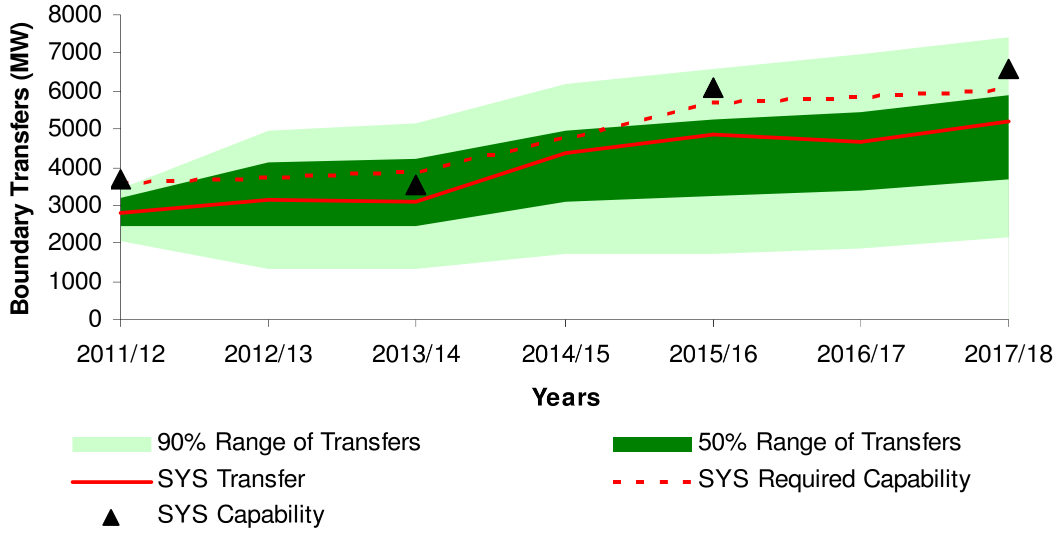
Taking into account the significant changes anticipated in the generation mix in the period to 2020, SPT and NGET are undertaking pre-construction design and engineering work on further upgrades to Boundary B6. These include series compensation and offshore HVDC schemes. Undertaking pre-construction engineering work positions the delivery of any project such that construction can commence when there is sufficient confidence that the reinforcement will be required.

Incorporating series compensation and the Western HVDC Link (with assumed 2000MW capacity) into the SYS background in 2015/16, together deliver a boundary capability of 6400MW.

Incorporating an Eastern HVDC Link from the Torness area (with assumed 2000MW capacity) into the SYS background in 2017/18, coincident with the commissioning of a significant volume of generation in the south east of the SPT area, increases boundary capability to approximately 8000MW.

## Boundary 7: NGET Upper North

**Figure 8.B7** Boundary Transfers and Capability
Boundary 7: Upper North to North

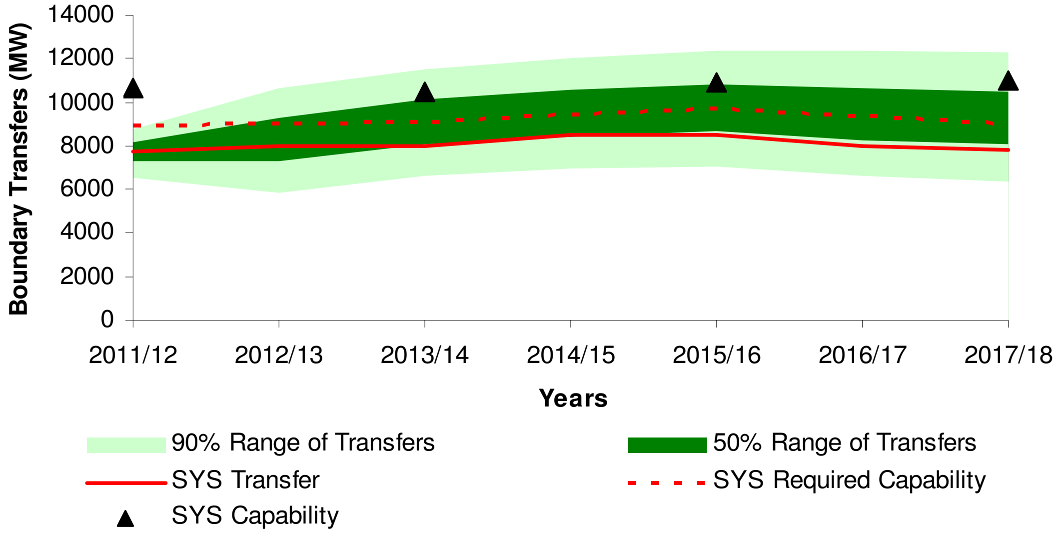


| Table 8-T7 - Boundary B7 NGET Upper North | | | | | | | |
|---|---|---|---|---|---|---|---|
| **Quantity (MW)** | **2011/12** | **2012/13** | **2013/14** | **2014/15** | **2015/16** | **2016/17** | **2017/18** |
| **B7E - EXPORT** | | | | | | | |
| Effective Generation | 11698 | 12131 | 12200 | 13494 | 13978 | 13868 | 14507 |
| Demand | 8886 | 8993 | 9102 | 9122 | 9123 | 9225 | 9329 |
| Required Transfer | 3587 | 3917 | 3880 | 5175 | 5678 | 5489 | 6048 |
| **B7I - IMPORT** | | | | | | | |
| Effective Generation | 47136 | 46703 | 46634 | 45340 | 44856 | 44966 | 44327 |
| Demand | 49948 | 49841 | 49732 | 49712 | 49711 | 49609 | 49505 |
| Required Transfer | -3587 | -3917 | -3880 | -5175 | -5678 | -5489 | -6048 |

Boundary B7 is one of the Anglo Scottish boundaries which is strongly affected by the flow of B6, as it is characterised by six 400kV primary AC circuits in close proximity to boundary B6. The reinforcements for B7 are the uprating of Harker-Hutton double circuit to 3100 MVA, and the West Coast HVDC link. This is demonstrated in 2015 which increases the SYS capability from 3,500 to 6,100 MW and is essential to meet compliance as flows increase. In later years (post 2015) the transfer increases further as more wind farms connect in Scotland. It is important to note that B7 can become highly constrained, if power flows increase from the North.

## Boundary 8: NGET North to Midlands

**Figure 8.B8** Boundary Transfers and Capability
Boundary 8: North to Midlands



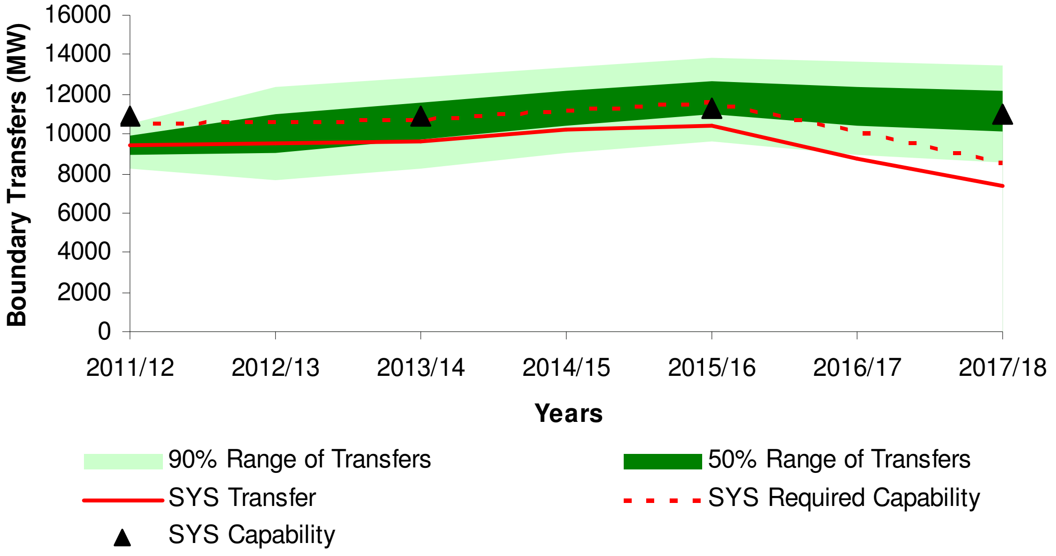
| **Table 8-T8 - Boundary B8 NGET North - Midlands** | | | | | | | |
|---|---|---|---|---|---|---|---|
| **Quantity (MW)** | **2011/12** | **2012/13** | **2013/14** | **2014/15** | **2015/16** | **2016/17** | **2017/18** |
| **B8E - EXPORT** | | | | | | | |
| Effective Generation | 29192 | 29343 | 29265 | 29772 | 29750 | 29582 | 29906 |
| Demand | 21434 | 21346 | 21260 | 21240 | 21206 | 21624 | 22049 |
| Required Transfer | 8890 | 9131 | 9140 | 9674 | 9695 | 9118 | 9027 |
| **B8I - IMPORT** | | | | | | | |
| Effective Generation | 29642 | 29491 | 29569 | 29062 | 29084 | 29252 | 28928 |
| Demand | 37400 | 37488 | 37574 | 37594 | 37628 | 37210 | 36785 |
| Required Transfer | -8890 | -9131 | -9140 | -9674 | -9695 | -9118 | -9027 |

Boundary B8 is the North to Midlands boundary, and is part of the wider group of system boundaries which separate England and Wales generation approximately midway throughout the country. The B8 boundary has an average capability of 10,500 MW throughout the years as the generation pattern across the country changes. A drop in transfers can be seen in comparison to previous year's statements due to generation closures north of the boundary and new generation south of the boundary.

The boundary capability is sufficient for the range of transfer under the SYS background. The required transfers range from 8,800 MW to 9,600 MW. Two distinctive points can be identified on the boundary graphs: An increase in transfer from 2011/12 to 2015/16 and a drop in transfer from 2015/16 to 2017/18. An increase in transfer can be explained by offshore windfarms such as Hornsea being connected, which leads to a net increase in transfer, as it compensates a number of coal units falling out of merit. The drop in transfer from 2015/16 to 2017/18 can also be explained by a number of CCGT plants falling out of merit and LCPD closures, which occur more on the north side of the boundary.

## Boundary 9: NGET Midlands to South

**Figure 8.B9** Boundary Transfers and Capability
Boundary 9: Midlands to South

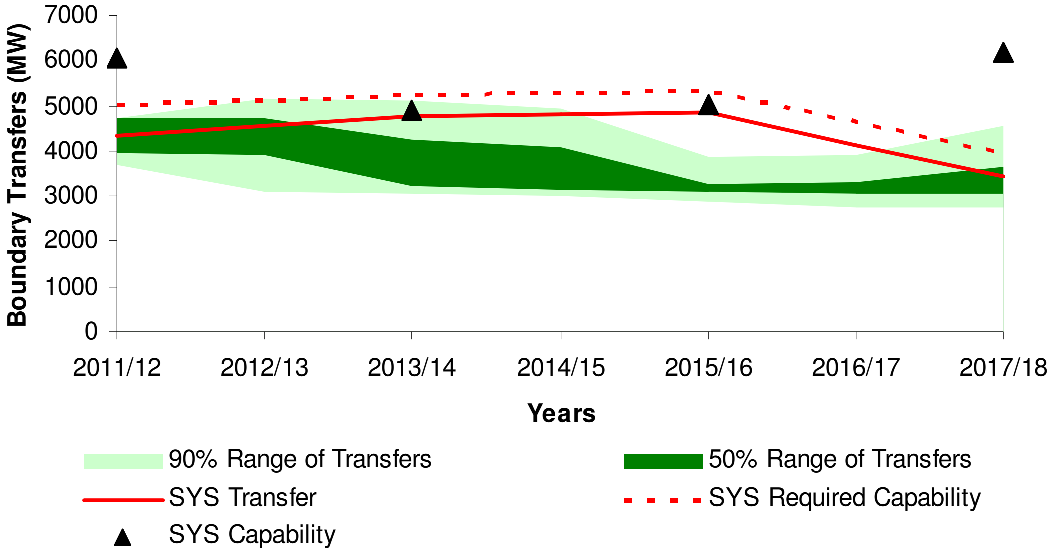


| **Table 8-T9 - Boundary B9 Midlands – South** | | | | | | | |
|---|---|---|---|---|---|---|---|
| **Quantity (MW)** | **2011/12** | **2012/13** | **2013/14** | **2014/15** | **2015/16** | **2016/17** | **2017/18** |
| **B9E - EXPORT** | | | | | | | |
| Effective Generation | 39219 | 39212 | 39052 | 39645 | 39887 | 38577 | 37599 |
| Demand | 29832 | 29642 | 29452 | 29454 | 29444 | 29821 | 30202 |
| Required Transfer | 10515 | 10705 | 10741 | 11333 | 11586 | 9910 | 8560 |
| **B9I - IMPORT** | | | | | | | |
| Effective Generation | 19615 | 19622 | 19782 | 19189 | 18947 | 20257 | 21235 |
| Demand | 29002 | 29192 | 29382 | 29380 | 29390 | 29013 | 28632 |
| Required Transfer | -10515 | -10705 | -10741 | -11333 | -11586 | -9910 | -8560 |

Boundary B9 has a similar required transfer capability trend to that of B8, and is more sensitive to generation change on either side of the boundary in later years. In the early years the boundary remains compliant, with a SYS Capability of around 11,000 MW. As generation increases from the north a thermal and voltage limitation occurs around the Cottam region. Already planned network reinforcements around Cottam, Keadby and West Burton, are required to increase the thermal capability of the region. In 2015/16, the boundary goes marginally non-compliant. However, as generation increases south of the boundary, a significant drop in transfer is shown between the years of 2015/16 to 2017/18 which eventually leads to the SYS boundary capability being compliant again.

## Boundary 10: NGET South Coast

**Figure 8.B10** Boundary Transfers and Capability
Boundary 10: South Coast

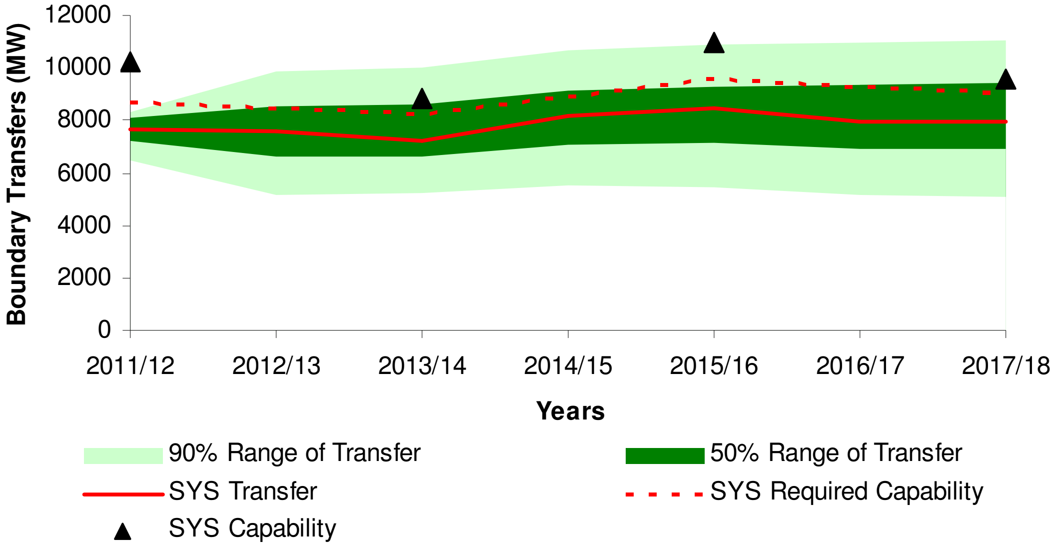


| Table 8-T10 - Boundary B10 NGET South Coast | | | | | | | |
|---|---|---|---|---|---|---|---|
| **Quantity (MW)** | **2011/12** | **2012/13** | **2013/14** | **2014/15** | **2015/16** | **2016/17** | **2017/18** |
| **B10E - EXPORT** | | | | | | | |
| Effective Generation | 3045 | 2831 | 2641 | 2589 | 2582 | 3251 | 3875 |
| Demand | 7384 | 7387 | 7389 | 7402 | 7418 | 7355 | 7290 |
| Required Transfer | -5011 | -5131 | -5228 | -5299 | -5327 | -4622 | -3960 |
| **B10I - IMPORT** | | | | | | | |
| Effective Generation | 55789 | 56003 | 56193 | 56245 | 56252 | 55583 | 54959 |
| Demand | 51450 | 51447 | 51445 | 51432 | 51416 | 51479 | 51544 |
| Required Transfer | 5011 | 5131 | 5228 | 5299 | 5327 | 4622 | 3960 |

The South Coast boundary is characterised by a high demand region with a sensitive voltage stability profile which is primarily due to lack of generation in and around the area. Boundary B10 is reliant on importing power from the Midlands and Thames Estuary. The required transfer ranges from approximately 4,600 MW to 4,000 MW in the later years, with the probability of the boundary falling out of compliance around 2013/14 to 2015/16 due to diminishing support from local generation. However the non-compliance is short lived as more generation is connected in the South Coast such as Hinkley Point C and the Atlantic Array windfarms, which restores local voltage support. The probabilistic range of transfers sits below the required transfers in the early years due to an assumed output from normally non-contributory generation.

