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Engineering Report 130

Issue 4 2023

Guidance on the application of Engineering Recommendation P2, Security of Supply

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Amendments since publication

Issue	**Date**	**Amendment**
Issue 4	February 2023	Minor revision to Issue 3 including the following principle changes: • Included explanation of **Group Demand** for class of supply A (Clause 5.2 added) and class of supply B (Clause 5.3 added). Description of **HV Circuit** types added (‘interconnected’ and ‘radial’). • Included guidance on implementing the reduced security of supply for specific class of supply B demand groups in accordance with the reduction included in EREC P2/8 (new Clause 6.4 and 6.5 added). • New examples added to Annex F (F.2 and F.3) to clarify assessment of **HV Circuit**s. • New Annex H added covering an explanation of analysis carried out on **HV Circuit**s.
Issue 3	August, 2019	Major revision of Issue 2 to: • Align EREP 130 with EREC P2/7 [N1] • Provide new guidance on assessing the contribution to security from **Demand Side Response (DSR)** Schemes and **Electricity Storage (ES)** • Update the F factors for assessing contribution to security from **Distributed Generation (DG)**, using recent data from **DG** • Differentiate the contribution to security from **DG**, **DSR Scheme**s and **ES** which is **Contracted** with a **Distribution Network Operator (DNO)** and that which is not

		This issue has largely been re-structured to improve the flow of the guidance, based on a revised step-by-step flow diagram (see Figure 1). This issue includes the following principal technical changes. Introduction: Updated to reflect expansion of scope and inclusion of **DSR Scheme**s and **ES**. Clause 1, Scope: Expanded to include **DSR** and **ES**. Clause 2, Normative references: Updated to reflect latest relevant references. Clause 3, Terms and definitions: All existing definitions amended to align with EREC P2/7 [N1]. New definitions added for: • **Cold Load Pickup** • **Contracted** • **Demand Facility** • **Demand Side Response Scheme** • **Electricity Storage** • **Non-Contracted** • **Regulatory Financial Performance Reporting** Clause 4, Assessment process overview: Major amendment of guidance on process to reflect a new Figure 1, which replaces the previous process flow diagram (Issue 2 Figure 5.1). Clause 5, Determine the **Group Demand** and class of supply: Major amendment of guidance on assessing **Group Demand**. New guidance added to explain what a demand group is (new Figure 2 added). More detailed guidance included on assessing **Latent Demand** with supporting Annex A. Clarification of de-minimis test when assessing **Latent Demand**. A new Figure 3 replaces the previous (Issue 2 Figure 5.2), and new guidance on taking account of **Cold Load Pickup**. Clause 6, Determine capacity of network assets and assess compliance: Major amendment of guidance with the removal of the previous flow diagram (Issue 2 Figure 5.3) considered to be unnecessary. New guidance (Clause 6.2) added on determining the ‘intrinsic network capacity’. New guidance (Clause 6.3) added on determining the **Transfer Capacity**. Clause 7, Contribution to **System Security** from **DG**, **DSR Scheme**s, and **ES**: General guidance when considering security contribution from **Contracted** and **Non-Contracted**. Clause 8, Contribution to **System Security** from **Contracted DG**, **DSR Scheme**s, and **ES**: New guidance added on assessing the contribution from **Contracted DG**, **DSR Scheme**s and **ES**, including the relevant considerations when developing such contracts. This Clause is supported by Annexes C and E. Clause 9, Contribution to **System Security** from **Non-Contracted DG**, **DSR Scheme**s, and **ES**: This clause now replaces the previous guidance on assessing contribution from **DG** which has been subject to amendment and additions, i.e., guidance now focuses on **Non-Contracted** aspects and includes new considerations for **DSR Scheme**s and **ES**. The guidance on de-minimis criteria for individual facilities/schemes has been clarified. The previous flow chart has been removed as it is no longer relevant (Issue 2 Figure 5.4). This clause is supported by Annexes B, D and E.

		Clause 10, Assessing compliance with Table 1: The main amendment to this clause includes new guidance (Clause 9.2) on conducting a high-level review of the options when the system capacity is insufficient to meet **System Security** requirements. Clause 11, Provision of **System Security**: New clause providing guidance on planning remedial work to address a deficiency in system capacity. Clause 12, Cost Benefit Analysis (CBA): New clause providing guidance on undertaking a supplementary CBA when the options identified for remedial works are not considered viable. Annex A, Identification of **Group Demand**: The previous guidance on **Group Demand** (Issue 2, Clause 6.6) has been subject to amendment. New guidance has been added to assist in determination of **Latent Demand**. Guidance on establishing **Latent Demand** of **DSR Scheme**s clarified and new guidance on establishing **Latent Demand** for **ES** added. Annex B, Capping **DG**/**DSR Scheme**s/**ES**: Previous guidance on capping (Issue 2, Clause 6.3) has been removed as the concept of establishing the ‘number of **DG** units equivalent to a **First Circuit Outage**’ is no longer relevant, i.e., **DG**/**DSR Scheme**s/**ES** are now considered on a ‘per facility’ basis. Hence, new guidance now added for capping, covering the capacities that are relevant. The guidance on common mode failures has been subject to a minor amendment to account for active management network. Annex C, Technical check list: Minor amendment to check list for **DG** to align with changes throughout document. New check list items added for **Non-Contracted DSR Scheme**s and **Non-Contracted ES**. Annex D, Approaches for assessing the contribution from **DG** to **System Security**: The F factors for **DG** have been subject to a major amendment following analysis of **DG** data collated over the period 2013-2018. The F Factor values for both non-intermittent and intermittent **DG** apply to the facility, i.e., the consideration of the availability of **DG** units and the number of **DG** units for non-intermittent types is no longer applicable. Hence, the F factor values in Approach 1 have been replaced with new values. New table for intermittent **persistence** has been added to replace the previous tables & graphs in Approach 2. The types of **DG** have been updated to reflect the majority of **DG** connections on **DNO** networks. The previous methodology in Approach 2, which required knowledge of the availability of **DG** units and the number of units in a facility, has been deleted as it is now longer relevant. A new methodology for Approach 2 has been added for non-intermittent **DG**, which uses capacity factors. Annex E, Influencing factors for **DG**/**DSR Scheme**s/**ES** Security Contribution: The previous guidance (Issue 2, Clause 6.2) on generation availabilities has been subject to major amendment. The explanation on establishing the availability of **DG** units has been deleted as it is no longer relevant. New guidance has been added for **DSR Scheme** considerations and **ES** considerations. Annex F, Examples: New examples have been added for **Group Demand**, **Transfer Capacity**, **DG**, **DSR Scheme**s and **ES**.

		Annex G, Interpretation of Imperial College London Report [N9] findings: New Annex added to capture derivation of the F factor tables in Annex D from the Imperial College London report [N9]. Bibliography: The list of relevant informative references has updated.
Issue 2	December, 2014	Minor amendment to incorporate requirements for **Demand Side Response (DSR)**. Document converted to the new ENA Engineering Report (EREP) template. This issue includes the following principal technical changes. Clause 3: New definition for **DSR** added. Footnote added for definition of **Latent Demand**. Clause 4.1: Added requirement to consider the contribution from **DSR**. Added explanation that **DSR** can be treated as either a reduction in **Group Demand** or an increase in System Capacity. Clause 6.10: New clause added for **DSR**. Clause 7.1: Added requirements for assessing the contribution from **DSR**. Annex A.4: Deleted reference to “ER G75/1”. Details of all other technical, general and editorial amendments are included in the associated Document Amendment Summary for this Issue (available on request from the Operations Directorate of ENA).

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Foreword

This Engineering Report (EREP) is published by the Energy Networks Association (ENA) and comes into effect from the date of publication. It has been prepared under the authority of the ENA Head of Engineering and has been approved for publication by the Distribution Code Review Panel (DCRP). The approved abbreviated title of this engineering document is “EREP 130”.

This document replaces and supersedes EREP 130, Issue 3.

It is expected that readers of this EREP are conversant with the requirements in EREC P2/8 [N1].

Whilst implementing the guidance set out in this EREP, it is expected that compliance with all relevant industry standards is adhered to, including those Standards referenced in Annex 1 of the Distribution Code [N8]

Where the term “shall” or “must” is used in this document it means the requirement is mandatory. The term “should” is used to express a recommendation. The term “may” is used to express permission.

NOTE: Commentary, explanation and general informative material is presented in smaller type, and does not constitute a normative element.

Introduction

Previous Issues of this Engineering Report (EREP) focused on assessing the contribution to **System Security** provided by **Distributed Generation (DG)**. However, Issue 7 of EREC P2 (P2/7) recognised that demand may be secured using a combination of “network assets and non-network assets”. Thus, Issue 3 of this EREP was extended to provide guidance on assessing the security contribution from:

- network assets;
- **DG**, **Demand Side Response (DSR)** Schemes, and **Electricity Storage (ES)**, that are **Contracted** with a **Distribution Network Operator (DNO)** to provide a security service; and
- **DG**, **DSR Scheme**s, and **ES**, that are not **Contracted** with a **DNO** to provide a security service.

Issue 4 of this EREP has been updated in co-ordination with the publication of EREC P2 Issue 8, hence it has been amended to provide guidance on implementing the specific reduction in security of supply that might apply for some class of supply B demand groups.

1 Scope

This Engineering Report (EREP) provides guidance on how to assess whether an electricity distribution system meets the security requirements specified in EREC P2/8 [N1] by means of security contribution from network assets, **Distributed Generation (DG)**, **Demand Side Response (DSR)** Schemes, or **Electricity Storage (ES)**. In order to achieve this, there is a need to establish the **Group Demand**, as defined in EREC P2/8 [N1] and to assess the means of securing this demand in accordance with the requirement of EREC P2/8 [N1] Table 1. This EREP provides technical guidance on this assessment.

This EREP provides guidance on quantifying the security contribution where the **DNO** has a contract with a **DG** facility, **DSR Scheme** provider or **ES** to provide a security service. It also provides guidance on assessing the fortuitous security contribution from a **DG**, **DSR Scheme** and **ES** to where there is no contract in place with the **DNO** to provide security services.

This EREP also provides general guidance on contractual considerations which are relevant when a **DNO** is assessing the security contribution from a **DG**, **DSR Scheme** and **ES** to satisfy the requirements of EREC P2/8 [N1]. However, the details of any contractual and commercial considerations are outside the scope of this technical document.

This EREP also provides guidance on the use of cost benefit analysis (CBA) to establish the justification or otherwise, for providing security differing from the requirements of EREC P2/8 [N1] Table 1.

2 Normative references

The following referenced documents, in whole or part, are indispensable for the application of this document. For dated references, only the edition cited applies. For undated references, the latest edition of the referenced document (including any amendments) applies.

[N1] ENA Engineering Recommendation P2 Issue 8, *Security of Supply.*

[N2] ENA Engineering Report 131, *Analysis Package for Assessing Generation Security Capability – Users’ Guide.*

[N3] Electricity Act 1989.

[N4] Utilities Act 2000.

[N5] Energy Act 2005.

[N6] The Electricity (Class Exemptions from the Requirement for a Licence) Order 2001.

[N7] The Electricity (Northern Ireland) Order 1992.

[N8] The Distribution Code of Licensed **Distribution Network Operator**s of Great Britain, https://www.dcode.org.uk.

[N9] **DG** data analysis report by Imperial College London, 2019.

3 Terms and definitions

For the purposes of this document, the following terms and definitions apply.

NOTE 1: Defined terms are capitalised and in bold font where they are used in the main text of this report.

NOTE 2: Where a definition is taken from another document, the reference to that document is listed beneath the definition in square brackets.

3.1
Capped
A limit (to the contribution to **System Security**) applied during the assessment stage to ensure that the contribution to **System Security** from the **DG**, **DSR Scheme**, or **ES** does not exceed the contribution to **System Security** from a **Circuit**

NOTE: The term "Capping" should be interpreted as having the same meaning.

3.2
Circuit

The part of an electricity supply system between two or more **Circuit** breakers, switches and/or fuses inclusive. It may include transformers, reactors, cables and overhead lines. Busbars are not considered as **Circuit**s and are to be considered on their merits.

[ENA EREC P2/8, Clause 3.1]

3.3
Circuit Capacity

The appropriate continuous rating or cyclic rating or, where it can be satisfactorily determined, the appropriate emergency rating, taking into account the relevant environmental conditions and the expected demand profile, which should be used for all **Circuit** equipment and associated protection systems.

NOTE: **Circuit Capacity** should be assessed in MVA.

[ENA EREC P2/8, Clause 3.2]

3.4
Cold Load Pickup
The difference between the **Measured Demand** on a **Circuit** following re-energisation of that **Circuit** and the demand on that **Circuit** which the **DNO** would have reasonably expected had no de-energisation occurred.

[ENA EREC P2/8, Clause 3.3]

3.5
Contracted
A bilateral agreement between a **DNO** and party providing **System Security** from a **DG** facility, a **DSR Scheme** or an **ES**.

3.6
Declared Net Capability (DNC)
The declared gross capability of a **DG**, measured in MW, less the normal total parasitic power consumption attributable to that plant.

NOTE 1: **Declared Net Capability (DNC)** as used in this Engineering Report should not be confused with declared net capacity (**DNC**) as used in the Electricity Act [N3] and the Electricity Order 2001 [N6].

NOTE 2: For the purpose of this definition the term "parasitic power consumption" refers to the electrical demand of the auxiliary equipment, which is an integral part of the **DG**, essential to the **DG**'s operation. For the avoidance of doubt "parasitic power consumption" does not include demand supplied by the **DG** to an on-site customer.

NOTE 3: The **DNC** of a **DG** facility is taken as the aggregate nameplate capacity of all the units within the **DG** facility, less any parasitic load.

3.7
Demand Facility
A facility connected to the distribution network which consumes electrical power.

3.8
Demand Side Response (DSR)
Demand that is controlled in response to an instruction issued as part of an agreed demand side management arrangement with the **DNO** or other party.

[ENA EREC P2/8, Clause 3.4]

NOTE 1: The electrical power consumption of a **Demand Facility** can be modified using **DSR**.

3.9
Demand Side Response Scheme (DSR Scheme)
A **DSR** arrangement which is being implemented at a **Demand Facility**.

3.10
Distributed Generation (DG)
A generating facility connected to the distribution network, where a generating facility is an installation comprising one or more generating units.

[ENA EREC P2/8, Clause 3.5]

3.11
Distribution Network Operator (DNO)
A person or legal entity named in Part 1 of the Distribution Licence and any permitted legal assigns or successors in title of the named party.

[ENA EREC P2/8, Clause 3.6]

NOTE 1: A **DNO** might also be referred to as a Distributor.

NOTE 2: The definition of a **DNO** also includes an Independent **Distribution Network Operator** (I**DNO**).

3.12
Electricity Storage (ES)
A facility connected to the distribution network which, behaves as **DG** when exporting power to the distribution system and, behaves as a **Demand Facility** when consuming electrical power from the distribution system.

NOTE 1: An example of an **ES** is a battery installation (treated as a **Demand Facility** when charging and **DG** when discharging).

NOTE 2: **DG** is differentiated from an **ES** as it does not store energy.

NOTE 3: **ES** is a form of 'other means' as referred to in ENA EREC P2/8.

3.13
Extra High Voltage (EHV)
An alternating current (AC) voltage above 20 kV RMS up to and including 132 kV RMS.

NOTE: Typical **EHV** distribution networks operate at a nominal voltage of 33 kV, 66 kV, or 132 kV.

3.14
First Circuit Outage (FCO)
A fault or pre-arranged **Circuit** outage.

[ENA EREC P2/8, Clause 3.7]

3.15
Generator
A person who generates electricity under licence or exemption under the Electricity Act 1989 [N3] (as amended by the Utilities Act 2000 [N4] and the Energy Act 2004 [N5]).

NOTE: The Electricity (Northern Ireland) Order 1992 [N7] is relevant as appropriate.

3.16
Group Demand
The **DNO**'s estimate of the maximum demand of the group being assessed for EREC P2/8 [N1] compliance with appropriate allowance for diversity.

NOTE 1: When estimating the maximum demand of the group the **DNO** should, where necessary, take into consideration (but not be limited to) the following: the **Latent Demand** due to **DG**, the **Latent Demand** due to **DSR**, the **Latent Demand** due to **ES**, the effect of Suppliers' time of use tariffs, the effect of Network Operator price signals, the effects of **Cold Load Pickup** and, data granularity implications (instantaneous peak vs. time averaged flow).

NOTE 2: The **Group Demand** at grid supply points must be consistent with the demand data submitted to a transmission company under the terms of the GB Grid Code [3].

3.17
High Voltage (HV)
An alternating current (AC) voltage above 1 kV RMS up to and including 20 kV RMS.

NOTE: Typical **HV** distribution networks operate at a nominal voltage of 6.6 kV, 11 kV, or 20 kV.

3.18
Intermittent Generation
A generation facility where the energy source of the prime mover cannot be made available on demand.

3.19
Latent Demand
The demand that would appear as an increase in **Measured Demand** if the **DG** was not operating, the **DSR** was not implemented or other means (e.g., time of use tariff, export from Electricity Storage) of suppressing the **Measured Demand** within the network (for which the **Group Demand** is being assessed) was not operating.

[ENA EREC P2/8, Clause 3.10]

NOTE 1: **Latent Demand** for an **ES** exists when there is export or restricted import, at the time of **Measured Demand**.

3.20
Low Voltage (LV)
An alternating current (AC) voltage up to and including 1 kV RMS.

NOTE: Typical **LV** distribution networks operate at a nominal voltage of 230 V (single-phase) and 400 V (three-phase).

3.21
Measured Demand
Summated demand measured at the normal (network) infeed points to the network for which **Group Demand** is being assessed.

[ENA EREC P2/8, Clause 3.11]

3.22
Non-Contracted
The absence of a bilateral agreement between a **DNO** and party providing **System Security** from a **DG** facility, a **DSR Scheme** or an **ES** facility.

NOTE: **Non-Contracted** does not prohibit the existence of a contract outside of **DNO** involvement.

3.23
Non-Intermittent Generation
A generation facility where the energy source for the prime mover can be made available on demand.

3.24
Persistence (T_m)
The minimum time for which output from **Intermittent Generation** must be continuously available for it to be considered to contribute to **System Security**.

3.25
Regulatory Financial Performance Reporting (RFPR)
A selection of documents and tables collected by Ofgem annually for the purposes of administering compliance and monitoring performance of **DNO**s in accordance with the regulatory framework.

NOTE: Refer to Ofgem guidance on **Regulatory Financial Performance Reporting**.

3.26
Second Circuit Outage (SCO)
A fault following a pre-arranged **Circuit** outage.

NOTE: The recommended levels of security are not intended at all times to cater for a first fault outage followed by a second fault outage or for a simultaneous double fault outage. Nevertheless, in many instances, depending upon switching and/or loading/generating arrangements, they will do so.

[ENA EREC P2/8, Clause 3.13]

3.27
System Security
The capability of a system to maintain supply to a defined level of demand under defined outage conditions.

[ENA EREC P2/8, Clause 3.16]

3.28
Transfer Capacity
The capacity of an adjacent network which can be made available within the times stated in EREC P2/8 Table 1. **Transfer Capacity** will be limited by **Circuit Capacity** or other practical limitations on power flow.

[ENA EREC P2/8, Clause 3.18]

4 Assessment process overview

When assessing whether a distribution system complies with the security requirements of EREC P2/8 [N1] **DNO**s should consider the contribution to **System Security** from:

a) network assets;

b) **DG** connected to its network;

c) Demand Facilities with **DSR Scheme**s connected to its network; and

d) **ES** connected to its network.

NOTE: The contribution to **System Security** from **DG**, **DSR Scheme**s and **ES** is variable dependant on whether the **DNO** has a contractual arrangement with the operator/provider of one of these non-network assets.

The guidance in this EREP simplifies the presentation of **Circuit** ratings and security contribution from **DG**, **DSR Scheme**s and **ES**, inferring a simple summation to assess aggregate capacities etc. However, in reality it will always be necessary to perform appropriately complex assessments, probably via modelling software, to ascertain that a **Circuit** is not unacceptably overloaded in the outage scenarios set out in EREC P2/8 [N1]. Note also Section 5.1 of EREC P2/8 [N1] where there is a specific requirement that equipment should not be overloaded to a point where it suffers unacceptable loss of life.

When seeking to assess whether a particular section of network is compliant with the security requirements in EREC P2/8 [N1] it is necessary to follow a procedure similar to that shown diagrammatically in Figure 1. This figure includes a number of stages and refers to clauses providing detailed guidance on each of these stages. For simplicity the security assessment process described in this EREP describes the general methodology which should be adapted by the **DNO** as appropriate.

For **DNO**s this exercise is a periodic one across the full network, supplemented by specific assessments at points on the network where the **System Security** needs to be reviewed as a result of changes in network design (including network reinforcement, diversions, and new connections), **DG** or ES developments or implementation of **DSR Scheme**s. Hence, ongoing compliance with EREC P2/8 [N1] should be achieved.

NOTE: When the reduced security of supply for class of supply B has been applied to a radial **HV Circuit** (see Clause 6.5) an assessment should be carried out when the network is reconfigured, a new connection provided or the **Circuit** diverted etc. as the length of the **HV Circuit** might increase and exceed the 1 km maximum total length criteria.

For substations serving a **Group Demand** over 12 MW the **DNO**s shall perform an annual security compliance review, normally aligned to the annual **RFPR** submission. In addition, for these substations, a security compliance review shall be performed where there are significant changes to network design (including network reinforcement and new connections), **DG** or **ES** developments or implementation of **DSR Scheme**s.

In assessing the security contribution from **DG**, **DSR Scheme**s and **ES**, the **DNO** will want to balance the effort required to obtain accurate data with the risks to loss of supplies from using inaccurate or uncertain data.

NOTE: An overview of the technical issues that may need to be considered are shown in the Technical Check List provided in Annex C of this report.

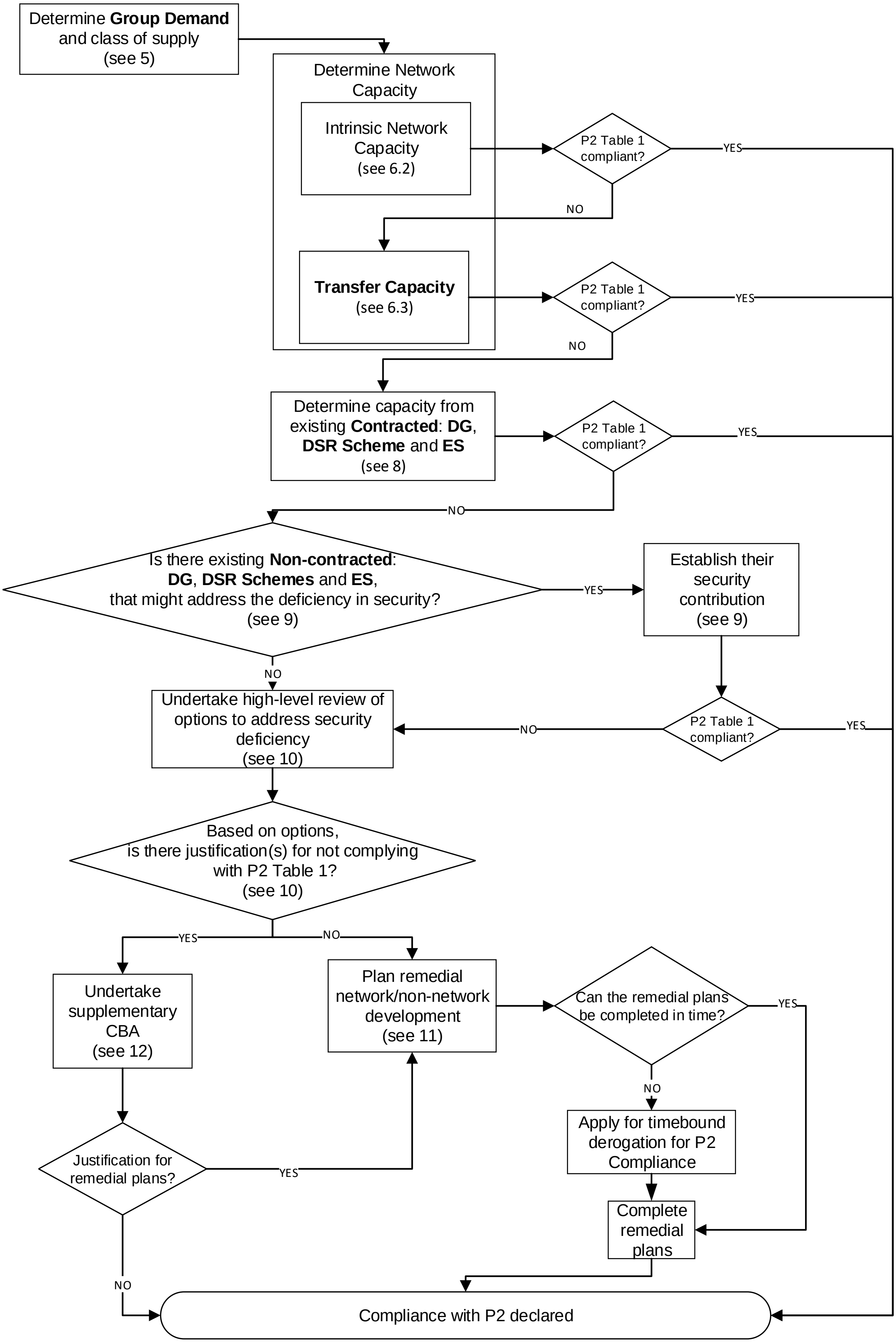


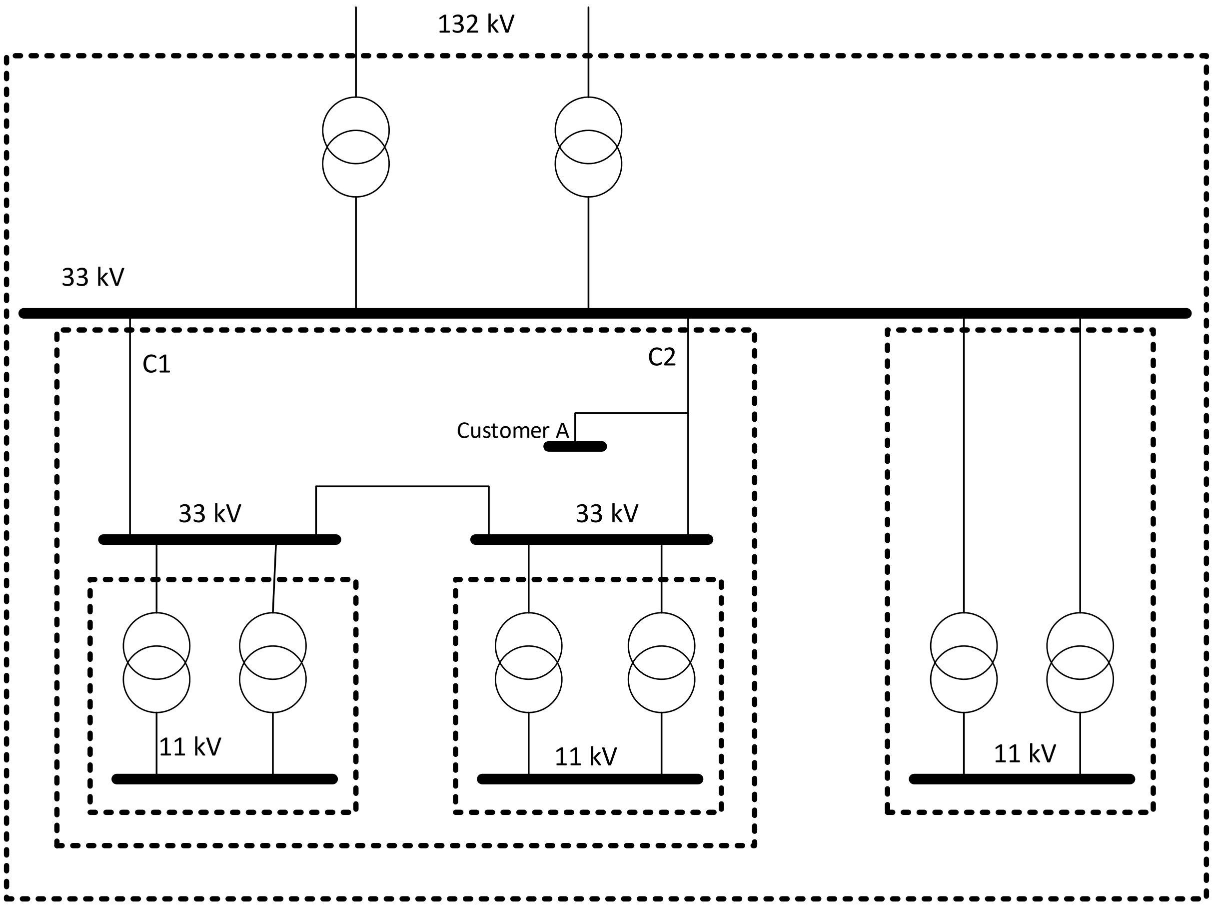
Figure 1 – The assessment process

5 Determine the Group Demand and class of supply

5.1 General

Considering a section of network, a **DNO** should identify the demand groups within its network where a security of supply assessment should be carried out. There will be numerous demand groups in a **DNO** network and lower voltage demand groups will combine to form larger demand groups, as illustrated in Figure 2. Not shown in Figure 2 are **HV** and **LV Circuit**s forming demand groups in class of supply A and B: Clauses 5.2 and 5.3 respectively covers these classes of supply.

