NETWORKS

Company Standard

The Distribution System Security and Planning Standards

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Issuing Authority:	Network Development & Electrification		
Content Owner:	Duffy. Clare (ESB Networks)		
Document Number:	DOC-170220-FOM	Version:	3.4
Document Status:	Effective	Status Date:	27/04/2021

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Foreword

As part of ESB Networks' Innovation Strategy, under the "Smarter HV and MV Customer Connections" innovation project, the methods used by ESB Networks to determine how to connect our customers to the distribution system, namely the Distribution System Security and Planning Standards ('the Standard'), were fundamentally reviewed in collaboration and consultation with stakeholders to establish how the Standard needed to evolve to meet the changing needs of our customers in a lower carbon future.

A key deliverable from the innovation project was the development of new Standard, and their implementation in a phased manner over time. A key focus of the changes was to facilitate connecting increasing amounts of renewable energy and facilitate new flexible solutions to enable renewables and support network operations and development.

This Standard was approved by the Commission for Regulation of Utilities (CRU).

Whilst there are technical content changes throughout the Standard, based on engagement with stakeholders, the following may be of particular interest to customers:

1. Increased transparency through the inclusion of more detailed distribution network planning criteria and information, such as asset loading levels, voltage regulation standards and network development policies. See Sections 3 and 8.

2. Inclusion of the ESB Networks Security of Supply Standard table. See Section 4.1.

3. Inclusion of the consideration of an appropriate contribution from Distributed Generation (DG) / Distributed Energy Resources (DER) to network development plans and Load Indices calculations. Further development timeline to be included in a separate 'Guide' document, to be developed over the early period of Price Review 5 (PR5). See Section 4.2.

4. Inclusion, as an interim measure, of provision for the expected future growth in microgeneration connections. See Section 7.3.6.

   A public consultation on this measure issued in late 2020, and the outcome will be reviewed in 2021. Any amendment following the consultation will be detailed in an updated revision of the ESB Networks' 'Non-Firm Access Connections for Distribution Connected Distributed Generators' Guide DOC-190220-FOT.

5. Inclusion of the introduction of Non-Firm Access (NFA) connection arrangements for generators with an associated initial application condition and further development timeline included in a separate ESB Networks' 'Non-Firm Access Connections for Distribution Connected Distributed Generators' Guide DOC-190220-FOT.

   The initial implementation of NFA is applicable at Medium Voltage (MV) for connections to High Voltage (HV) stations where the MV sectionaliser is currently operated Normally Open, or the planned connection results in a Normally Open sectionaliser arrangement.

   Development of NFA into further areas involving the use of signalling and communications to trial secondary or ramped down reductions to Maximum Export Capacity (MEC) shall be implemented in a phased manner over time, and as indicatively set out in the roadmap in the Annex of the ESB Networks' 'Non-Firm Access Connections for Distribution Connected Distributed Generators' Guide DOC-190220-FOT, contingent on full network visibility and congestion management tools. See Section 7.4.

6. Inclusion of the technical criteria applied to the assessment of Energy Storage facilities (e.g. Battery Facilities) when such sites are used to provide System Services. See Section 7.5.

7. Inclusion of the introduction of the use of Non-Wires Alternatives (NWA) or 'Flexibility' services, such as the contracting of demand response, generation or energy storage solution to defer or delay a conventional

network reinforcement, with an associated initial application condition and further development timeline included in a separate ESB Networks' 'Non-Wires Alternatives to Network Development' Guide DOC-140220-FOL (including details of screening process to be applied by ESB Networks).

The initial implementation of NWA shall be on a contractual basis for defined demand response provision during defined time periods.

Development of NWA into further areas involving the use of signalling and communications for activation of further flexibility products for use during contingencies, shall be implemented in a phased manner over time, and as indicatively set out in the roadmap in the Annex of the ESB Networks' 'Non-Wires Alternatives to Network Development' Guide DOC-140220-FOL, contingent on full network visibility and congestion management tools. See Section 8.2.

This document (DOC-170220-FOM) supersedes the documents listed in Table 1.