## Boundary 11: NGET North East and Yorkshire

**Figure 8.B11** Boundary Transfers and Capability
Boundary 11: North East & Yorkshire

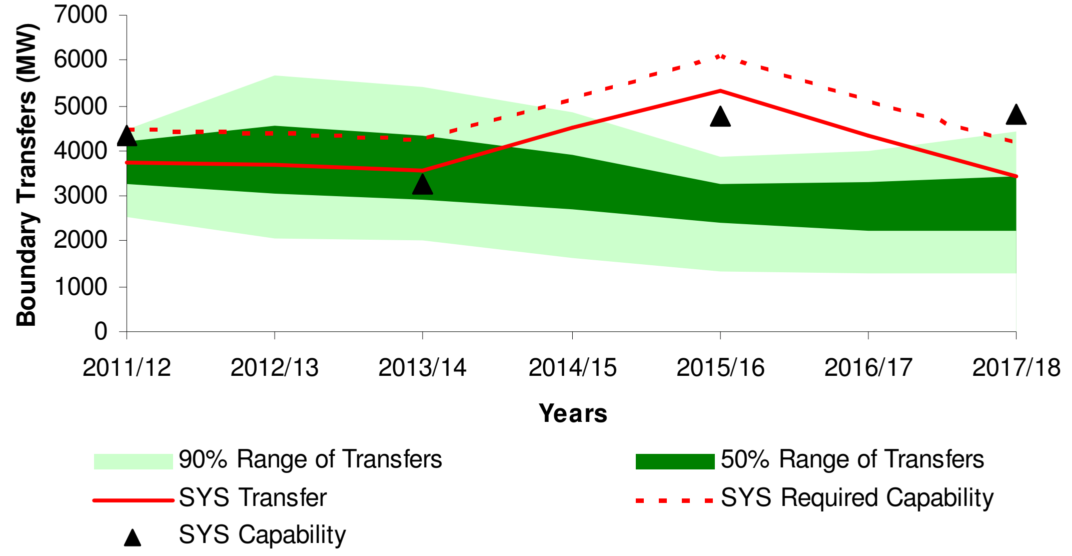


| **Table 8-T11 - Boundary B11 NGET North East & Yorkshire** | | | | | | | |
|---|---|---|---|---|---|---|---|
| **Quantity (MW)** | **2011/12** | **2012/13** | **2013/14** | **2014/15** | **2015/16** | **2016/17** | **2017/18** |
| **B11E - EXPORT** | | | | | | | |
| Effective Generation | 21835 | 21863 | 21605 | 22503 | 22746 | 22263 | 22387 |
| Demand | 14176 | 14276 | 14378 | 14323 | 14249 | 14336 | 14423 |
| Required Transfer | 8686 | 8614 | 8254 | 9219 | 9548 | 8983 | 9024 |
| **B11I - IMPORT** | | | | | | | |
| Effective Generation | 36999 | 36971 | 37229 | 36331 | 36088 | 36571 | 36447 |
| Demand | 44658 | 44558 | 44456 | 44511 | 44585 | 44498 | 44411 |
| Required Transfer | -8686 | -8614 | -8254 | -9219 | -9548 | -8983 | -9024 |

Boundary B11 is the North East and Yorkshire boundary and transfers the bulk of the power from the Anglo Scottish boundaries to Central and North West. The required transfer increases steadily throughout the period of 2011/12 to 2015/16, indicating the lack of net generation in the south of England and some conventional generating units coming out of merit. In 2016/17 the transfers decrease due to an increase in generation south of the boundary. It can be seen from the figure that the SYS capability is higher than the required capability throughout the seven years, and increases to its maximum in 2015/17 of 10,995 MW; due to the West Coast HVDC link and other associated TIRG works which results in a thermal increase of the boundary circuits.

## Boundary 12: NGET South & South West

**Figure 8.B12** Boundary Transfers and Capability
Boundary 12: South & South West

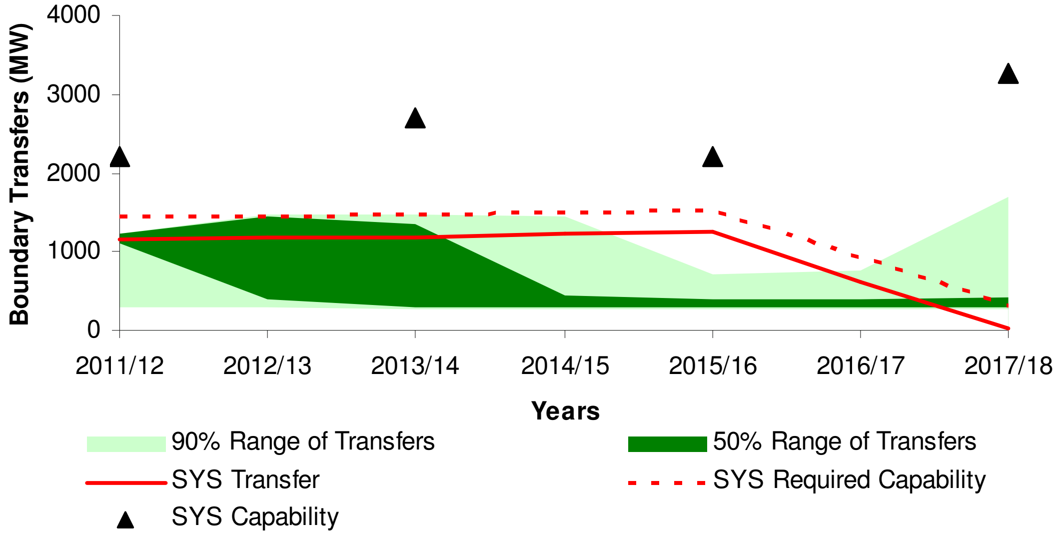


| Table 8-T12 - Boundary B12 NGET South & South West | | | | | | | |
|---|---|---|---|---|---|---|---|
| **Quantity (MW)** | **2011/12** | **2012/13** | **2013/14** | **2014/15** | **2015/16** | **2016/17** | **2017/18** |
| **B12E - EXPORT** | | | | | | | |
| Effective Generation | 8877 | 8927 | 9045 | 8105 | 7298 | 8177 | 8933 |
| Demand | 12605 | 12603 | 12600 | 12608 | 12620 | 12498 | 12373 |
| Required Transfer | -4470 | -4398 | -4257 | -5235 | -6084 | -5060 | -4157 |
| **B12I - IMPORT** | | | | | | | |
| Effective Generation | 49957 | 49907 | 49789 | 50729 | 51536 | 50657 | 49901 |
| Demand | 46229 | 46231 | 46234 | 46226 | 46214 | 46336 | 46461 |
| Required Transfer | 4470 | 4398 | 4257 | 5235 | 6084 | 5060 | 4157 |

Boundary B12 is the South and South West boundary, which transfers power from the Midlands to the South Coast. In 2015/16 the required transfer spikes due to particular plant in the boundary falling out of merit. This can be overcome by a combination of operational measures and applied reinforcements. As Hinkley Point C and the Atlantic Array connect in 2017/18 a drop in planned transfer is encountered as the local generation within the zones feeds the local demand, a net decrease in transfer is encountered; thus minimising its reliance on importing power from the boundary.

## Boundary 13: NGET South West

**Figure 8.B13** Boundary Transfers and Capability
Boundary 13: South West



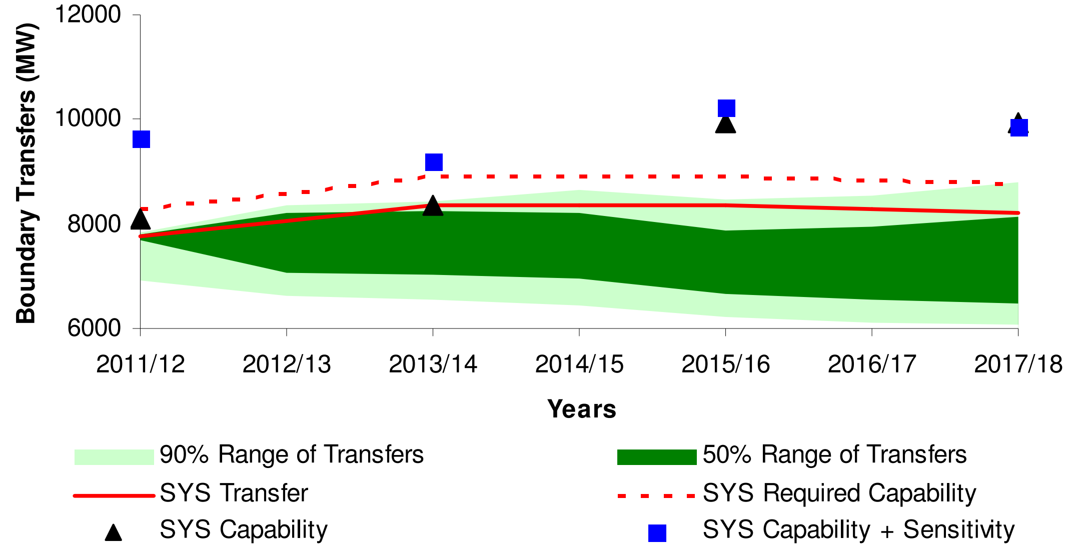
| Table 8-T13 - Boundary B13 NGET South West | | | | | | | |
|---|---|---|---|---|---|---|---|
| **Quantity (MW)** | **2011/12** | **2012/13** | **2013/14** | **2014/15** | **2015/16** | **2016/17** | **2017/18** |
| **B13E - EXPORT** | | | | | | | |
| Effective Generation | 1786 | 1760 | 1748 | 1713 | 1708 | 2382 | 3024 |
| Demand | 2950 | 2944 | 2937 | 2944 | 2951 | 3002 | 3053 |
| Required Transfer | -1444 | -1462 | -1466 | -1513 | -1530 | -911 | -324 |
| **B13I - IMPORT** | | | | | | | |
| Effective Generation | 57048 | 57074 | 57086 | 57121 | 57126 | 56452 | 55810 |
| Demand | 55884 | 55890 | 55897 | 55890 | 55883 | 55832 | 55781 |
| Required Transfer | 1444 | 1462 | 1466 | 1513 | 1530 | 911 | 324 |

Boundary B13 is located at the southern most tip of the UK, running from the Severn Estuary to the South Coast, East of Mannington. It is characterised with high zonal demand. As the generation increases throughout the SYS period, and begins to exceed the local demand, the boundary becomes an exporting boundary during the summer period due to light loads within the region.

The SYS transfer remain fairly constant throughout the early SYS periods fluctuating around 1,100MW; but with the connection of new offshore windfarms within the South West, an increase in generation leads to reduction in transfer. The SYS capability of boundary B13 exceeds the boundary transfers significantly throughout the years, and the addition of the new overhead line from Hinckley Point to Seabank increases the thermal capability of the boundary in later years. Thus in 2017/18 the SYS capability increases from approximately 2,200 MW to 3,200 MW.

## Boundary 14: NGET London

**Figure 8.B14** Boundary Transfers and Capability
Boundary 14: London

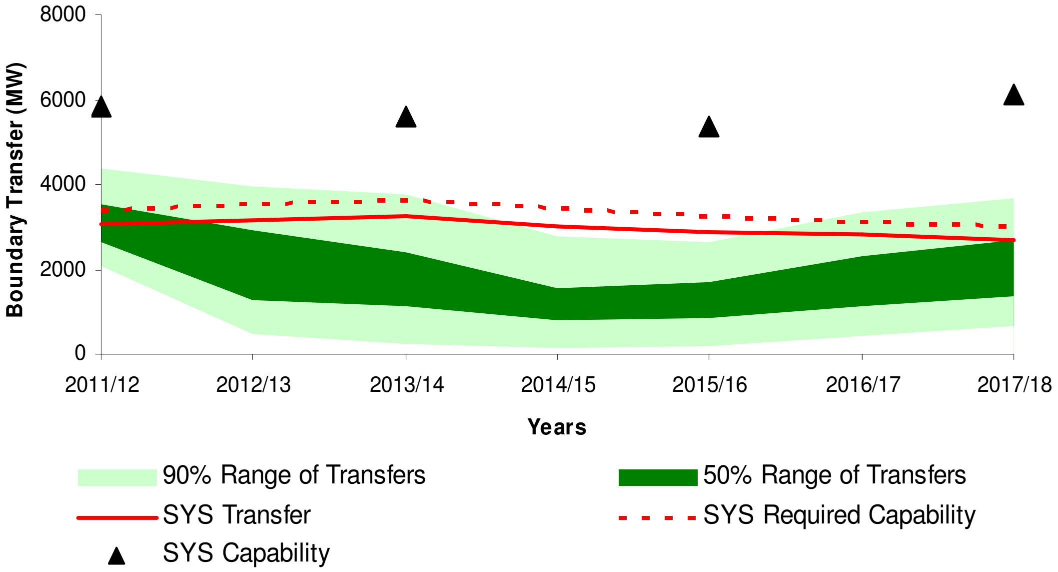


| **Table 8-T14 - Boundary B14 NGET London** | | | | | | | |
|---|---|---|---|---|---|---|---|
| **Quantity (MW)** | **2011/12** | **2012/13** | **2013/14** | **2014/15** | **2015/16** | **2016/17** | **2017/18** |
| **B14E - EXPORT** | | | | | | | |
| Effective Generation | 1750 | 1724 | 1712 | 1861 | 2044 | 2035 | 1992 |
| Demand | 9504 | 9791 | 10078 | 10234 | 10395 | 10301 | 10205 |
| Required Transfer | -8268 | -8595 | -8909 | -8927 | -8915 | -8827 | -8769 |
| **B14I - IMPORT** | | | | | | | |
| Effective Generation | 57084 | 57110 | 57122 | 56973 | 56790 | 56799 | 56842 |
| Demand | 49330 | 49043 | 48756 | 48600 | 48439 | 48533 | 48629 |
| Required Transfer | 8268 | 8595 | 8909 | 8927 | 8915 | 8827 | 8769 |

B14 covers Central London and the surrounding outer London areas. It relies on importing power from generators outside the boundary, namely the Thames Estuary region to feed the London demand of approximately 10,000 MW. As the Seven Year Statement assumes that approximately 1,800 MW on average is being generated in London, approximately 8,200 MW is assumed to be imported from other generators outside of the boundary. Boundary B14 is characterised with high local demand and minimal generation in comparison to the other boundaries. London's energy import relies heavily on a number of 400 and 275kV circuits such as the 275 kV Tilbury-Warley-Elstree circuits and the Littlebrook-West Thurrock circuits bringing power from the surrounding areas. Additional stress can be placed on the surrounding circuits if the European interconnectors in the Thames Estuary export to the continent causing increased power flows through London and across B14. This can be seen in figure 8. B14 by a low SYS capability. However, when the links are at float shown as a sensitivity, the capabilities are higher and achieve compliance in all years. Reinforcement schemes are adopted around the London region to ensure that the boundary is compliant against a number of credible conditions.