The **DNO** should carry out a bespoke assessment of the **Latent Demand** based on the principles in Clause 5.4.



NOTE: ‘Dashed’ lines indicate a section of network and hence a demand group.

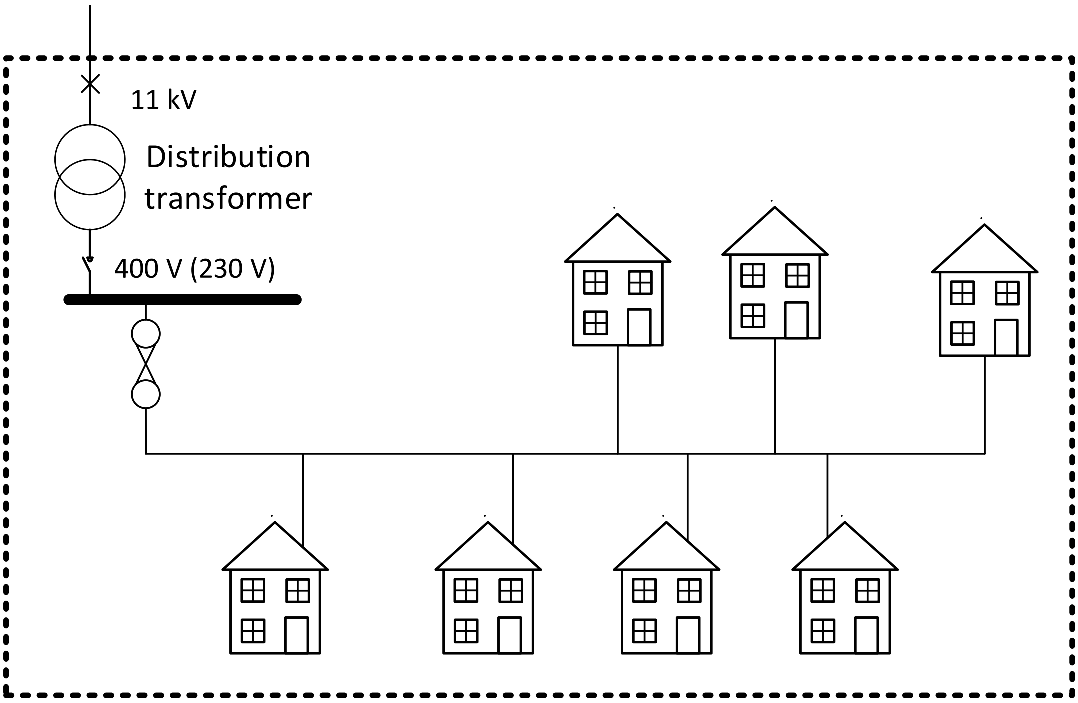
Figure 2 – Typical demand groups (section of network) in a network

To identify the class of supply (see Table 1 in EREC P2/8 [N1]) for each demand group, the **Group Demand** first needs to be established – Figure 7 outlines the process and the need to determine the **Measured Demand**, any **Latent Demand** and the effects of **Cold Load Pickup**.

In Figure 2, consider the scenario where the supply to Customer A has been interrupted due to a fault on **Circuit** C2. In this case, where Customer A has agreed to a single **Circuit** risk agreement, EREC P2/8 [N1] states that this customer’s supply is considered to be restored when there is an outage on **Circuit** C2. Customer A’s demand is included in the **Group Demand** and used to establish the class of supply. However, where such a customer has a connection agreement with the **DNO** requiring only single **Circuit** security, EREC P2/8 [N1] considers this to be a form of a **DSR Scheme** contract between the customer and the **DNO** and that for the purpose of complying with the requirement to supply the 'minimum demand to be met', activation of this **DSR Scheme** is equivalent to restoration of demand.

5.2 Class of supply A

EREC P2/8 [N1] class of supply A relates to **Group Demand**s up to 1 MW. A (11/0.4 kV) distribution transformer supplying one or more **LV Circuit**s is normally covered by this size of **Group Demand**. The maximum rating of a distribution transformer typically deployed when there is no contribution to security of supply from **Transfer Capacity**, **DG**, **DSR Scheme**s, or **ES**, is 1 MVA (nameplate rating). Higher rated distribution transformers are available and may be installed, but the requirements of class of supply A are only applicable if the **Group Demand** is less than or equal to 1 MW, regardless of transformer rating. There is a note in EREC P2/8 Table 1 which permits the **Group Demand** to exceed of 1 MW provided that it is within the overload capacity (cyclic load capacity) of a 1 MVA transformer. In all other situations where the **Group Demand** is greater than 1 MW, the **Group Demand** shall be considered as being a class of supply B.



NOTE: Dashed line indicates a section of network and hence a demand group.

Figure 3 – Typical Class of Supply A demand group

5.3 Class of supply B

EREC P2/8 [N1] class of supply B relates to **Group Demand**s over 1 MW and up to 12 MW. **HV Circuit**s normally supply a **Group Demand** in the range 1-12 MW, which is considered to be a class of supply B. **HV Circuit**s are typically supplied from primary substations and provide supplies to customers in an area local to the primary substation.

NOTE: The term **HV Circuit** refers to a series of underground cables and/or overhead lines, together with the associated switchgear, connecting distribution substations to one or more primary substations. Hence, a **HV Circuit** is made up of a series of individual **Circuit**s between substations.

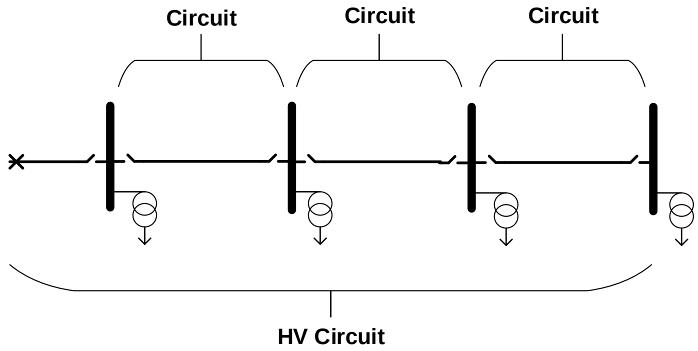
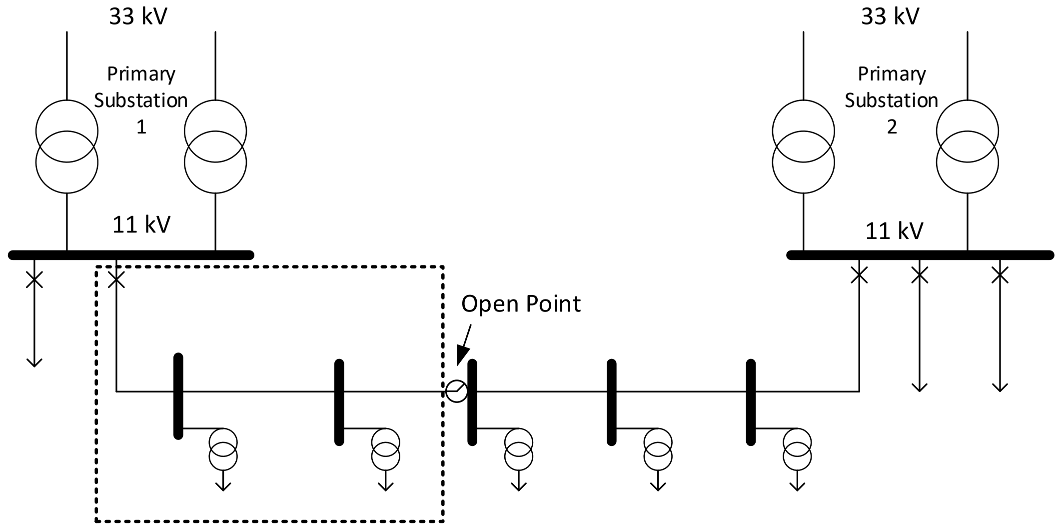


Figure 4 – Relationship between Circuit and HV Circuit

HV Circuits will be configured either as a 'radial' or 'interconnected' **Circuit**:

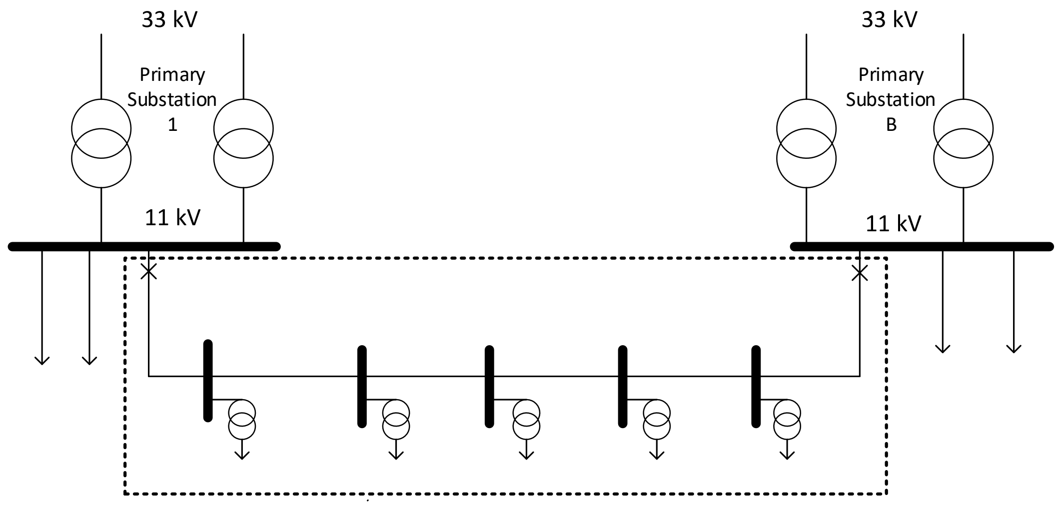
a) Radial **HV Circuit** – a series of **Circuit**s (each comprising underground cables and/or overhead lines and associated switchgear) with a single point of supply, with connection to one or more alternative points of supply via 'open' points to one or more **HV Circuit**s used to maintain customer supplies during outages. The majority of **HV Circuit**s in GB are designed and operated as radial **Circuit**s.



NOTE: Dashed line indicates a section of network and hence a demand group.

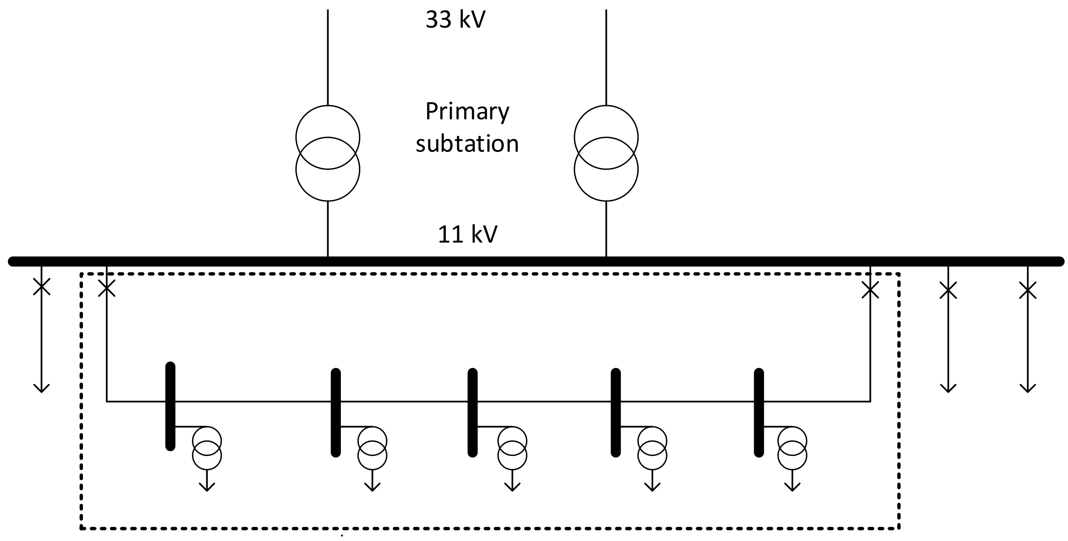
Figure 5 – Typical radial HV Circuit

b) Interconnected **HV Circuit** – a series of **Circuit**s (each comprising underground cables and/or overhead lines and associated switchgear) with two or more points of supply. This commonly entails primary substations operating in parallel, which requires more complex **Circuit** protection arrangements compared to radial **HV Circuit**s.



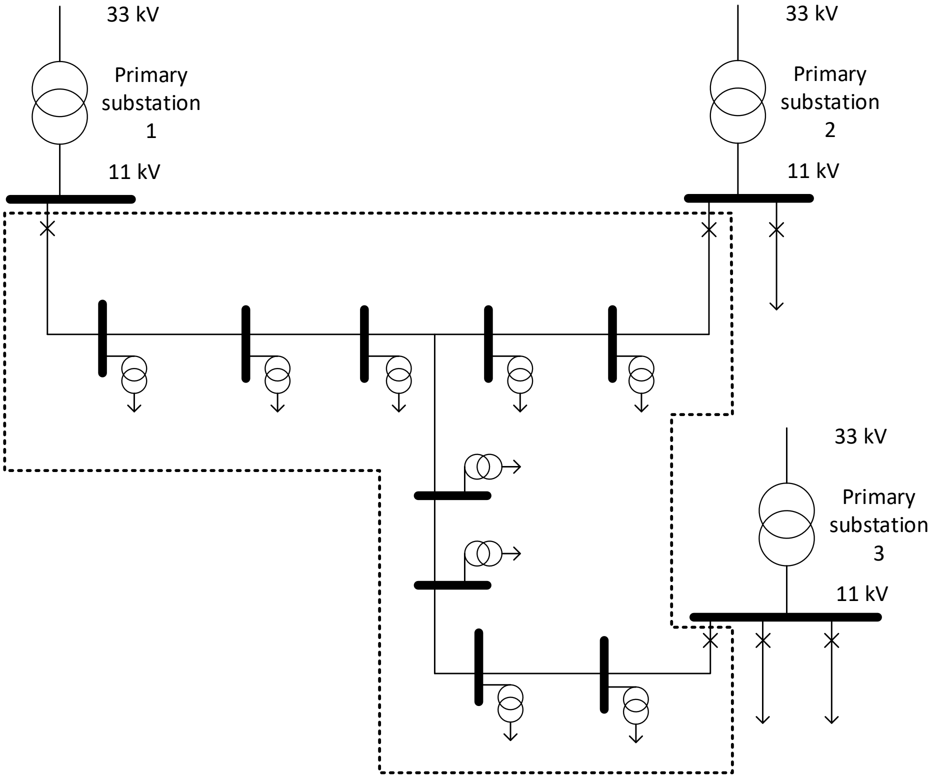
NOTE: Dashed line indicates a section of network and hence a demand group. The demand group may include the primary substation transformers if the load on all **HV Circuit**s is within the class of supply.

Figure 6A – Typical interconnected HV Circuit (between two primary substations)



NOTE: Dashed line indicates a section of network and hence a demand group.

Figure 6B – Typical interconnected HV Circuit (loop on one primary substation)



NOTE: Dashed line indicates a section of network and hence a demand group. The demand group may include the primary substation transformers if the load on all HV Circuits is within the class of supply.

Figure 6C – Typical interconnected HV Circuit (between three primary substations)

Determination of **Group Demand** for a demand group comprising a **HV Circuit** firstly requires identification of the **Circuit**s supplying a group of customers. By way of example in Figure 5 the relevant **Circuit** is that between and including the circuit-breaker at primary substation 1 and the open point, in Figure 6A the relevant **Circuit** is that between and including the two circuit-breakers at the primary substations.

5.4 Measured Demand and Latent Demand

If there is **DG**, a **DSR Scheme** or **ES** connected to the network connected within the demand group, it will be necessary for the **DNO** to determine whether there is any **Latent Demand** (see Annex A) and, if so it should be added to the **Measured Demand** to establish the **Group Demand**. However, to avoid excessive and unproductive computation, there is a de-minimis test to determine the extent of **Latent Demand** assessment required.

- If the aggregate capacity of **Non-Contracted**, **DG**, **DSR Scheme**s (where this can be readily established), and **ES**, is less than 5% of **Measured Demand**, then the **Group Demand** should be taken as being the same as the **Measured Demand**.

The de-minimis test shall exclude capacity of **Contracted DG**, **DSR Scheme**s, and **ES**, as the **DNO** should account for **Latent Demand** associated with these contracts (see Figure 7).

The **DNO** should establish the **Latent Demand** based on the principles outlined in this Clause and Annex A. With experience, further clarity may emerge which could be incorporated into later issues of this EREP.

5.5 Cold Load Pickup

The **DNO** should also consider whether the **Group Demand** should be increased to cater for the effects of **Cold Load Pickup**. **Cold Load Pickup** is only a concern when supplies to particular electrical loads are being restored following a period of interruption. The following are examples of loads which may exhibit **Cold Load Pickup** characteristics.

i. Electrical heating.
ii. Refrigeration.
iii. Air conditioning.
iv. Heat pump (HP), and
v. Electric vehicle (EV).

The magnitude of the **Cold Load Pickup** is dependent on a number of factors including the:

- duration of the outage;

  Typically, the longer the duration, the greater the **Cold Load Pickup** as the natural diversity of the demand is lost.

- time of day and year when the outage occurs; and

  Outages in winter particularly, during the evening and overnight, would typically have a greater impact on the **Cold Load Pickup** resulting from electric heating. Outages in summer, particularly during the day, would typically have a greater impact on the **Cold Load Pickup** resulting from air conditioning load.

- nature of the load.

  Cold Load Pickup is likely to have an impact on the observed **Measured Demand** that reduces over a period of several hours. However, some demand such as EV chargers may impose a demand lasting only several seconds when supply is restored to a fully charged battery.

Historically the effects of **Cold Load Pickup** have not been explicitly taken into account in establishing the **Group Demand** and the effects have been accommodated within the short time rating of network assets. With increased use of cyclic and emergency ratings for **Circuit**s, their capability to accommodate **Cold Load Pickup** may need to be established. The following criteria should be considered when evaluating the impact of **Cold Load Pickup** on the **Group Demand**:

a) **Cold Load Pickup** should not be ignored if there is awareness that the network assets may not have sufficient short-time rating or there is likelihood of a **Cold Load Pickup** event at a time of peak Measure Demand; and

b) **Cold Load Pickup** may be ignored if the particular load is less than 10% of the total load for rural networks (where the majority of the network is overhead) and less than 30% for urban networks (where the majority of the network is underground)[1].

[1] A report by Manchester University in 2016 [4] on the assessment of **LV** network capacity for electric vehicle (EV) and photovoltaic (PV) connection, found that the existing **LV** networks could host a certain percentage of these onerous loads prior to issues arising with capacity.

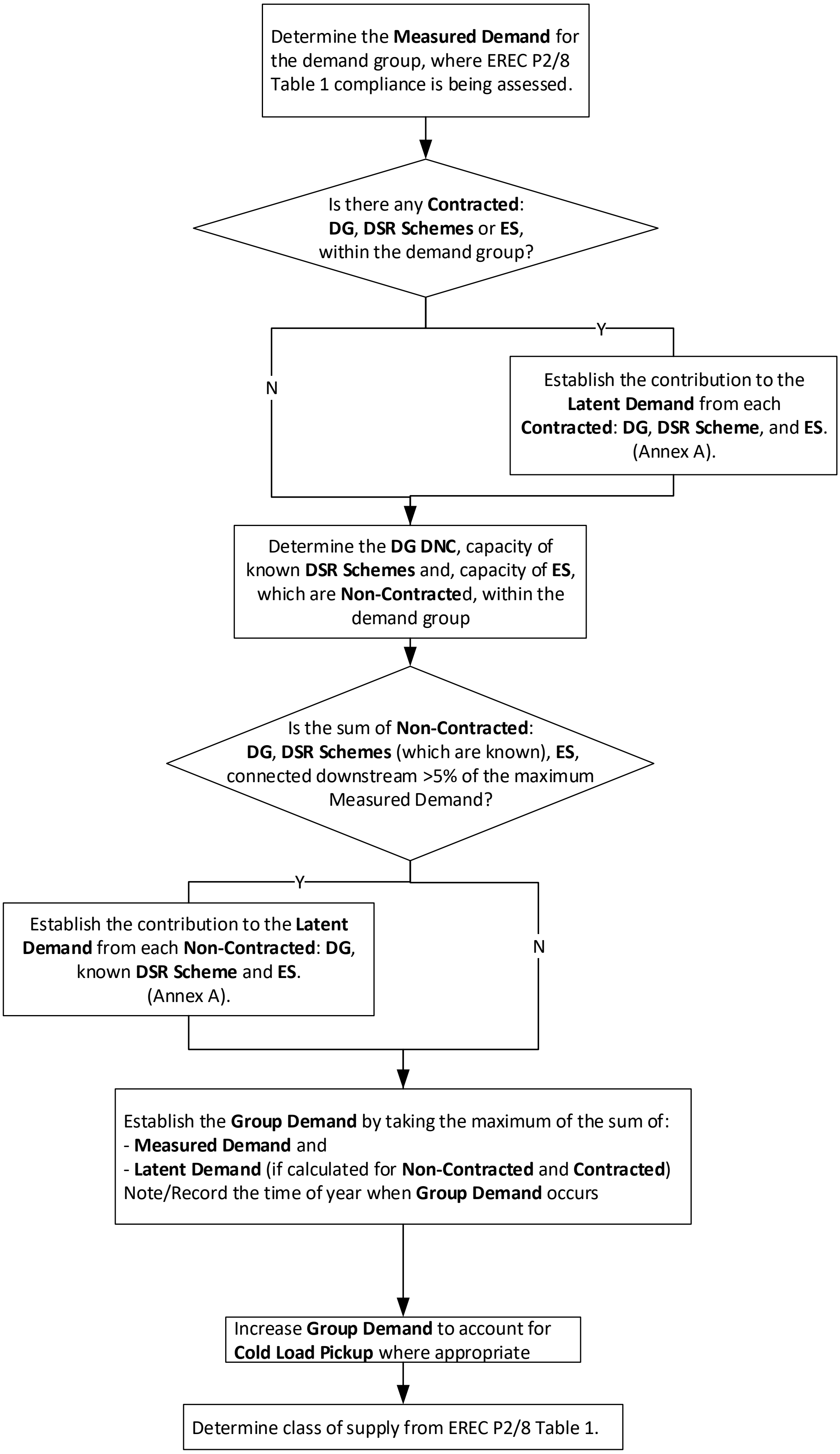


Figure 7 – Determine Group Demand and class of supply Group Demand

6 Determine capacity of network assets and assess compliance

6.1 General

The next step is to identify the capacity of the existing network assets and establish if they are capable of securing the **Group Demand** identified in Clause 5, in accordance with the criteria specified in ER P2/8 Table 1 [N1].

NOTE: Voltage criteria and differing **Circuit** capacities and impedances may be limiting factors in determining the network capacity under **FCO** and **SCO** conditions. In such situations the use of network analysis software becomes essential to determine the network capacity.

For **FCO**s, the **Circuit Capacity** should normally be based on the cold weather ratings, but if the **Group Demand** is likely to occur outside the cold weather period the ratings for the appropriate ambient conditions should be used. Where the **Group Demand** does not decrease at the same rate as the **Circuit Capacity** (e.g., with rising temperature) special consideration is needed.

For **SCO**s, in view of the proportions of **Group Demand** to be met in EREC P2/8 [N1] Table 1, the ratings appropriate to the appropriate ambient conditions of the period under consideration should be used, which may be other than winter conditions.

The term ‘class of supply’ is associated with a MW quantity in EREC P2/8 [N1], but **Circuit Capacity** should be considered in MVA with due regard for generating plant MW sent out and MVAr capability where appropriate.

6.2 Intrinsic network capacity

The intrinsic network capacity should be established by considering the **Circuit Capacity** of each **Circuit** supplying the demand group. The intrinsic network capacity is that which is available from the **Circuit**(s) supplying the demand group under system intact and the depleted network conditions that need to be secured to the level set out in Table 1 of EREC P2/8[N1]: it is the capacity available within 60 s of the commencement of an outage.

NOTE: 60 s relates to an automatic switching facility that does not depend on communications, requires no local manual or remote initiation and which has been appropriately planned and designed considering the load on network assets and protection settings. A hot standby arrangement where an on-site transformer normally out-of-service is automatically switched in-to-service within 60 s of an outage occurring would be considered to be part of the intrinsic capacity.