Table 1: Superseded Documents

Document No.	Title	Full / Partial
DOC-261103-AFX	The Distribution System Security and Planning Standards, Revision 1.	Full
DOC-300414-BTC	The Distribution System Security and Planning Standards, Revision 2.	Full

Introduction

ESB Networks DAC is licensed by the Commission for Regulation of Utilities (CRU) under S.I. 280 of 2008 as the Distribution System Operator (DSO) for Ireland, and as such, in discharge of this function, is required to:

> *' operate and ensure the maintenance of and develop, as necessary, a safe, secure, reliable, economical and efficient electricity distribution system…'*

To this end, condition 11 of the DSO Licence calls for ESB Networks to prepare this document: "*The Distribution System Security and Planning Standards*".

The planning and security of supply standards are prepared in adherence to the Distribution Code, which specifies the relationship between the Grid Code and Distribution Code.

This document additionally outlines ESB Networks' approach to the development of the distribution network and gives details of how the connection of new demand load and embedded generators to the distribution system are assessed. It is intended as a guide to users of the distribution system and is referred to in the Distribution Code.

In developing the distribution system, ESB Networks shall engage as required with Eirgrid, as Transmission System Operator (TSO), to ensure that the overall electricity system (both distribution and transmission) is developed in a coordinated manner. Furthermore, and as also set out in condition 11 of the DSO licence, ESB Networks have consulted with Eirgrid in the preparation stages of this most recent revision.

The Distribution System Security and Planning Standards have been revised a number of times since first publication, as set out in Table 2.

Table 2: Document Revision History

Name	ESB Networks Document Number	Approval Date
Revision 0	N/A	2002
Revision 1	DOC-261103-AFX	September 2003
Revision 2	DOC-300414-BTC	January 2015

i. Scope

This document sets out the planning and security of supply standards applicable to ESB Networks, and applied by the Network Development & Electrification function, in the planning of the MV and HV distribution network in Ireland.

It additionally provides information to customers, demand load and distributed generator developers and consultants considering connections to the distribution system at MV and HV.

The document is structured as follows:

- Section 1 overviews the aim of planning, in terms of the forward development of the distribution system
- Section 2 sets out the applicable voltage standards
- Section 3 sets out the applicable equipment loading standards
- Section 4 sets out the applicable security of supply standards

- Section 5 sets out the applicable power quality standards
- Section 6 covers general principles on HV and MV network development
- Section 7 provides information for customers seeking a connection to the distribution system in the form of information required and details of assessment studies carried out
- Section 8 provides the definition and general information on the Least Cost Technically Acceptable (LCTA) methodology used by ESB Networks in network development and customer connections
- A number of informative annexes cover various topics including voltage regulation, substation requirements, harmonic planning levels and indicative generator connections

ii. Mandatory References

The following documents are referred to in the text in such a way that some or all of their content constitutes requirements of this document. For dated references, only the edition cited applies. For undated references, the latest edition of the referenced document applies.

Table 3: Mandatory Reference

Document No.	Title
DTIS-250701-BDW	Conditions Governing Connection to the Distribution System
DOC-060416-EEY	Distribution Code
DOC-140105-AIL	Distribution Loss Adjustment Factors
DOC-291111-BJK	Distribution System Operator Licence - ESB Networks
DOC-310810-AZK	Joint TSO/DSO Group Processing Approach Charging and Rebating Principles
DOC-190220-FOT	Non-Firm Access Connections for Distribution Connected Distributed Generators
DOC-140220-FOL	Non-Wires Alternatives to Network Development

1. The Aim of Network Planning

The distribution system should be planned, designed, maintained and operated so that it can support the provision to customers of connections to their contracted level of power in compliance with power quality, safety and environmental standards at minimum overall cost over the medium to long term.

The planning horizon for general network development is medium term, e.g. 5 years with an outlook for up to 10 years.

The planning horizon for more strategic system development; network re-structuring, system optimisation, voltage conversion, etc, is longer term, e.g. 10 up to 25 years.