## Boundary 15: NGET Thames Estuary

**Figure 8.B15** Boundary Transfers and Capability
Boundary 15: Thames Estuary



| Table 8-T15 - Boundary B15 NGET Thames Estuary | | | | | | | |
|---|---|---|---|---|---|---|---|
| **Quantity (MW)** | **2011/12** | **2012/13** | **2013/14** | **2014/15** | **2015/16** | **2016/17** | **2017/18** |
| **B15E - EXPORT** | | | | | | | |
| Effective Generation | 5214 | 5285 | 5395 | 5189 | 5073 | 5073 | 4990 |
| Demand | 2150 | 2155 | 2161 | 2193 | 2226 | 2273 | 2322 |
| Required Transfer | 3384 | 3489 | 3634 | 3395 | 3244 | 3168 | 3008 |
| **B15I - IMPORT** | | | | | | | |
| Effective Generation | 53620 | 53549 | 53439 | 53645 | 53761 | 53761 | 53844 |
| Demand | 56684 | 56679 | 56673 | 56641 | 56608 | 56561 | 56512 |
| Required Transfer | -3384 | -3489 | -3634 | -3395 | -3244 | -3168 | -3008 |

B15 is referred to the Thames Estuary boundary with significant generation in Dungeness (nuclear), Damhead Creek (CCGT) and Kingsnorth (coal) with future wind power entering from the east generated by Rounds 1 and 2 windfarms such as the London Array wind farms. However even though generation is high within this zone, a drop in transfer is encountered in later years, as numerous LCPD and coal fired power station close or fall out of merit. This is somewhat counter balanced by new renewable generation and new CCGT plants. In essence the required transfer remains fairly constant throughout the SYS years, with a SYS capability exceeding the transfers. Against the SYS background the capability of this boundary exceeds the required transfers of this boundary for all the years, however the interconnectors to France and the Netherlands can change the boundary requirements by up to 6GW dependant on whether they import or export power. To manage this large range of potential transfers it is necessary to keep a high boundary capability to avoid possible restrictions.

## Boundary 16: NGET North East, Trent & Yorkshire

**Figure 8.B16** Boundary Transfers and Capability
Boundary 16: North East, Trent & Yorkshire

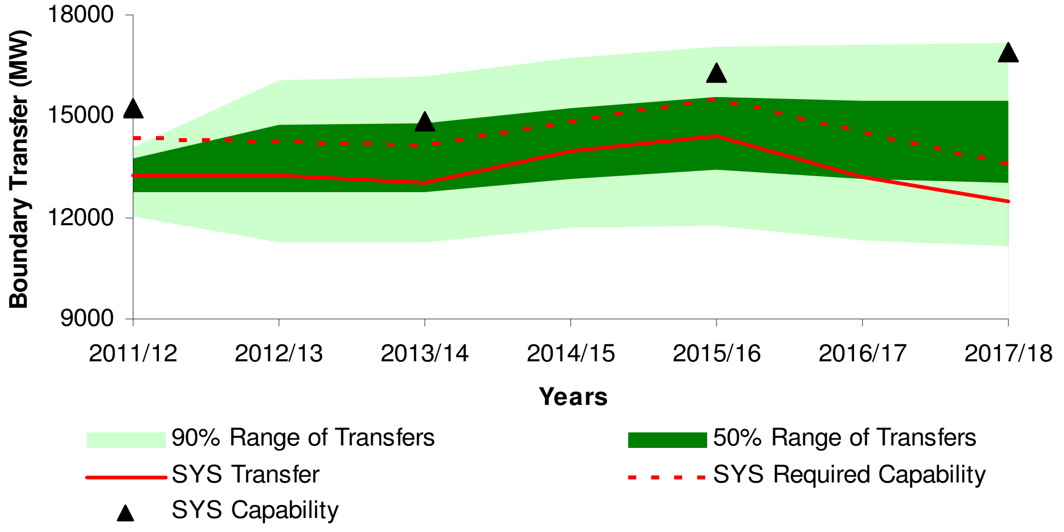


**Table 8-T16 - Boundary B16 NGET North East, Trent & Yorkshire**

| Quantity (MW) | 2011/12 | 2012/13 | 2013/14 | 2014/15 | 2015/16 | 2016/17 | 2017/18 |
|---|---|---|---|---|---|---|---|
| **B16E - EXPORT** | | | | | | | |
| Effective Generation | 28376 | 28491 | 28370 | 29284 | 29666 | 28445 | 27721 |
| Demand | 15133 | 15242 | 15352 | 15309 | 15248 | 15250 | 15252 |
| Required Transfer | 14341 | 14349 | 14120 | 15087 | 15539 | 14299 | 13558 |
| **B16I - IMPORT** | | | | | | | |
| Effective Generation | 30458 | 30343 | 30464 | 29550 | 29168 | 30389 | 31113 |
| Demand | 43701 | 43592 | 43482 | 43525 | 43586 | 43584 | 43582 |
| Required Transfer | -14341 | -14349 | -14120 | -15087 | -15539 | -14299 | -13558 |

Boundary B16 is the North East, Trent and Yorkshire boundary which cuts across from western side of Scottish border to the east coast of central England. The transfer trend characteristics follow similar to that of B8, B9 and B11, with the range of required transfer varying from approximately 13,500 MW to 15,500 MW. The SYS capability is sufficient for boundary compliance through out all years. The critical limitation of this boundary is a thermal overload on the West Burton to High Marnham circuit, and West Burton to Cottam circuit. The already planned uprating of these circuits and the addition of the West Coast HVDC link, ensures that the boundary is compliant in later years.

## Boundary 17: NGET West Midlands

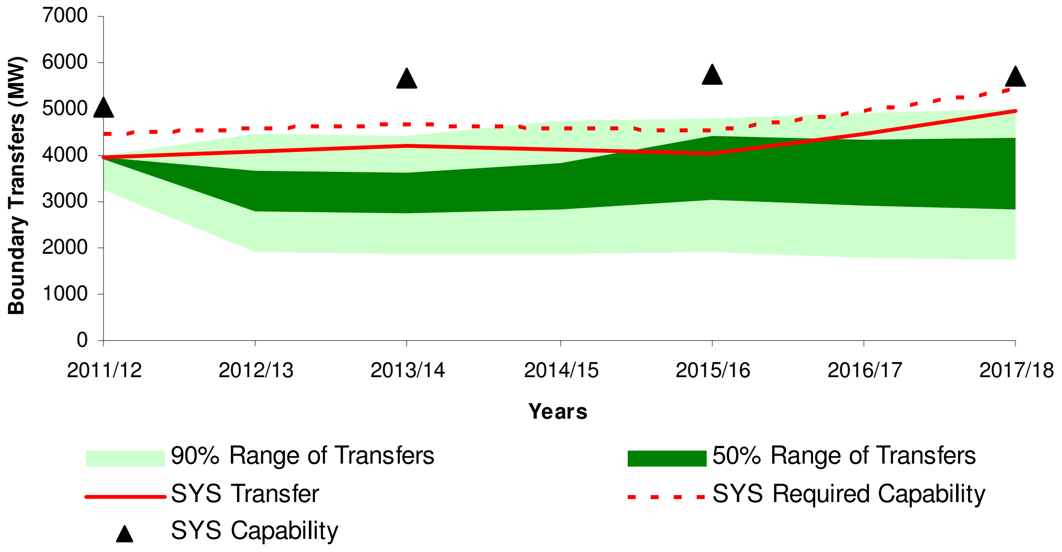


**Figure 8.B17** Boundary Transfers and Capability
Boundary 17: West Midlands

| **Table 8-T17 - Boundary B17 NGET West Midlands** | | | | | | | |
|---|---|---|---|---|---|---|---|
| **Quantity (MW)** | **2011/12** | **2012/13** | **2013/14** | **2014/15** | **2015/16** | **2016/17** | **2017/18** |
| **B17E - EXPORT** | | | | | | | |
| Effective Generation | 3486 | 3241 | 3023 | 3092 | 3217 | 2814 | 2359 |
| Demand | 7441 | 7330 | 7217 | 7227 | 7240 | 7282 | 7325 |
| Required Transfer | -4465 | -4588 | -4684 | -4630 | -4523 | -4952 | -5431 |
| **B17I - IMPORT** | | | | | | | |
| Effective Generation | 55348 | 55593 | 55811 | 55742 | 55617 | 56020 | 56475 |
| Demand | 51393 | 51504 | 51617 | 51607 | 51594 | 51552 | 51509 |
| Required Transfer | 4465 | 4588 | 4684 | 4630 | 4523 | 4952 | 5431 |

Boundary B17 is classified as the West Midlands boundary and historically suffers from a lack of local generation as well as having a high dependency of importing power from Northern zones to meet its demands. The thermal capability of the boundary under SQSS standards is in the region of 5,500 MW, but suffers from voltage violations in later years as conventional plant fall out of merit or close which reduces reactive support to the region. Throughout the SYS period the boundary capability is sufficient to meet the boundary requirements.

## Indicative Reinforcements for licence compliance

The list of reinforcement schemes presented in Table 8.2 provides an indication of those reinforcements that may be required to ensure continued compliance with the Licence Standard across the 17 major SYS boundaries at the time of peak for the given SYS background, i.e. to remedy capability deficits.

These indicative schemes would be additional to the currently planned transmission reinforcements listed in Table 6.2, and which already form part of the SYS background.
The additional schemes would be required, not only for compliance across the 17 SYS boundaries ('inter-zonal' reinforcements), but also for compliance across a number of boundaries internal to the zones delineated by the 17 SYS boundaries ('intra-zonal' reinforcements). The developments listed are those required for the specific SYS background. The additional indicative schemes would be varied to meet the changing needs of the system as it evolves.

Once the need for a particular reinforcement is established the detailed specification will be considered. By way of example, for reactive compensation plant, the optimal location, size and desired performance will be the subject of detailed analyses nearer the time when there is a need to commit to the work.

Some of the works listed in Table 8.2 will have been made a condition of particular 'GB Agreements' for connection to and use of the GB system. That is, a condition will have been included in certain agreements stipulating that the works would have to be completed before connection to or use of the GB Transmission System is permitted. This is in order to ensure continued compliance of the system with the Licence Standard and to safeguard the interests of all Users of the GB Transmission System in respect of security of supply.

## Indicative Reinforcements required to meet Environmental Targets

In June 2008, the Government published its consultation on a UK Renewable Energy Strategy. Following on from this, the Electricity Networks Strategy Group (ENSG), a cross industry group jointly chaired by the Department of Energy and Climate Change and Ofgem, asked the three GB Transmission Licensees, National Grid, Scottish Hydro Electric Transmission and Scottish Power Transmission with the support of an Industry Working Group to take forward a study to:

- Develop electricity generation and demand scenarios consistent with the EU target for 15% of the UK's energy to be produced from renewable sources by 2020; and
- Identify and evaluate a range of potential electricity transmission network solutions that would be required to accommodate these scenarios.

In March 2009, ENSG published a report 'Our Electricity Transmission Network: A Vision For 2020':

http://www.ensg.gov.uk/assets/1696-01-ensg_vision2020.pdf

which discharged the action placed on the Transmission Licensees. The reinforcements identified in this report are based on a range of scenarios that take account the significant changes anticipated in the generation mix between now and 2020. In particular, the scenarios examined the potential transmission investments with the connection of large volumes of onshore and offshore wind generation required to meet the 2020 renewables target, whilst, at the same time, facilitating the connection of other essential new generation, such as new nuclear that will be needed to reduce carbon emissions and maintain continued security of supply.

The study concluded that, provided the identified reinforcements are taken forward in a timely manner, they can be delivered to required timescales. It should also be noted that the reinforcements identified in this report are designed to facilitate connection of a large volume of different types of generation in a given area, not dependent on a single generation project proceeding, and where the lead time for the combined transmission reinforcements in a given area would exceed the time taken to construct the generation, i.e. lack of transmission capacity would have a potential negative impact in meeting renewable targets and/or accommodating generation required to maintain continued security of supply.

The development of the potential reinforcements are phased to achieve a 2020 delivery date with the initial phase being delivered in 2015 based on the prospective growth of renewables in each region. It is recognised that there will continue to be a degree of uncertainty about the volume and timing of generation growth in any given area. It is therefore proposed to continue to monitor the development of the market and update the scenarios accordingly. The proposed transmission reinforcements will be developed in such a manner as to ensure that the options are maintained at minimum costs. By undertaking pre-construction engineering work positions the delivery of each project such that construction can be commenced when there is sufficient confidence that the proposed reinforcements will be required. This is the least regrets solution, i.e. the minimum commitment to secure the ability to deliver to required timescales.

Following Ofgem initial consultation phase on Strategic investments, funds have been made available to undertake the pre-construction engineering for reinforcements identified by the study and these are being developed without requirements for User commitment. It is anticipated that Ofgem will undertake further consultation with regard establishing a regulatory framework which will facilitate taking forward the reinforcements identified by the report and any additional anticipatory reinforcement which may be required to facilitate the objectives identified in the report.

**Table 8.1 - GUM Boundaries Defined by SYS Study Zone**

| **Boundary Number** | **Boundary Name** | **SYS Study Zone/s (one side of boundary )** |
|---|---|---|
| B1 | North West Export | Z1 |
| B2 | North-South | Z1, Z2 |
| B3 | Sloy Export | Z3 |
| B4 | SHETL-SPT Boundary | Z1, Z2, Z3, Z4 |
| B5 | North-South | Z1, Z2, Z3, Z4, Z5 |
| B6 | SPT-NGET Boundary | Z1, Z2, Z3, Z4, Z5, Z6 |
| B7 | Upper North-North | Z1, Z2, Z3, Z4, Z5, Z6, Z7 |
| B8 | North to Midlands | Z1, Z2, Z3, Z4, Z5, Z6, Z7, Z8, Z9 |
| B9 | Midlands to South | Z1, Z2, Z3, Z4, Z5, Z6, Z7, Z8, Z9, Z10, Z11 |
| B10 | South Coast | Z16, Z17 |
| B11 | North East & Yorkshire | Z1, Z2, Z3, Z4, Z5, Z6, Z7,Z8 |
| B12 | South & South West | Z13, Z16, Z17 |
| B13 | South West | Z17 |
| B14 | London | Z14 |
| B15 | Thames Estuary | Z15 |
| B16 | North East, Trent & Yorkshire | Z1, Z2, Z3, Z4, Z5, Z6, Z7, Z8, Z10 |
| B17 | West Midlands | Z11 |

**Table 8.2 Indicative Developments**

| Location | Works | Affected Boundaries/Licensee |
|---|---|---|
| Higm Marnham - Ratcliffe | Uprating on the High Marnham to Ratcliffe circuits | NGET |
| Ratcliffe - Staythorpe | Uprating of the Ratcliffe to Staythorpe circuit | NGET |
| Grendon – West Burton | Uprating of the Grendon to West Burton circuit | NGET |
| Ninfield | Install reactive compensation (1MSC) | NGET |
| Feckenham | Install reactive compensation (1MSC) | NGET |
| Cottam | Install reactive compensation (1MSC) | NGET |
| Staythorpe | Install reactive compensation (1MSC) | NGET |
| Ratcliffe on Soar | Install reactive compensation (1MSC) | NGET |
| Pelham | Install reactive compensation (1MSC) | NGET |

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      Zone 7: North & North-East England .... 13
      Zone 8: Yorkshire .... 13
      Zone 9: North West England & North Wales .... 13
      Zone 10: Trent .... 14
      Zone 11: Midlands .... 14
      Zone 12: Anglia & Bucks .... 14
      Zone 13: South Wales & Central England .... 14
      Zone 14: London .... 15
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# Chapter 9

# Opportunities

## Introduction

This chapter provides a commentary on those parts of the National Electricity Transmission System (NETS) most suited to new connections and to the transport of further quantities of electricity. The information presented draws on that contained in the previous chapters, in particular Chapter 8 (Transmission System Capability).

Readers are reminded that anyone considering a development at a specific site and requiring additional technical information relating to that site may contact us for assistance as explained in "Further Information" in Chapter 1.

