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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

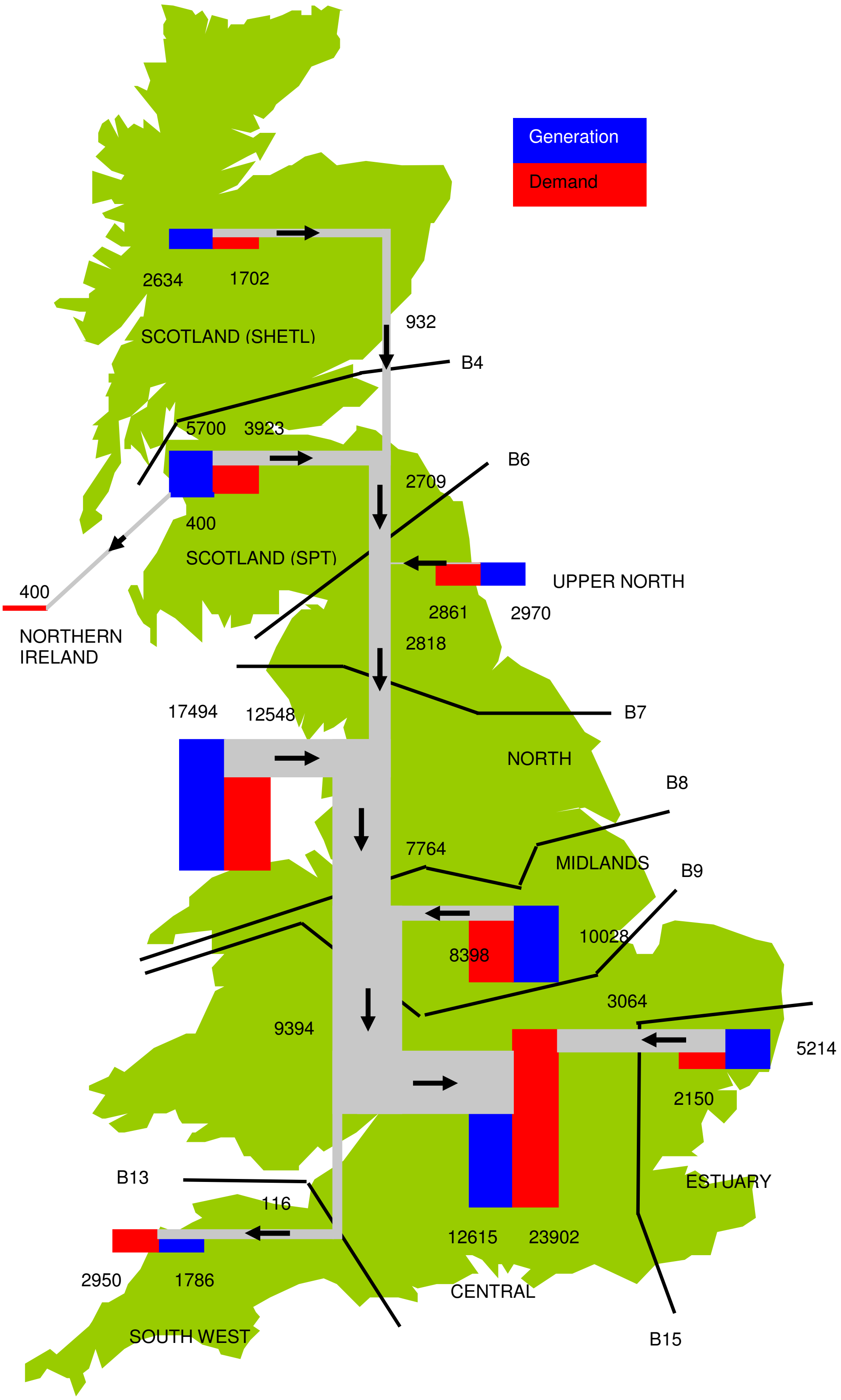
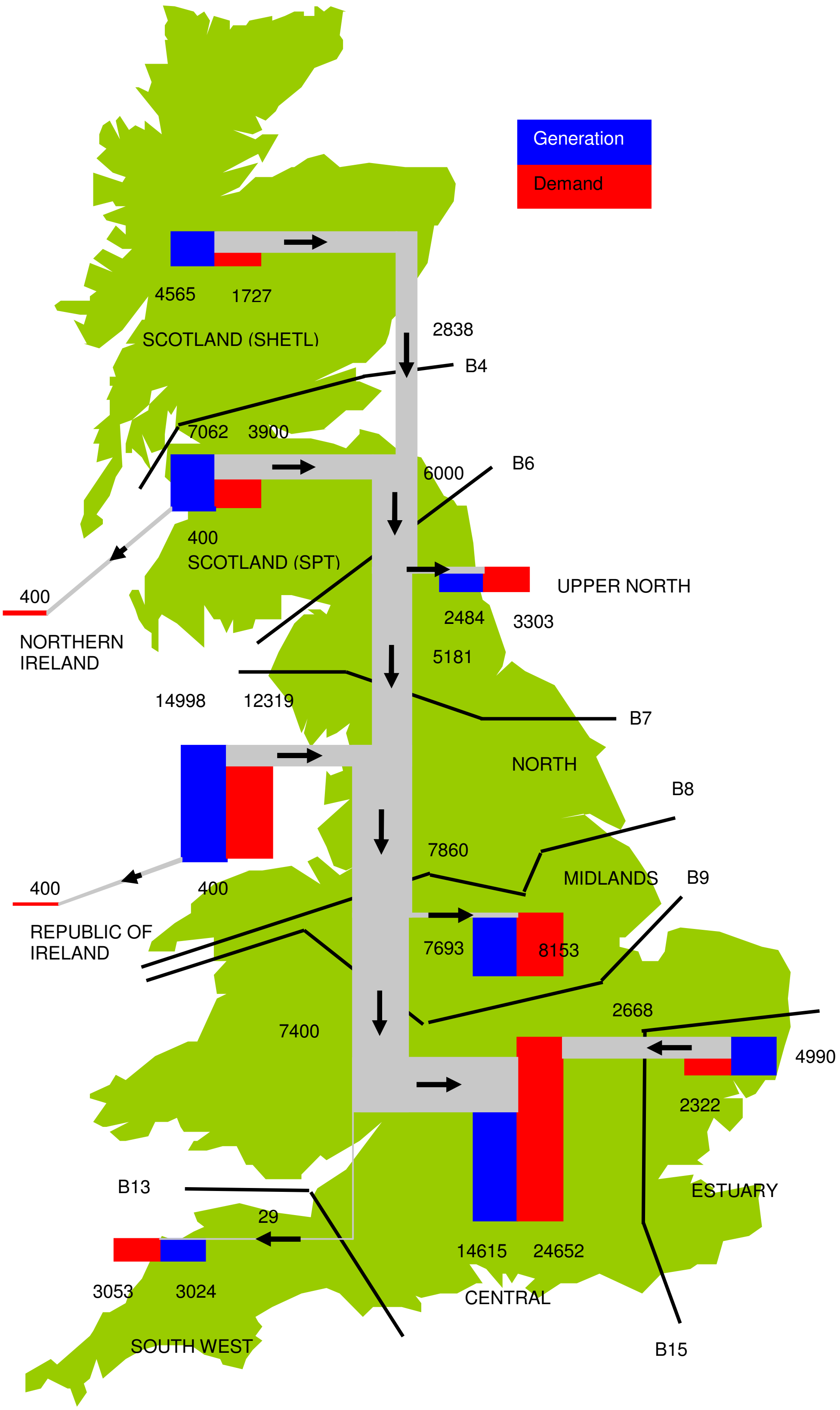