The aim of planning is to ensure that the distribution system is developed in an orderly and cost-effective manner to deliver a safe, secure and reliable distribution system having due regard to the environment. It is necessary to ensure that there is capacity available to meet new connections, whether demand load or generation, as they arise, and to meet ongoing growth requirements. It is also necessary to ensure that new connections are made:

- in an economic fashion, taking uncertainty into account;
- in a way that is technically acceptable;
- with a view to the needs of customers and the distribution network in the transition to a low carbon future.

2. Voltage Standard

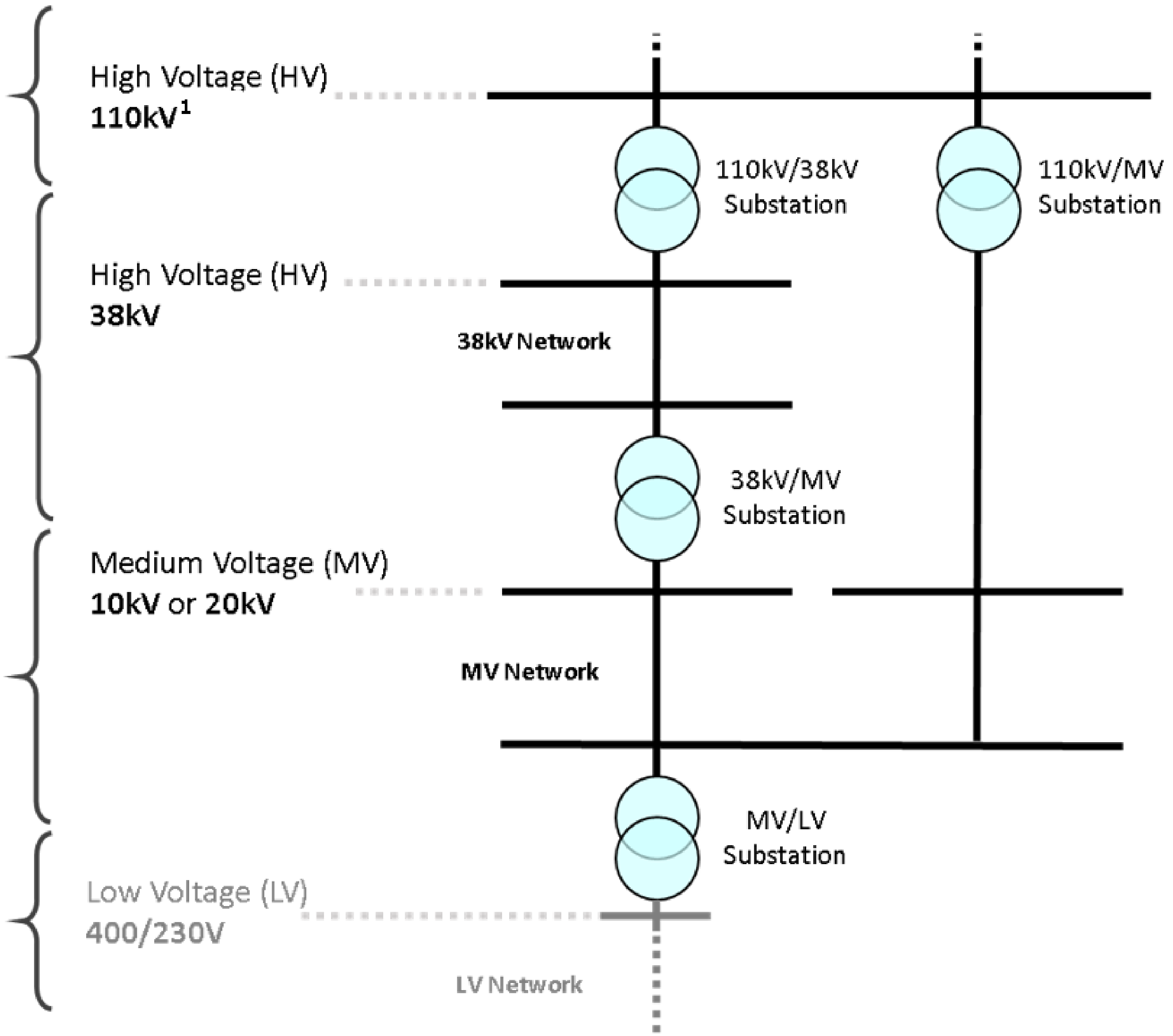
2.1 Distribution System Voltage Levels

There are a number of standard voltages in use on the distribution system in Ireland and customers are connected at one of these levels. Voltage levels at which a connection can be provided are set out in Table 4.