Notwithstanding the opportunities set out in this chapter, the three Transmission Licensees will continue to comply with Transmission Licence obligations and make offers to any User or potential new User wishing to use the NETS in respect of new generation and/or demand. The timescales, required by each Transmission Licensee to complete any necessary transmission work, associated with a new development, is, amongst other things, a function of the size and location of the development. In some instances no infrastructure reinforcement work at all will be required and no delay will be incurred. That is, if the required transmission reinforcement is localised and not environmentally contentious, the necessary work can normally be completed in similar timescales to that of the customer’s project. However, where the development requires extensive and/or contentious transmission work (with the associated need for Planning Consent and possible Public Inquiries), it may not always be possible for the relevant Transmission Licensee to fully meet the customer’s wishes with respect to timescales. Nevertheless, all three Transmission Licensees will always endeavour to meet their customer’s requirements.

This chapter also contains a section on Ancillary Services. Amongst other things this section presents information on possible future opportunities for Users to provide Ancillary Services under contract to ourselves.

## Use of External Interconnections

### Introduction

The section on "Interconnections with External Systems" in Chapter 3 explained that our transmission system is directly interconnected with those of France, Northern Ireland and the Netherlands by early 2011. By the end of 2012 there will be a further interconnection with Southern Ireland. Parties that have acquired rights to use these External Interconnections are, subject to the relevant market arrangements and agreements, able to trade between the electricity market in Great Britain and those of the External Systems.

### France Link

Under NETA, new arrangements for obtaining access to the link were introduced and these continue under BETTA. The arrangements allow for capacity to be allocated in either direction via a system of auctions. These are jointly administered by National Grid and the French Transmission System Operator (RTE). Details of the access arrangements including the auction process can be found on the RTE and National Grid Website, namely: http://www.nationalgrid.com/uk

### Northern Ireland Link

This link is owned by Moyle Interconnector Limited and operated by System Operator Northern Ireland (SONI), who also administer the sale of capacity on the interconnector on behalf of Moyle. The relevant Website address is: http://www.soni.ltd.uk

### Netherlands Link

A DC link for interconnection with the Netherlands electricity system was commissioned in early 2011. The link has a capacity of 1000MW, capable of bi-directional flow, and will be connected at Grain 400kV substation.

### Eire Link

Eirgrid is developing an 500MW HVDC interconnecter to join Eire to the NGET network at Deeside. The interconnector is proposed for connection in 2012 and is currently under construction.

## New Demand

The majority of single new demands are less than 50MW in size (e.g. a large new car production plant). However, the demand from a new steelworks could be in the region of 150MW. In any event, a step-change of say 150MW of demand is usually too small a value to affect any single zone significantly. In general terms, there is likely to be sufficient additional capability over a whole zone of the supergrid to be able to accommodate any single new demand of this size without requiring major reinforcement into the whole zone. Reinforcements at and into a particular Grid Supply Point may be required for a new demand, and in some cases additional reactive compensation may also be required, and a prospective new entrant should contact us for a detailed discussion of an individual site.

An exception might be the introduction of such a step-change of load at certain points within or around some southern areas. For example, the London area has a large demand; approaching one tenth of the system peak demand. The London boundary is close to its thermal limit although planned work, some in Table B.7c and some in Table 8.2, will ensure continued compliance. A large step-change in demand might, dependent on exact location, require major reinforcement.

It should also be remembered that, whilst a 150MW demand increase may not have an appreciable effect upon the particular zone in which it is located, it could have a more global effect on the overall system. For instance additional demand in the south could, under certain circumstances, advance the need for major inter zonal transmission reinforcement between the north and the south. Each case needs to be considered on its own merits.

## New Generation

### Overview

In general terms, the disposition of demand and generation across the NETS is such that much of the generation capacity is located in or towards the northern and midland parts of England based on location of fuel, while much of the demand is located in the southern parts of the system. In consequence, the resultant power flows are broadly from the northern parts to the southern parts of the system, particularly at times of the system peak demand.

The disposition of the reported increase in generating capacity from 2010/11 to 2017/18 is described in ”Generation Disposition” in Chapter 3. In particular, Appendix F Table F.9 details the capacity changes on a zonal basis.

It should be remembered that the figures shown in tables such as Table F.9 reflect the current contracted position and take no account of future uncertainty. As mentioned previously, it is reasonable to suppose that further new applications for power station connections will be received and, at the same time, some existing contracts may be modified or terminated and some existing power stations will close.

It should also be noted that capacities in Table 3.11 and other tables in Chapter 3 do not include the embedded Medium and Small generation and embedded External Interconnections with External Systems. The capacity of such embedded generation sources is the subject of Chapter 4 (Embedded and Renewable Generation).

A key message arising from the analyses of boundary power transfers is that, with the increase in new generation planned over the next seven years, the resultant power flows through the Scottish and English grid systems to the Midlands would require significant reinforcement. The future is uncertain and it may be that not all projects may proceed to completion. With the implementation of Connect and Manage, new generation connection offers may be made ahead of this reinforcement. In addition some existing fossil fuel stations may close due to technical or commercial reasons, or due to environmental legislation, e.g. following the introduction of the Large Combustion Plant Directive in 2008 and the IED directive in 2016.

## Completion of the Transmission Access Review

On 27 July 2010, DECC published the government response to their technical consultation on the model for improving grid access, explaining that the Government had decided to implement an enduring Connect and Manage (C&M) approach to transmission access. This new approach became live on 11 August 2010, and from this date the necessary industry code and licence modifications became effective.

The full response can be found at:

http://www.decc.gov.uk/en/content/cms/consultations/improving_grid/improving_grid.aspx

The new arrangements continue the principle introduced under Interim Connect and Manage (ICM), namely generation projects are allowed to connect to the transmission system in advance of the completion of the wider transmission reinforcement works. The works that are required to be completed prior to a generator connecting are classed as 'Enabling Works' as defined in the government response and also set out within the new section 13 of the Connection and Use of System Code (CUSC).

To help interested parties understand how the new C&M regime will work in practice, we have prepared a "Connect and Manage Guidance" document which can be found on the National Grid website at:

http://www.nationalgrid.com/uk/Electricity/GettingConnected/PoliciesAndGuidance/

## Other Regime Developments

Other significant development work that may impact on connections are Ofgem's Project TransmiT (a review of Transmission charging and associated connection arrangements) and CUSC Modification Proposal 192 on the development of enduring user commitment. Further information on these two developments can be found in Chapter 10 of this document.

## Generation Opportunities

This section provides an indication of the likely connection dates that we would currently expect to offer to connection applications in various geographical locations around the country. These dates have been based around those that have been offered to projects that have recently been transitioned to the new Connect and Manage arrangements.

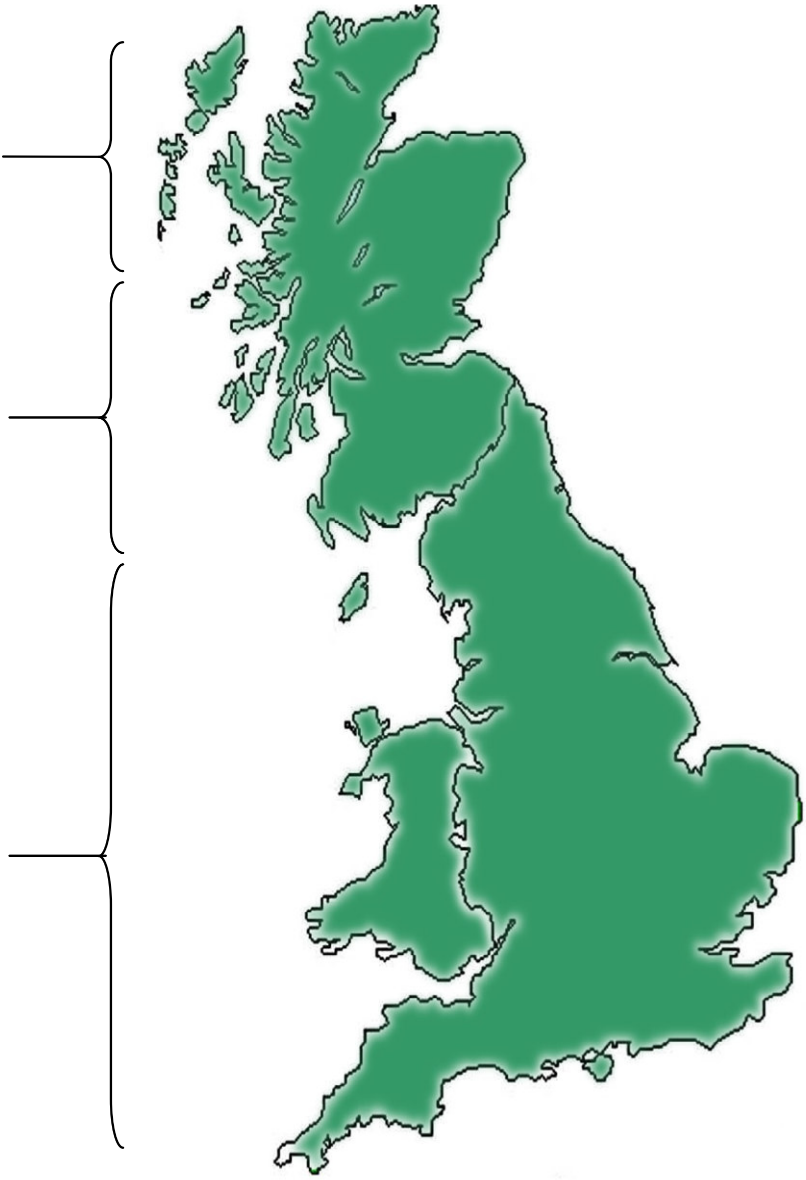
The information on connection dates is provided in the two figures 9.1 and 9.2. Figure 9.1 provides a high level overview of the likely connection dates around the country, whilst Figure 9.2 highlights areas where local difficulties tend to extend lead times.

Please note that these are indicative only and are subject to confirmation on an individual case by case basis. We welcome the opportunity to discuss your aspirations for grid connections ahead of any formal application. To discuss an individual project please contact your Customer Agreement Manager or our Customer Services team. The contact details for the Electricity Customer Connections manager are julian.leslie@uk.ngrid.com or 01926 653350.

In the interim, we provide future updates to likely connection dates through our quarterly publication of the Transmission Network Quarterly Connections Updates (TNQCU), copies of which can be found at:

www.nationalgrid.com/uk/Electricity/GettingConnected/gb_agreements/

**Figure 9.1 – Illustrative Connection Timescales**



**2016 - 2017**
Lots of embedded.
Often Grid Supply Point reinforcements

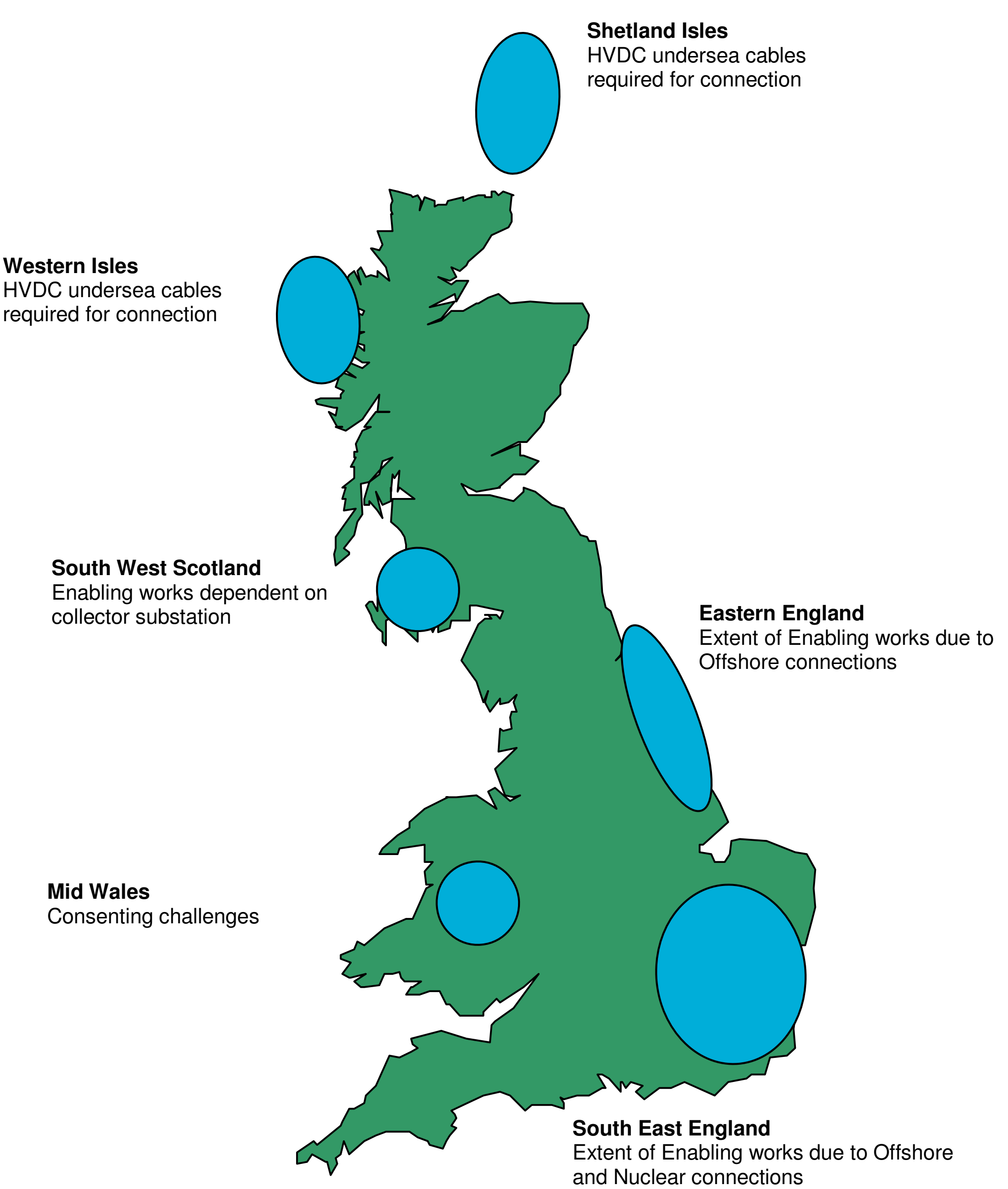
**2014 – 2016**
Dependant on size (smaller projects earlier).

Less connection applications than further north.

**2012 - 2016.**
Shorter timescales for embedded, dependant on local Grid Supply Point

**2015 / 2016.**
Larger new projects, possibly earlier in some areas

**Figure 9.2 – Illustrative Connection Timescales – Areas of local difficulty**



## Strategic Investment

The information contained in this year's SYS reflects the report delivered by the Energy Networks Strategy Group (ENSG) – Our Electricity Network – A Vision for 2020. The work carried out for ENSG identifies a set of transmission reinforcements that would facilitate the connection of renewable generation to help meet the Government's 2020 climate change targets. These works are now progressing ahead of full user commitment, as the date for construction becomes closer, the user commitment is increasing and hence these works identified will be completed (subject to achieving consents) in time to facilitate the connection of new contracted generation.

## Demand TNUoS Tariff Zones

The demand TNUoS tariff zones correspond to the original Regional Electricity Company (REC) franchise areas in England and Wales, and the geographical areas of the two Scottish electricity companies.

A demand customer's zone is effectively determined by the Grid Supply Point (GSP) Group to which the customer is deemed to be connected. In the case of a directly-connected power station, the generation tariff zone applicable relates to the geographical location of the transmission substation (connection site) to which the station is connected. In the case of an embedded power station, the generation tariff zone applicable relates to the transmission substation to which that station is deemed connected.

Table 9.1 shows the tariffs applicable from 1st April 2011.