For classes of supply B to E inclusive, the intrinsic network capacity should be determined under **FCO** conditions, i.e., with an outage of the most critical **Circuit**.

For classes of supply D and E, the intrinsic network capacity should also be determined under **SCO** conditions, i.e., with an outage of both the first and second most critical **Circuit**s.

In the event that the intrinsic network capacity is insufficient to meet the requirements of EREC P2/8 [N1] it will be necessary for the **DNO** to establish if the **Transfer Capacity** is sufficient to meet any deficiency in **System Security**.

6.3 Transfer Capacity

The **Transfer Capacity** should be established when the intrinsic network capacity is insufficient to comply with the requirements of EREC P2/8 [N1] Table 1.

Transfer Capacity relates to the capability of an adjacent network to supply demand of a given demand group during **FCO** and **SCO** conditions. Hence in addition to being affected by the **Circuit Capacity** of the interconnection between the demand groups, **Transfer Capacity** is dependent on the capacity of an adjacent demand group(s) to the one being assessed.

Transfer Capacity is generally utilised by network re-configuration via:

- Automatic switching of available network capacity via a local or remote management system (typically within 15 mins) i.e., local or remote automation;
- Manual switching of available network capacity via a remote management system (typically within 15 mins) i.e., remote control; or
- Manual switching of available network capacity via local operation of equipment (typically within 3 hrs).

The following considerations are relevant when assessing the available **Transfer Capacity**.

a) Capacity of each **Circuit** used to implement the transfer and the time to implement.

   The **Circuit Capacity** of the **Circuit**(s) used to transfer demand relevant to the time when the transfer is required and the demand profile that it would be exposed to.

b) Availability & reliability of each **Circuit** used to implement the transfer.

   The co-ordination of planned outages is critical when considering the use of **Transfer Capacity**. Unless there is a high probability that a **Circuit**(s) is/are available for demand transfer, it may be prudent to reduce the theoretical **Transfer Capacity** to reflect a **Circuit**'s unavailability.

c) Gross and net demand (if any) on each **Circuit** used to implement the transfer.

   Unless a **Circuit**(s) being considered is clean, i.e., there are no customers connected to it, it is necessary to establish the demand headroom available on the **Circuit**. Hence, before the **Circuit**(s) is/are used to transfer demand, the gross demand (demand without **DG**/**DSR Scheme**s/**ES** operating) and net demand (demand with **DG**/**DSR Scheme**s/**ES** operating) should be established. This requires additional assessment in accordance with Clause 5.

   In determining the capacity of a **Circuit**(s) to be used to implement demand transfer, the effects and response of any **DG**/**DSR Scheme**s/**ES** must be considered once it is operating as a Transfer **Circuit**, e.g., fault level implications for connected **DG** or **ES**.

d) Impact of the demand transfer on the demand group to which the demand (or generation) is transferred.

   The **DNO** should consider whether the demand group 'receiving' the demand transfer will continue to operate within its acceptable operating limit.

e) Whether interruptible demand on the adjacent network should be interrupted to create capacity for the transfer.

   Where relevant, the **DNO** should establish if it is acceptable to interrupt the supply to customers not affected by the **FCO** or **SCO** in order to create the capacity in the receiving demand group to implement the demand transfer.

f) Application of pre-outage transfer and post outage transfer.

   The **DNO** may consider it normal practice to re-configure the network in advance of a planned **FCO**. This may use the same **Transfer Capacity** as that applied following an unplanned outage.

g) Temporary network re-arrangement due to seasonal effects.

   The **DNO** may re-configure the network to an alternative 'normal' arrangement during seasonal events which may affect the **Transfer Capacity** of a demand group. In this case a security assessment should be considered for each seasonal network configuration.

In the event that the intrinsic network capacity and **Transfer Capacity** is insufficient to meet the requirements of Table 1 of EREC P2/8 [N1] it will be necessary for the **DNO** to assess the security contribution of **DG**, **DSR Scheme**s and **ES**. With regards to item c) above, the **DNO** may have already initiated this assessment.

6.4 Class of supply B

Assessing the compliance of an **HV Circuit** with EREC P2/8 [N1] requires a determination of the intrinsic network capacity, in accordance with Clause 6.2, and the **Transfer Capacity**, in accordance with Clause 6.3, under the appropriate network conditions. In the case of a class of supply B demand group, this is under **First Circuit Outage (FCO)** conditions.

For a radial **HV Circuit** the intrinsic network capacity is zero, and the **Transfer Capacity** depends on the capacity of the interconnecting **HV Circuit**s together with the associated time required to make this **Transfer Capacity** available (including time for network switching to isolate the faulted **Circuit** and restore supplies from healthy **Circuit**s). The presence of remote control/automation of switching will significantly influence the time to restore supplies.

For an interconnected **HV Circuit** the intrinsic capacity of the **Circuit** is relied upon to maintain supplies in the event of a **FCO**, rather than the **Transfer Capacity**. Hence, network switching to isolate the fault and re-supply customers from adjacent **HV Circuit**s is not relevant for interconnected **HV Circuit**s. However, because the interconnected **HV Circuit** is supplied from multiple sources, the capacity will need to be established using network modelling (determining the most onerous **Circuit** fault within the interconnected **Circuit**s).

Annex F.2 and F.3 detail typical security of supply assessments for a **HV Circuit**.

6.5 Reduction for Class of Supply B

6.5.1 Introduction

In Table 1 of EREC P2/8 [N1] there is an option to permit a reduced security of supply for a class of supply B demand group.

The intention of permitting a reduction in the security of supply for some class of supply B demand groups is to increase the efficiency of the network by accommodating additional load without the need for reinforcement that would otherwise be required where the adverse impact associated with such additional load on customers is expected to be small.

The reduction in the security of supply in class of supply B demand groups is:

- For a **First Circuit Outage**, the minimum demand to be met within 3 hours: **Group Demand** minus 1.2 MW.

This reduction in security of supply can only be applied where the following criteria are satisfied.

a) Where the **Group Demand** is supplied by a **HV Circuit** which is designed and operated as radial **HV Circuit** and not an interconnected **HV Circuit** (see Clause 5.3).

b) Where the **Group Demand** is not supplied by a primary substation comprising a single **EHV**/**HV** transformer (an example of a primary substation comprising a single **EHV**/**HV** transformer is a substation with a single incoming 33 kV supply equipped with one 33/11 kV transformer supplying one or more 11 kV **Circuit**s).

c) Where the total length of the radial **HV Circuit** is less than 1 km i.e., the length of all cable/overhead line connected, including tee-offs, between the supplying **Circuit**-breaker at the primary substation and the open point(s).

d) The 1.2 MW of demand that may remain off supply for up to 3 hours after a **First Circuit Outage** shall not be part of a single class of supply A demand group i.e., the 1.2 MW of demand off supply shall be formed from two or more class of supply A demand groups. To explain this further, consider a fault on the first **Circuit** section from primary substation 1 in Figure 8– the reduction in security of supply would permit 1.2 MW of demand at two or more demand groups (e.g. W_{SUB} and X_{CCT}) not to be restored within 3 hours. The **HV Circuit** would not be compliant if more than 1 MW of demand at a single substation or on a single teed **Circuit** could not be restored within 3 hours as that demand group would not comply with the requirements of class of supply A demand groups.

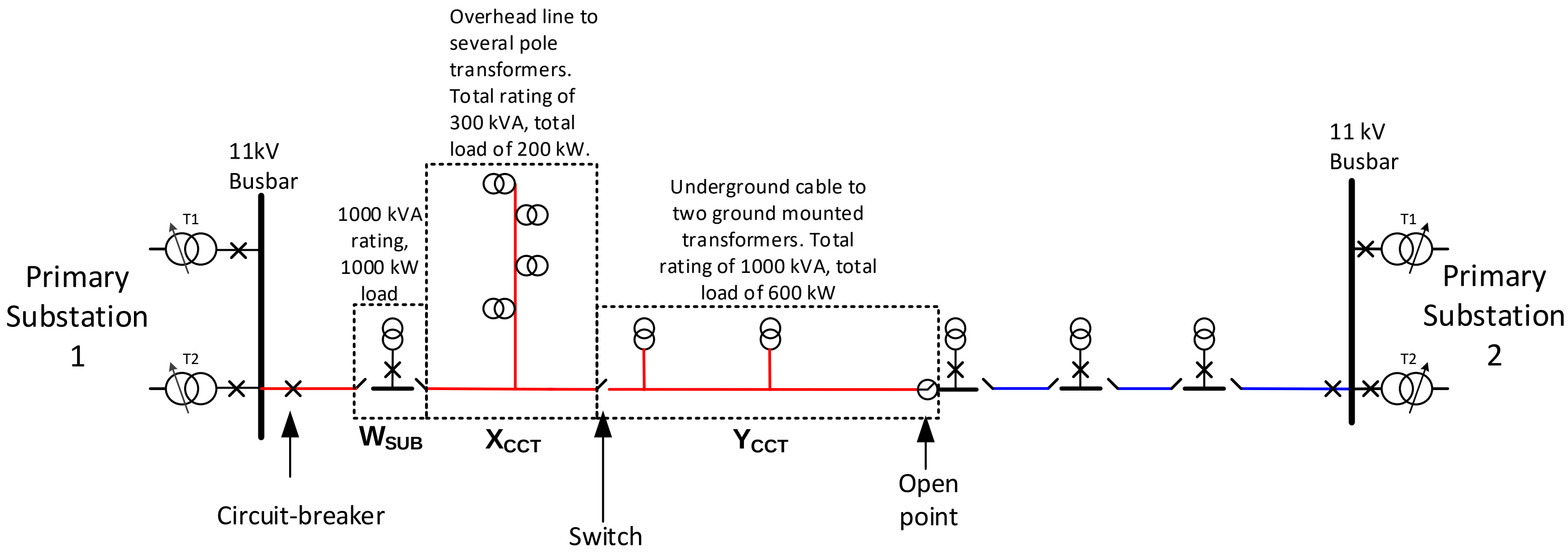


Figure 8 – Demand Groups on a typical HV Circuit

NOTE 1: Figure 8 depicts two radial **HV Circuit**s (red and blue). The red **HV Circuit** comprises a mixture of underground cable and overhead line. It is less than 1 km long which is inclusive of the teed **HV Circuit**, X_{CCT}.

NOTE 2: W_{SUB} is a ground mounted substation, X_{CCT} depicts a **Circuit** supplying a teed overhead line to several pole mounted transformers, and Y_{CCT} depicts a **Circuit** up to the open point and supplying two ground mounted transformers.

NOTE 3: W_{SUB} is a demand group which falls into the scope of class of supply A i.e., up to 1 MW. The reader is reminded that EREC P2/8 [N1] allows the load on a single 1000 kVA transformer to be “extended to cover the overload capacity of that transformer”.

NOTE 4: X_{CCT} is a demand group and class of supply A i.e., 200 kW off supply for repair time (for a **Circuit** fault)

NOTE 5: Y_{CCT} is a demand group and class of supply A i.e., 600 kW off supply for repair time (for a **Circuit** fault).

NOTE 6: The combined demand of W_{SUB} and X_{CCT} is 1.2 MW – this may be restored in repair time for a **FCO** i.e., for a fault on the cable between Primary Substation 1 and W_{SUB} where, the **Transfer Capacity** available from the Open Point is limited to 600 kW (only Y_{CCT} restored by switching).

NOTE 7: Without the relaxation reinforcement would be required e.g. to increase the **Transfer Capacity** from the blue **Circuit** by 200 kW. With the relaxation reinforcement is not required.

7 Contribution to System Security from DG, DSR Schemes, and ES

In considering the security contribution from means other than network assets, the **DNO** can initiate this by establishing whether the aggregate capacity of **DG**, **DSR Scheme**s and **ES** connected to the network might be sufficient to meet any deficiency in **System Security**. If the aggregate is less than any deficiency, the actual **DG**/**DSR Scheme**/**ES** security contribution will definitely be inadequate to meet the requirements of EREC P2/8 [N1] Table 1 and it will be necessary for the **DNO** to consider remedial options (reinforcement, additional **DSR** arrangements etc). However, the security contribution of the **DG**, **DSR Scheme**s and **ES** might still be of value, in limiting the extent of remedial options.

In the event of the **DNO** needing to rely on **DG**, **DSR Scheme**s and **ES**, during **Circuit** outages, the **DNO** needs to decide whether to rely on the fortuitous contribution associated with their normal commercial operation, or to enter into a commercial arrangement with the **DG**/**DSR Scheme**/**ES** operator/owner. Clause 8 describes the aspects that should be considered when the **DNO** is entering into a contract arrangement, and Clause 9 describes the assessment of **DG**/**DSR Scheme**s/**ES** which are not **Contracted** with the **DNO**.

There will be **DG**/**DSR Scheme**s/**ES** for which the **DNO**:

- cannot assess the output profiles, either from established or newly connecting **DG**/**DSR Scheme**s/**ES**; or
- considers that the **DG**/**DSR Scheme**s/**ES** does not exhibit predictable and steady output profiles; or
- requires a security contribution beyond that associated with the normal observed profile, either to extend to 24 hrs operation, or to provide temporarily greater MW support.

In these cases where the **DNO** is seeking to rely on the security contribution, the **DNO** should consider entering into a contract with the **DG**/**DSR Scheme**/**ES** owner/operator. The contract would specify the security contribution that the **DG**/**DSR Scheme**/**ES** owner/operator is able to offer, and provide acceptable reassurance that they will be able to provide the capacity when required by the **DNO**. The contract is likely to be such that the **DG**/**DSR Scheme**/**ES** operator/owner takes the risk of the facility being unable to provide an agreed capacity upon request.

The **DNO** should assess whether the costs, risks and benefits of procuring a **System Security** contribution from **DG**/**DSR Scheme**s/**ES**, through such a contract, is a more efficient and cost-effective option overall compared to a reliance on fortuitous security contribution of **Non-Contracted DG**/**DSR Scheme**s/**ES** or, additional **System Security** that would be provided by increasing the intrinsic capacity of the network or **Transfer Capacity**, for example by reinforcement.

8 Contribution to System Security from Contracted DG, DSR Schemes, and ES

8.1 General

Where the **DNO** has a contract with a **DG**, **DSR Scheme** or **ES** owner/operator which governs requests or operational instructions from the **DNO**, then the security contribution should be based on the terms of the bilateral agreement. The contract shall have considered dominance (Annex B) whereby the **DNO** is satisfied that any necessary capping has been accounted for within the contract.

8.2 Determine the security contribution from Contracted DG

The issues that may need to be considered by a **DNO** when looking to enter into a contract with a **DG** owner/operator for the provision of a contribution to **System Security** are described below.

a) Number and capacity of generating units in the **DG**, i.e., **DNC** of the **DG** facility.

b) **DG** action on receipt of **DNO** request/instruction for operation and:

    i. response time, e.g., cold start/warm start/reconnection times required;

    ii. minimum export required;

    iii. minimum duration of required operation;

c) Communication arrangement with **DG** facility, including the resilience of these arrangements.

d) **DG** stability requirements and interface protection:

    i. Agreed operating parameters and settings;

    ii. Fault ride through capability required;

    Evidence should be presented to demonstrate that the **DG** will ride through a range of credible network outages. Clause 9.3.1 provides guidance on assessing fault ride through for **DG** (which is relevant for both **Contracted** and **Non-Contracted DG**).

e) Availability/reliability requirements.

f) Coordination of **DNO** and **DG** planned outages.

g) The provision of information required to monitor the operation of the **DG**.

The **Contracted DG** security contribution associated with the **DG** shall be based on the terms of the contract.

The security contribution associated with the contract shall incorporate any necessary capping of the **DG** security contribution to avoid dominance in accordance with EREC P2/8 [N1] Clause 5.2. Annex B of this EREP includes further guidance on capping.

8.3 Determine the security contribution from Contracted DSR Schemes

The issues that might need to be considered by a **DNO** when looking to enter into a contract with a **Demand Facility** owner/operator for the provision of a contribution to **System Security** via a **DSR Scheme**, are described below.

a) Maximum import capacity of **Demand Facility**.

b) **Demand Facility** action on receipt of **DNO** request/instruction:

- Response time;

- Reduction in demand required expressed as either a maximum import or reduction of present demand (e.g., expressed a percentage of MW reduction);
- Minimum and maximum duration of required reduction (e.g., hours per day, minimum and maximum number of continuous days).

c) Communication arrangement with **Demand Facility**.

d) Coordination of **DNO** and **Demand Facility** outages.

e) The provision of information required to monitor the operation of the **Demand Facility** and the **DSR**.

For a **Contracted DSR Scheme**, a contribution to security shall be applied when that import constraint is considered to be active and have an observed effect at the time period being assessed. The magnitude of the security contribution from the active constraint shall be based on the observed performance under the terms of the contract, but cannot be greater than the **Latent Demand**.

The magnitude of the security contribution from the active constraint shall be based on the terms of the contract.

When establishing the magnitude of the security contribution for the contract, it is expected that the **DNO** takes account of the following factors:

i. An increase in demand reduction magnitude increases the security contribution;

ii. An increase in demand reduction duration (generally but not necessarily) increases the security contribution;

iii. An increase in demand recovery period increases the security contribution;

iv. A reduction in energy recovery increases the security contribution;

v. A more uniform energy recovery increases the security contribution;

vi. A reduction in the ratio of **DSR Scheme** capacity: peak network demand, increases the security contribution; and

vii. A peakier load profile increases the security contribution.

The contract shall incorporate any necessary capping of the **DSR Scheme** security contribution to avoid dominance in accordance with EREC P2/8 [N1] Clause 5.2. Annex B of this EREP includes further guidance on capping.

8.4 Determine the security contribution from Contracted ES

Contracted ES is **ES Contracted** to export at time of peak and/or ES **Contracted** not to import at time of peak.

The issues that may need to be considered by a **DNO** when looking to enter into a contract with an ES facility owner/operator for the provision of a contribution to **System Security** are described below.

a) Maximum capacity of **ES** facility – for both export and import.

b) Agreed cycle of operation for **ES** facility:

i. Hourly/daily sequence of operations, i.e., times of import and times of export;

ii. Duration of operating sequences (charge/discharge cycle time).

c) **ES** facility action on receipt of **DNO** request/instruction for operation:

   i. Response time, e.g., cold start/warm start/reconnection times required;
   ii. Minimum export required;
   iii. Minimum duration of export required;
   iv. Reduction in demand required expressed as either a maximum import or reduction of present demand (e.g., expressed a percentage of MW reduction).

d) During **ES** export – stability requirements and interface protection;

   i. Agreed operating parameters and settings;
   ii. Fault ride through capability required;

   Evidence should be presented to demonstrate that the facility will ride through a range of credible network outages. Clause 9.3.1 provides guidance on assessing fault ride through for generation (relevant for both **Contracted** and **Non-Contracted**).

e) Availability/reliability requirements for **ES** facility.

f) Coordination of **DNO** and **ES** planned outages.

The contribution to security from **ES** which is **Contracted** to export shall be based on the terms of that contract.

When establishing the contribution value for the contract, it is expected that the **DNO** takes account of the following factors:

i. An increase in **ES** capacity increases the security contribution;
ii. An increase in **ES** power increases the security contribution;
iii. A reduction in **ES** charge time increases the security contribution;
iv. An increase in **ES** efficiency increases the security contribution;
v. A reduction in the ratio of **ES** power: peak network demand, increases the security contribution;
vi. A peakier load profile increases the security contribution.

For **ES** which is **Contracted** to constrain its import (akin to a **Contracted DSR Scheme**), a contribution to security shall be applied when that import constraint is considered to be active and have an observed effect at the time period being assessed. The value of the security contribution from the active constraint shall be based on the observed performance under the terms of the contract, but cannot be greater than the **Latent Demand**.

The contract shall incorporate any necessary capping of the **ES** security contribution to avoid dominance in accordance with EREC P2/8 [N1] Clause 5.2. Annex B of this EREP includes further guidance on capping.

9 Contribution to System Security from Non-Contracted DG, DSR Schemes, and ES

9.1 General

Where the **DNO** relies on the fortuitous security contribution of **Non-Contracted DG**/**DSR Scheme**s/**ES**, it should be assessed in accordance with the guidance in this Clause. Where the **DNO** has a need for a definitive security contribution then the costs, risks and benefits of procuring this from a **DG**/**DSR Scheme**/**ES** owner/operator should be assessed (see Clause 7).

If the aggregate capacity of **Non-Contracted**, **DG**, **DSR Scheme**s which are known, and **ES**, is greater than any system capacity deficiency identified it will be necessary to carry out further analysis to calculate the security contribution from these sources.

NOTE: The aggregate capacity of **Non-Contracted** items will have been considered earlier in the assessment process, during calculation of **Group Demand** (see Clause 5).

The aggregate of **Non-Contracted** capacity may contain all or some of the items in a) - d):

a) **Non-Contracted DG** (the **DNO** should have notification records of all **DG** connected to its network);

b) **Non-Contracted DSR Scheme**s which are known to the **DNO** (the **DNO** may have visibility of a **DSR Scheme** through information available from a third party);

c) **Non-Contracted ES** export (the **DNO** should have notification records of all **ES** connected to its network);

d) **Non-Contracted ES** import constraints which are known to the **DNO** (the **DNO** may have visibility of an **ES** import constraint through information available from a third party).

9.2 De-minimis criteria

In addition to the de-minimis test in Clause 5, there is another de-minimis test for **Non-Contracted DG**/**DSR Scheme**s/**ES** to establish whether the individual capacity is sufficiently small that it is considered inappropriate to assess its security contribution. It seems reasonable to base this de-minimis test on the **Group Demand** of the network to which the **DG**/**DSR Scheme**/**ES** is connected. It is recognised that establishing an appropriate de-minimis threshold is subjective, therefore a pragmatic approach needs to be taken. This report recommends that the de-minimis threshold should be set at 5% of **Group Demand**. Additionally, assessments of security contribution are not necessary for a facility below 100 kW in capacity, i.e., **DNC** of the **DG**, maximum reduction in demand associated the known **DSR Scheme**, capacity of the **ES**.

9.3 Determine the security contribution from Non-Contracted DG

The process for assessing the fortuitous contribution to **System Security** that can be provided by **DG** is described in the following sub-clauses. Where there is more than one **DG** facility in a network, a similar process is followed to establish the security contribution from each **DG** facility. The overall security contribution from **DG** within the demand group is taken to be the arithmetic sum of the contribution from each **DG** facility within that network.

When assessing the contribution to **System Security** from **DG** it is necessary to use one of the three approaches described in Annex D. Furthermore, the following influencing factors may be considered in further detail when assessing the **DG** contribution to security (see Annex E).

- Availability;

- Operating regime;
- Remote generation;
- Intermittency.

By using either generic **DG** information or bespoke operational data for a particular **DG**, it is possible to establish the F factors and hence the security contribution for each **DG**.

This fortuitous contribution is based on the expected normal operational behaviour associated with typical **DG** operation in GB.

The assessment of **Non-Contracted DG** shall incorporate any necessary capping of the security contribution to avoid dominance in accordance with EREC P2/8 [N1] Clause 5.2. Annex B of this EREP includes further guidance on capping.

9.3.1 Assessing the ride through capability of the DG

In the context of utilising the security contribution from **DG** to ensure compliance with the requirements of Table 1 of EREC P2/8 [N1], it will be necessary for the **DNO** to be satisfied with how the **DG** will respond to events on the network.

For example, during a network fault that results in a **FCO** event:

a) the **DG** will need to be either stable enough to remain connected during the fault and then continue to support the requisite level of demand during the period of the **FCO**, or until the demand can be transferred to an alternative network; or

b) if the **DG** disconnects as a result of the fault, it will be necessary for the **DG** to reconnect and synchronise to the network to support the requisite level of demand either:

    i. within the times allowable in Table 1 of EREC P2/8 [N1]; or

    ii. sufficiently rapidly to prevent any overloading of any remaining network assets supplying demand.

Unless the **DNO** has modelled the transient **DG** performance and has evidence to demonstrate that the **DG** will ride through a range of credible network outages it should be assumed that the **DG** will trip during a **FCO** or SCO unplanned outage. Similarly, the **DNO** should confirm the reconnection arrangements with the **DG** operator rather than assuming that a **DG** will automatically reconnect to the system once the network voltage and frequency has returned within normal pre-fault limits. The behaviour of **DG** will be less certain during an unplanned outage than during a planned outage. For a demand group where supply continuity is required for a SCO, transient performance should be modelled under planned outage conditions.

9.4 Determine the security contribution from Non-Contracted DSR Schemes

DSR Schemes may be present on a network but not **Contracted** with the **DNO**. In these cases, the assessment of **DSR Scheme** contribution to security would require either – **DNO** knowledge of the **DSR Scheme** or detailed research to determine existence of controlled demand reduction. The **DNO** is unlikely to have access to appropriate detailed data and this EREP recommends that **Non-Contracted DSR Scheme**s should be assumed to have no contribution to security, unless the **DNO** is aware of site-specific details.

Where the **DNO** is aware of **Non-Contracted DSR Scheme**s through liaison with third parties, the details should be acquired where possible. In this case the security contribution should be assessed based on the available information following the principles in Clause 8.3. The **DNO** should take a view of the confidence they have of this information.

Any assessment of **Non-Contracted DSR Scheme**s shall incorporate necessary capping of the security contribution to avoid dominance in accordance with EREC P2/8 [N1] Clause 5.2. Annex B of this EREP includes further guidance on capping.

Since the demand reduction associated with a **DSR Scheme** is implemented in response to an instruction, it is distinct from other forms of demand reduction such as supplier time-of-use (TOU) tariffs. An ongoing research project by Scottish and Southern Electricity Networks suggests that there is insufficient evidence that financial incentives, e.g., TOU tariffs, are effective in changing consumer behaviour. Conversely, **DNO**s may acquire demand profiles of specific customers and details of specific types of tariff arrangements which demonstrate a change in consumer load patterns e.g., 'E7' off-peak heating time switched load, or wind spilling tariffs, where there is a recognizable and predictable link between the tariff and **Group Demand**. However, unless there is a strong link between tariffs/schemes and a reduction in demand, based on collated data, this EREP recommends that they should not be considered during assessment of network security, i.e., there is no **Latent Demand** and hence no contribution to security.

9.5 Determine the security contribution from Non-Contracted ES

The security contribution from **Non-Contracted ES** should be based on the recorded details for the facility – the **DNO** should have the import and export profile of **ES** facilities (for facilities >30 kW) connected to its network. The security contribution from **Non-Contracted ES** export should be subject to a site-specific study using the modelling tool described in ENA EREP 131 [N2] (see Annex D.5). The security contribution from **Non-Contracted ES** import should be subject to a site-specific study based on the principles in Clause 8.4.

The assessment of the security contribution from **Non-Contracted ES** shall incorporate any necessary capping of the security contribution to avoid dominance in accordance with EREC P2/8 [N1] Clause 5.2. Annex B of this EREP includes further guidance on capping.

The import from **Non-Contracted ES** should be assumed as being accounted in the normal demand profile, i.e., within the **Measured Demand**.