The standard configuration of the distribution system is as illustrated schematically in Figure 1.

All voltage levels shown are nominal values.

Figure 1: Representation of the Distribution System



[1] The 110kV system is primarily a transmission system voltage and connections at this voltage level are normally dealt with by Eirgrid (as TSO), however certain exceptions exist including:

- The 220/110kV transformers at Inchicore, Carrickmines and Ringsend Bulk Supply Points and the 110kV networks within Dublin city and surrounding area are deemed to be DSO operated networks.
- Tail-fed 110kV substations and connecting circuits used to connect lower voltage demand customers are deemed to be DSO operated installations and it is possible that in time such substations may be looped and typically become part of the transmission network. Where this is the case, the network shall be developed in consultation with Eirgrid in accordance with transmission system standards or developed in such a way as to allow these standards to be easily met in the future.

The distribution system shall be planned to maintain the operating voltages within the ranges specified in Table 4.

Table 4: Standard voltages on the MV and HV systems

Voltage Level	Distribution Nominal Voltage	Declared Supply Voltage	Nominal Sending Voltage	Normal Operating Voltage Range (under steady state and normal operating conditions)	Contingency Operating Voltage Range	Maximum Voltage at PCC with Demand Load	Maximum Voltage at Distributed Generator Site
High Voltage (HV)	110,000 Volts (110kV)	110.0kV	Generally TSO Controlled	105.0kV - 120.0kV	99.0kV - 120.0kV	120.0kV	120.0kV
	38,000 Volts (38kV)	40.0kV	41.6kV	36.5kV - 43.0kV	34.8kV- 43.0kV	43.0kV	43.8kV
Medium Voltage (MV)	20,000 Volts (20kV)	21.0kV	21.40kV	20.1kV - 22.1kV	19.1kV- 22.1kV	22.1kV	22.5kV
	10,000 Volts (10kV)	11.0kV	10.70kV[2]	10.1kV - 11.1kV	9.5kV - 11.1kV	11.1kV	11.3kV

The distribution system shall be planned such that the voltages at the various levels remain within the normal operating range when the network is in its normal configuration. In the event of loss of a network element leading to standby feeding, voltage should be maintained within the contingency operating range. Such contingency performance should be limited as far as possible in both extent and duration, e.g. by re-sectionalising networks, performing emergency repairs, etc.

This is consistent with European Standard EN50160 Voltage Characteristics of Electricity Supplied by Public Distribution Systems.

The operating ranges include provision for voltage rise at the point of common coupling (PCC) for distributed generators.

Annex A provides an explanation of how the permitted voltage drops and voltage rises ensure that voltages remain within the permitted ranges in Table 4.

2.1.1 Permitted Voltage Drop

In order to maintain the voltage performance summarised in Table 4, the voltage drops along the networks should not exceed the limits[3] indicated for normal and for contingency operating conditions, as defined in EN 50160 and as shown in Table 5.

The allocation of voltage bandwidth is based on economic development of the network and may change over time as part of planning policy, or in relation to specific network developments.

[2] The nominal sending voltage in urban networks is 10.4kV.
[3] Voltages outside of these ranges may exist for short periods of time in emergency situations.

Table 5: Permitted voltage drops

Description	Sending Set Point V_s	Maximum Network Voltage Drop	
		Normal	Contingency
HV – 110kV	See 2.1.1.1 below		
HV – 38kV	41.6kV	**10.5%** = 4.3kV to 37.3kV	**14.5%** = 6kV to 35.6kV
MV – 20kV	21.4kV	**5%** = 1.1kV to 20.3kV	**10%** = 2.1kV to 19.3kV
MV – 10kV	10.7kV[4]	**5%** = 0.5kV to 10.2kV	**10%** = 1.1kV to 9.6kV

2.1.1.1 Distribution 110kV Networks

Main source voltages on the 110kV networks are generally controlled by TSO. Permitted voltage drops on distribution 110kV networks should be determined on a case by case basis; however volt drop assessments shall maintain the receiving voltage on all distribution 110kV and lower voltage (38kV and MV) busbars within the ranges specified in Table 4 and take account of the operating voltage range on the TSO interfacing 110kV busbar.