**Table 9.1 - Demand TNUoS Tariffs applicable from 1st April 2011**

| Zone No. | Zone Name. | HH Zonal Tariff (£/kW) | NHH Zonal Tariff (p/kWh) |
|---|---|---|---|
| 1 | Northern Scotland | 6.535401 | 0.886871 |
| 2 | Southern Scotland | 11.730556 | 1.666105 |
| 3 | Northern | 15.684824 | 2.170176 |
| 4 | North West | 19.449161 | 2.736856 |
| 5 | Yorkshire | 19.582975 | 2.704505 |
| 6 | N Wales & Mersey | 20.204644 | 2.952899 |
| 7 | East Midlands | 22.205396 | 3.095769 |
| 8 | Midlands | 23.811436 | 3.387267 |
| 9 | Eastern | 22.671734 | 3.127405 |
| 10 | South Wales | 22.846195 | 3.097454 |
| 11 | South East | 26.737000 | 3.736654 |
| 12 | London | 27.943266 | 3.779345 |
| 13 | Southern | 27.567648 | 3.910939 |
| 14 | South Western | 28.408897 | 3.887151 |

For further information on charging please see the “Use of System Tariff Zones” section in Chapter 6 and also the “Transmission Pricing” section in Chapter 10, both of which contain useful links to the National Grid charging website.

## Ancillary Services

### Overview

To operate the system on a real time basis National Grid as NETSO requires access to a range of services. These services are used to balance supply and demand in an economic manner, and to maintain quality and security of supply in accordance with the NETS SQSS. To this end National Grid procures a number of ancillary services from a variety of different providers including generation, demand side and interconnector participants.

The various categories of ancillary services for which National Grid contract are set out in the table below:

| **Ancillary Services** | | |
|---|---|---|
| **Part I - System (Mandatory)** | **Part II – System (Necessary)** | **Commercial** |
| ■ Reactive<br>■ Frequency response | ■ Black Start<br>■ Fast Start<br>■ System to Generator Operational Tripping Scheme | ■ Enhanced reactive<br>■ Firm frequency response<br>■ Reserve –<br>■ Short Term Operating reserve;<br>■ Fast Reserve;<br>■ Balancing Mechanism Start Up (Warming)<br>■ System to System Services including Emergency Instruction<br>■ Maximum generation<br>■ Commercial Intertrip/ Energy Management Systems<br>■ Constraint management |

More information on each of the above can be found on the National Grid website at:
http://www.nationalgrid.com/uk/Electricity/Balancing/services/

Although the above services are provided by a party once connected to the relevant distribution or transmission system, discussion with National Grid as to what services could potentially be provided can commence prior to connection (see Contact Us section below). This is particularly pertinent for a service such as Black Start where it may be more cost efficient to install necessary additional equipment required to provide a service during the construction of a site rather than to retrofit.

### Future Balancing Services Requirements and Opportunities

Operating the Electricity transmission network in 2020

In June 2009, National Grid published an initial consultation on a range of issues and associated challenges to operating the electricity networks in 2020, a number of which arise as a result of a significant change in the GB generation mix. This consultation also coincided with publication of two documents detailing National Grid's subsequent future requirement for both reserve and frequency response services in order to manage these developments (http://www.nationalgrid.com/uk/Electricity/Balancing/services/FutureRequirements/).

A further consultation is to be published in summer 2011 which looks to refine the 'operating in 2020' document and provide further analysis and views on these issues. This updated 2020 document will be published on the National Grid website in the following location, where the original consultation and responses can also be found:

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

## Demand side and Aggregation

Services can generally be provided to National Grid in one of two ways, either an increase in generation or a reduction in electricity demand by parties connected to the NETS or relevant Distribution Network. Historically, balancing services have typically been provided by generation participants but National Grid has been actively promoting demand side participation in balancing services over recent years and has been successful in the integration of demand side service provision in services such as Short-Term Operating Reserve (STOR) and Frequency Response. More information regarding demand side participation in balancing services can be found at: http://www.nationalgrid.com/uk/Electricity/Balancing/demandside/.

In addition to demand side, National Grid has also encouraged smaller generation volumes into balancing services markets via an aggregation model. This allows a number of smaller loads (which alone may be too small to participate in balancing services where typically the minimum requirement is 3MW) to be aggregated from a number of sites. This model works particularly well in the STOR service where a number of aggregating companies actively participate. A list of such companies, along with contact details, can be found on the National Grid website at:
http://www.nationalgrid.com/uk/Electricity/Balancing/demandside/aggregators/

## Connect and Manage

Following the implementation of an enduring Connect and Manage (C&M) approach to transmission access on 11 August 2010, generation projects are allowed to connect to the transmission system in advance of the completion of the wider transmission reinforcement works. Connection of generators ahead of the completion of these wider works means that parts of the transmission system will not be compliant with the NETS SQSS until these works are completed.

This, in turn, means that National Grid as system operator will be required to manage this non compliance as there are likely to be more bottlenecks in the system and therefore an increase in constraints. A range of constraint management tools are available for this purpose, including fast de-load, commercial intertrips and Energy Management Systems, some of which may be required prior to connection in accordance with the relevant bilateral connection agreement.

National Grid will be seeking to initiate discussion regarding constraint management agreements prior to connection with providers where this is applicable.

National Grid would welcome discussion of the above balancing services opportunities with either new or existing providers. Should you wish to discuss any of the balancing services then please call Nigel Fox (Contracts and Settlements Manager) on 01926 656823 or your relevant balancing services account manager.

## Zonal Power Losses

It was explained in "Zonal Power Losses" in Chapter 7 that the effectiveness, in system terms of any new generating station is related, in part, to the effect it has on system losses. Clearly, if a new power station were to be located in the north, and this were to displace the operation of southern generation, then the north to south power flows would increase, transmission losses would increase and some of the output of the new station would, in effect, be ‘lost’ to the system. However, if the new power station were to be located in the south and this displaced northern generation, the converse would be true. That is, north to south power flows would decrease, system losses would decrease and the relative net effect would be as if a larger station had been installed.

Table 7.5 illustrates the effectiveness, in terms of optimising (i.e. minimising) overall transmission system losses, of locating additional generation in each of the 17 SYS Study Zones in turn. That table presents the 17 zones in order of effectiveness and thereby provides a useful and reasonably robust indicator of relative merits. The resultant order is consistent with the relative order of generation opportunities, discussed in the previous section, and the relative order of generation TNUoS charges across the system.

For comparison, the main tables from Schedule 1 of our 2011/12 ‘Statement of Use of System Charges’, are available on the “Charging” web pages on the National Grid website:

http://www.nationalgrid.com/uk/Electricity/Charges/chargingstatementsapproval/

However, please note that, whilst similar, the 17 SYS Study Zones used for the purpose of displaying zonal power losses differ from the 20 generation and 14 demand TNUoS tariff zones.

Generators are also subject to local circuit and substation tariffs. Details of these can be found at:

http://www.nationalgrid.com/uk/Electricity/Charges/usefulinfo/

## Zonal Commentary

This section complements the previous sections of this chapter by providing additional information on opportunities for new generation capacity presented on the basis of individual zones or groups of zones. The following zonal commentary considers the opportunities for new generation on the probabilistic background as well as the SYS background.

The section "Boundary Commentary" in Chapter 8 describes the wide range of probabilistic transfers across the 17 SYS boundaries over the next seven-year period. The reader is guided to the description of the probabilistic transfers for each boundary shown in Figure 8.B1, Figure 8.B2, Figure 8.B3, Figure 8.B4, Figure 8.B5, Figure 8.B6, Figure 8.B7, Figure 8.B8, Figure 8.B9, Figure 8.B10, Figure 8.B11, Figure 8.B12, Figure 8.B13, Figure 8.B14, Figure 8.B15, Figure 8.B16 and Figure 8.B17 within this section. The adoption of a probabilistic view of future boundary transfer levels recognises the fact that there is uncertainty in the future generation and demand background. Clearly, this has an impact on the likely opportunities for the connection of new generation onto the transmission network. The commentary below seeks to address the opportunities for new generation given this level of uncertainty.

Clearly, generation and demand backgrounds, which increase North to South transfers, tend to precipitate the need for major inter-zonal transmission reinforcement and thereby reduce northern opportunities. Such backgrounds would include further northern planting and/or the export of power to France at times of peak. Conversely, backgrounds which reduce north to south transfers tend to increase northern opportunities and/or relax the need for major inter-zonal transmission reinforcement. Such backgrounds would include new generation in the South.

In considering the following zonal commentary it is useful to cross reference Table 7.1, which presents the studied generation, demand and transfer for each zone and the boundary commentary section "Boundary Commentary" in Chapter 8. Please note, however, that Table 7.1 is on the basis of the 'SYS background' and that the generation capacities given are the 'studied' or contributory capacities (based on Table F.4) rather than installed capacities.

For ease of reference, each zonal commentary includes the relevant extract of Table 7.1, repeated in Table 9.Z1 to Table 9.Z17 for each of the SYS Study Zones. Please refer to Table F.4 for the effect of generation capacity changes in terms of other plant displaced from being contributory under the SYS background. For further information, Table F.8 in Appendix F gives details of each new generation project together with its SYS Study Zone.

## Zone 1: North West (SHETL)

**Table 9.Z1 - SYS Study Zone Z1, North West (SHETL)**

| **Quantity (MW)** | **2011/12** | **2012/13** | **2013/14** | **2014/15** | **2015/16** | **2016/17** | **2017/18** |
|---|---|---|---|---|---|---|---|
| Effective Generation | 915 | 992 | 1100 | 1675 | 1655 | 1646 | 1638 |
| Demand | 511 | 515 | 520 | 509 | 507 | 506 | 506 |
| Planned Transfer | 404 | 477 | 580 | 1166 | 1148 | 1140 | 1132 |

The SHETL North West zone encompasses the area to the north and west of Fort Augustus, Beauly (near Inverness) and Keith. This area includes a significant amount of existing hydro generation, new renewable generation and the Foyers pumped storage scheme. Demand in this zone is significantly lower than the installed generation; consequently this zone is normally an exporting zone.

Generation in this zone is increasing at a significant rate due to the high volume of new renewable generation seeking connection in the area. Consequently, opportunities for connection of new generation are very low in this zone.

## Zone 2: North (SHETL)

**Table 9.Z2 - SYS Study Zone Z2, North (SHETL)**

| **Quantity (MW)** | **2011/12** | **2012/13** | **2013/14** | **2014/15** | **2015/16** | **2016/17** | **2017/18** |
|---|---|---|---|---|---|---|---|
| Effective Generation | 990 | 985 | 1019 | 1286 | 1440 | 1643 | 1775 |
| Demand | 609 | 611 | 616 | 618 | 610 | 609 | 609 |
| Planned Transfer | 381 | 374 | 403 | 668 | 830 | 1034 | 1166 |

The SHETL North zone comprises the area to the north of Errochty and Tealing, and to the east of a line drawn between Keith and Errochty. This area includes the thermal power station at Peterhead and some new renewable generation. Demand in this zone is significantly lower than the installed generation; consequently this zone is normally an exporting zone.

Generation in this zone is increasing gradually due to the connection of new renewable generation in the area. Consequently, opportunities for connection of new generation are very low in this zone.

## Zone 3: Sloy (SHETL)

**Table 9.Z3 - SYS Study Zone Z3, Sloy (SHETL)**

| Quantity (MW) | 2011/12 | 2012/13 | 2013/14 | 2014/15 | 2015/16 | 2016/17 | 2017/18 |
|---|---|---|---|---|---|---|---|
| Effective Generation | 273 | 299 | 333 | 325 | 322 | 316 | 177 |
| Demand | 65 | 66 | 67 | 66 | 68 | 70 | 67 |
| Planned Transfer | 208 | 233 | 266 | 259 | 254 | 246 | 110 |

The Sloy zone in the south west of the SHETL system encompasses the flows to the north and south of the Sloy busbar. In comparison to the 132kV infrastructure in the area, this boundary includes a significant amount of existing hydro generation and new renewable generation in Kintyre and Argyll. Demand in the area is centred around Oban and Mull, Lochgilphead and Islay and Campbeltown and Arran. The power flows are normally into this zone from Killin in the north and out of the zone to the south towards Windyhill (near Glasgow).

New renewable generation in Kintyre and Argyll is increasing over time and reinforcement is needed to accommodate the required capability. Consequently, opportunities for connection of new generation are very low in this zone.

## Zone 4: South (SHETL)

**Table 9.Z4 - SYS Study Zone Z4, South (SHETL)**

| Quantity (MW) | 2011/12 | 2012/13 | 2013/14 | 2014/15 | 2015/16 | 2016/17 | 2017/18 |
|---|---|---|---|---|---|---|---|
| Effective Generation | 456 | 453 | 449 | 474 | 1071 | 1050 | 975 |
| Demand | 517 | 520 | 527 | 540 | 541 | 548 | 545 |
| Planned Transfer | -61 | -67 | -78 | -66 | 530 | 502 | 430 |

Zone 4 comprises the southern part of the SHETL system excluding the Sloy zone. In view of the system limitations to the south of this zone, opportunities for connection of new generation are very low in this zone.

## Zone 5: North (SPT)

**Table 9.Z5 - SYS Study Zone Z5, North (SPT)**

| Quantity (MW) | 2011/12 | 2012/13 | 2013/14 | 2014/15 | 2015/16 | 2016/17 | 2017/18 |
|---|---|---|---|---|---|---|---|
| Effective Generation | 2158 | 2164 | 1914 | 1950 | 1915 | 2110 | 2289 |
| Demand | 1193 | 1183 | 1170 | 1170 | 1175 | 1167 | 1169 |
| Planned Transfer | 965 | 981 | 744 | 780 | 740 | 944 | 1120 |

In view of the system limitations within and to the south of this zone, opportunities for connection of new generation are very low.

## Zone 6: South (SPT)

**Table 9.Z6 - SYS Study Zone Z6, South (SPT)**

| Quantity (MW) | 2011/12 | 2012/13 | 2013/14 | 2014/15 | 2015/16 | 2016/17 | 2017/18 |
|---|---|---|---|---|---|---|---|
| Effective Generation | 3942 | 4283 | 4417 | 4611 | 4167 | 4114 | 5173 |
| Demand | 3130 | 3133 | 3136 | 3141 | 3135 | 3133 | 3131 |
| Planned Transfer | 812 | 1150 | 1281 | 1470 | 1032 | 981 | 2042 |

Boundary 6 is the primary importing border from Scotland to England in the UK, which relates zone areas 6 and 7. Zone 6 includes significant capacity of generating plant which includes new onshore wind farms. Opportunities for connecting new generation in this zone are considered to be very low, due to the limiting factors found south of the border. However there might be a slight possibility beyond 2016 due to the new HVDC cables being installed and the closure of Cockenzie coal fired power station.

## Zone 7: North & North-East England

| **Table 9.Z7 - SYS Study Zone Z7, North & North East England (NGET)** | | | | | | | |
|---|---|---|---|---|---|---|---|
| **Quantity (MW)** | **2011/12** | **2012/13** | **2013/14** | **2014/15** | **2015/16** | **2016/17** | **2017/18** |
| Effective Generation | 2970 | 2961 | 2976 | 3181 | 3446 | 2993 | 2484 |
| Demand | 2861 | 2964 | 3067 | 3078 | 3091 | 3196 | 3303 |
| Planned Transfer | 109 | -3 | -91 | 103 | 355 | -204 | -819 |

Zone 7 is the upper north of England and lies beneath the SPT network and carries the bulk flow from Scotland to England especially in later years as a number of CCGT units fall out of merit. The net transfer varies from an exporting zone to an importing zone by a few hundred Megawatts in 2016/17 to approximately 800 MW in 2017/18. The network in this region is a mixture of 275kV and 400 kV circuits with many generators connected. As transfers from Scotland increase, and new generation connects to this zone; a need for further reinforcement in the area is essential to meet future demand in England & Wales and to achieve renewable targets. Given the high through flows through this zone and the limited transmission capability, there is little opportunity for further connections without major works.