10 Assessing compliance with EREC P2/8 Table 1

10.1 General

Once the contribution to **System Security** from **DG**/**DSR Scheme**s/**ES** has been determined, it is a simple matter of adding this value to the level of security contribution provided by the network assets. The network under consideration can be deemed compliant with the requirements of Table 1 of EREC P2/8 [N1] if the aggregate of the:

- Intrinsic network capacity;
- **Transfer Capacity**;
- **Contracted DG**/**DSR Scheme**s/**ES**; and
- **Non-Contracted DG**/**DSR Scheme**s/**ES**, is sufficient to meet the level of security required in Table 1.

It is critically important to note that this capability assessment needs to be done for each of the time periods specified in Table 1 of EREC P2/8 [N1]. For instance, in the case of Class C, the two time periods of concern are the demand that must be recovered in 15 mins and the demand that must be recovered in 3 hrs. Both periods must be assessed separately since the required demand, the number of **Circuit**s and the security contribution from **DG**/**DSR Scheme**s/**ES** could be different in each case. Compliance with EREC P2/8 [N1], is required for each time period.

If the demand to be met exceeds the system capacity (i.e., the capacity provided by the network assets plus the contribution from **DG**/**DSR Scheme**s/**ES**) under **FCO** conditions in any one time period, the system is declared as not complying with the requirements of Table 1 of EREC P2/8 [N1]. If the network under consideration is compliant under **FCO** conditions, then the process moves to checking for compliance under conditions of a SCO, noting that under EREC P2/8 [N1] the requirement to secure demand after a SCO only applies to **Group Demand**s in excess of 100 MW.

10.2 High-level review of options

In the event that the system capacity is insufficient to meet **System Security** requirements, as detailed in Table 1 of EREC P2/8 [N1], the **DNO** should undertake a review of the options to address the deficiency, such as:

- network reinforcement; and
- establishing contracts with **DG**, **DSR Scheme**, and **ES** owner/operator.

The review of the options should consider:

- bu**dg**et costs associated with the network and non-network options;
- estimate of the longevity of the solution based on the demand growth scenarios; and
- the asset management strategy and network planning policy for the **DNO**.

Having understood the bu**dg**et costs, coupled with the benefits of the options, the **DNO** should ascertain if compliance with Table 1 of EREC P2/8 [N1] is:

a) economically justifiable; and

b) aligns with the overall asset management strategy.

Should the high-level review of options indicate the compliance with Table 1 of EREC P2/8 [N1] is justifiable, then in-depth planning of the work should commence. Otherwise, the **DNO** shall prepare a supplementary cost benefit analysis (see Clause 11).

11 Provision of System Security

In order to remain compliant with EREC P2/8 [N1], the **DNO** must ensure that there is or is planned to be sufficient **System Security** to meet the forecast **Group Demand**. Where a deficiency in **System Security** is identified, a detailed analysis of the options considered in Clause 10 should be undertaken. The detailed analysis should identify whether any network reinforcement or new contractual arrangements can be implemented in a timely manner, i.e., in advance of the demand group becoming non-compliant with the requirements of Table 1 of EREC P2/8 [N1]. Options considered should include:

a) Increasing the intrinsic network capacity (for example, network reinforcement, re-assessing the **Circuit Capacity**, assessing options for enhancing network voltage management);

b) Increasing the **Transfer Capacity** or the reducing the time for implementing **Transfer Capacity** (for example by applying network automation);

c) Implementing contractual arrangements for security services from **DG**/**DSR Scheme**s/**ES**; and

d) Implementing a combination of a), b) and c)

In the case where network reinforcement or appropriate contractual arrangements cannot be completed in advance of the **DNO** network becoming non-compliant with Table 1 of EREC P2/8 [N1], the **DNO** shall request a technical derogation from Ofgem [5] for a specified period of time, i.e., timebound derogation.

12 Cost Benefit Analysis (CBA)

A supplementary CBA shall be prepared when the **DNO**'s high-level review of remedial works indicates that the options are not economically justifiable and/or do not align with its asset management strategy.

The CBA shall be based on the costs of achieving the minimum requirements set out in Table 1 of EREC P2/8 [N1]. It should primarily assess whether the cost of the reinforcement or implementing security service contracts to comply with the requirements in Table 1 are reasonable when compared with the improvements in the **System Security** that would be expected to be delivered.

The **DNO**'s own CBA template or the latest CBA template available from Ofgem may be used. The CBA should primarily be based on the rate of return principle (discount rate), and should also consider:

a) Network losses and the economic value of those losses; and

b) The cost of supply interruptions to customers;

   Expected Energy Not Supplied (EENS) is expressed in MWh over a specific time period (e.g., a year). Using the concept of EENS, it is possible to monetise the shortfall in system capacity where Value of Lost Load (VoLL) has also been calculated since the EENS can then be multiplied by VoLL. Hence, a change in EENS rising from remedial actions may be assessed based on:

   - VoLL= £17,000 / MWh; different values of VoLL can be used where deemed appropriate by the **DNO**
   - VoLL impact assessed for an appropriate period of time, relevant for the CBA

In the case where the supplementary CBA justifies providing additional **System Security** to meet the requirements of EREC P2/8 [N1] Table 1, the **DNO** should progress plans for this, otherwise the CBA shall be used to demonstrate compliance with EREC P2/8 [N1].

Annex A
(normative)

Identification of Group Demand

A.1 General

In order to ensure that there is sufficient **System Security**, it is necessary to identify the **Group Demand** to be secured. This requires that, as far as reasonably practicable **Latent Demand** within the network is identified and added to the recorded or **Measured Demand**, taking appropriate account of diversity and coincidence of demand and **DG**/**DSR Scheme**/**ES** profiles, to establish the **Group Demand**.

Latent Demand associated with generation, for example **DG** and **ES** export, is a straightforward concept which does not warrant detailed explanation.

DSR Schemes are considered as an increase in system capacity, hence the **DNO** will need to consider the extent to which the **Measured Demand** should be increased to reflect the demand that has been constrained by the **DSR Scheme** in order to establish the **Group Demand** that needs to be secured. Likewise, if an **ES** facility is **Contracted** not to import, then the **Measured Demand** will need to be increased by the constrained import, i.e., the **Latent Demand** for the **ES** not importing (akin to a **DSR Scheme**).

Equation 1 shall be applied when determining **Latent Demand**.

Latent Demand =	**Contracted** and **Non-Contracted** (where known) **DG** export at the time of **Measured Demand** + Amount by which the import at a **Demand Facility** is reduced by a **Contracted** or **Non-Contracted** (where known) **DSR Scheme**, which is active at the time of **Measured Demand** + **Contracted** or **Non-Contracted** (where known) **ES** export at the time of **Measured Demand** + Amount by which the import at an **ES** facility is reduced by a **Contracted** import constraint, which is an active at time of **Measured Demand**	Equation. 1

As implied in Equation 1, a **DSR Scheme** or **ES** import constraint contract, which is considered not to be active at the time of **Measured Demand** has no latency, i.e., **Latent Demand** = 0 MW. When deciding whether the demand/import constraint was active for a particular facility, the **DNO** should consider the following options to determine the **Latent Demand**.

a) The terms of any Contract with the **DNO**

This option could be used where the **DNO** has details of a contract and assumes that the maximum import capacity is required at the time of **Measured Demand** and is thus being constrained at or below a certain (as per a contract) value.

b) Measured import and observed unconstrained demand

This option could be used where the **DNO** has knowledge of and understands the demand profile for the particular facility to ascertain the actual demand which is being constrained at the time of **Measured Demand**.

Assessing the **Latent Demand** for an **ES** which is **Contracted** to constrain import may become complicated if the **ES** is actually exporting at the time of Measure Demand. However, the **ES** may change operation in a very short time span, i.e., switch from export to import quickly, and the **DNO** should consider such scenarios. Example F.7.2 provides more guidance on such a scenario.

A.2 Establishing the Latent Demand of Contracted DG, DSR Scheme and ES

A.2.1 Contracted export

Where a **DNO** has a contract with a **DG** or **ES** facility to export, then the **Latent Demand** will be influenced by the contract and it should be appropriately established as described in Annex A.4 or Annex A.5.

A.2.2 Contracted import constraint

Where the **DNO** has a contract with a **Demand Facility** (**DSR Scheme**) or an import constraint contract with an **ES** Facility, then the **Latent Demand** may be determined using one of the options a) or b) in Annex A.1. The implications using the options is described below.

a) The terms of the Contract with the **DNO**

This method returns the maximum value of the **Latent Demand** as it is determined by the difference between the maximum import capacity (stipulated in the contract) and the constrained import capacity. The value may be an overestimate as the customer may not plan to take their maximum import capacity at the time of peak **Measured Demand**.

b) Measured import and observed unconstrained demand

This method returns a 'diversified' value of **Latent Demand**, i.e., the customer may not necessarily wish to operate at maximum import capacity during the time when they are being constrained. This method is more difficult to apply as it requires an understanding and knowledge of what the import would have been had no import restriction been active, rather than assuming the customer would import their maximum import capacity. The **DNO** could determine the 'diversified' **Latent Demand** by assessing the customer's import over a suitable period so that patterns in their import during periods when it is both constrained and unconstrained are established.

The example in F.6.4 indicates how the options a) and b) may be applied to a **DSR Scheme** and the example in F.7.2 indicates how the options may be applied to an **ES** with constrained import.

A.3 Establishing the Latent Demand of Non-Contracted DG, DSR Scheme and ES

A.3.1 General

For **Non-Contracted DG**/**DSR Scheme**s/**ES**, the most rigorous assessment would require the impact of **DG**/**DSR Scheme**s/**ES** known at each network node to be assessed for each half hour period, where the half hour timescale relates to the information typically available from **DNO** SCADA or the Elexon Settlements system. This analysis is potentially extensive, and in the case of Demand Facilities with on-site generation, **DSR Scheme**s with third parties, or a site with an **ES**, obtaining the relevant data could be difficult.

The key issue associated with establishing the **Latent Demand** and hence the **Group Demand** is striking a balance between the need to undertake significant analysis, with data that may not be readily available, and the risks associated with there being insufficient network assets and **DG**/**DSR Scheme**s/**ES** to support the **Group Demand**. The risk arises because if, for example:

- the export from a **DG** is effectively being considered as negative demand, i.e., the **DG** has a 100% F Factor or security contribution, or;
- a reduction in demand at a **Demand Facility** in response to a third party **DSR Scheme** contract is effectively being considered as negative demand, i.e., the **DSR Scheme** provides a 100% security contribution.

The magnitude of the risk relates to the aggregate capacity of **Non-Contracted DG**/**DSR Scheme**s/**ES** in the network under consideration rather than the size of any individual **DG**/**DSR Scheme**/**ES**. It is recognised that establishing an appropriate approach is subjective, and that a pragmatic approach, needs to be taken. Hence, the 5% de-minimis test described in Clause 5 (the 5% figure is a practical limit and relates to the accuracy of typical **DNO** SCADA information).

Where the aggregate capacity of **Non-Contracted DG**/**DSR Scheme**s/**ES** exceeds 5% of the **Measured Demand**, but comprises large numbers of very small facilities, the capacity from these units need not be added to the **Measured Demand**, as there will probably be sufficient diversity for the overall network risk to be small. However, if the **DNO** considers the effect of such facilities to be material, the use of generic profiles for **DG**/**DSR Scheme**s/**ES** would facilitate further assessment of the **Latent Demand**.

A.3.2 Non-Contracted export

For **DG** or **ES** export which is **Non-Contracted**, the extent of the analysis required to determine the **Latent Demand** is dependent upon a number of factors including:

- whether the **DG**/**ES** is directly connected to the **DNO** network (see Annex A.4), as would typically be the case for landfill generation or a wind farm, or is embedded in a customer's installation with a significant amount of on-site demand (see Annex A.5), as would typically be the case for an industrial site with CHP generation plant; and
- the coincidence of the maximum value of the **Measured Demand** and the maximum output from **DG** in the network for which **Group Demand** is being established.

A.3.3 Non-Contracted import constraint

Having established appropriate details of any **Non-Contracted DSR Scheme** or **Non-Contracted ES** import constraint, the **Latent Demand** should be determined as described in Annex A.1 options a) or b).

A.4 Establishing the Latent Demand from generation only sites, i.e., merchant DG

For a **DG** facility where there is no on-site demand, the contribution to **Latent Demand** is the export from the **DG** facility to the network. As indicated above, the most rigorous method is to summate the recorded half hourly output from all the **DG** (greater than 100 kW) for the network. These half hourly contributions are then added to the half hourly network demands measured at network entry points to establish the profile of demand from which the maximum demand, i.e., the **Group Demand**, can be found. However, where it is believed that there is good coincidence between the time of the maximum value of the **Measured Demand** and the maximum value of the contribution to **Latent Demand** from each **DG** facility, it will often be sufficiently accurate to estimate the **Latent Demand** by summating the export from the **DG** facility, at the time of the maximum **Measured Demand**.

A.5 Establishing the Latent Demand from customers' demand sites with on-site generation

Where a demand site comprises **DG** with a capacity greater than 100 kW, wherever possible the actual site demand (i.e., the demand measured for the site plus the contribution to the **Latent Demand** associated with the on-site **DG**) should be established and the contribution to **System Security** from the **DG** should be assessed in accordance with EREC P2/8 [N1].

There are a number of options outlined below for treating demand sites with generation, which have differing requirements for the availability and quality of network and generation data. The purpose of describing these options is primarily to expand on some of the issues that need to be considered when assessing the contribution to **Group Demand** from such sites. Implementation of some of these methods may require an enhancement of existing data systems.

- Option 1. Obtain separate demand and generation data from the site operator in order to separately assess both the overall site demand and the security contribution from the on-site generation.
- Option 2. As Option 1, but where data from the site operator is not available and the **DNO** uses data from other sources, e.g., its own SCADA data and export information from the BSC Settlements system. The **DNO** would need to be comfortable that it had sufficiently accurate data to undertake the analysis before applying this option. The security contribution from the generation would be considered separately.
- Option 3. Estimate the contribution to **Group Demand** by ignoring any contribution to **Latent Demand** by the on-site generation and assume that only the maximum import capacity has to be met. It is important to recognise that the maximum site demand may be different from the maximum import capacity and any difference should be treated in the same way as for any other demand site that has a possible maximum demand different from its maximum import capacity. The security contribution from the generation would be considered separately.

  It is worth noting that where the customer has a maximum import capacity lower than the site maximum demand, they are effectively managing internally the risk of their generation not operating and in this case it may not be appropriate for the security contribution of the generation to be separately assessed.

- Net Option 1. The **DNO** could develop a model of the on-site generation in net terms based on the import/export data at the ownership boundary. Information may be obtained from the **DNO** SCADA system and/or the BSC Settlements system. In this case there would be no requirement to separately assess the security contribution from the generation.
- Net Option 2. The most general option is to explicitly allow the **DNO** to use its engineering judgement to determine the appropriate contribution to **Latent Demand** of the site to be used in an assessment of **Group Demand**. In this case there would be no requirement to separately assess the security contribution from the generation.

An approach based on Option 1 is the most robust and is the preferred approach where sufficient data is available and a high degree of accuracy is required. However as described above the application of a pragmatic option for disaggregating the demand and generation will often be sufficient.

A pragmatic approach for assessing the contribution to **Latent Demand** by on-site generation plant has been identified. This method is not completely rigorous but is generally thought to be appropriate where it is obvious by inspection that there is good coincidence between the maximum values of the **Latent Demand** and **Measured Demand**. This technique does cater for the following risks:

- basing the on-site demand on the import/export data at the ownership boundary – which could lead to an under engineered network; and
- ignoring the on-site generation and assuming that the maximum import capacity has to be met – which could lead to an over engineered network.

The technique for establishing **Group Demand** is therefore to take the lesser of the following two conditions.

- The expected generation output (G) at the time of the maximum **Measured Demand**, or
- The site maximum import capacity (A) minus the site import[2] (D) at the time of maximum **Measured Demand**. (i.e., A-D).

and add it to the maximum value of the **Measured Demand**.

*i.e., **Group Demand** = maximum **Measured Demand** + min. [G, (A – D)]*

The contribution to **System Security** of the **DG** should then be treated independently in accordance with Annex D.

[2] Note that for a site that is exporting to the DNO's network, the import is simply a negative quantity.

Annex B
(normative)

Capping DG/DSR Schemes/ES

B.1 Dominance and capping

A principle of EREC P2/8 [N1] is that outage events relate to **Circuit**s rather than loss of **DG**/**DSR Scheme**/**ES** contribution, i.e., no individual **DG**/**DSR Scheme**/**ES** should be dominant. The conditions that should be applied to test for dominance are as follows:

a) the security contribution of each of the following items shall be limited to the capacity of the largest **Circuit**:

   i. **DNC** of the largest **Contracted DG** facility;

   ii. DNC of the largest Non-Contracted DG;

   iii. Aggregate **DNC** of multiple **Non-Contracted DG** facilities which are susceptible to common mode failure (see B.2);

   iv. Capacity of the largest **Contracted DSR Scheme** provided by a **Demand Facility**;

   v. Aggregate capacity of **Contracted DSR Scheme**s which are susceptible to common mode failure (See B.2);

   vi. Capacity of the largest **Non-Contracted DSR Scheme** which the **DNO** is aware of, i.e., a known **DSR Scheme**;

   vii. Capacity of the largest **Contracted ES** export

   viii. Aggregate capacity of multiple **Contracted ES** facilities which export and are susceptible to common mode failure (see B.2);

   ix. Capacity of the largest ES which is **Contracted** to restrict import;

   x. Capacity of the largest **Non-Contracted** ES import restriction which the **DNO** is aware of, i.e., a known **ES** import restriction.

b) the security contribution of the two largest **DG**/**DSR Scheme**/**ES**, as set out in items i) -x) shall be limited to the aggregate rating of the two largest **Circuit**s.

If the first condition is not met (i.e., the **DG**/**DSR Scheme**/**ES** would otherwise dominate), then the capacity used to assess the security contribution must be **Capped** so that the **DG**/**DSR Scheme**/**ES** does not dominate and hence an outage of the largest **Circuit** can be taken to be the **FCO**. The process then continues with the calculation of the system capacity under this outage condition which is:

- the **Circuit Capacity** of the remaining **Circuit**(s); plus
- any **Transfer Capacity**; plus
- the appropriate **DG**/**DSR Scheme**/**ES** contribution determined in Clauses 7 and 8.

A similar Capping process is used to ensure that the **SCO** relates to the outage of the second largest **Circuit**.

B.2 Common mode failures

Common mode failure of **DG**, **DSR Scheme**s and ES can occur for a variety of reasons. EREC P2/8 [N1] requires that common mode failure of any active network management, protection, or control system associated with **DG** and **DSR** is considered. Other types of common mode failure are as follows.

- Fuel Source (**DG**) Failure of common fuel supply such as the gas supply to several landfill generating units on the same site; mains gas supply to CCGTs etc. should there be a gas network security problem, etc.
- Connection (**DG**, **DSR Scheme**, **ES**) It is possible that significant **DG**/**DSR Scheme**/**ES** contribution to **Group Demand** is connected via a single **Circuit**. It is necessary to check that loss of this **Circuit** would not trigger materiality considerations, although this is unlikely to happen in practice.
- Stability (**DG**, **ES**) Inability of certain types of **DG**/**ES** or types of protection to remain stable and/or ride through a system disturbance.

To avoid common mode failures of **DG**/**DSR Scheme**/**ES** degrading **System Security** beyond that expected in EREC P2/8 [N1] it is appropriate to cap the security contribution from any **DG**/**DSR Scheme**/**ES** that is subject to common mode failure as provided in Annex B.1. Each type of **DG**/**DSR Scheme**/**ES** could be subject to common mode failure.

Annex C
(informative)

Technical check list

C.1 Introduction

This Annex contains checklists for the various phases of the assessment process, as outlined in the main document. These checklists are intended as an aide-memoir for the network designer rather than being a definitive activity list.

C.2 Establish Group Demand

	Complete
Recorded maximum demand	
Latent Demand for **Contracted DG**/**DSR Scheme**/**ES**	
De-minimis test for **Non-Contracted DG**/**DSR Scheme**/**ES** and hence any **Latent Demand**	

C.3 Establish network capability

	Complete
Circuit Capacity of individual **Circuit**s appropriate to time of year	
Time of year of recorded maximum **Group Demand**	
Network **Transfer Capacity**	
Time within which **Transfer Capacity** is available	

C.4 Establish Contracted DG/DSR Scheme/ES security contribution

	Complete
Assess **DG Contracted** security contribution	
Consider general **DG** issues in accordance with Annex C.6	
DSR Scheme Contracted security contribution	
ES Contracted security contribution	

C.5 Establish Non-Contracted DG security contribution

	Complete
Assess **Non-Contracted** security contribution in accordance with Annex D	
Consider general **DG** issues in accordance with Annex C.6	

C.6 General DG considerations

	Complete
For each DG facility:	
C.6.1 General	
Capacity of **DG**	
Type of **DG**	
½ hourly output profile	
Merchant or process linked?	
C.6.2 Technical	
Interface protection • operating parameters and settings • ride through capability	
DG stability	
Status of the technology (proven/experimental)	
Evidence of good management procedures	
Proven performance track record, consistent capacity factor	
What are the cold start/warm start/reconnection times for generation?	
C.6.3 Fuel	
Contracted fuel supply	
Uninterruptible fuel supply (gas)	
Fuel stocks available	
C.6.4 Commercial	
Ability for **DNO** to request operation	
Contracted repair and maintenance	
Coordination of network and **DG** planned outages	
Expected lifespan of the **DG** plant	
C.6.5 Contract (where appropriate)	

Contracts in place	
Ability to operate on demand	
Appropriate communications with **Generator**/**DG** plant to be in place	
C.6.6 Network & DG related issues	
Will generation under outage overload any remaining plant	
Does the generation need to run to a different loading pattern immediately - can the governor cope	
Can the automatic voltage regulation (AVR) cope with the required PF under outage conditions etc.	
Will protection for remaining network still work/discriminate with generation	
Is the **DG** exposed to any common mode failure (e.g., gas supplies; drought)	
Will the **DG** cause voltage violations during outages	
Communication arrangements between **DNO** and **Generator**	

C.7 Establish Non-Contracted DSR Schemes security contribution

	Complete
Where the **DNO** is aware of **Non-Contracted DSR Scheme**s through liaison with third parties, the details should be acquired	
Where the **DNO** is aware of time-of-use tariffs and price signals which affect consumer demand, the details should be acquired	

C.8 Establish Non-Contracted ES Schemes security contribution

	Complete
Where the **DNO** is aware of **Non-Contracted ES** through liaison with third parties, the details should be acquired	

Annex D
(normative)

Approaches for assessing the contribution from Non-Contracted DG to System Security

D.1 General

This Annex describes three approaches for assessing the security contribution from **Non-Contracted DG** to **System Security**. Use of these approaches will form an integral part of the assessment process described in Clause 8.3.

Approach 1 provides the simplest method to assess the contribution. Approach 2 provides an additional assessment method for **DG** which is more specific than Approach 1; and Approach 3 is used where it is necessary to carry out bespoke analysis using site specific data.

D.2 Approach 1 – Generic approach

Approach 1 is a simple method based on the use of look-up tables and graphs. The look-up tables (Tables D.2, D.2.1 and D.2.2) are based on the analysis of export data of typical **DG** facilities by Imperial College London [N9]. This data related to:

a) export data at the point where the **DG** is connected to the **DNO** network;

NOTE: The data was categorised on **DG** technology type, i.e., the energy source associated with the **DG** facility. The number of separate generating units associated with a particular facility is not considered.

b) data sampled at 30 min intervals;

c) data collated over the period 2013-2018, inclusive.

It is valid to use Approach 1 in the following situations:

- where the **DG** type is one of those cited in Tables D.2.1 or D.2.2; and
- where a ‘first pass’ assessment is required to determine if a particular **DG** facility is likely to have sufficient capacity to provide a sufficient security contribution to satisfy a particular requirement.

Each **DG** facility should be assessed individually and the aggregate **DG** security contribution is the arithmetic sum of all the facility contributions. This summation gives a conservative assessment of the **DG** contribution.

Table D.2

Distributed Generation Technology Type	**Contribution (see NOTE 1 below)**
DG as listed in Table D.2.1	F % of **DNC**
DG as listed in Table D.2.2	F % of **DNC**
NOTE 1: The contributions derived from this table apply from the point of time when the **DG** is connected or reconnected to the demand group following the commencement of an outage. This may be immediately if the **DG** does not trip, otherwise it will be from the point of time when the **DG** is reconnected.	

Table D.2.1 — F factors in % for Non-Intermittent Generation

DG Technology Type (NOTE 2)	**Period of assessment (NOTE 3)**	
	Winter	**Summer**
Biomass	30%	25%
Landfill gas	28%	27%
Waste	35%	32%

NOTE 1: The F factors for **Non-Intermittent Generation** are not affected by the number of units at an individual site. It is assumed that the energy source for the prime mover is available on demand so that **persistence** does not need to be considered.

NOTE 2: For **DG** technology types not listed in this table, it is preferable to seek site specific data to assess the contribution to **System Security** in accordance with EREP 131 [N2].

NOTE 3: Summer period refers to months May – August inclusive. Winter period refers to months November – February inclusive.

NOTE 4: The percentage values in this table are representative of the mean (M) minus 1 standard deviation (SD). Refer to commentary in Annex G for further explanation.

Table D.2.2 — F factors in % for Intermittent Generation

DG Technology Type (NOTE 2 & 3)	Persistence, T_m (hours)										
	½	**2**	**3**	**6**	**12**	**18**	**24**	**48**	**120**	**360**	**480**
Onshore wind (Winter)	17%	15%	15%	14%	11%	9%	7%	4%	2%	1%	1%
Onshore wind (Summer)	13%	12%	11%	9%	8%	6%	4%	2%	0%	0%	0%
Offshore wind (Winter)	22%	21%	20%	19%	17%	15%	12%	7%	2%	1%	1%
Offshore wind (Summer)	16%	16%	15%	13%	11%	9%	7%	3%	0%	0%	0%
Hydro run-of-river (Winter)	19%	19%	18%	18%	17%	16%	15%	12%	5%	0%	0%
Hydro run-of-river (Summer)	7%	7%	7%	7%	6%	5%	4%	2%	1%	0%	0%
Hydro water reservoir (Winter)	12%	12%	10%	9%	7%	4%	3%	3%	2%	0%	0%
Hydro water reservoir (Summer)	5%	5%	4%	2%	1%	0%	0%	0%	0%	0%	0%
Solar (Winter)	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Solar (Summer)	12%	11%	10%	9%	3%	2%	0%	0%	0%	0%	0%

NOTE 1: The F factors for **Intermittent Generation** are related directly to the period of continuous generation (i.e., Persistence).

NOTE 2: For **DG** technology types not listed in this table, it is preferable to seek site specific data to assess the contribution to **System Security** in accordance with EREP 131 [N2].