Figure 7.2 - ACS Power Flow Pattern for 2017/18



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

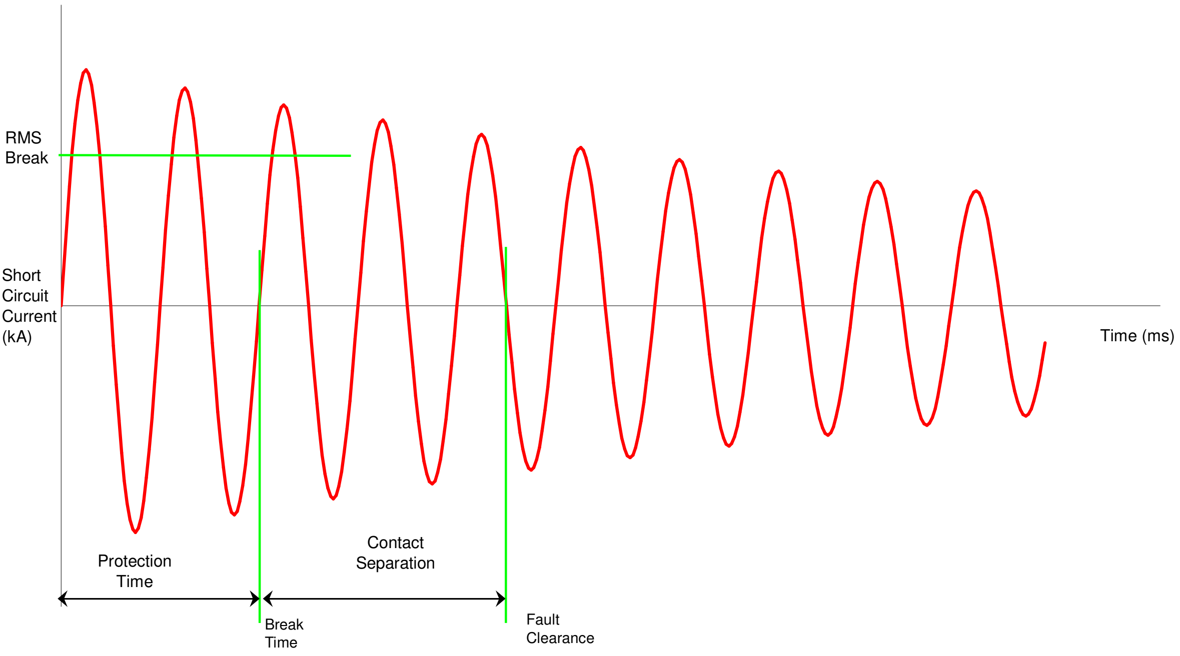
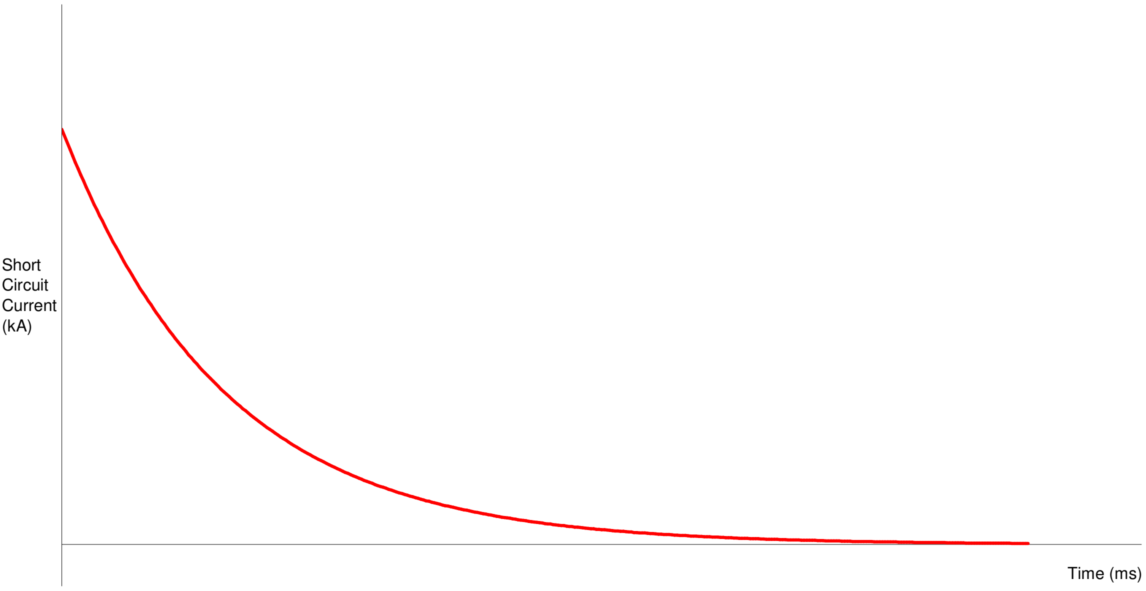


Figure 7.6 - DC Component of Short Circuit Current



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.

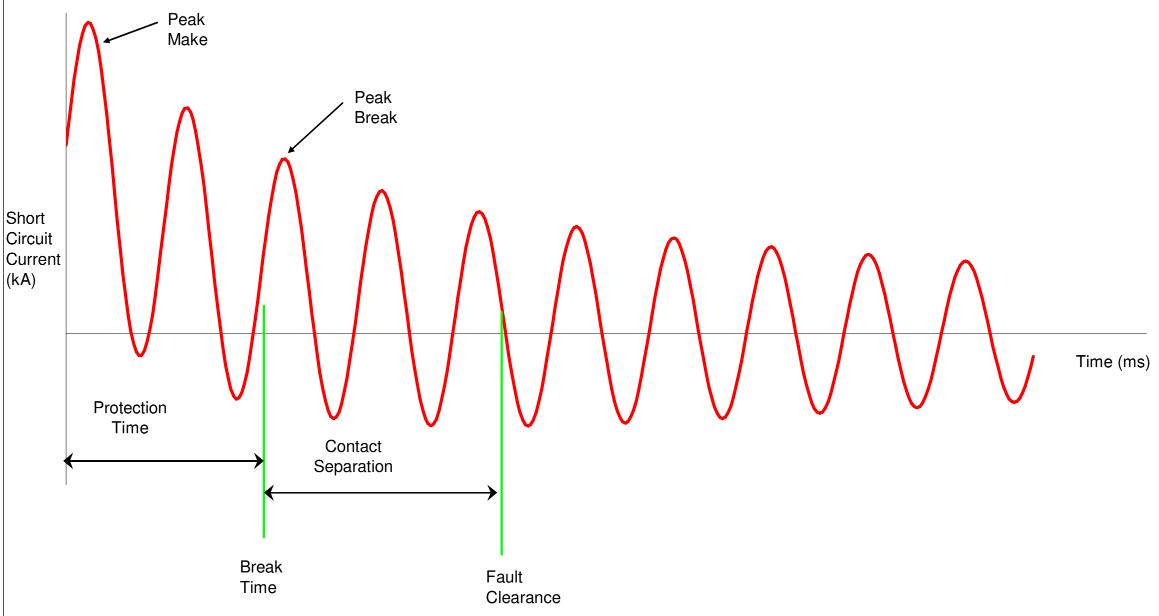
Breaking Duties

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