## Zone 8: Yorkshire

| **Table 9.Z8 - SYS Study Zone Z8, Yorkshire (NGET)** | | | | | | | |
|---|---|---|---|---|---|---|---|
| **Quantity (MW)** | **2011/12** | **2012/13** | **2013/14** | **2014/15** | **2015/16** | **2016/17** | **2017/18** |
| Effective Generation | 10137 | 9732 | 9405 | 9008 | 8768 | 8395 | 7880 |
| Demand | 5291 | 5283 | 5276 | 5200 | 5127 | 5111 | 5094 |
| Planned Transfer | 4846 | 4449 | 4130 | 3808 | 3641 | 3284 | 2786 |

This zone encompasses a diverse range of generation sources from conventional coal plants to offshore wind in later years throughout the SYS period. It can be seen from Table 9.Z8 that the net export decreases throughout the seven year period, as many large coal fired units either fall out of merit or close due to the LCPD. There are numerous new generation connections to this region, however additional new connections may be possible in later years.

## Zone 9: North West England & North Wales

| **Table 9.Z9 - SYS Study Zone Z9, North West England & North Wales (NGET)** | | | | | | | |
|---|---|---|---|---|---|---|---|
| **Quantity (MW)** | **2011/12** | **2012/13** | **2013/14** | **2014/15** | **2015/16** | **2016/17** | **2017/18** |
| Effective Generation | 7357 | 7480 | 7660 | 7269 | 7004 | 7319 | 7518 |
| Demand | 7257 | 7070 | 6882 | 6918 | 6956 | 7288 | 7625 |
| Planned Transfer | 100 | 409 | 778 | 351 | 48 | 31 | -107 |

Zone 9 is located in the North West of England and North Wales which covers Cheshire, greater Manchester and Cumbria. It is characterised with high generation and demand levels which tend to compliment each other, leading to a very low net transfer from this zone. The transmission network region is a mixture of 275kV and 400kV and aids in transferring the bulk power from the upper north zone. Some potential exists in the North Wales region for new connections; however larger projects would require further reinforcements. As the bulk of the transfer travels South West to meet some of the localised demand in London, under a fault or outage condition some of the 400kV circuits within zone 9 can be overloaded substantially due to a concentrated import from Scotland.

## Zone 10: Trent

**Table 9.Z10 - SYS Study Zone Z10, Trent (NGET)**

| Quantity (MW) | 2011/12 | 2012/13 | 2013/14 | 2014/15 | 2015/16 | 2016/17 | 2017/18 |
|---|---|---|---|---|---|---|---|
| Effective Generation | 6542 | 6628 | 6765 | 6781 | 6920 | 6182 | 5334 |
| Demand | 957 | 966 | 974 | 986 | 999 | 914 | 828 |
| Planned Transfer | 5585 | 5662 | 5790 | 5795 | 5921 | 5268 | 4506 |

Zone 10 is located North East of the Midlands and includes Trent and the upper Wash region. This zone has a high generation concentration with low demand, giving an excess in transfer from the net generation. The zone compromises mainly of 400kV circuits which take the bulk of the power, and has considerably high fault levels due to the high concentration of generation. Due to the high flows, the transmission capacity is at its maximum and additional reinforcements or uprating of existing lines are necessary for any future generation connections.

## Zone 11: Midlands

**Table 9.Z11 - SYS Study Zone Z11, Midlands (NGET)**

| Quantity (MW) | 2011/12 | 2012/13 | 2013/14 | 2014/15 | 2015/16 | 2016/17 | 2017/18 |
|---|---|---|---|---|---|---|---|
| Effective Generation | 3486 | 3241 | 3023 | 3092 | 3217 | 2814 | 2359 |
| Demand | 7441 | 7330 | 7217 | 7227 | 7240 | 7282 | 7325 |
| Planned Transfer | -3955 | -4089 | -4195 | -4135 | -4023 | -4469 | -4966 |

The West Midlands is classified as zone 11, with a high demand and some generation. The West Midlands is an importing boundary and relies heavily on the transfer from the North West over numerous 400kV circuits which is then stepped down to 275kV to feed the localised demand. It is anticipated that a number of coal fired plants within the West Midlands will close due to the LCPD proposals, but will be replaced with efficient CCGT plants allowing the planned transfer to remain fairly constant throughout the majority of the SYS period. It can be noted that the planned transfer increases by approximately 20% from 2011/12 to 2017/18 which is predominately due to a net reduction in generation despite new generation commissioning.

## Zone 12: Anglia & Bucks

**Table 9.Z12 - SYS Study Zone Z12, Anglia & Bucks (NGET)**

| Quantity (MW) | 2011/12 | 2012/13 | 2013/14 | 2014/15 | 2015/16 | 2016/17 | 2017/18 |
|---|---|---|---|---|---|---|---|
| Effective Generation | 3773 | 3863 | 3983 | 4648 | 5405 | 6106 | 6715 |
| Demand | 4744 | 4820 | 4897 | 4959 | 5023 | 5075 | 5127 |
| Planned Transfer | -970 | -957 | -914 | -311 | 382 | 1031 | 1589 |

This zone is classified as East Anglia and Bucks which compromises of the southern Wash region, Grendon, Buckinghamshire and Norfolk. Table 9.Z12 shows that the zone is changed from an importing boundary in 2011/12 to an exporting boundary in 2017/18 which is mostly attributed to numerous offshore windfarms being connected beyond 2015/16. This in turn reduced the North to South power flows as the zonal demand remains fairly constant throughout the years. If further generation is to be added to this zone, a number of reinforcements need to be implemented, as the zone changes from an importing to an exporting zone.

## Zone 13: South Wales & Central England

**Table 9.Z13 - SYS Study Zone Z13, South Wales & Central England (NGET)**

| Quantity (MW) | 2011/12 | 2012/13 | 2013/14 | 2014/15 | 2015/16 | 2016/17 | 2017/18 |
|---|---|---|---|---|---|---|---|
| Effective Generation | 5833 | 6095 | 6404 | 5516 | 4717 | 4926 | 5057 |
| Demand | 5221 | 5216 | 5211 | 5206 | 5203 | 5144 | 5083 |
| Planned Transfer | 611 | 879 | 1193 | 310 | -486 | -217 | -25 |

Zone 13 is the South Wales and Central England zone which consists of Bristol, Gloucestershire and Wiltshire and possesses a larger portion of the MITS which connects the north of England and Wales to the south. In the early years the zone exports power to the East aiding in supporting the load in London, but then begins to import power in the later years, as numerous coal fired power stations fall out of merit. The thermal capability of the transmission network in this region is more than sufficient to import or export power, but restrictions occur in this zone as round 3 windfarms connect.

## Zone 14: London

**Table 9.Z14 - SYS Study Zone Z14, London (NGET)**

| Quantity (MW) | 2011/12 | 2012/13 | 2013/14 | 2014/15 | 2015/16 | 2016/17 | 2017/18 |
|---|---|---|---|---|---|---|---|
| Effective Generation | 1750 | 1724 | 1712 | 1861 | 2044 | 2035 | 1992 |
| Demand | 9504 | 9791 | 10078 | 10234 | 10395 | 10301 | 10205 |
| Planned Transfer | -7755 | -8067 | -8366 | -8373 | -8351 | -8267 | -8214 |

Inner and outer London is encompassed in zone 14, and is characterised with high demand and low generation; thus making it reliant on surrounding zones to transfer power into London. The majority of the London transmission network is at 275kV with the main London feeders being at 400kV allowing the connection of generation within London at suitable key locations across the zone. However if generation is to be connected in a concentrated region, major reinforcement upgrades would be required to export the power to the rest of the zone. Under either option, generation opportunity in London is considered high, in order to reduce its reliance on importing power from other zones.

## Zone 15: Thames Estuary

**Table 9.Z15 - SYS Study Zone Z15, Thames Estuary (NGET)**

| Quantity (MW) | 2011/12 | 2012/13 | 2013/14 | 2014/15 | 2015/16 | 2016/17 | 2017/18 |
|---|---|---|---|---|---|---|---|
| Effective Generation | 5214 | 5285 | 5395 | 5189 | 5073 | 5073 | 4990 |
| Demand | 2150 | 2155 | 2161 | 2193 | 2226 | 2273 | 2322 |
| Planned Transfer | 3065 | 3130 | 3235 | 2997 | 2848 | 2800 | 2669 |

The Thames Estuary zone consists of a mixture of generation including nuclear and CCGT plants, as well as some offshore wind farms. The generation exceeds the demand giving a surplus in generation and a high planned transfer which slightly drops in later years, as older conventional plants close. Two interconnectors exist within this zone; one being the French link and the other being the BritNed link. From Sellindge there is an existing HVDC which interconnects the NGET network to the French RTE network, while the Britned HVDC link (based in the Isle of Grain) interconnects to the Dutch TenneT network. The interconnectors may have a large effect on transfers and flows by importing and exporting power in and out of the NGET network.

## Zone 16: Central South Coast

**Table 9.Z16 - SYS Study Zone Z16, Central South Coast (NGET)**

| Quantity (MW) | 2011/12 | 2012/13 | 2013/14 | 2014/15 | 2015/16 | 2016/17 | 2017/18 |
|---|---|---|---|---|---|---|---|
| Effective Generation | 1259 | 1072 | 893 | 876 | 873 | 869 | 851 |
| Demand | 4433 | 4443 | 4452 | 4458 | 4466 | 4353 | 4237 |
| Planned Transfer | -3174 | -3371 | -3558 | -3583 | -3593 | -3483 | -3386 |

Zone 16 is the Central South Coast zone which covers a large portion of the south of England. The transmission network in this region consists of five 400kV circuits which interconnects the South Coast with London, Thames Estuary, South Wales and the South West of England. Little change occurs in generation within this zone, except for a CCGT unit falling out of merit. The opportunity for new generation development can be regarded as medium.

## Zone 17: South West England

**Table 9.Z17 - SYS Study Zone Z17, South West England (NGET)**

| Quantity (MW) | 2011/12 | 2012/13 | 2013/14 | 2014/15 | 2015/16 | 2016/17 | 2017/18 |
|---|---|---|---|---|---|---|---|
| Effective Generation | 1786 | 1760 | 1748 | 1713 | 1708 | 2382 | 3024 |
| Demand | 2950 | 2944 | 2937 | 2944 | 2951 | 3002 | 3053 |
| Planned Transfer | -1164 | -1184 | -1190 | -1231 | -1243 | -620 | -29 |

Zone 17 is the South West of England and separates its zone from the rest of the UK via the B13 boundary. The zone is reliant on importing power from the South West and Central South Coast over two 400kV double circuits. Only two large power stations exist within this zone Hinkley point B nuclear and Langage CCGT, which supplies approximately two thirds of the demand throughout the early years. The zonal generation and demand becomes fairly balanced in 2017/18 as Hinkley Point C nuclear connects and supplies an additional 1,670 MW of generation to the zone. The potential for generation connection is low for the zone.

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# Chapter 10

# Market Overview

## Introduction

The Energy Act (2004) received Royal Ascent in July 2004. Under powers granted by this legislation the Secretary of State directed changes to licences and designated changes to codes that together provided for the introduction of the British Electricity Trading and Transmission Arrangements (BETTA), which were subsequently introduced on 1 April 2005. They replaced the previous New Electricity Trading Arrangements (NETA) in England and Wales, and the separate arrangements that existed in Scotland and the British Grid System Agreement (BGSA). This chapter provides an overview of BETTA and reports on related issues such as governance, institutional and contractual arrangements, and also provides a link to the Offshore Development Information Statement (ODIS) which gives information on the development of offshore generation.

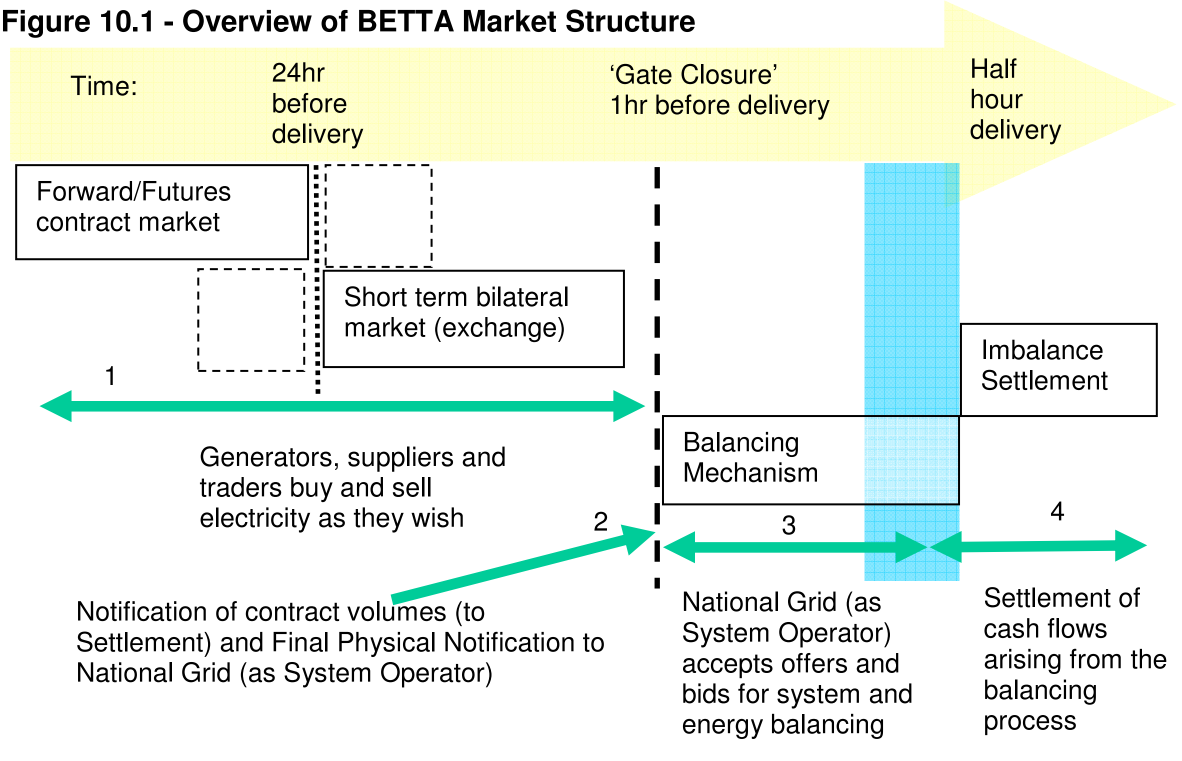
The chapter concludes with a generalised summary of some of the main requirements placed upon users in relation to their obligations to become party to the various codes and charges under BETTA.

## British Electricity Trading and Transmission Arrangements

### The Market Structure

The arrangements under BETTA are based on bilateral trading between generators, suppliers, traders and customers across a series of markets operating on a rolling half-hourly basis. Under these arrangements generators self despatch their plant rather than being centrally despatched by the System Operator. There are three stages to the new wholesale market, plus a post-event new settlement process. These are illustrated in Figure 10.1.

**Figure 10.1 - Overview of BETTA Market Structure**



Participation in the bilateral markets (i.e. the Forward/Futures contract market and the Short-term bilateral markets) and the Balancing Mechanism (i.e. offer/bid submission) is optional. Participation in Settlements is mandatory. In addition, certain categories of generator are required to provide Physical Notifications. The Balancing and Settlement Code (BSC) provides the framework within which participants comply with the Balancing Mechanism and Settlement Process. The BSC is administered by a non-profit making entity called Elexon. Information on Elexon is available from its website: www.elexon.co.uk.

The BSC also specifies the process for modifying the BSC itself. All modifications to the BSC are approved by the Authority (Ofgem) and must, in order to be approved, better facilitate achieving the applicable BSC objectives.

Gate Closure is the point in time when market participants notify the System Operator of their intended final physical position and is set at one hour ahead of real time. In addition, no further contract notification can be made to the central settlement systems.

## Forwards and Futures Contract Market

The bilateral contracts markets for firm delivery of electricity operate from a year or more ahead of real time (i.e. the actual point in time at which electricity is generated and consumed) and typically up to 24 hours ahead of real time. The markets provide the opportunity for a seller (generator) and buyer (supplier) to enter into contracts to deliver/take delivery, on a specified date, of a given quantity of electricity at an agreed price.

The markets are optional with participants having complete freedom to agree contracts of any form. Formal disclosure of price is not required.