NOTE 3: Summer period refers to months May – August inclusive. Winter period refers to months November – February inclusive.

NOTE 4: The percentage values in this table are representative of the mean (M) minus 1 standard deviation (SD). Refer to commentary below Table D.2.1 for further explanation.

NOTE 5: Recommended values of $\mathbf{T_m}$ are shown in Table D.2.3.

Table D.2.3 — Recommended values for T_m

P2/8 class of supply	Switching (see NOTE 2 below)	Maintenance	Other outage (see NOTE 3 below)
A (**FCO**)	N/A	N/A	N/A
B (**FCO**)	15 mins / 3 hours	2 hours	24 hours
C (**FCO**)	15 mins / 3 hours	18 hours	15 days
D (**FCO** and **SCO**) (see NOTE 4 below)	60 s / 3 hours (see NOTE 5 below)	24 hours	90 days
E (**FCO** and **SCO**) (see NOTE 4 below)	60 s	24 hours	90 days

NOTE 1: The recommended values for $\mathbf{T_m}$ for the three system conditions may be applied at the time that an infeed is lost. For example, “Switching” values apply where the **DG** contribution is only required for the time necessary to reconfigure the system by switching operations.

NOTE 2: Switching values for $\mathbf{T_m}$ are only appropriate where sufficient intrinsic network capacity and **Transfer Capacity** exist, as described in Clauses 6.2 and 6.3 respectively. 15 mins is only applicable for Class C supply as defined in Table 1 of EREC P2/8 [N1].

NOTE 3: Examples of “other outage” are an unplanned outage or an outage as part of a major project.

NOTE 4: **SCO** only applies for demands greater than 100 MW.

NOTE 5: 60 s only applies where compliance is achieved by automatic demand disconnection of 20 MW or less.

D.3 Approach 2 – Using capacity factors

This approach is applicable to **Non-Intermittent Generation** and offers a more in-depth assessment of the security contribution in comparison Approach 1.

Approach 2 uses the concept of a ‘capacity factor’ which is defined as:

Capacity factor = (**DG** energy output for the assessment period) / (**DG DNC** x number of hours in the assessment period)

The capacity factors in Table D.3 are based on data collated by Imperial College London [N9] over the period 2013-2018, inclusive.

Table D.3 — F factors in % for Non-Intermittent Generation for varying capacity factors

Capacity factor range % (NOTE 1)	Period of assessment (NOTE 2)	
	Winter	**Summer**
Biomass (NOTE 3)		
80-max.	49%	46%
60-80	36%	35%
40-60	26%	29%
20-40	3%	6%
2-20	0%	0%
Landfill gas		
80-max.	67%	62%
60-80	56%	57%
40-60	47%	50%
20-40	23%	21%
2-20	8%	9%
Waste		
80-max.	67%	63%
60-80	57%	51%
40-60	43%	40%
20-40	23%	27%
2-20	2%	8%

NOTE 1: For **DG** technology types not listed in this table, it is preferable to seek site specific data to assess the contribution to **System Security** in accordance with EREP 131 [N2].

NOTE 2: Summer period refers to months May – August inclusive. Winter period refers to months November – February inclusive.

NOTE 3: The data analysis for biomass **Generator**s showed that capacity factors may vary more than 20% year to year, for more than 50% of the population. Hence, the F factors have been reduced accordingly to account for the variability. Refer to commentary in Annex G for further explanation.

NOTE 4: The percentage values in this table are representative of the mean (M) minus 1 standard deviation (SD). Refer to commentary in Annex G for further explanation.

D.4 Approach 3 – Computer package approach

This approach uses a computerised model of the methodology which was used to create the tables used in Approaches 1 and 2. It offers the ability to accommodate a wide range of data and assumptions, and permits the underpinning conditions of the other approaches to be relaxed and modified. It is therefore appropriate for special studies and bespoke analyses.

Approach 3 may be used to assess the contribution to security associated with export from **Non-Contracted ES**.

Approach 3 relies on the **DNO** obtaining a set of input data. This data could be provided by the **Generator** or from other sources, such as the **DNO**s own records. The exact details of the data required and how to use the analysis package are described in EREP 131 [N2]. The package is implemented in Microsoft Excel ® using the VBA environment and is available from the Energy Networks Association (ENA). The package calculates the security contributions from **DG** and can be used for assessing for compliance with EREC P2/8 [N1].

The analysis package is intended for use only by those users competent in undertaking assessments as outlined in this document. It is not intended to substitute the users' judgment or review of such assessments i.e.; the user would be expected to judge the appropriateness of the output from the analysis package. Hence, there is no guarantee that that the analysis package will provide correct and accurate outputs in every case.

The analysis package is offered to users without any technical support, apart from the guidance detailed in described in EREP 131 [N2]. It is subject to update and amendment only when deemed necessary by ENA in the case of a revision of this document or EREP 131 [N2].

Annex E
(informative)

Influencing factors for DG Contribution

E.1 DG availabilities

E.1.1 General

The considerations in this Annex are relevant to both **Contracted** and **Non-Contracted DG**.

The contribution to **System Security**, stipulated in a contract with the **DG**, may be informed by the considerations in this Annex.

The F factors in Tables D.2.1 and D.2.2 are based on data taken from **DG** which is considered typical or average. When undertaking a site specific assessment of **DG** security contribution, the **DNO** may be aware of issues affecting the average expected reliability of the facility: technical, commercial and fuel availability considerations described below may be relevant. These considerations may also be relevant for new **DG** connecting to the network with no prior history.

Operation over the first year or two of a new **DG** could be used to confirm the appropriateness of using the F-factors in Tables D.2.1 and D.2.2.

E.1.2 Technical availability

Technical availability is constrained by planned or unplanned outages of the **DG**.

It can be observed that where the operator allows the **DG** to run continuously with full fuel being available, a good example being landfill gas, modern **DG** demonstrates generally very high technical availability.

E.1.3 Fuel source availability

Fuel source availability can be constrained by any restrictions in the primary energy source preventing the **DG** from achieving expected output over any time period. The impact of fuel source constraints is greatest where the **DG** has high technical and commercial availability but where fuel is limited or variable. Wind farms are an obvious example of this.

Landfill Gas is also a good example, where there may be high technical availability and continuous running to burn off the gas. However, the output may be limited by the absolute fuel availability with, say, a 1.5 MW unit having a continuous output constrained at 1 MW.

Some plant, such as CCGT installations, will have interruptible gas supplies, and where invoked, would reduce the fuel availability element of the overall availability.

E.1.4 Commercial availability

Commercial availability can be considered as being the result of the operator choosing, for financial reasons, to run their plant below full output or to take the plant off-line for any time period.

For example, the primary factor normally influencing the running of a CHP plant, and hence its commercial availability, will be the need to provide heat for a process on the same site. This may result in export to the system only being available when process demand falls, and in the plant being taken off-line for periods within a 24 hr cycle. In this case the implications associated with estimation of **Group Demand** must be taken into account.

Similarly, CCGT plant is observed to have high technical availability, typically above 90%, together with good fuel availability. However, when operated as a merchant **DG** site with its main objective being to meet energy contracts, or provide energy balancing services, the availability of its full output is under the control of the operator and will be varied for purely commercial reasons.

E.2 Remote generation

When assessing the security contribution from a **DG** that is electrically remote from the point on the network where the contribution is being assessed (e.g., the infeed substation busbars), the key issue relates to the reliability of the network assets between the **DG** and the network point where a security contribution is required; this may affect the actual security contribution from the **DG**. This effect need not be considered further unless there is particular reason to believe that the availability of the network assets is significantly less than that for a typical network.

Hence, if a **DG** is considered to be above the de-minimis level, then it should not be considered as being ‘too remote’ to provide a security contribution to a particular network and the security contribution should be assessed in accordance with the assessment procedures described in this report.

E.3 Intermittent Generation and selection of T_m

Table 1 of EREC P2/8 [N1] requires that some or all demand (depending on class of supply) should be restored within 15 mins or 3 hrs, or after the time to repair. Therefore, when looking to include a security contribution from **DG** a necessary part of the assessment process will be to ensure that the **DG** can provide a security contribution in the required restoration time and continue to contribute for the repair time or until demand transfers are effected. For example, following a forced **FCO** for a **Group Demand** in Class C, any contribution must be initially available in 15 min as required in Table 1 of EREC P2/8 [N1]), and fully available by 3 hrs. Once available, it is assumed that the **DG** needs to remain available for the duration of the forced outage, which for Class C is assumed to be 15 days, based on an emergency repair time for a 132 kV transformer, or until sufficient **Transfer Capacity** can be made available.

NOTE: The considerations in the paragraph above are also relevant for **DSR Scheme**s and **ES**.

Different values of $\mathbf{T_m}$ might be appropriate depending on network configuration and worst case repair time. Indicative values for $\mathbf{T_m}$ are shown in Table D.2.3 in Annex D.

Annex F
(informative)

Examples

F.1 Primary substation Group Demand example – class of supply C

This example is intended to demonstrate the calculation of **Group Demand** for a typical primary substation.

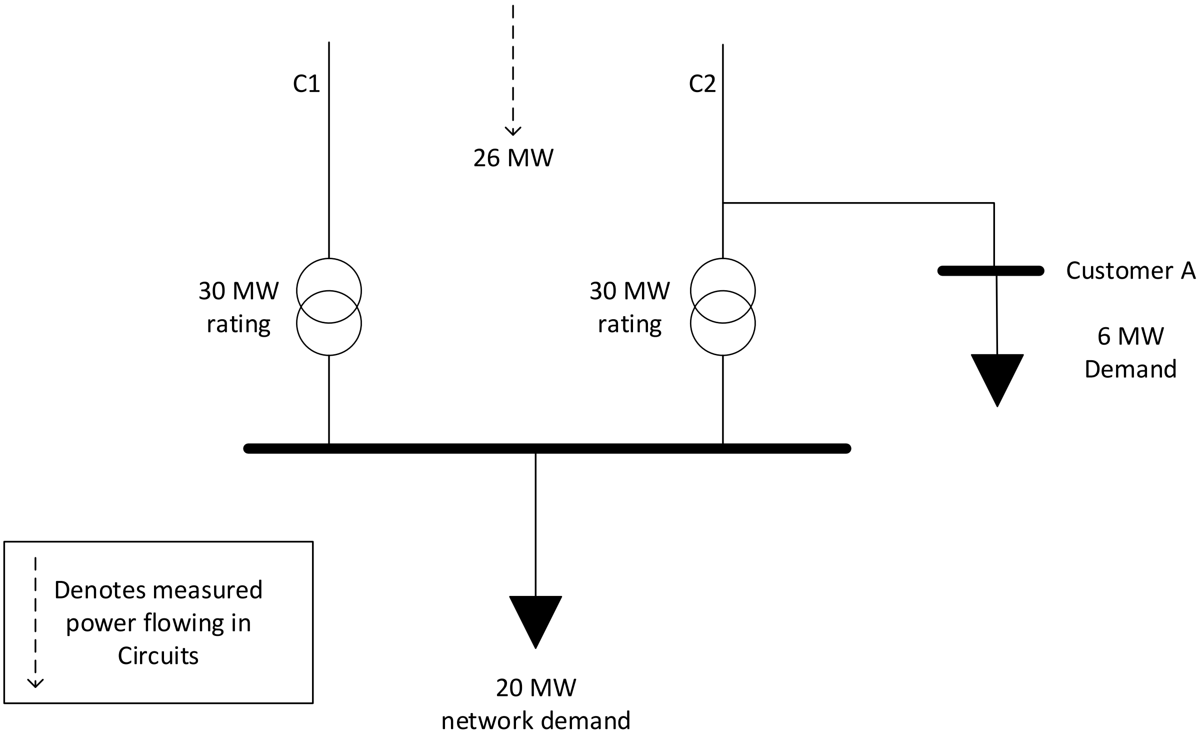


Figure F.1 – Primary substation Group Demand example Group Demand

a) Determine **Group Demand**

i. Measured Demand = 26 MW

ii. Latent Demand

Contracted DG/DSR Schemes/ES – none

Non-Contracted DG/DSR Schemes/ES – none

iii. Cold Load Pickup = 0 MW

iv. **Group Demand** = 26 MW (Class C)

b) Determine Network Capacity

i. Intrinsic network capacity

FCO capacity = 30 MW, available immediately. (From Table 1 of EREC P2/8 [N1] under an **FCO**, there is a requirement to secure partial demand within 15 mins and all demand within 3 hrs, except Customer A who has agreement to a single **Circuit** supply. The **FCO** capacity of 30 MW is sufficient to meet the **Group Demand** of 26 MW).

SCO capacity = 0 MW (from Table 1 of EREC P2/8 [N1] under a **SCO**, there is no requirement to secure any demand).

The intrinsic network capacity of 30 MW under an **FCO** is sufficient to meet the 26 MW of **Group Demand**. There is no requirement to consider **Transfer Capacity** or contribution from **DG**/**DSR Scheme**s/**ES**.

Given that intrinsic network capacity is greater than **Group Demand**: the system is compliant with Table 1 of EREC P2/8 [N1], regardless of an outage on **Circuit** C1 or C2. Note that for an outage of **Circuit** C2 (3-ended **Circuit**), the supply to Customer A is considered to be immediately restored following an outage of the **Circuit** C2: the agreed single **Circuit** connection agreement is equivalent to a **DSR** arrangement which is activated during loss of the **Circuit** C2 (see EREC P2/8 [N1] Table 1 note on 'minimum demand to be met').

F.2 Interconnected HV Circuit assessment example – class of supply B

This example is intended to demonstrate the EREC P2/8 [N1] compliance assessment of a typical interconnected **HV Circuit** – it does not consider the class of supply C demand group comprising the three primary substations.

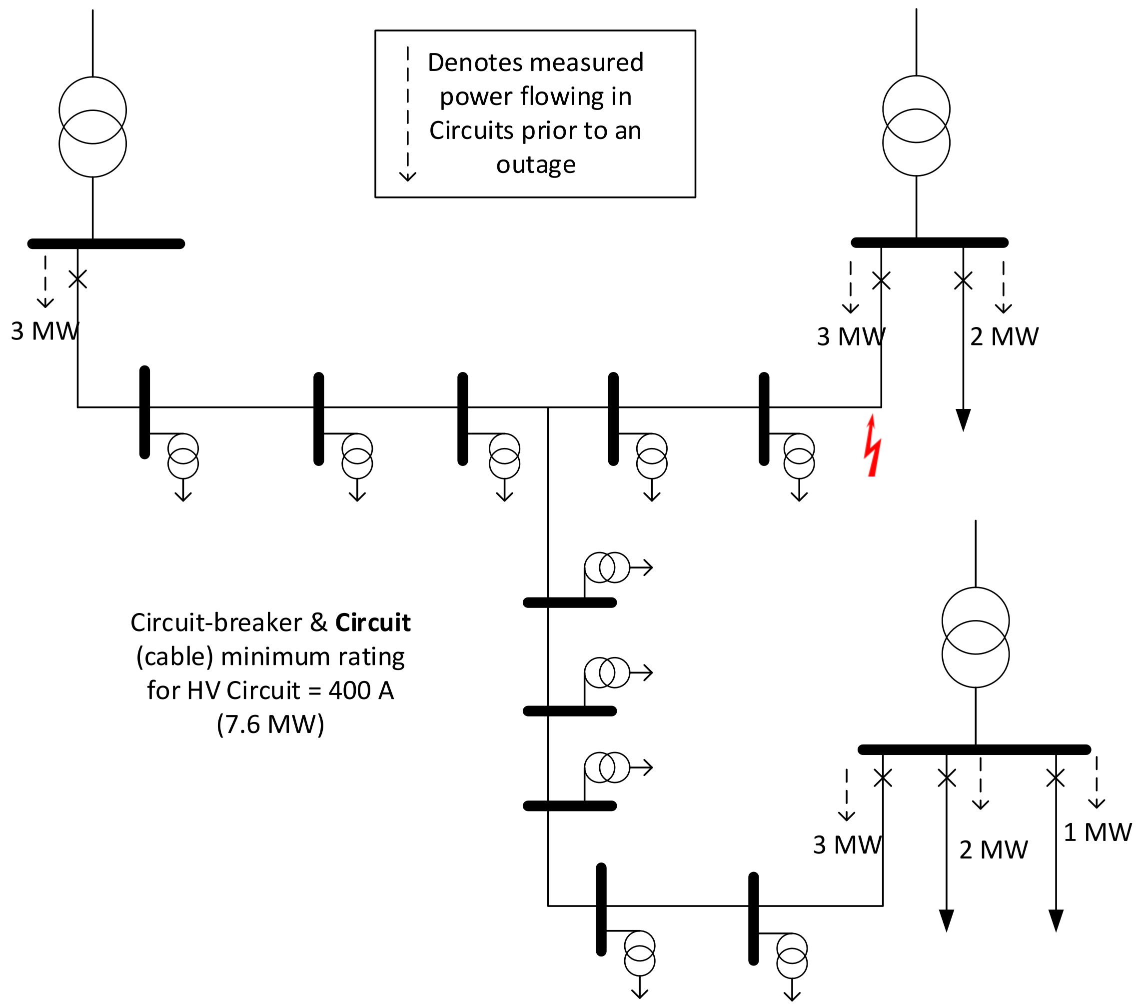


Figure F.2 – Assessing an interconnected HV Circuit

The **Circuit** being assessed is the interconnected **HV Circuit** supplied from the three primary substations.

a) Determine **Group Demand**

i. **Measured Demand** = 9 MW

ii. **Latent Demand**

Contracted DG/DSR Schemes/ES – none

Non-Contracted DG/DSR Schemes/ES – none

iii. **Cold Load Pickup** = 0 MW

iv. **Group Demand** = 9 MW (Class B)

b) Determine Network Capacity

i. Intrinsic network capacity

FCO capacity = 15.2 MW, available immediately. (From Table 1 of EREC P2/8 [N1] under an **FCO**, there is a requirement to restore **Group Demand** minus 1 MW [8 MW] of demand within 3 hrs and restoration of the remaining demand within repair time).

NOTE: Network modelling would be required to corroborate the value of 15.2 MW i.e., to confirm load sharing is equal between the primary transformers.

SCO capacity = not determined (from Table 1 of EREC P2/8 [N1] under a **SCO**, there is no requirement to secure any demand).

The intrinsic network capacity of 15.2 MW under an **FCO** is sufficient to meet the 9 MW of **Group Demand**. There is no requirement to consider **Transfer Capacity** or contribution from **DG**/**DSR Scheme**s/**ES**.

Given that intrinsic network capacity is greater than **Group Demand**: the system is compliant with Table 1 of EREC P2/8 [N1].

F.3 Radial HV Circuit assessment example

This example is intended to demonstrate the EREC P2/8 [N1] compliance assessment of a typical radial **HV Circuit**.

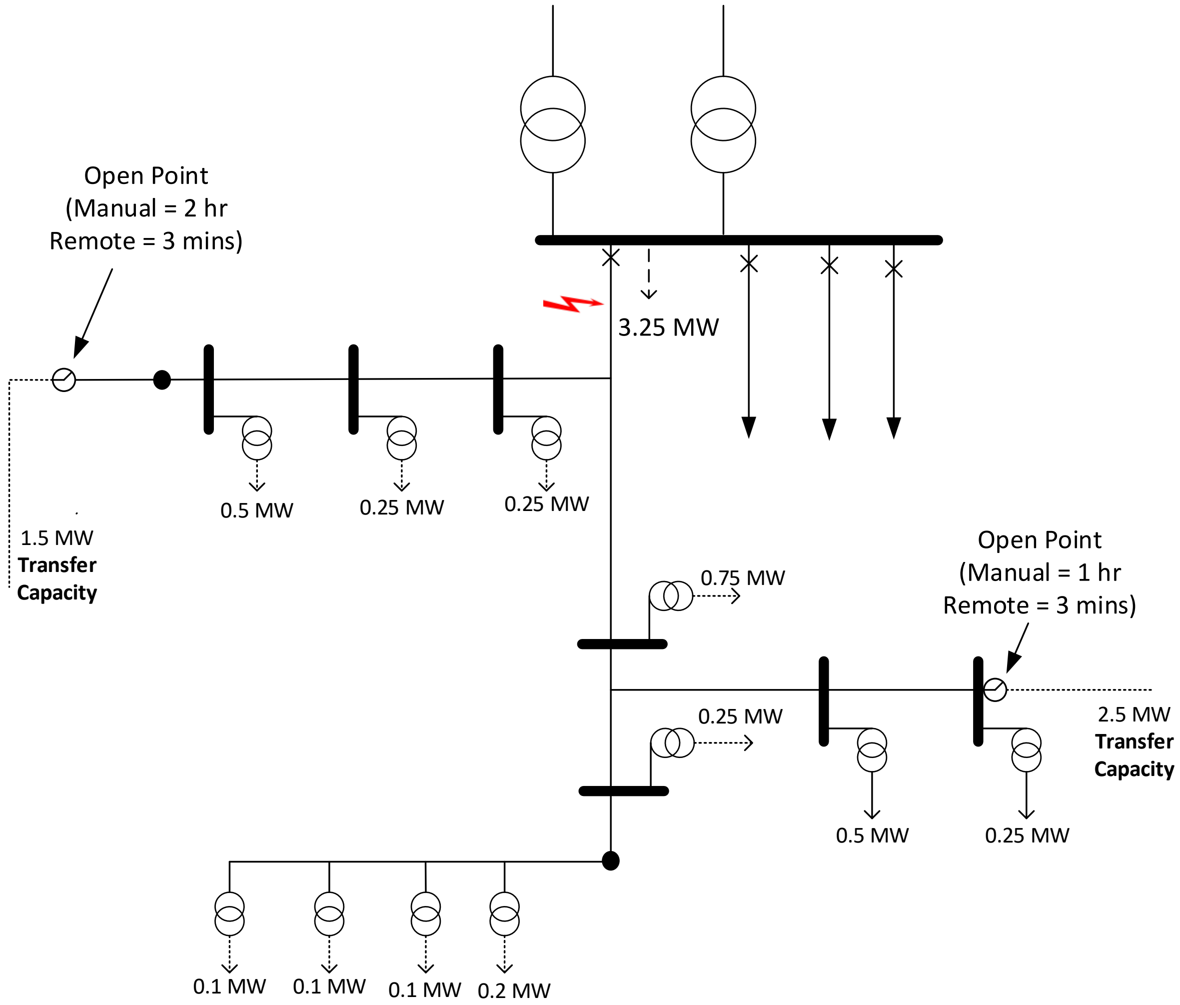


Figure F.3 – Assessing a radial HV Circuit

a) Determine **Group Demand**

i. **Measured Demand** = 3.25 MW

ii. **Latent Demand**

Contracted DG/DSR Schemes/ES – none

Non-Contracted DG/DSR Schemes/ES – none

iii. **Cold Load Pickup** = 0 MW

iv. **Group Demand** = 3.25 MW (Class B)

b) Determine Network Capacity

i. Intrinsic network capacity

FCO capacity = 0 MW. (From Table 1 of EREC P2/8 [N1] under an **FCO**, there is a requirement to restore **Group Demand** minus 1 MW [2.25 MW] of demand within 3 hrs and restoration of the remaining demand within repair time)

SCO capacity = not determined (from Table 1 of EREC P2/8 [N1] under a **SCO**, there is no requirement to secure any demand).

The intrinsic network capacity is insufficient to meet the requirements of EREC P2/8 [N1] and it is necessary to consider the **Transfer Capacity**.

ii. **Transfer Capacity** = 4 MW available.

The time to provide this **Transfer Capacity** ranges from 3 minutes to over 3 hours. Before the **Transfer Capacity** can be utilised the faulty section of **Circuit** needs to be located and isolated. The time to restore supplies is therefore a combination of fault location and isolation time, and switching time.

In conclusion, if the process of locating and isolating the faulted **Circuit** and completing switching to implement sufficient **Transfer Capacity** can be completed within 3 hours, the **Circuit** is compliant with Table 1 of EREC P2/8 [N1], if not it is non-compliant.

F.4 Transfer Capacity for single transformer primary

This example is intended to demonstrate the EREC [N1] P2/8 compliance assessment of **Transfer Capacity** for a typical single transformer primary substation (see F.8 and F.9 for other examples).

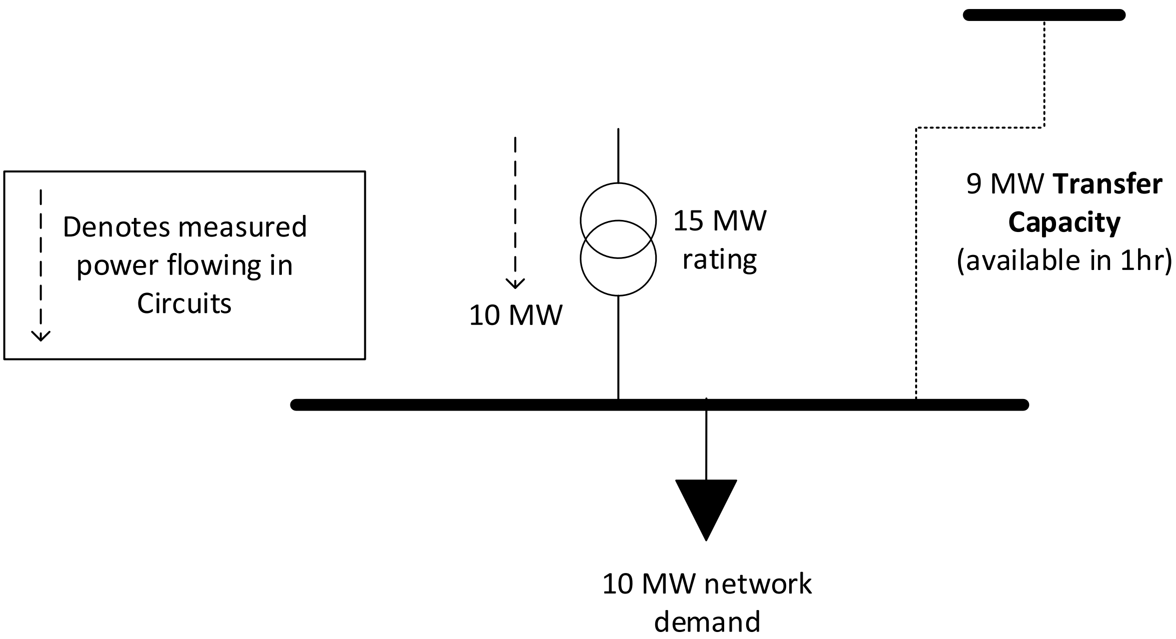


Figure F.4 – Transfer Capacity example

a) Determine **Group Demand**

i. **Measured Demand** = 10 MW

ii. **Latent Demand**

Contracted DG/DSR Schemes/ES – none

Non-Contracted DG/DSR Schemes/ES – none

iii. **Cold Load Pickup** = 0 MW

iv. **Group Demand** = 10 MW (Class B)

b) Determine Network Capacity

i. Intrinsic network capacity

FCO capacity = 0 MW (from Table 1 of EREC P2/8 [N1] under an **FCO**, Class B requires restoration for **Group Demand** minus 1 MW [9 MW] of demand within 3 hrs and restoration of the remaining demand within repair time

SCO capacity = 0 MW (from Table 1 of EREC P2/8 [N1] under a **SCO**, there is no requirement to secure any demand).