The Forwards and Futures Contract Market is intended to reflect electricity trading over extended periods and represents the majority of trading volumes. Although the market operates typically up to a year ahead of real time, trading is possible up to Gate Closure.

## Short-term Bilateral Markets (Power Exchanges)

Power Exchanges operate over similar timescales, although trading tends to be concentrated in the last 24 hours.

The markets are in the form of screen-based exchanges where participants trade a series of standardised blocks of electricity (e.g. the delivery of xMWh over a specified period of the next day). Power Exchanges enable sellers (generators) and buyers (suppliers) to fine-tune their rolling half hour trade contract positions as their own demand and supply forecasts become more accurate as real time is approached. The markets are firm bilateral markets and participation is optional. One or more published reference prices are available to reflect trading in the Power Exchanges.

## Balancing Mechanism

The Balancing Mechanism operates from Gate Closure through to real time and is managed by National Grid in its role as National Electricity Transmission System Operator (NETSO). It exists to ensure that supply and demand can be continuously matched or balanced in real time. The mechanism is operated with the System Operator acting as the sole counter party to all transactions.

Participation in the Balancing Mechanism, which is optional, involves submitting ‘offers’ (proposed trades to increase generation or decrease demand) and/or ‘bids’ (proposed trades to decrease generation or increase demand). The mechanism operates on a ‘pay as bid’ basis.

It is shown (under “Balancing Services”) that we purchase offers, bids and other services to match supply and demand, resolve transmission constraints and thereby balance the system. As part of this process we are also required to ensure that the system is run within operational standards and limits (see entry on Licence Standard in References).

Generators and suppliers registered within the Balancing and Settlement Code are bound by the relevant requirements of the Grid Code which includes the arrangements for System Operator to accept Balancing Mechanism bids and offers, for calling off Balancing Services and for dealing with emergencies.

We have a general duty to operate the transmission system in an efficient, economic and co-ordinated manner through the procurement and utilisation of Balancing Services including Balancing Mechanism bids and offers. Our NETSO Incentive Scheme normally covers this duty.

As the market moves towards the Balancing stage, we need to be able to assess the physical position of market participants to ensure security of supply is maintained effectively and efficiently. To this end, all market participants are required to inform us of their planned net physical flows onto and/or from the system. Initial Physical Notifications (IPNs) are submitted at 11.00a.m. at the day ahead stage. These are continually updated until Gate Closure when they become the Final Physical Notifications (FPNs).

## Imbalances and Settlements

Power flows are metered in real time to determine the actual quantities of electricity produced and consumed at each location. The magnitude of any imbalance between participants' contractual positions (as notified at Gate Closure) including accepted offers and bids, and the actual physical flow is then determined. Imbalance volumes are settled at one of the dual imbalance prices; System Buy Price (SBP) and System Sell Price (SSP).

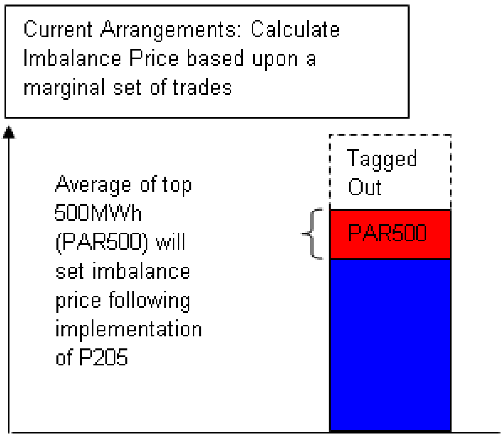
## Imbalance Pricing Arrangements

From 5th November 2009, we as NETSO 'flag' when we believe a bid-offer acceptance may resolve a transmission constraint. We also flag forward trade actions and certain System Operator to System Operator actions over interconnectors which we believe may resolve a transmission constraint, or which are used to avoid other adverse effects on the systems joined by the interconnection. This flagging is undertaken to enable high priced constraint actions to be removed from the imbalance price calculations.

Flagged actions are assessed against unflagged actions to determine whether they were more expensive than the unflagged actions. If they were, then the price associated with the flagged action is removed. If they weren't, then the flagged action retains its price.

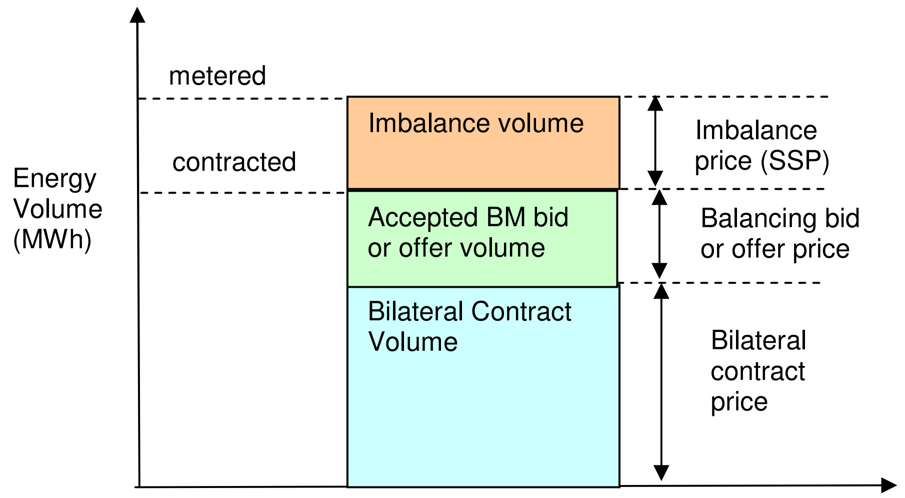
Where prices are removed, a 'replacement price' is calculated from a volume-weighted average of the most expensively priced 100 MWh of priced actions. If there are less than 100 MWh of priced actions, all the priced volume is used to calculate the replacement price.

**Figure 10.2 - Imbalance Price Calculation**



Imbalance prices are intended to serve as an appropriate incentive for market participants to efficiently manage their contractual energy position ahead of gate closure. There is therefore a link between imbalance prices and plant margin in that the incentive on a participant to balance determines the level and value of contracting in the forward markets. This price signals drives plant availability, and in the longer term should sustain investment in new capacity. It is therefore essential that imbalance prices are set to provide the appropriate incentives in this respect. Figure 10.3 provides a simplified example where the metered energy output of a generator exceeds the contracted position.

**Figure 10.3 - Energy Imbalance**



There is a positive imbalance volume for which the generator would only be paid at SSP. Under normal circumstances SBP exceeds SSP. Had there been a negative imbalance volume, the system would have bought at SBP to compensate and so the generator would be charged at SBP. The use of dual imbalance prices is intended to provide an incentive for participants to balance their own position as accurately as possible.

Finally, in addition to energy imbalance charges there is also provision in the market rules for an information imbalance charge. Information imbalance corresponds to the difference between the expected delivery (as indicated by FPNs plus accepted BM bids and offers), on the one hand and metered output/consumption on the other. This charge is currently set at zero.

## Balancing Mechanism Reporting Service (BMRS)

As part of the BETTA arrangements, market participants have access to information to enable them to trade to balance their positions and self despatch their plant. The Balancing Mechanism Reporting Service (BMRS) is the service for reporting the necessary information that includes:

- Demand forecasts from National Grid
- Generation availabilities and margins
- Imbalance forecasts based on participants' Physical Notifications
- Submitted BM offer and bid volumes and prices
- Accepted BM trades and imbalance prices
- A variety of other information related to market operation

Forecast information is primarily made available for the day ahead and on the day. Submitted BM data is made available shortly after Gate Closure. Accepted bids and offers and initial imbalance prices are published shortly after real time. LogicaCMG operates the systems for this process under contract to Elexon, and administers a dedicated web-site providing near real-time information available at http://www.bmreports.com/.

# Market Governance

## The Balancing and Settlement Code (BSC)

The BSC sets out the rules governing the operation of the Balancing Mechanism (BM) and the Imbalance Settlement process. It also sets out the relationships and responsibilities of all market participants.

All Licence holders (i.e. transmission, generation, supply and distribution) are required to be registered within the BSC. Parties registered within the BSC may or may not choose to participate in the Balancing Mechanism (BM). Participation is defined as submitting an “offer” or a “bid” and is not dependent on its acceptance.

Parties exempt from holding a Licence may nevertheless choose to sign the framework agreement by which the BSC is made contractually binding. They may then also choose to participate in the BM. However, those parties who sign the BSC, whether licensed or licence exempt, are also likely to be required to sign on to the Connection and Use of System Code (CUSC).

A copy of the code may be obtained from http://www.elexon.co.uk, which also has links to all BSC change process documentation including modifications to the code itself.

## The Grid Code (GC)

National Grid has a Licence Obligation in consultation with the other participants, to prepare and at all times to have in force and to implement, comply with, and review regularly, a Grid Code which would set down the operating procedures and principles governing our relationship with all users of the transmission system, be they generating companies, suppliers or suppliers’ customers, Externally Interconnected Parties or users with systems directly connected to the transmission system.

The Grid Code is designed to permit the development, maintenance and operation of an efficient, co-ordinated and economical system for the transmission of electricity, to facilitate competition in the generation and supply of electricity and to promote the security and efficiency of the power system as a whole.

The Grid Code covers all material and technical aspects relating to connections and to the operation and use of the transmission system or, in as far as relevant to the operation and use of the transmission system, the operation of the electric lines and electrical plant connected to it or to a distribution system. It also specifies data which system users are obliged to provide to us for use in the planning and operation of the transmission system, including demand forecasts, availability of generating sets and intended dates of overhaul of large generating sets.

All parties connected to, or involved in the use of, the transmission system, including National Grid, are subject to the Grid Code. Please note that amongst other things, the Grid Code requires that participants embedded within another party’s system (e.g. distribution system) must ensure that their physical notifications (see Balancing Mechanism Reporting Service (BMRS)), bids and offers are feasible with respect to their host network. Users' Licences and the Connection and Use of System Code (CUSC) give legal force to the Grid Code. Any changes to the Grid Code are subject to the approval of the Authority (Ofgem).

The Grid Code, along with associated information on its structure is available at

http://www.nationalgrid.com/uk/Electricity/Codes/

## The Connection and Use of System Code (CUSC)

National Grid is required under the Transmission Licence to be a party to the CUSC Framework Agreement and comply with the CUSC. It is also a requirement for holders of a generation, distribution or supply licence to be a party to the CUSC Framework Agreement and comply with the CUSC. In addition to licensees, the following parties need to be a party to the CUSC Framework Agreement and comply with the CUSC. Users who are:

- Required to sign an agreement pursuant to the Balancing and Settlement Code; or
- Not licensed nor subject to the Balancing and Settlement Code but who are directly connected to the National Grid Transmission System; or
- Who are Embedded and required pursuant to Paragraph 6.5 of the CUSC to have an agreement with National Grid.

The CUSC is a licence-based code setting out within it the principal rights and obligations in relation to connection to and/or use of the NETS and also relating to the provision of certain Balancing Services. The CUSC was developed as a replacement to the previous Master Connection and Use of System Agreement (MCUSA), which had been used since Vesting. All persons who were party to the MCUSA as at the CUSC Implementation Date continued as Original Parties to the CUSC Framework Agreement. Other Parties who have since acceded to the CUSC are additional parties.

The CUSC contains obligations for CUSC signatories to comply with the relevant provisions of the Grid Code, and obligations to pay charges in accordance with the Charging Statements.

## The System Operator – Transmission Owner Code (STC)

The STC is the legal document, which forms the high level contractual framework for the interactions between NETSO all Transmission Licensees (National Grid Electricity Transmission plc, Scottish Power Transmission Ltd, Scottish Hydro Electric Transmission Ltd and all offshore Transmission Licensees) and makes provision for certain interactions between these parties. These interactions include:

- The Transmission Owners providing Transmission Services to the NETSO
- Directions from the NETSO to configure the NETS
- Transmission Outage Planning
- Joint Transmission Investment Planning
- Governance of the STC and amendments to it
- Dispute resolution

The STC is supported by a number of procedures (STC Procedures or STCPs) that set out in greater detail the roles, responsibilities, obligations and rights etc of the NETSO and the TOs.

# National Grid's Role and Obligations

## Licence Obligations

Section C of the Transmission Licence (System Operator Standard Conditions) places a number of obligations upon National Grid in relation to, amongst other things, the Balancing and Settlement Code (BSC) and these include:

- National Grid shall at all times have in force and comply with, a Balancing and Settlement Code
- National Grid shall operate the transmission system in an efficient, economic and co-ordinated manner
- Having taken into account the relevant price and technical differences, National Grid shall not discriminate between any persons or classes of persons in its procurement of Balancing Services.

Under the arrangements of BETTA, NGET, SPT and SHETL each have Transmission Licences that stipulate certain obligations. However, in its role as the NETSO, National Grid has extra responsibilities as indicated above. The SO-TO code (STC) sets out the arrangements for the interface between the NETSO and the Scottish Transmission Operators.

http://www.nationalgrid.com/uk/indinfo/stc/mn_stc.html

## Balancing Services

The services that we procure, as NETSO, in order to operate the transmission system constitute Balancing Services.

Balancing Services include:

- Ancillary Services
- Offers and bids made in the Balancing Mechanism
- Other services available to National Grid which serve to assist us in operating the transmission system in accordance with the Electricity Act 1989 or the Conditions in an efficient and economic manner

Ancillary Services, under the Grid Code, can be Part 1 System Ancillary Services, Part 2 System Ancillary Services or Commercial Ancillary Services. Part 1 System Ancillary Services are those which Users are required to have available in accordance with the Grid Code. Part 2 System Ancillary Services are those optional services (e.g. black start capability) set out in the Grid Code, which the User has agreed to have available. Commercial Ancillary Services are other optional services (e.g. hot standby) described in the Grid Code, which the User has agreed to have available.

Balancing Mechanism offers and bids are commercial services offered by generators and suppliers and procured through arrangements set out in the BSC. They represent the willingness to increase or decrease the energy output from BM Participants in exchange for payment.

Other Services refers to commercial services that can be entered into with any party, which are classified neither as Ancillary Services nor BM offers or bids. These services can be provided by parties who are not authorised electricity operators. This category would include any service provided by parties that are not signatories to the BSC and may also include the procurement of energy ahead of BM timescales.

For further information on Balancing Services, please see the following website:-

http://www.nationalgrid.com/uk/indinfo/balancing

### Information Provision

There are five documents which we produce pursuant to Condition C16 of the Transmission Licence which have particular relevance in this area, namely the:

- Procurement Guidelines
- Balancing Principles Statement
- Balancing Services Adjustment Data (BSAD) Methodology Statement
- Applicable Balancing Services Volume Data (ABSVD) Methodology Statement
- System Management Actions Flagging (SMAF) Methodology Statement

The Procurement Guidelines set out the kinds of Balancing Services which we may be interested in purchasing, together with the mechanisms by which we envisage purchasing such services. The Procurement Guidelines are not prescriptive of every possible situation that we are likely to encounter, but rather represent a generic statement of the procurement principles we expect to follow.

The Balancing Principles Statement defines the broad principles and criteria (the Balancing Principles) by which we determine, at different times and in different circumstances, which Balancing Services we will use to assist in the operation of the transmission system (and/or to assist in doing so efficiently and economically), and when we would resort to measures not involving the use of Balancing Services. The Balancing Principles Statement is designed to indicate the broad framework in which we will make balancing action decisions.

The Balancing Services Adjustment Data (BSAD) Methodology Statement sets out information on relevant Balancing Services that will be taken into account under the BSC for the purpose of determining Imbalance Price(s).

The Applicable Balancing Services Volume Data statement sets out the information on Applicable Balancing Services that will be taken into account under the Balancing and Settlement Code for the purposes of determining imbalance volumes.

The System Management Actions Flagging (SMAF) Methodology Statement sets out the means which we will use to identify balancing services that are for system management reasons for the purpose of determining Imbalance Price(s).