The intrinsic network capacity is insufficient to meet the requirements of EREC P2/8 [N1] and it is necessary to consider the **Transfer Capacity**.

ii. **Transfer Capacity** = 9 MW available within 1 hr under an **FCO** (and **SCO**)

In conclusion, the total **System Security** capacity under an **FCO** is 9 MW, available within 1 hr, which is sufficient for a Class B supply (the remaining 1 MW is restored in repair time). The distribution system is compliant with Table 1 of EREC P2/8 [N1]. For further development of this example, refer to F.5.1.

F.5 Contracted DG example

This example demonstrates how the **System Security** of, a distribution system containing **DG** which is **Contracted** with the **DNO**, should be assessed.

An **DG** has a **DNC** of 8 MW and operates to an agreed contract with the **DNO**. The contract requires the **DG** to export 5 MW at an agreed time of the day.

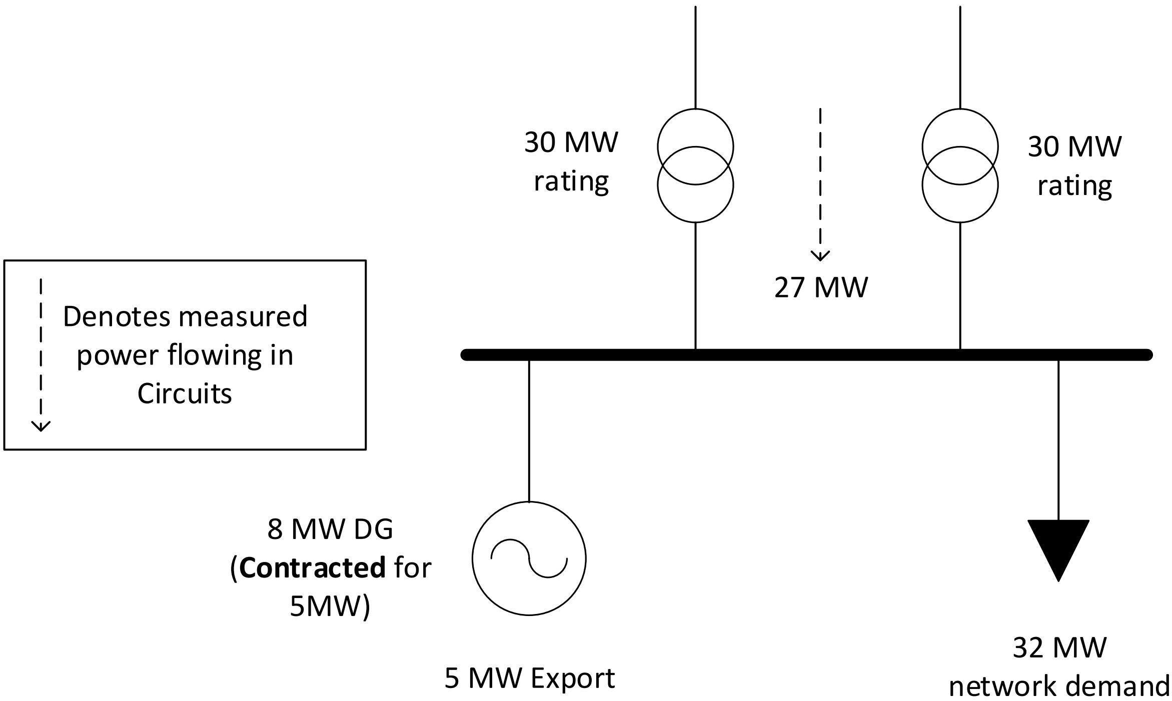


Figure F.5 – Contracted DG example

a) Determine **Group Demand**

i. Measured Demand = 27 MW

ii. Latent Demand

Contracted DG/DSR Schemes/ES – 5 MW (export from Contracted DG)

Non-Contracted DG/DSR Schemes/ES – none

iii. Cold Load Pickup = 0 MW

iv. **Group Demand** = 32 MW (Class C)

b) Determine Network Capacity

i. Intrinsic network capacity

FCO capacity = 30 MW, available immediately. (From Table 1 of EREC P2/8 [N1] under an **FCO**, there is a requirement to secure partial demand within 15 mins and all demand within 3 h).

SCO capacity = not determined (from Table 1 of EREC P2/8 [N1] under a **SCO**, there is no requirement to secure any demand).

The intrinsic network capacity of 30 MW under an **FCO** is insufficient to meet the 32 MW of **Group Demand** i.e., there is a deficiency of 2 MW.

ii. **Transfer Capacity** = 0 MW available under an **FCO** or **SCO**

Given that **Group Demand** is greater the intrinsic network capacity and no **Transfer Capacity** is available, there is a deficiency in **System Security** of 2 MW. Hence, it is now necessary to consider contribution to security from other means: **DG**/**DSR Scheme**s/**ES**.

iii. Security contribution from **Contracted DG** = 5 MW, available immediately (the **DG** contract stipulates the contribution and includes a requirement to remain connected under a fault forming the **FCO**. The **DG** is not designed to run in island mode and hence, there is no contribution under an **SCO**).

The total **System Security** capacity under an **FCO** is 35 MW, compared to a **Group Demand** of 32 MW. There is no requirement to secure demand under an **SCO**. The distribution system is compliant with Table 1 of EREC P2/8 [N1].

F.6 Contracted DSR Scheme

The following examples demonstrates how the **System Security** of, a distribution system containing a **DSR Scheme** which is **Contracted** with the **DNO**, should be assessed.

F.6.1 Constrained import

Customer A consists of a 5 MW **Demand Facility**, whose connection agreement with the **DNO** stipulates that their load (import) is constrained to 2 MW at the time of peak demand on the distribution system.

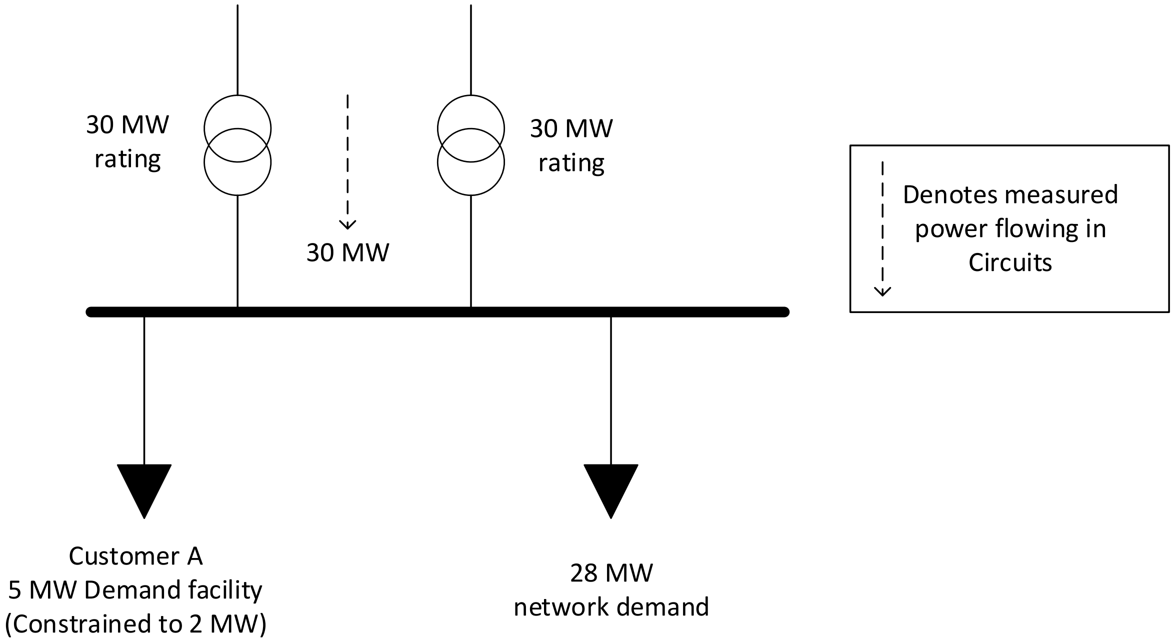


Figure F.6.1 – Constrained import

a) Determine **Group Demand**

i. Measured Demand = 30 MW

ii. Latent Demand

Contracted DG/**DSR Scheme**s/**ES** – 3 MW (The **DNO** is aware, from specific load information, that Customer A 'would like' 5 MW at the time of peak load. Since the **DSR Scheme** is active it is constraining Customer A import to 2 MW).

Non-Contracted DG/DSR Schemes/ES – none

iii. Cold Load Pickup = 0 MW

iv. **Group Demand** = 33 MW (Class C)

b) Determine Network Capacity

i. Intrinsic network capacity

FCO capacity = 30 MW, available immediately. (From Table 1 of EREC P2/8 [N1] under an **FCO**, there is a requirement to secure partial demand within 15 mins and all demand within 3 hrs).

SCO capacity = not determined (from Table 1 of EREC P2/8 [N1] under a **SCO**, there is no requirement to secure any demand).

The intrinsic network capacity of 30 MW under an **FCO** is insufficient to meet the 33 MW of **Group Demand** i.e., there is a deficiency of 3 MW.

ii. **Transfer Capacity** = 0 MW available under an **FCO** or **SCO**

Given that **Group Demand** is greater than the intrinsic network capacity and no **Transfer Capacity** is available, there is a deficiency in **System Security** of 3 MW. Hence, it is now necessary to consider contribution to security from other means: **DG**/**DSR Scheme**s/**ES**.

iii. Security contribution from **Contracted DSR Scheme** = 3 MW, available immediately under an **FCO**.

In conclusion, the total **System Security** capacity under an **FCO** is (30+3) MW, compared to a **Group Demand** of 33 MW. There is no requirement to secure demand under an **SCO**. The distribution system is compliant with Table 1 of EREC P2/8 [N1].

F.6.2 Intertripping arrangement

Customer A consists of a 5 MW **Demand Facility**, whose connection agreement with the **DNO** stipulates that the supply is automatically tripped during an outage of either feeding **Circuit**. Hence, Customer A can import 5 MW whilst the system is intact but they would be disconnected in the event of an **FCO**.

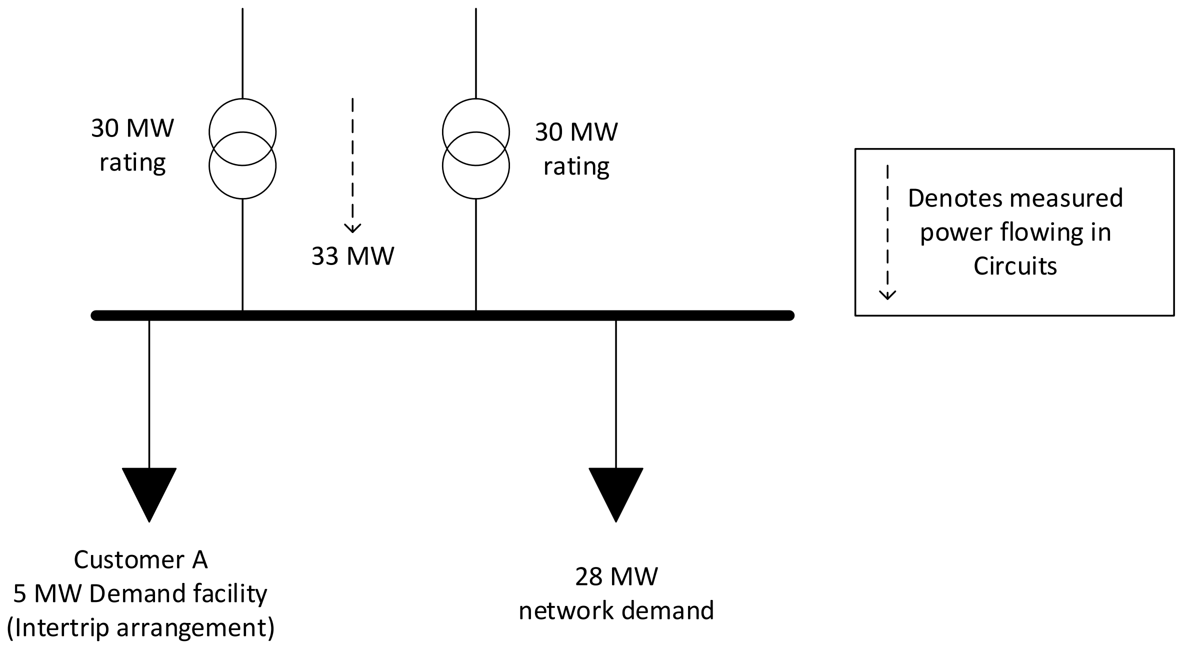


Figure F.6.2 – Intertripping arrangement

a) Determine **Group Demand**

i. **Measured Demand** = 33 MW (this includes 5 MW load to Customer A)

ii. Latent Demand

Contracted DG/**DSR Scheme**s/**ES** – none i.e., the intertripping arrangement is not actively managing Customer A's demand in an intact system and hence there is no **Latent Demand**.

Non-Contracted DG/DSR Schemes/ES – none

iii. Cold Load Pickup = 0 MW

iv. **Group Demand** = 33 MW (Class C)

b) Determine Network Capacity

i. Intrinsic network capacity

FCO capacity = 30 MW, available immediately. (From Table 1 of EREC P2/8 [N1] under an **FCO**, there is a requirement to secure partial demand within 15 mins and all demand within 3 hrs).

SCO capacity = not determined (from Table 1 of EREC P2/8 [N1] under a **SCO**, there is no requirement to secure any demand).

The intrinsic network capacity of 30 MW under an **FCO** is insufficient to meet the 33 MW of **Group Demand** i.e., there is a deficiency of 3 MW.

ii. **Transfer Capacity** = 0 MW available under an **FCO** or **SCO**

Given that **Group Demand** is greater than the intrinsic network capacity, and no **Transfer Capacity** is available, it is now necessary to consider contribution to security from other means: **DG**/**DSR Scheme**s/**ES**.

iii. Security contribution from **Contracted DSR Scheme** = 5 MW, available immediately under an **FCO** (Customer A tripped under an **FCO**).

The total **System Security** contribution capacity is 35 MW compared to a **Group Demand** of 33 MW; hence the system is compliant with Table 1 of EREC P2/8 [N1].

F.6.3 Active Network Management (ANM) system

Customer A consists of a 2 MW **Demand Facility** and Customer B consists of a 3 MW **Demand Facility**. The import by A and B are monitored and controlled by the same ANM system. The **DNO**'s connection agreements with A and B stipulate that the load (import) is constrained to ensure the summated demand of both Customers (A+B) is not greater than 2 MW at the time of peak demand on the distribution system.

Figure F.3.3 depicts the power flows at the time of peak demand: it is assumed by the **DNO** that both Customers A and B wish to import their maximum demand (5 MW combined) but are constrained to 2 MW by the ANM i.e., the **Latent Demand** is assumed to be the maximum value of 3 MW. An alternative approach is for the **DNO** to assess the load profiles of Customer A and B and determine if both Customers actually require their maximum allowance at the time of peak i.e., diversified **Latent Demand** (see Annex A.1).

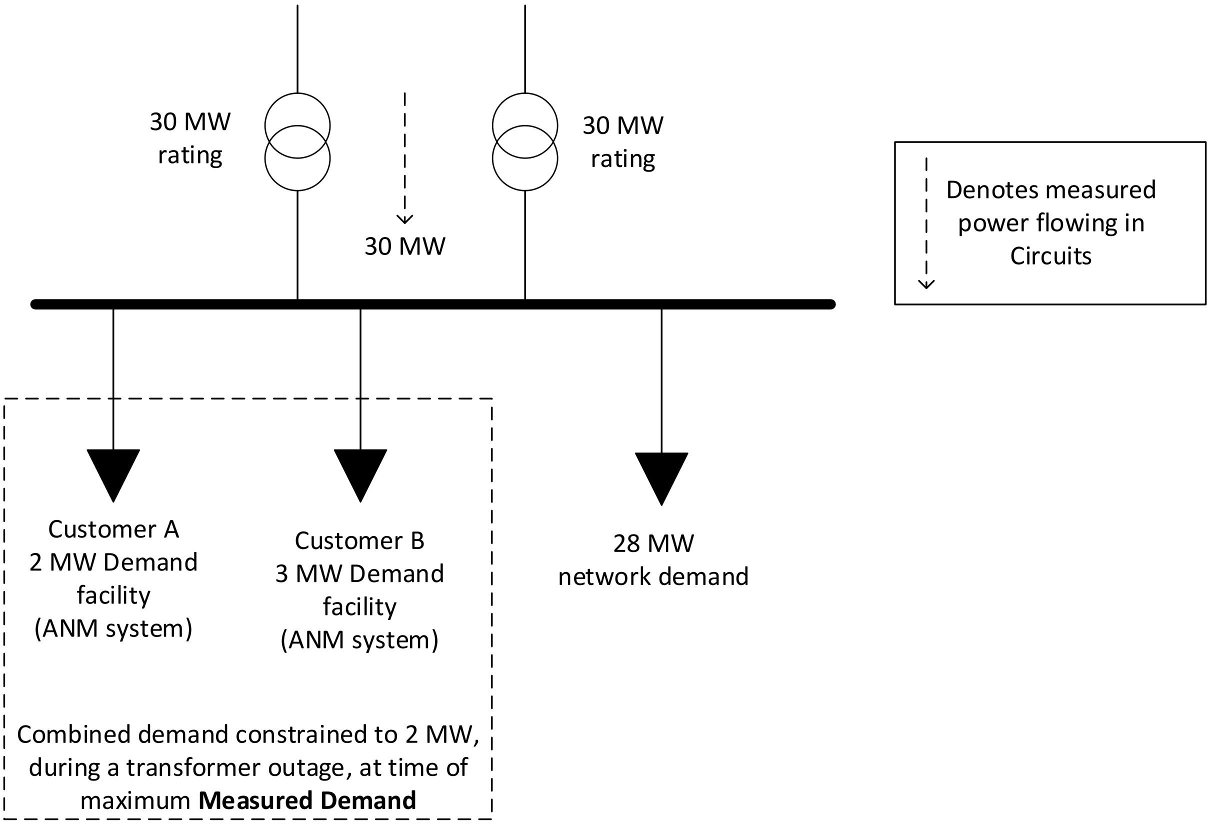


Figure F.6.3 – ANM system

a) Determine **Group Demand**

i. Measured Demand = 30 MW

ii. Latent Demand

Contracted DG/**DSR Scheme**s/**ES** – 3 MW i.e., the ANM system is actively managing Customer A and B's demand and constraining to 2 MW, from an assumed maximum of 5 MW.

Non-Contracted DG/DSR Schemes/ES – none

iii. Cold Load Pickup = 0 MW

iv. **Group Demand** = 33 MW (Class C)

b) Determine Network Capacity

i. Intrinsic network capacity

FCO capacity = 30 MW, available immediately. (From Table 1 of EREC P2/8 [N1] under an **FCO**, there is a requirement to secure partial demand within 15 mins and all demand within 3 hrs).

SCO capacity = not determined (from Table 1 of EREC P2/8 [N1] under a **SCO**, there is no requirement to secure any demand).

The intrinsic network capacity of 30 MW under an **FCO** is insufficient to meet the 33 MW of **Group Demand** i.e., there is a deficiency of 3 MW.

ii. **Transfer Capacity** = 0 MW available under an **FCO** or **SCO**

Given that **Group Demand** is greater the intrinsic network capacity, and no **Transfer Capacity** is available, it is now necessary to consider contribution to security from other means: **DG**/**DSR Scheme**s/**ES**.

iii. Security contribution from **Contracted DSR Scheme** = 3 MW, available immediately under an **FCO** (Customer A and B constrained prior to an **FCO** event).

The total **System Security** contribution capacity is 33 MW compared to a **Group Demand** of 33 MW; hence the system is compliant with Table 1 of EREC P2/8 [N1].

F.6.4 Import constraint vs. operating regime

Two Demand Facilities (Customer A and B) each have a constraint imposed on their import via a contract with the **DNO** i.e., **Contracted DSR Scheme**. The constraint applies at an agreed time of day.

The contracts have been in place for a number of years – the Demand Facilities are not necessarily operating as originally envisaged by the contracts.

The **DNO** is closely monitoring the import for each Customer, i.e., the **DNO** has an understanding of the operating regime at each **Demand Facility**. Hence, the **DNO** has sufficient information to undertake a detailed assessment of **Latent Demand**. The two customers are operating at the time of the **Measured Demand** as described in Table F.6.4.1.

Table F.6.4.1 — Demand Facilities' operating regimes

Customer	Demand Facility operation
A	Importing 1.5 MW (**DNO** is aware that the Customer does not require any more import at the time of **Measured Demand**)
B	Importing 0 MW (**DNO** is aware that the Customer has changed its production and no longer runs plant at the time of **Measured Demand**)

The **DNO** has two options:

- Option 1: Treat the assessment of **Latent Demand** based on the measured data for Customers A and B. This assumes that the measured data is sufficiently reliable to reflect the operating regime of Customer A and B going forward; or
- Option 2: Treat the assessment of **Latent Demand** based on the contract it has with Customers A and B.

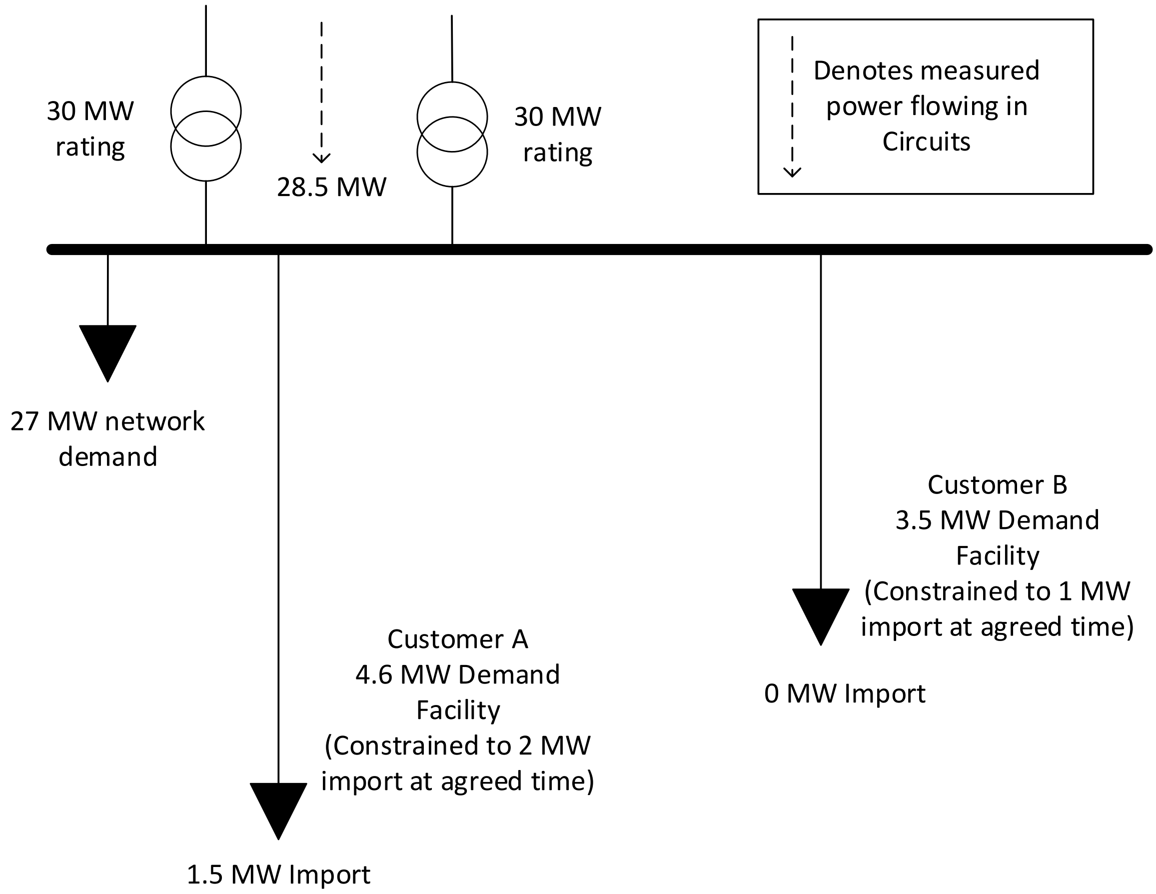


Figure F.6.4 – DSR Scheme contracts

Instead of examining a thorough step-by-step assessment for Option 1 and Option 2, as for other examples, a summary of the **Group Demand** calculation and the contribution to security is compared in Table F.6.4.2.

Table F.6.4.2 — Summary comparison of Options 1 & 2

	Option 1	**Option 2**
Group Demand	28.5 + 0(A) + 0(B) = 28.5 MW	28.5 + 3.1(A) + 3.5(B) = 35.1 MW
Security Contribution	30 + 0 = 30 MW	30 + 2.6(A) + 2.5(B) = 35.1 MW
	Option 1 assessment allows the **DNO** to re-allocate the 1.5 MW of capacity which Customer A and B were originally expected to take when constrained. There are obviously risks to this approach as the Customers could change their operating regime. To address this risk, this may prompt the **DNO** to re-evaluate the contracts.	Option 2 assessment proves that the worst-case outcome works, i.e., the reason for the contracts.

F.7 Contracted ES

F.7.1 Export contract

An **ES** facility consists of 5 MW of installed battery storage and operates to an agreed contract with the **DNO**. The contract requires the **ES** facility to export 5 MW at an agreed time of the day.

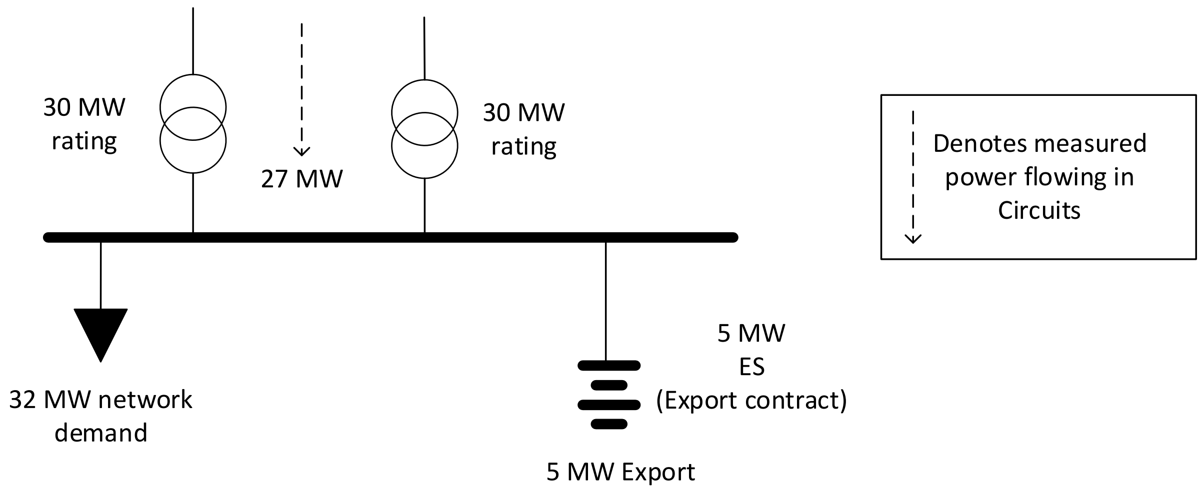


Figure F.7.1 – ES export contract

a) Determine **Group Demand**

i. Measured Demand = 27 MW

ii. Latent Demand

Contracted DG/**DSR Scheme**s/**ES** – 5 MW (export from **ES**).