Further information and electronic versions of the above documents are available from:-

http://www.nationalgrid.com/uk/indinfo/balancing

## The Offshore Development Information Statement

The Offshore Development Information Statement (ODIS) is produced in accordance with Special Condition C4, and is available at the following location.

https://www.nationalgrid.com/uk/Electricity/ODIS/

The main purpose of the Statement is to facilitate the achievement of the coordinated development of the offshore and onshore electricity grid in Great Britain. The network solutions identified in this report represent a vision of how the offshore and onshore reinforcements could be developed; it is the responsibility of individual onshore/offshore network owner to develop detailed designs. In developing these detailed designs it is envisaged that this Statement will provide guidance in determining the optimum solutions.

# Transmission Pricing

## Charging Statements

We produce three Charging Statements in accordance with the requirements of the Transmission Licence. Whereas the contractual obligation to pay charges resides within the Connection and Use of System Code (CUSC), the principles that underpin these charges are contained in the Charging Statements.

The three Charging Statements are; the Statement of Use of System Charges; the Statement of Use of System Charging Methodology; and the Statement of the Connection Charging Methodology.

It is a requirement of our Transmission Licence that we charge in accordance with the above Statements. The Statements contain sufficient detail to enable our customers to make a reasonable estimate of their charges. The documents are kept under continual review and any amendments are approved by Ofgem.

Please refer to Chapter 9 Table 9.1 for the Transmission Use of System Charges table for charges applicable from 1st April 2011.

For a comprehensive description, please refer to the Charging Statements which are available at the following web site: www.nationalgridinfo.co.uk/charging/index.html.

The follow paragraphs provide a brief summary of National Grid's charges.

## Connection Charges

All customers who are directly connected to the NETS are subject to Connection Charges.

These charges enable National Grid to recover, with a reasonable rate of return, the costs involved in providing the assets that afford connection to the NETS. The Connection Charges relate to the costs of assets installed solely for and only capable of use by an individual User and take into account the asset value and age. Connection Charges additionally include a maintenance component and an overhead component based on the asset value.

## Transmission Network Use of System (TNUoS) Charges

Transmission Network Use of System charges reflect the cost of installing, operating and maintaining the transmission system for the Transmission Owner (TO) activity function of the Transmission Businesses of each Transmission Licensee. These activities are undertaken to the standards prescribed by the Transmission Licenses, to provide the capability to allow the flow of bulk transfers of power between connection sites and to provide transmission system security.

The basis of charging to recover the allowed revenue is the Investment Cost Related Pricing (ICRP) methodology, which was approved for use for GB in March 2005. Charges are based on the customer's location and on their import and export requirements as calculated by a DC Load flow (DCLF) ICRP transport model. The GB charging methodology was implemented in April 2005.

TNUoS tariffs are set to recover 27% of revenue from users that export onto the system (Generators) and 73% of revenue from users that import from it (Suppliers). Tariffs are calculated annually and typically published by 31 January for the charging year commencing on 1 April. However, arrangements exist to allow National Grid to revise tariffs at other times within the year. The CUSC requires a two month notice period for a change in Use of System tariffs.

### Generation TNUoS Charges

Generators are charged a zonal charge dependent on which tariff zone their power station is connected, together with a specific local charge dependent on the type of connection. There are currently 20 generation TNUoS tariff zones (see Figure A.1.3 and Chapter 6: "Use of System Tariff Zones"). The charges for these zones display a north to south differential and vary from positive tariffs in the north to negative tariffs in some southern zones. The locational zonal charge reflects whether the generation contributes to or alleviates the need for additional transmission reinforcement/investment on the Main Interconnected Transmission System (MITS). The specific locational charge is dependent on whether the connecting substation has redundancy i.e. is single or double busbar, and the type and length of connecting circuits to that substation. The basis of the generation charge is the highest Transmission Entry Capacity (TEC) applicable over the year for positive tariff zones, or the average of the three highest metered exports over the winter period for negative tariff zones.

The Transmission Entry Capacity (TEC) of a power station is defined as the access capacity that the generator has requested to export power onto the main transmission system. We use this as input into its planning studies to determine the wider system infrastructure requirements and as the basis for TNUoS charges. TEC is the permitted sum of outputs from the Balancing Mechanism units comprising the power station less station demand, expressed in MW averaged over a Settlement Period.

### Demand TNUoS Charges

There are 14 demand TNUoS tariff zones (see Figure A.1.4 and "Use of System Tariff Zones" in Chapter 6), these map to the 14 distribution network operator areas The TNUoS tariffs for demand (paid by suppliers) reverse the north to south trend seen in generation tariffs. Whilst there is a minimum tariff of zero, this collar is not needed due to the revenue that is expected to be recovered from demand (73%) i.e. all tariffs are above zero. Suppliers' charges for half-hourly, metered demand are based on the average of the actual demand supplied during the Triad. The Triad is defined as the three half hour settlement periods of highest transmission system demand during November to February of a Financial Year, separated by 10 clear days. Non half-hourly metered demand charges are on the basis of energy demand over the half hours 16.00 – 19.00 inclusive from 1 April to 31 March.

## Balancing Services Use of System (BSUoS) Charges

The Transmission Licence allows us to derive revenue in respect of Balancing Services through the Balancing Services Use of System (BSUoS) charges. We in our role as NETSO, have a responsibility to keep the electricity system in balance (energy balancing) and to maintain quality and security of supply (system balancing). Under the Balancing Services Incentive Scheme we are incentivised on the procurement of services for energy and system balancing and other costs associated with operating the system.

Customers pay for the cost of Balancing Services and any incentivised payments/receipts through BSUoS charges. All users registered within the Balancing and Settlement Code (BSC) are liable to pay BSUoS charges based on their energy taken from or supplied to our transmission system and is calculated every settlement period.

## Project TransmiT

Project Transmit is an 'Ofgem's independent review of the charging arrangements for gas and electricity transmission networks, and the connection arrangements.

Project TransmiT will be delivered in a number of phases – the first looking to collect evidence and determine whether all or part of the transmission charging regime should be modified. It will also aim to identify what changes can be made to facilitate the timely connection of new (including low carbon) generation.

More information on TransmiT and development of changes to the frameworks can found at Ofgem's dedicated webpage:

http://www.ofgem.gov.uk/Networks/Trans/PT/Pages/ProjectTransmiT.aspx

As part of the TransmiT project National Grid raised **CMP192 Enduring Arrangements for User Commitment**. This seeks to bring a methodology for setting Generation User Commitment, for pre ad post commissioning generators, under the CUSC arrangements.

As of May 2011 a CUSC working group is underway developing the proposed methodology. This will then go through a full Industry consultation before being submitted to Ofgem for decision in Autumn 2011. During this period National Grid are applying interim arrangements, details of which can be found on the National Grid website at:

http://www.nationalgrid.com/uk/Electricity/GettingConnected/PoliciesAndGuidance/

## Participants' Requirements

### Licence Requirements

Under the provision of the Utilities Act 2000, the Secretary of State's power to grant (and, in the case of supply, extend) electricity licences has been removed. These provisions bring the Electricity Act, 1989 into line with the Gas Act, 1995, where licences may be granted only by the Authority (Ofgem). Accordingly, having determined and published standard conditions to be included in each type of electricity licence, the Secretary of State has no role in the subsequent modification of the standard conditions save only a power to veto modifications proposed by the Authority (Ofgem).

Under the provisions of the Utilities Act 2000, supply and distribution have become separate licensable activities. The previous distinction in legislation between public electricity supplier (PES) and second-tier supply licences have been removed and the supply and distribution businesses of the PES have been put into separate legal entities. There is a bar on the same person holding both an electricity supply and an electricity distribution licence. As a result of this and other changes, the concept of a PES has ceased to exist. However, there is no provision requiring separate supply and distribution companies to be owned separately.

#### Transmission Licence

Transmission licences are granted under Section 6 (1) (b) of the Electricity Act, 1989. National Grid, SPT and SHETL are currently the holders of the three transmission licences. However, it is possible for further onshore and offshore transmission licences to be granted.

#### Generation Licences

Generation licences are granted pursuant to Section 6 (1) (a) of the Electricity Act, 1989. In essence, any power station capable of providing 100MW or more to the total system in Great Britain is required to have a Generation Licence. In this context the total system means the NETS and all distribution systems. Furthermore, a distribution system means a system, which consists (wholly or mainly) of low voltage lines and electrical plant and is used for conveying electricity to any premises or to any other distribution system.

Power stations capable of exporting between 50MW and 100MW to the total system that connected after 30 September 2000 may apply to the Department of Energy and Climate Change (DECC) to seek a Licence Exemption (see Chapter 4: "Technical and Data Requirements"). Power Stations that are not capable of exporting 50MW or more to the total system are automatically exempt from the requirement to hold a generation licence.

### Supply Licences

Supply Licences are granted pursuant to Section 6 (1) (d) of the Electricity Act, 1989. The concept of geographically mutually exclusive authorised areas, which applied to the previous PES licences does not apply to supply licences. Supply licences may be granted in respect of all customers throughout Great Britain, or may relate to specific geographical areas or customer groups.

As with distribution, some functions necessary to ensure that everyone has reasonable access to electricity, previously carried by the PES in relation to supply, continues and this obligation is imposed through the licences.

### Distribution Licences

Distribution licences are granted under Section 6 (1) (c) the Electricity Act, 1989. The concept of geographically mutually exclusive authorised areas for distribution is retained.

## Consents Under the Electricity Act 1989

### Section 36 Consent (S36)

This refers to Section 36 of the Electricity Act 1989 which specifies that a generating station of over 50MW capacity shall not be constructed, extended or operated except in accordance with a consent granted by the Secretary of State within England and Wales and the Scottish Executive in Scotland. The relevant office takes into account views on particular applications, including views of the local planning authority and, in certain circumstances, may call a public inquiry into a proposal. When granted, consent lasts for five years within which time a project must show signs of construction.

Many of the tables giving information on power stations located in Appendix F (and totalled in Chapter 3) include an indication of whether that plant has obtained S36 and S14 consent or not. For completeness Appendix F.6 lists power stations under construction, for which Section 36 and Section 14 consent has been given, and Appendix F.5 lists power stations, not yet under construction, for which Section 36 and Section 14 consent has been given. The output capacities (MW) given in the tables are intended to reflect the 'transmission contracted' capacities shown elsewhere in this Statement. The information presented in the tables represents our current view obtained through market intelligence and should not be relied upon; better information may be available through other sources.

### Section 14 Consent (S14)

This refers to Section 14 of the Energy Act 1976.

Section 14(1) prohibits the establishment or conversion of an electricity generating station fuelled by oil or natural gas unless notice has been given to the Secretary of State. The Secretary of State may direct, having regard to current energy policies, that the proposal be not carried out or be carried out in accordance with specified conditions.

Section 14(2) makes similar provisions in respect of the making or extension of contracts for obtaining of natural gas to such a station. Stations less than 10MW, and contracts of up to a year's duration, are excepted by Orders under the Act.

Section 14(3) allows the Secretary of State to halt any proposals notified to him, if he considers it expedient, having due regard to current energy policy. This clause may be exercised, for instance, to prevent a project being built which has had Section 36 consent for five years but which, in the opinion of the Secretary of State, has shown no evidence of construction.

### Section 37 Consent (S37)

This refers to Section 37 of the Electricity Act 1989, which specifies that, subject to certain exemptions, an electric line shall not be installed or kept installed above ground except in accordance with a consent granted by the Secretary of State. Exceptions include:

- Electric lines with a nominal voltage of 20kV or less used to supply a single consumer;
- Electric lines within premises in the occupation or control of the person responsible for its installation; or
- Such other cases as may be prescribed.

### Infrastructure Planning Commission

From 1 March 2010, the Infrastructure Planning Commission (IPC) became responsible for processing new planning applications under the Planning Act 2008. Section 36 applications received before 1 March 2010 will remain as part of the previous process as described above with new applications for consents having to go through the IPC for examination and decision.

## Compliance with Industry Codes

Table 10.1 at the end of this chapter provides a generalised summary of some of the main requirements placed on generators, suppliers and distributors in relation to their obligations to become party to the various codes and charges discussed earlier in this chapter.

The table is intended only as an initial quick reference guide for readers unfamiliar with the arrangements under BETTA. There may well be variations to the requirements depending on circumstances. The table has been constructed on the basis of the following generalised rules:

- All **directly connected power stations** and directly connected Distribution Systems are required to accede to the **CUSC**.
- All **power stations** (regardless of whether they are directly connected or embedded) capable of exporting 100MW or more to the total system normally require a **Licence**.
- All holders of a **Licence** (regardless of whether they are directly connected or embedded) are required to accede to the **CUSC** and sign the **BSC**
- If **Licence-Exempt**, a User may choose to sign the **BSC** and accede to the **CUSC**;
- If registered within **BSC**, a User may choose to participate in the **BM**;
- **Licence-exempt** embedded generation may nevertheless be required to become party to the **CUSC** or sign an appropriate Bilateral Agreement under the requirements of CUSC Condition 6.5.
- If party to the **CUSC**, a User is bound by and must comply with relevant parts of the **Grid Code**; and
- If party to the **CUSC**, a User has an obligation to pay any relevant charges in accordance with the **Charging Statements**.

## Bilateral Agreements

Finally, the section on ”Bilateral Agreements” in the online Glossary under the Generation Terminology section describes the three types of Bilateral Agreement, namely: the Bilateral Connection Agreement (BCA); the Bilateral Embedded Generation Agreement (BEGA); and the Bilateral Embedded Licence Exemptible Large Power Station Agreement (BELLA).

The descriptions outline the relationships between the types of agreement, the class of power station, the type of connection to the system, the appropriate terminology for power station output and the appropriate charges. For ease of reference that information has been condensed, tabulated and re-presented here as Table 10.2 at the end of this chapter.

**Table 10.1 - Generalised Summary of Main Requirements Placed on Generators, Suppliers and Distributors**

| Market Participants | BSC | BM | CUSC | GC | Charges | | |
|---|---|---|---|---|---|---|---|
| | | | | | Connection | TNUoS | BSUoS |
| **Licence Holders** | | | | | | | |
| Power Stations | yes | optional | yes | yes | if direct | yes | yes |
| Suppliers | yes | optional | yes | yes | no | yes | yes |
| Distributors | yes | no | yes | yes | yes | no | no |
| **Licence Exempt** | | | | | | | |
| Large Embedded Power Stations | Yes (subject to CUSC 6.29) | optional if BSC | yes | yes | no | if BSC (subject to CUSC 6.29) | if BSC (subject to CUSC 6.29) |
| Medium & Small Embedded Power Stations | optional | optional if BSC | if BSC or if required by CUSC Condition 6.5 | if CUSC | no | if BSC | if BSC |
| Transmission Connected Power Stations | Yes (subject to CUSC 6.29) | optional if BSC | yes | yes | yes | if BSC (subject to CUSC 6.29) | if BSC (subject to CUSC 6.29) |

Notes for Table 10.1:

1. BSC=Balancing and Settlement Code
2. BM=Balancing Mechanism
3. CUSC=Connection and Use of System Code
4. GC=Grid Code
5. Connection=Connection Charge
6. TNUoS=Transmission Network Use of System Charge
7. BSUoS=Balancing Services Use of System Charge

**Table 10.2 - Relationships between Types of Bilateral Agreement, Power Station, Connection, Output Terminology and Charges**

| Type of Bilateral Agreement | Type of Power Station | Generation Licence | Connection | | Power Station Output Terminology | | | Charges Applicable | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | Embedded | Direct | TEC | CEC | Size of Power Station | Connection | TNUoS | BSUoS |
| BCA | All | yes | | yes | yes | yes | | yes | yes | yes |
| BEGA | All | yes | yes | | yes | | | | yes | yes |
| BELLA | Large | no | yes | | | | yes | | if BSC | if BSC |

Notes for Table 10.2:

1. BCA=Bilateral Connection Agreement
2. BEGA=Bilateral Embedded Generation Agreement
3. BELLA=Bilateral Embedded Licence Exemptable Large Power Station Agreement
4. A BCA is also for Directly Connected Distribution Systems, Non-Embedded Customer Sites and Interconnector Owners
5. A BEGA is also for Use of System for a Small Power Station Trading Party and a Distribution Interconnector Owner
6. In the case of a BELLA, the relevant Large Power Station must be SMRS registered or CMRS by an appropriate User