Non-Contracted DG/DSR Schemes/ES – none

iii. Cold Load Pickup = 0 MW

iv. **Group Demand** = 32 MW (Class C)

b) Determine Network Capacity

i. Intrinsic network capacity

FCO capacity = 30 MW, available immediately. (From Table 1 of EREC P2/8 [N1] under an **FCO**, there is a requirement to secure partial demand within 15 mins and all demand within 3 hrs).

SCO capacity = not determined (from Table 1 of EREC P2/8 [N1] under a **SCO**, there is no requirement to secure any demand).

The intrinsic network capacity of 30 MW under an **FCO** is insufficient to meet the 32 MW of **Group Demand** i.e., there is a deficiency of 2 MW.

ii. **Transfer Capacity** = 0 MW available under an **FCO** or **SCO**

Given that **Group Demand** is greater the intrinsic network capacity and no **Transfer Capacity** is available, there is a deficiency in **System Security** of 2 MW. Hence, it is now necessary to consider contribution to security from other means: **DG**/**DSR Scheme**s/**ES**.

iii. Security contribution from **Contracted ES** = 5 MW, available immediately (the **ES** contract stipulates the contribution and includes a requirement to remain connected under a fault forming the **FCO**. The **ES** is not designed to run in island mode and hence, there is no contribution under an **SCO**).

The total **System Security** capacity under an **FCO** is 35 MW, compared to a **Group Demand** of 32 MW. There is no requirement to secure demand under an **SCO**. The distribution system is compliant with Table 1 of EREC P2/8 [N1].

F.7.2 Import contract vs. operating regime

Three **ES** facilities (Customer A, B and C) consist installed battery storage. The import by each **ES** is constrained, via contracts with the **DNO**, to 3 MW at an agreed time of day. The contracts with the **DNO** do not stipulate an export requirement.

The contracts have been in place for a number of years – the **ES** facilities are not necessarily operating as originally envisaged by the contracts.

The **DNO** is closely monitoring the export and import from each **ES**, i.e., the **DNO** has an understanding of the operating regime at each **ES** facility. Hence, the **DNO** has sufficient information to undertake a detailed assessment of **Latent Demand**. The three customers are operating at the time of the **Measured Demand** as described in Table F.7.2.1.

Table F.7.2.1 — ES operating regimes

Customer	ES operation
A	Importing 3 MW (**DNO** is aware that the **ES** would like to import 7 MW at the time of **Measured Demand**)
B	Importing 0 MW (**DNO** is aware that the **ES** has changed its operating regime and is no longer charging/discharging at the time of **Measured Demand**) NOTE 1
C	Exporting 2 MW (**DNO** is aware that the **ES** has changed operating regime from import to export at the time of **Measured Demand**)
NOTE 1: For an **ES** facility that is energised but not importing or exporting i.e., not charging/discharging, the **DNO** would expect a nominal current to be present.	

The **DNO** has two options:

- Option 1: Treat the assessment of **Latent Demand** based on the measured data for Customers A, B and C. This assumes that the measured data is sufficiently reliable to reflect the operating regime of Customer A, B and C going forward; or
- Option 2: Treat the assessment of **Latent Demand** based on the contract it has with Customers A, B and C.

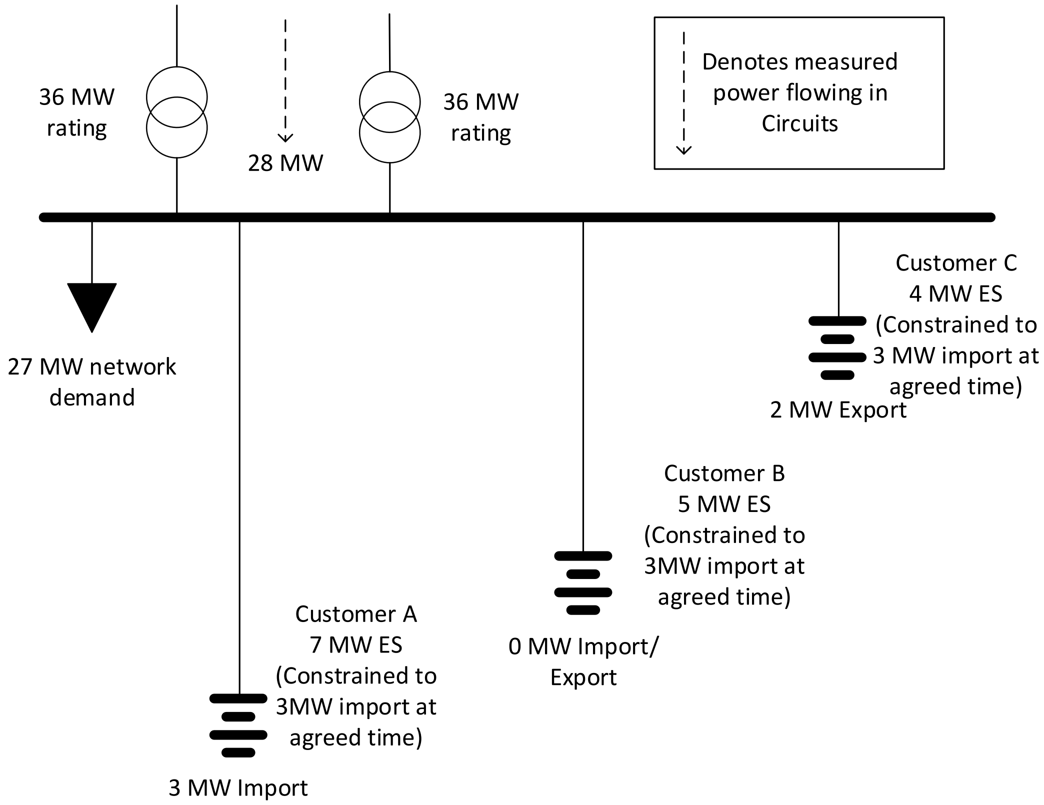


Figure F.7.2 – ES import only contract

Instead of examining a thorough step-by-step assessment for Option 1 and Option 2, as for other examples, a summary of the **Group Demand** calculation and the contribution to security is compared in Table F.7.2.2.

Table F.7.2.2 — Summary comparison of Options 1 & 2

	Option 1	**Option 2**
Group Demand	28 + 4(A) + 0(B) + 2(C) = 34 MW	28 + 4(A) + 5(B) + 6(C) = 43 MW NOTE 1
Security Contribution	36 + 4 (A) = 40 MW NOTE 2	36 + 4(A) + 2(B) + 1(C) = 43 MW NOTE 2
	Option 1 assessment allows the **DNO** to re-allocate the 6 MW of capacity which Customer B and C were originally expected to take when constrained. There are obviously risks to this approach, as the Customers could change their operating regime. To address this risk This may prompt the **DNO** to re-evaluate the contracts.	Option 2 assessment proves that the worst-case outcome works, i.e., the reason for the contracts.
NOTE 1: The worst case for the **ES** at Customer C is 'changing' its normal operation at the time of **Measured Demand** from export to import within the **DNO**'s network planning period. Hence, worst case **Latent Demand** is 6 MW. NOTE 2: The **ES** at Customer C is exporting 2 MW outside of a contract with the **DNO**. Hence, any security contribution would be based on an analysis using EREP 131, which would be lower than 2 MW. It is assumed to be 0 MW.		

F.8 Non-Contracted ES

F.8.1 New ES connection consideration

A **DNO** is considering a connection application for an **ES** facility which will consist of 3 MW of storage and requires to charge (import) full capacity at the time of distribution system peak demand. Prior to **ES** connection, the network is as shown in Figure F.4. The expected arrangement with the **ES** facility connected is shown in Figure F.8.1.

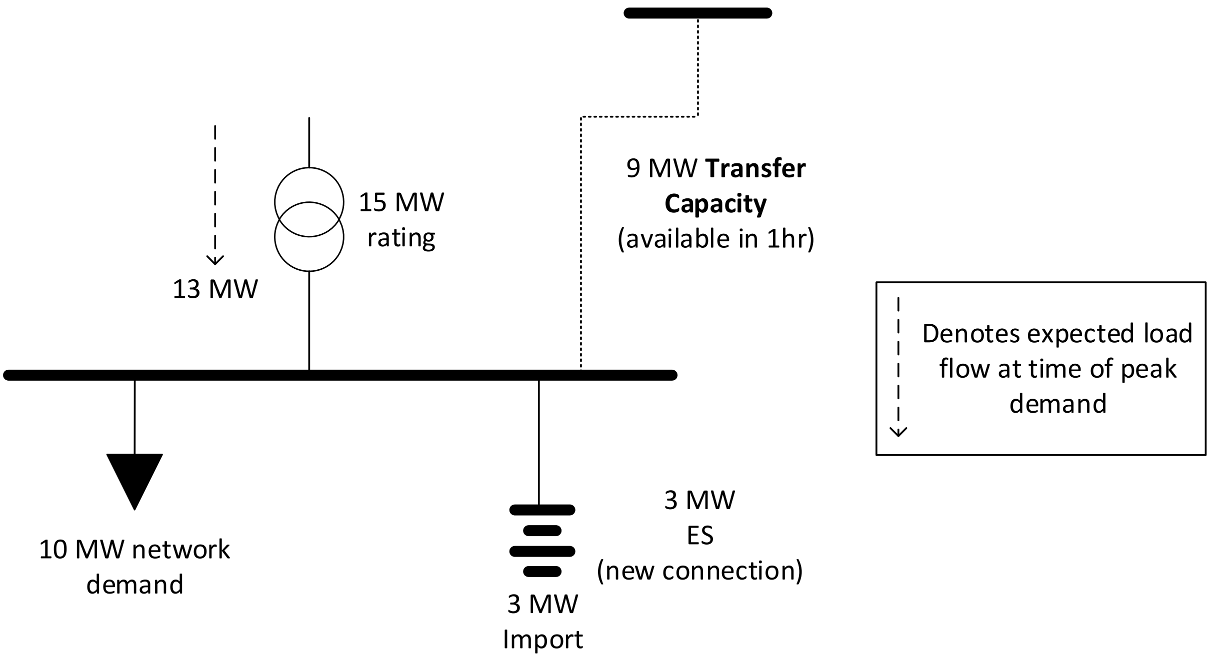


Figure F.8.1 – New ES connection consideration

a) Determine **Group Demand**

i. **Measured Demand** = 13 MW (expected at time of maximum demand after **ES** connection)

ii. Latent Demand

Contracted DG/DSR Schemes/ES – none

Non-Contracted DG/DSR Schemes/ES – none

iii. Cold Load Pickup = 0 MW

iv. **Group Demand** = 13 MW (Class C)

b) Determine Network Capacity

i. Intrinsic network capacity

FCO capacity = 0 MW. (From Table 1 of EREC P2/8 [N1] under an **FCO**, there is a requirement to secure 'the smaller of **Group Demand** - 12 MW or 2/3 **Group Demand**', i.e., 1 MW within 15 mins and all demand within 3 hrs).

SCO capacity = not determined (from Table 1 of EREC P2/8 [N1] under a **SCO**, there is no requirement to secure any demand).

The intrinsic network capacity of 0 MW under an **FCO** is:

- insufficient to meet the 15 mins requirement to restore 1 MW, i.e., there is a deficiency of 1 MW.

- insufficient to meet the 3 hrs requirement to restore **Group Demand** (13 MW), i.e., there is a deficiency of 13 MW.

ii. **Transfer Capacity** = 9 MW available within 1 hr under an **FCO**

There is a deficiency in **System Security** of 1 MW within 15 mins and 4 MW [13-9] within 3 hrs. There is no available contribution from **DG**/**DSR Scheme**s/**ES** – the **ES** is not **Contracted** with the **DNO** to provide **System Security** and the assessed security contribution assessed in accordance with EREP 131 is negligible. Hence, with the proposed **ES** connection, the distribution system is not compliant with Table 1 of EREC P2/8 [N1].

It should be noted that without the **ES** connection (as described in F.3), the **Group Demand** would be 10 MW (Class B): from Table 1 of EREC P2/8 [N1] under an **FCO**, Class B requires restoration for 9 MW of demand within 3 hrs and restoration of the remaining demand within repair time – this can be satisfied without the **ES** connection.

The next step is for the **DNO** to undertake a review of the options (see Clause 9.2) to address the deficiency, such as:

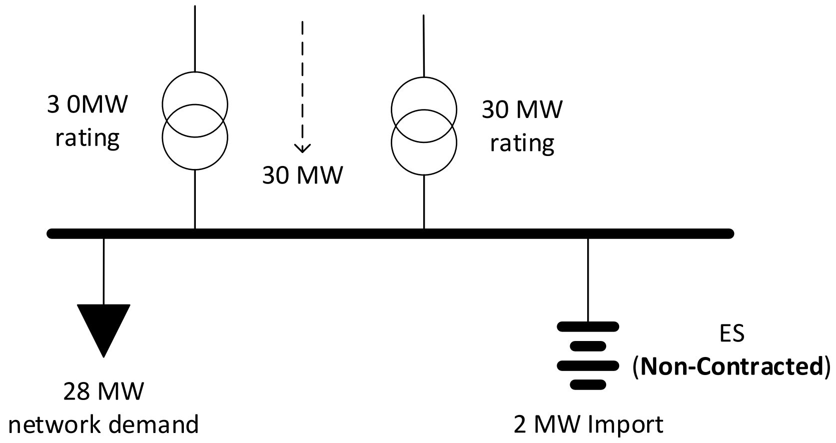
- network asset reinforcement; and
- establishing a contract with the **ES** owner/operator

The most efficient solution is likely to be for the **ES** owner/operator to be offered a connection with a constrained import to manage the customer related risk of not complying with the requirements of Table 1 of EREC P2/8 [N1].

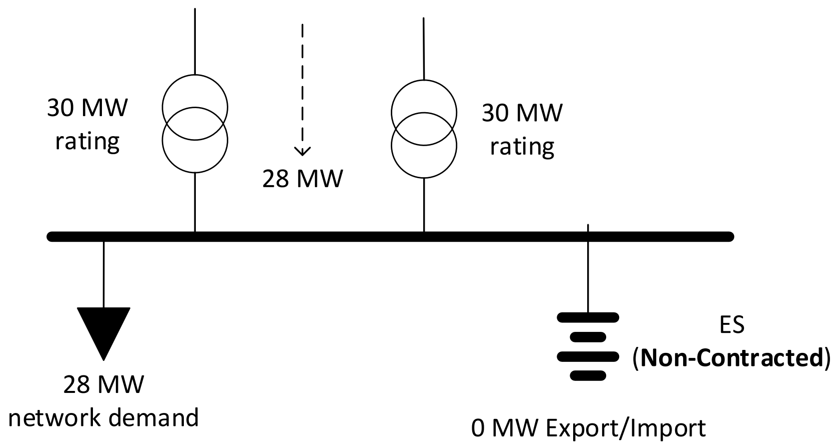
However, a supplementary CBA (see Clause 12) may be required when the **DNO**'s high-level review indicates that the options are not economically viable and/or align with the asset management strategy.

F.8.2 Established ES

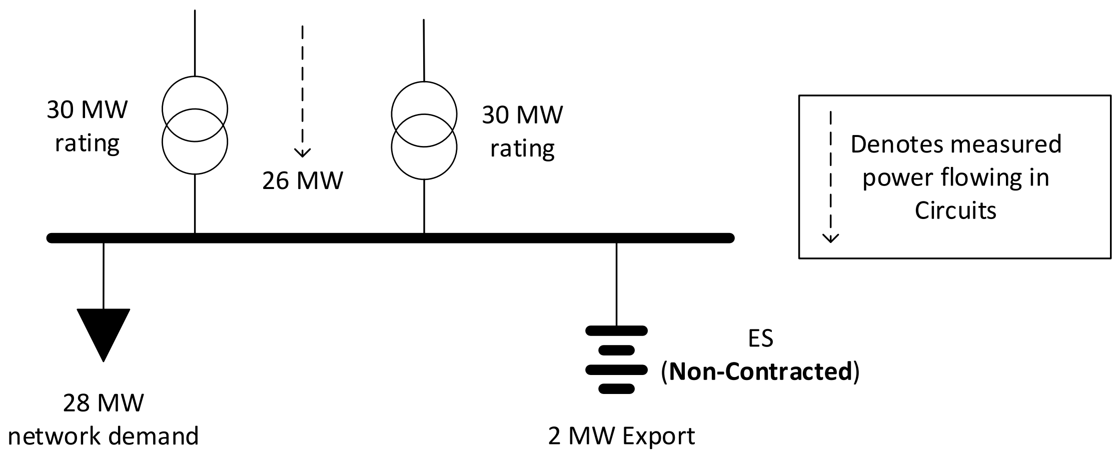
An **ES** facility consists of 5 MW of installed battery storage and operates outside of any contract with the **DNO**. Three scenarios are considered as depicted in Figure F.8.2.



1) ES Importing 2 MW



2) ES Importing 0 MW



3) ES Exporting 2 MW

Figure F.8.2 – Non-Contracted ES

a) Determine **Group Demand**

i. Measured Demand

- Scenario 1 = 30 MW
- Scenario 2 = 28 MW
- Scenario 3 = 26 MW

ii. Latent Demand

Contracted DG/DSR Schemes/ES – Latent Demand associated with ES.

- Scenario 1: **Latent Demand** = 0 MW
- Scenario 2: **Latent Demand** = 0 MW
- Scenario 3: **Latent Demand** = 2 MW (**ES** export)

Non-Contracted DG/DSR Schemes/ES – none

iii. Cold Load Pickup = 0 MW

iv. Group Demand

- Scenario 1: **Group Demand** = 30 MW (Class C)
- Scenario 2: **Group Demand** = 28 MW (Class C)
- Scenario 3: **Group Demand** = 28 MW (Class C)

b) Determine Network Capacity

i. Intrinsic network capacity

FCO capacity = 30 MW, available immediately. (From Table 1 of EREC P2/8 [N1] under an **FCO**, there is a requirement to secure partial demand within 15 mins and all demand within 3 hrs).

SCO capacity = not determined (from Table 1 of EREC P2/8 [N1] under a **SCO**, there is no requirement to secure any demand).

Given that intrinsic network capacity is greater than or equal to the **Group Demand** for all scenarios, no consideration of the security contribution assessment from **ES** is necessary and the system is compliant with Table 1 of EREC P2/8 [N1]. However, for completeness, the contribution from **ES** for all scenarios is determined:

ii. Security contribution from **Non-Contracted ES**

- Scenario 1: There is no contribution to security from the **ES**.
- Scenario 2: There is no contribution to security from the **ES**, although previous profile data may indicate a likelihood of export.
- Scenario 3: The 2 MW export from the **ES** should be subject to an assessment using the methodology described in ENA EREP 131, i.e., contribution should be based on appropriate data analysis. Otherwise the contribution to security shall be assumed to be 0 MW.

F.9 Distribution system with multiple Non-Contracted DG

This example have been designed to demonstrate the assessment of security contribution from multiple **Non-Contracted DG** facilities, in accordance with this EREP.

The distribution system used is illustrated in Figure F.9. The **DNO** knows that the system contains:

- an onshore wind farm having a **DNC** of 35 MW;
- a landfill gas **DG** installation having a **DNC** of 8 MW;
- a waste **DG** installation having a **DNC** of 1 MW;
- Fifty 1 kW microgeneration units at various locations in the demand group;
- an industrial site that has a biomass **DG** installation which operates 24 hrs per day at an output of 10 MW.

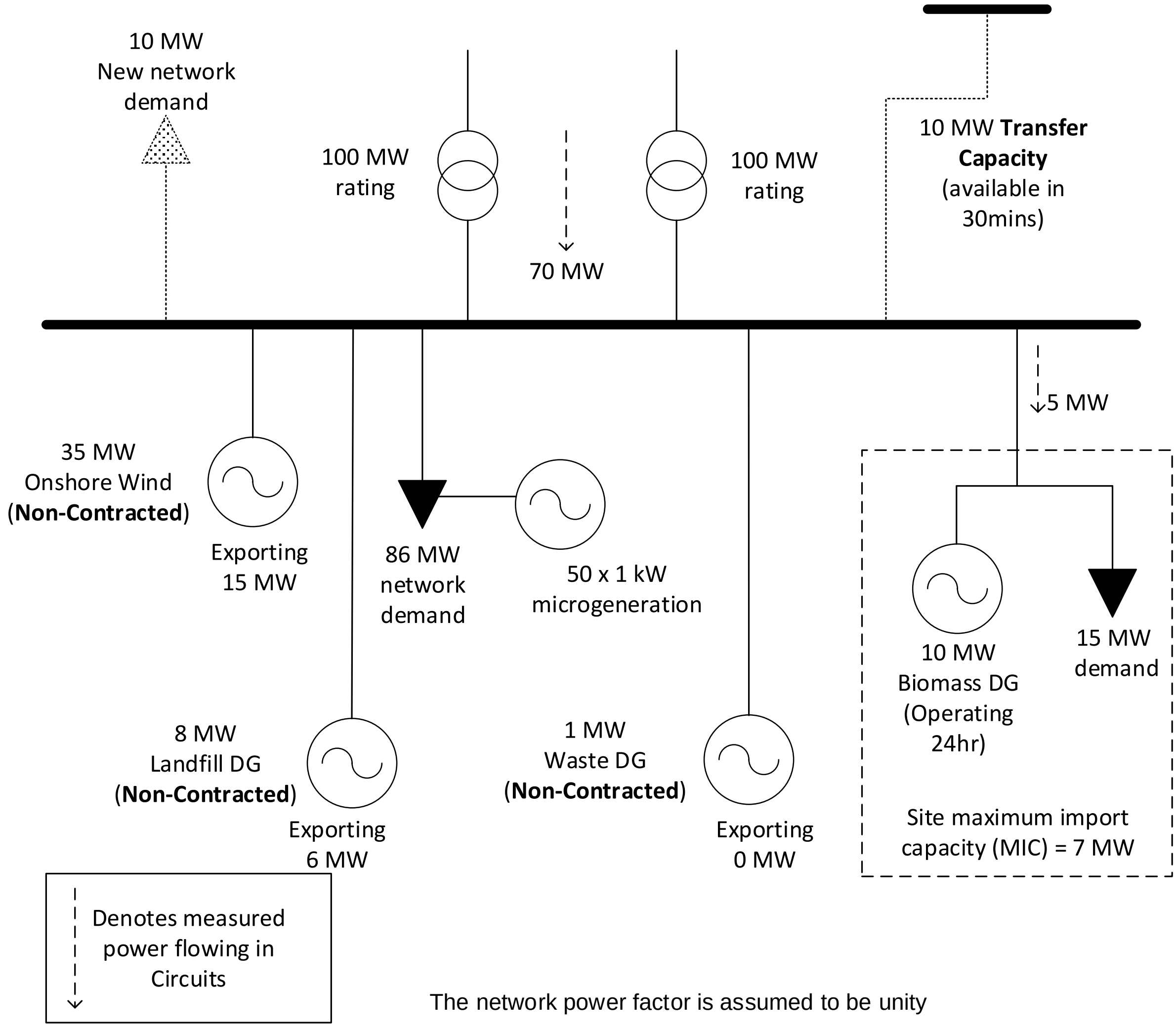


Figure F.9 – Multiple Non-Contracted DG

There are two scenarios considered:

i. Scenario 1 (see F.9.1) – an assessment which ignores the new demand of 10 MW

ii. Scenario 2 (see F.9.2) – the assessment which includes the new demand of 10 MW

For simplicity the examples use Approach 1 of Annex D to determine the contributions from the sources of generation where relevant.

F.9.1 Scenario 1 – Assessment which ignores new network demand

a) Determine **Group Demand**

i. Measured Demand: 70 MW.

ii. Latent Demand

Contracted DG/DSR Schemes/ES – none

Non-Contracted DG/DSR Schemes/ES – Capacity of downstream generation: (35) + (1) + (8) + 10) = 54 MW.

The sum of the downstream generation is > 5% of the **Measured Demand**, hence it is necessary to analyse the generation to establish the **Latent Demand** contribution to **Group Demand**.

Using the approach in Annex A, Equation 1.

- Onshore wind = 15 MW.
- Waste **DG** = 0 MW.
- Landfill gas **DG** = 6 MW.
- There are only a small number of microgeneration units with a low aggregate capacity, hence their impact on the **Group Demand** can be neglected.
- For the industrial site, there is sufficient information about the load and generation to apply the simple analysis in Annex A.2, i.e., the smaller of the expected generation output at a time of maximum **Measured Demand** (10 MW), and the ASC (7 MW) minus the import at the time of the maximum **Measured Demand** (5 MW), should be added to the **Measured Demand**, i.e., 2 MW, the smaller of (10) and (7 – 5).

iii. Cold Load Pickup = 0 MW

iv. **Group Demand** = 70 + 15 + 0 + 6 + 2 = 93 MW (Class D).

NOTE: The **Group Demand** is subtly different from the actual connected demand of 86 MW of existing load plus the 5 MW of net demand from the industrial site. This is because the **Group Demand** includes 2 MW of **Latent Demand** associated with the industrial site, i.e., demand that would appear if the generation at the industrial site was not running.

b) Determine Network Capacity

i. Intrinsic network capacity

FCO capacity = 100 MW, available immediately. (From Table 1 of EREC P2/8 [N1] under a **FCO**, there is a requirement to secure all the demand immediately [assuming that there is no automatic disconnection][3]. The **FCO** capacity of 100 MW is sufficient to meet the 93 MW of demand.)

SCO capacity = 0 MW (from Table 1 of EREC P2/8 [N1] under a **SCO**, there is a requirement to secure all the demand within the time to restore the arranged outage)

ii. **Transfer Capacity** – not necessary to assess as intrinsic network capacity is sufficient to secure the **Group Demand**. For completeness,

10 MW available within 30 min under **FCO** or **SCO** conditions.

Given that intrinsic network capacity is greater than **Group Demand**, the system is compliant with Table 1 of EREC P2/8 [N1].

F.9.2 Scenario 2 – assessment which includes new network demand

In order to continue to demonstrate the application of EREC P2/8 [N1], this example develops Scenario 1 but with additional demand connected such that the **Measured Demand** increases by 10 MW.

a) Determine the **Group Demand**

[3] Strictly EREC P2/8 [N1] permits of the automatic disconnection of up to 20 MW of demand in this scenario. However, many DNO networks are not currently designed to automatically disconnect demand, and this example is based on the assumption that all demand should be supplied immediately.

i. **Measured Demand**: (70 + 10) = 80 MW.

ii. Latent Demand

Contracted DG/DSR Schemes/ES – none

Non-Contracted DG/**DSR Scheme**s/**ES** – Capacity of downstream generation: (35) + (1) + (8) + 10) = 54 MW.

The sum of the downstream generation is > 5% of the **Measured Demand**, hence it is necessary to analyse the generation to establish the **Latent Demand** contribution to **Group Demand**.

Using the approach in Annex A, Equation 1.

- Onshore wind = 15 MW.
- Waste **DG** = 0 MW.
- Landfill gas **DG** = 6 MW.
- There are only a small number of microgeneration units with a low aggregate capacity, hence their impact on the **Group Demand** can be neglected.
- For the industrial site, there is sufficient information about the load and generation to apply the simple analysis in Annex A.2, i.e., the smaller of the expected generation output at a time of maximum **Measured Demand** (10 MW), and the ASC (7 MW) minus the import at the time of the maximum **Measured Demand** (5 MW), should be added to the **Measured Demand**, i.e., 2 MW, the smaller of (10) and (7 – 5).

iii. Cold Load Pickup = 0 MW

iv. **Group Demand** = 80 + 15 + 0 + 6 + 2 = 103 MW (Class D).

b) Determine Network Capacity

i. Intrinsic network capacity

FCO capacity = 100 MW, available immediately (From Table 1 of EREC P2/8 [N1] under a **FCO**, there is a requirement to secure all the demand immediately [assuming as before that there is no automatic disconnection]. Hence, there is a **FCO** deficiency of (103 - 100) = 3 MW.)

SCO capacity = 0 MW (from Table 1 of EREC P2/8 [N1] under a **SCO**, as the **Group Demand** exceeds 100 MW, there is a requirement to secure the smaller of; **Group Demand** minus 100 MW, and 1/3 of **Group Demand**, i.e., 3 MW within 3 hrs. As 10 MW **Transfer Capacity** is available within 30 min, there are sufficient network assets to meet the **SCO** requirements, there being an excess of 7 MW. There is a further requirement to secure all the demand within the time to restore the arranged outage.

ii. Transfer Capacity

Available immediately = 0 MW

Available within 30 minutes = 10 MW

As 10 MW **Transfer Capacity** is available within 30 min, there are sufficient network assets to meet the **SCO** requirements, there being an excess of 7 MW. However, there is a **FCO** deficiency of 3 MW (required immediately) and the network is non-compliant with EREC P2/8 [N1].

It is now necessary to consider contribution to security from other means: **DG**/**DSR Scheme**s/**ES**.

c) Security contribution capacity from **DG**/**DSR Scheme**s/**ES**

iii. Security contribution from **Non-Contracted DG**

iv. The aggregate of the **DNC**s of the **Non-Contracted DG** in the network can be calculated. If this aggregate is less than the capacity deficit revealed in Step b) above, then there is no possibility that the **DG** capacity will make the network compliant. If the aggregate exceeds the deficit then further analysis is required.

v. The aggregate of all the **Non-Contracted DG** connected in the network = 35 + 1 + 8 + 10 = 54 MW. Hence there is the potential for the connected **Non-Contracted DG** to meet **System Security** deficiency, and the analysis therefore continues with step i.1:

- Step i.1 – Check each **DG** source against the de-minimis criterion

NOTE: See also Clause 9.2.

The microgeneration units are excluded from the compliance assessment as they are, even in aggregate, less than 100 kW.

The onshore wind farm (35 MW) is approximately 33% of the **Group Demand**, i.e., above the de-minimis criterion, and therefore the security contribution should be assessed.

The waste **DG** (1 MW) is less than 5% of the **Group Demand** (103 MW), i.e., below the de-minimis criterion, and is therefore not considered further.

The landfill **DG** (8 MW) is approximately 7% of the **Group Demand**, i.e., above the de-minimis criterion, and therefore the security contribution should be assessed.

The biomass **DG** (10 MW) is approximately 10% of the **Group Demand**, i.e., above the de-minimis criterion, and therefore the security contribution should be assessed.

- Step i.2 – Fault ride-through capability

NOTE: See also Clause 9.3.1.

The behaviour of each **DG** rated above the de-minimis limit, under the relevant outage conditions should be assessed. In this example, it is assumed that system studies have been carried out to demonstrate that the onshore wind farm and biomass facility remain connected under a fault forming the **FCO** condition and that the landfill **DG** will disconnect under fault conditions (e.g. owing to the sensitivity of its protection systems), and the **DNO** has agreed with the **DG** that they will automatically reconnect to the system within 30 min. **DG** contribution under **SCO** conditions can only be provided in practice in the event that the **DG** has been designed to run in island mode, or alternatively that there is sufficient interconnection to the rest of the total system to allow the **DG** to resynchronise.

- Step i.3 – Establish security contributions

NOTE: See also Clause 9 and Annex D.

At this point in the process the contribution from each **DG** facility can be established. In this example, Approach 1 (Table D.2.1 and Table D.2.2) in Annex D are used to establish the contributions from the **DG**. The time of year relevant for this example is winter.

*Landfill **DG***

– The F factor for the landfill gas **DG** = 22%.

– The security contribution from the landfill **DG** = ((22/100) x 8) = 1.7 MW.

*Onshore wind farm **DG***

The security contribution from the wind farm is dependent upon the required value of T_m. In this example, the most onerous **FCO** relates to an outage of one of the two 100 MW network **Circuit**s for a major reconstruction project.

– From Table D.2.3, the required value of $\mathbf{T_m}$ = 90 days.

– From Table D.2.2, the F factor for the wind farm = 0.

– From Table D.2, the security contribution from the onshore wind farm = (0/100 x 35) = 0 MW.

However, in this example the wind farm has the capability to provide continuity of supply under **FCO** conditions in the time period between the inception of the **FCO** and the time when the **Transfer Capacity** of the network can be utilised, in this case 30 min. A $\mathbf{T_m}$ value of 30 mins is used to assess this capability.

– From Table D.2.3, the required value of $\mathbf{T_m}$ = 30 mins.

– From Table D.2.2, the F factor for the onshore wind farm = 15%.

– From Table D.2, the security contribution from the onshore wind farm = ((15/100) x 35) = 5.2 MW.

*Biomass **DG***

– The F factor for the Biomass **DG** = 32%.

– The security contribution from the biomass **DG** = ((32/100) x 10) = 3.2 MW.

- <u>Step i.4 – Checking for dominance</u>

NOTE: See also Clause 9.3 and Annex B.

By inspection, it can be seen that the contribution to **System Security** from each of the **DG** facilities is less than the capacity of one of the incoming **Circuit**s, and hence the **DG** is not dominant and Capping is not required.

- <u>Step i.5 – Time durations</u>

NOTE: See also Clause 9.3.

Table F.6 summarises the security contribution from each **DG** facility and the time after the outage when the contribution is available. The security contribution after the **SCO** will depend upon the ability of the **DG** to synchronise with the depleted network conditions.

Table F.9 — Scenario 2 – DG contribution after a FCO

Distributed Generation	Security contribution (MW)	Time in which the DG is available post a FCO
Onshore wind farm (35 MW)	5.2	Immediately (but only for 30 mins)
Waste (1 MW)	0	N/A
Landfill (8 MW)	1.7	After 30 mins
Biomass (10 MW)	3.2	Immediately

- <u>Step i.6 – Checking for compliance with EREC P2/8 [N1] Table 1</u>

NOTE: See also Clause 10.

The relevant network assets are the two transformers supplying the network, i.e., the capacity of each network infeed **Circuit** = 100 MW. The contribution to **System Security** from the generation established in Step i.3 is combined with the contribution from the network assets for both the **FCO** and **SCO** condition in each of the relevant time periods, i.e., immediately, within 3 hrs and within the time to restore the arranged outage.

***FCO** capacity (time period: inception of **FCO** to 30 mins)*

From Table 1 of EREC P2/8 [N1] under **FCO**, there is a requirement to secure all the demand immediately (assuming that there is no automatic disconnection). Considering the security provided by network assets and **DG** facilities, there is a **FCO** capacity of (100 + 5.2 + 3.2) = 108.4 MW, i.e., a surplus of (108.4 - 103) = 5.4 MW.

***FCO** capacity (time period: 30 mins from inception of **FCO** to 3 hrs)*

From Table 1 of EREC P2/8 [N1] under **FCO**, there is a requirement to secure all the demand immediately (assuming that there is no automatic disconnection). Considering the security provided by network assets and generation, there is a **FCO** capacity of (100 + 10 + 1.7 + 3.2) = 114.9 MW, i.e., a surplus of (114.9 - 103) = 11.9 MW. The change in capacity arises due to the fact that the onshore wind farm contribution has been replaced by the **Transfer Capacity** that is switched within 30 min of the inception of the fault and the resynchronisation of the landfill gas installation. The 10 MW **Transfer Capacity** can be sustained indefinitely, whilst the contribution provided from the wind farm will reduce with time.

The **FCO** capacity is the lower of these two figures, i.e., 108.4 MW.

***SCO** capacity (Time period: from inception of **SCO** to 30 mins)*

SCO capacity immediately available = 3.2 MW (Biomass) plus 5.2 MW (onshore wind farm), although unless island mode operation is viable, this contribution can only be utilised if the transfer capability provides a **Circuit** to which the **DG** can be synchronised. Hence this capacity is zero in the event that no facility for island operation exists.

***SCO** capacity (Time period: 30 mins from inception of **SCO** to 3 hrs)*

SCO capacity available within 30 min = 10 MW (**Transfer Capacity**) + 1.7 MW (Resynchronised landfill **DG**) + 3.2 MW (Biomass) = 14.9 MW, i.e., a surplus of (114.9 - 103) = 11.9 MW. This condition could persist for extended periods and hence it would be inappropriate to consider any contribution from the onshore wind farm as $\mathbf{T_m}$ could be in excess of 120 h. It is worth noting that the contribution to **System Security** from **DG** could only be realised if the generation could be synchronised to the system supplied from the **Transfer Capacity Circuit**. If this were not the case, the **SCO** capacity would be limited to the **Transfer Capacity** (10 MW).

In summary, by considering the contribution to **System Security** from the network assets alone, there is a **FCO** deficiency of 3 MW and a **SCO** surplus of 7 MW. Hence the network is non-compliant with EREC P2/8 [N1].

Taking the contribution to **System Security** from **Non-Contracted DG** into account produces a **FCO** surplus of 5.4 MW. The increase in **FCO** capability arises due to the output from the onshore wind farm covering the period between the inception of the outage and the **Transfer Capacity** becoming available.

The **SCO** surplus may increase to 11.9 MW due to the contribution from the reconnected landfill **DG**, the biomass **DG** and the **Transfer Capacity**, but may be limited to 7 MW provided by the **Transfer Capacity**. In either case, the system can be considered to be EREC P2/8 [N1] compliant.

The **DNO** would need to consider whether a contract was required with the Biomass **DG** (see Clause 7).

Annex G
(normative)

Interpretation of Imperial College London Report [N9] findings

G.1 General

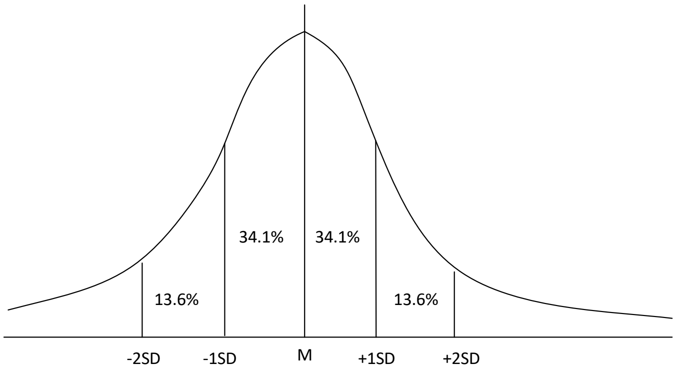
The Imperial College London report ‘Review of EREP 130 F Factors’ [N9] presents the full results of the analysis carried out by Imperial College London. These results have been used to produce the following tables in Annex D:

- Table D.2.1
- Table D.2.2
- Table D.3

The Imperial College London analysis calculates the Average, Minimum, Maximum and Standard Deviation of the F Factors of a large number of DC cases. In order to produce a single F Factor value for each technology type (for each season and capacity factor band where appropriate) in EREP 130 Annex D, the Average F Factor (more specifically the mean, M) minus 1 Standard Deviation (SD) is used. This means that there is a probability of 84.1% that the delivered **DG** security contribution is the calculated value (i.e., F Factor x **DG DNC**) or higher. This is considered to be a reasonable planning value to use.

The commentary below provides further explanation.

A normal population distribution about a mean value, M, is shown. The percentage of population within a standard deviation (SD) of the M follows the values shown, Hence, for 1SD below M, this represents 84.1% of the population



The following sections shows how the information from the Imperial College London report has been used to establish the values in EREP 130 Annex D.

References to Tables 5, 6, 9 and 10 in the following sections refer to tables in the Imperial College London report [N9].

G.2 Derivation of F Factors in Table D.2.1 for non-intermittent renewable DG types

Technology Type	Winter						Summer					
	Number	Average	Min	Max	St Dev	Ave-1 St Dev	Number	Average	Min	Max	St Dev	Ave-1 St Dev
Biomass	76	52%	4%	86%	22%	30%	75	46%	4%	83%	21%	25%
CHP	13	29%	4%	60%	22%		14	25%	6%	55%	16%	
Fossil Gas	31	17%	2%	70%	20%		19	25%	2%	82%	29%	
Fossil Oil	8	33%	5%	56%	22%		6	44%	5%	83%	25%	
Gas	11	24%	3%	49%	19%		9	25%	7%	39%	13%	
Geothermal	2	4%	3%	4%	1%							
Marine - Tidal	3	16%	8%	29%	11%		2	15%	7%	23%	11%	
Mixed	27	38%	5%	79%	26%		26	42%	2%	81%	22%	
Other Generation	17	9%	2%	18%	6%		12	10%	4%	17%	5%	
Other, CHP	62	27%	2%	80%	24%		63	26%	3%	75%	23%	
Landfill Gas	74	51%	3%	83%	23%	28%	73	50%	4%	100%	23%	27%
Waste	71	54%	2%	82%	19%	35%	69	48%	5%	78%	16%	32%
NOTE 1: Replicated from Table 5. Seasonal statistical parameters of F Factors for non-intermittent **DG** in the Imperial College London Report [N9]												
NOTE 2: Data items in red font are used in EREP 130 Table D.2.1												
NOTE 3: Other technology types are considered to either insufficiently well-defined or too small sample size for inclusion in EREP 130												

G.3 Derivation of F Factors in Table D.2.2 for intermittent renewable DG types

Technology Type	Season	Values	Persistence, h											
			0.5	2	3	6	12	18	24	48	120	360	480	Comments
Onshore wind	Winter	Average (%)	26	24	24	22	19	16	14	9	4	3	3	
		Min (%)	6	6	5	5	4	3	2	1	1	1	1	
		Max (%)	59	58	57	56	54	52	48	38	18	16	16	
		St Dev (%)	9	9	8	8	8	7	7	5	2	2	2	
		Ave - 1 St Dev	17	15	15	14	11	9	7	4	2	1	1	Value for $\mathbf{T_m}$ 3 amended to 15% in Table D.2.2 as F Factors can't increase
	Summer	Average (%)	19	18	17	15	13	11	9	6	3	3	3	
		Min (%)	5	5	4	4	3	2	2	1	1	1	1	
		Max (%)	40	38	37	35	31	28	27	26	22	18	14	
		St Dev (%)	6	6	6	6	5	5	5	4	3	2	1	
		Ave - 1 St Dev	13	12	11	9	8	6	4	2	0	0	0	Values for $\mathbf{T_m}$ 360, 480 set to zero as F Factors can't increase
Offshore wind	Winter	Average (%)	32	31	30	29	26	23	20	13	6	4	4	
		Min (%)	6	5	5	4	4	3	2	1	1	1	1	
		Max (%)	51	49	48	46	43	40	37	26	19	19	18	
		St Dev (%)	10	10	10	10	9	8	8	6	4	3	3	
		Ave - 1 St Dev	22	21	20	19	17	15	12	7	2	1	1	
	Summer	Average (%)	24	23	22	20	17	15	13	8	4	3	3	
		Min (%)	3	2	2	2	1	1	1	1	1	1	1	
		Max (%)	35	34	33	31	30	30	29	28	25	20	12	
		St Dev (%)	8	7	7	7	6	6	6	5	4	3	2	
		Ave - 1 St Dev	16	16	15	13	11	9	7	3	0	0	0	Values for $\mathbf{T_m}$ 480 set to zero as F Factors can't increase.

(continued)

Technology Type	Season	Values	Persistence, h											
			0.5	**2**	**3**	**6**	**12**	**18**	**24**	**48**	**120**	**360**	**480**	**Comments**
Solar	**Winter**	Average (%)	6	6	5	4	2	2	2	2	2	2	2	
		Min (%)	3	3	3	2	1	1	1	1	1	1	1	
		Max (%)	13	12	12	10	5	5	5	4	4	4	4	
		St Dev (%)	2	2	2	1	1	1	1	1	0	0	0	
		Ave - 1 St Dev	0	0	0	0	0	0	0	0	0	0	0	Values set to zero as Solar can't contribute to security if demand peak is after dusk
	Summer	Average (%)	16	15	14	12	5	2	2	2	2	2	2	
		Min (%)	3	3	3	2	1	1	1	1	1	1	1	
		Max (%)	22	22	21	20	9	3	3	3	3	3	3	
		St Dev (%)	4	4	4	3	2	0	0	0	0	0	0	
		Ave - 1 St Dev	12	11	10	9	3	2	0	0	0	0	0	Values for $\mathbf{T_m}$ >18 set to zero as Solar can't contribute to security overnight
NOTE 1: Replicated from Table 9. F Factors for intermittent renewables **DG** types in the Imperial College London Report [N9]														
NOTE 2: Data items in red font are used in EREP 130 Table D.2.2														
NOTE 3: Where F Factors are adjusted from the (Ave - 1St Dev) formulae, justification is provided in the comments														

G.4 Derivation of F Factors in Table D.2.2 for intermittent hydro DG types

Technology Type	Season	Values	Persistence, h											
			0.5	2	3	6	12	18	24	48	120	360	480	Comments
Hydro run-of-river and poundage	Winter	Average (%)	36	36	35	35	34	33	31	28	21	10	9	
		Min (%)	6	6	6	6	6	5	5	4	2	1	1	
		Max (%)	74	74	74	74	74	74	73	73	69	56	52	
		St Dev (%)	17	17	17	17	17	17	16	16	16	13	12	
		Ave - 1 St Dev	19	19	18	18	17	16	15	12	5	0	0	
	Summer	Average (%)	17	17	16	16	15	14	13	11	8	3	3	
		Min (%)	3	3	2	1	1	1	1	1	1	1	1	
		Max (%)	41	41	41	41	41	41	40	39	33	12	8	
		St Dev (%)	10	10	9	9	9	9	9	9	7	3	2	
		Ave - 1 St Dev	7	7	7	7	6	5	4	2	1	0	0	
Hydro water reservoir	Winter	Average (%)	29	29	28	27	26	23	22	21	18	12	10	
		Min (%)	4	4	4	2	1	1	1	1	1	1	1	
		Max (%)	76	76	76	75	74	72	70	70	68	60	56	
		St Dev (%)	17	17	18	18	19	19	19	18	16	13	12	
		Ave - 1 St Dev	12	12	10	9	7	4	3	3	2	0	0	
	Summer	Average (%)	16	16	15	14	13	12	11	10	9	6	5	
		Min (%)	3	3	3	3	2	1	1	1	1	1	1	
		Max (%)	70	70	70	70	70	69	69	67	61	52	52	
		St Dev (%)	11	11	11	12	12	12	12	12	11	8	7	
		Ave - 1 St Dev	5	5	4	2	1	0	0	0	0	0	0	Values for $\mathbf{T_m}$ >18 set to zero as F Factors can't increase

(continued)

NOTE 1: Replicated from Table 10. F Factors for intermittent hydro **DG** types in the Imperial College London Report [N9]
NOTE 2: Data items in red font are used in EREP 130 Table D.2.2
NOTE 3: Where F Factors are adjusted from the (Ave - 1St Dev) formulae, justification is provided in the comments

G.5 Derivation of F Factors in Table D.3 for non-intermittent renewable DG types

Capacity Factor	Winter						Summer					
	Number	Average	Min	Max	St Dev	Ave - 1St Dev	Number	Average	Min	Max	St Dev	Ave - 1St Dev
Biomass												
90%	22	76%	64%	86%	6%	49%	15	72%	61%	83%	7%	46%
70%	20	60%	42%	78%	11%	36%	18	58%	30%	77%	12%	35%
50%	11	45%	32%	57%	9%	26%	19	42%	30%	55%	7%	29%
30%	18	30%	23%	37%	4%	3%	12	32%	28%	36%	3%	6%
10%	5	7%	4%	14%	4%	0%	11	13%	4%	20%	7%	0%
Other, Landfill Gas												
90%	22	74%	50%	83%	7%	67%	21	72%	53%	100%	10%	62%
70%	14	65%	41%	75%	9%	56%	14	66%	43%	78%	9%	57%
50%	15	51%	43%	57%	4%	47%	13	54%	42%	58%	4%	50%
30%	12	29%	20%	36%	6%	23%	14	29%	11%	40%	8%	21%
10%	11	13%	3%	19%	5%	8%	11	13%	4%	19%	4%	9%
Waste												
90%	7	73%	64%	82%	6%	67%	4	71%	60%	78%	8%	63%
70%	39	64%	40%	75%	7%	57%	26	59%	44%	72%	8%	51%
50%	14	50%	37%	58%	7%	43%	26	45%	36%	54%	5%	40%
30%	5	26%	22%	28%	3%	23%	8	31%	22%	36%	4%	27%
10%	6	7%	2%	15%	5%	2%	5	14%	5%	20%	6%	8%

(continued)

NOTE 1: Replicated from Table 6. F Factors of **Non-Intermittent Generation** for different capacity factors and seasons in the Imperial College London Report [N9]
NOTE 2: Data items in red font are used in EREP 130 Table D.3
NOTE 3: The data analysis for biomass **Generator**s showed that capacity factors may vary more than 20% year to year, for more than 50% of the population. To accommodate this to some extent the F factors have been reduced by applying that of the next lowest capacity factor value. For example, rather than use a 70% F Factor (76-6) for a biomass plant with a 90% capacity factor, a 49% F Factor (60-11) is used

Annex H
(informative)

Commentary on the reduction of HV Circuit security of supply

H.1 Summary of analysis

Following discussion with BEIS and Ofgem regarding EREC P2/7, ENA Member Companies conducted some analysis to identify if there were any scenarios where the security of supply requirements could be reduced to allow the connection of additional demand without having a material impact on customers.

This Annex H summarises the analysis and the conclusions that arose from it.

The analysis was carried out by comparing the Expected Energy Not Supplied (EENS) of a **HV Circuit** under two scenarios:

i. The EENS for a group of customers supplied by a **HV Circuit** which is compliant with the minimum requirements set out in EREC P2/7;

ii. The EENS for the same group of customers supplied by a **HV Circuit** which is complaint with a minimum requirement less than that set out in EREC P2/7.

The comparison of i) and ii) allowed the benefit of supplying additional demand on a **HV Circuit** to be balanced against the adverse impact of the longer restoration time that would be experienced by some customers. The following key aspects were considered during the analysis.

a) **Measured Demand**

The majority of **HV Circuit**s have a **Measured Demand** of 1 to 4 MW with the predominant demand on a radial **HV Circuit** being in the range 1.5 to 2 MW. The assessment of the reduction in security of supply is based on the majority of **HV Circuit Measured Demand** values.

b) **HV Circuit** length and fault rate

It was found that an average fault rate per km per annum for GB **HV Circuit**s was 0.09 (this was typical for both underground and overhead **Circuit**s, although the fault rate of overhead **Circuit**s was marginally higher).

As the **HV Circuit** length increases, the fault rate per annum increases. Hence the 1 km **HV Circuit** length for the reduction in security of supply is based on a **Circuit** with a low fault rate.

c) Load duration curve

For any **HV Circuit** a load duration curve (LDC) may be plotted – it is a representation of the load versus the time for which the load was at or above a particular value. The area under a LDC (MW, hrs) represents the total energy (e.g., MWh) supplied via the **HV Circuit** for the period of time represented. The LDC may be simplified by:

i. converting the load and time to per unit values and;

ii. using two points on the graph which represent the predominant trend lines.

A large range of simplified LDCs were considered in the analysis of **HV Circuit** security of supply. The ‘average’ LDC shape derived from the analysis is depicted in Figure H.1: together with the fault rate, **Circuit** length and load, and this was used to derive the 1 km and 1.2 MW criteria.

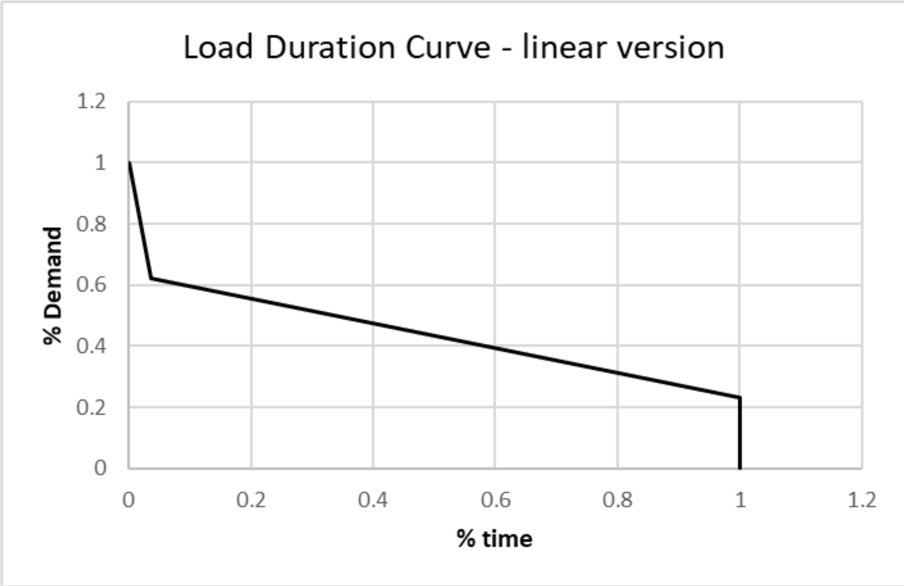


Figure H.1 – HV Circuit LDC used during derivation of reduced security of supply criteria

Bibliography

For dated references, only the edition cited applies. For undated references, the latest edition of the referenced document (including any amendments) applies.

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