2.1.2 Permitted Voltage Rise

Distributed generators connected to the distribution network can cause voltage rise.

The voltage rise permitted at the terminals of a generator is given in Column 8 of Table 4. Interfacing equipment at the generator site shall be rated to handle voltages up to the levels indicated in Column 8 of Table 4 as part of normal operations. This relates in particular to the tapping range for transformers and the insulation rating for circuits and equipment.

2.1.3 Voltage Regulators

2.1.3.1 38kV Voltage Regulators

Where 38kV voltages exceed voltage standard limits, 38kV regulators may be used to compensate, however the regulator should not restrict the throughput of the circuit. Careful consideration should be given to their application and operational considerations and practicalities should also be accounted for.

2.1.3.2 MV Voltage Regulators

Where MV network volt drop frequently exceed voltage standards limits, network voltage regulators (boosters) may be used to compensate, however the regulator should not restrict the throughput of the circuit. Regulators should be limited to no more than one regulator in series in an MV network for normal feeding and no more than three in series for standby feeding. A regulator may typically be installed at or near a normally open point.

2.1.4 Voltage Unbalance

Loads should be balanced across the phases on three-phase distribution networks so that the voltage unbalance as seen by any three-phase customer does not exceed 2%. The standard measure of voltage unbalance is the negative sequence voltage expressed as a percentage of the positive sequence voltage at the point in question. An estimate can be made by taking the maximum phase voltage deviation from average as a percentage of the average of the three-phase voltages at the point of interest.

[4] The nominal sending voltage in urban networks is 10.4kV.

Voltage unbalance on the MV busbars in distribution stations should not exceed 0.5% under normal feeding conditions. Where it does, all MV feeders supplied from the station should be assessed for phase balancing to distribute the total load on the station more evenly across the three-phases. In certain cases, long / heavily loaded upstream 38kV and 110kV lines may also need to be assessed for transposition to reduce the impact of asymmetrical circuit reactance.

3. Equipment Loading Standard

Networks and equipment including overhead and underground circuits, HV and MV transformers, HV station busbars and switchgear should be sized for expected peak loading conditions over the investment timeframe.

3.1 HV Station Transformers

3.1.1 Standard Transformer Sizes

Current standard distribution transformer sizes are indicated in Table 6.

Table 7 indicates distribution transformer sizes which are available for the connection of distributed generation in generation-only hub stations, or as standalone transformer installations in existing demand stations subject to limitations and technical acceptability[5].

Table 6: Current standard distribution transformer sizes

Voltage Level	Size (MVA)
220/110kV	250
110/38kV	63 31.5
110kV/MV	31.5 20
38kV/MV	15[6] 10 5
20/10kV (Interface)	4

Table 7: Additional distribution transformer sizes typically for the connection of distributed generation

Voltage Level	Size (MVA)
110/20kV	63
38/20kV	31.5

3.1.2 Transformer Load Limits

The load limit values in the following tables are in percentage of name-plate rating, e.g. 5MVA, 20MVA, etc. Normal loading needs to be restricted below these values to provide standby cover (including short term contingency) for an outage of a transformer.

Certain transformers may be de-rated and may have reduced long and short time loading capability below these levels and special load limits may apply due to location (e.g. indoor HV stations with reduced air circulation), in addition to associated ancillary equipment, equipment age, fault history, etc.

Transformers are operated in accordance with the IEC 60076 Loading Guide.

[5] Conditions include (but not limited to) availability of space, possible future requirements for demand load connections, etc.
[6] A 15MVA transformer is permissible where appropriate to local conditions.

For an outage of a transformer in a typical two transformer station, the full load transfers to the remaining healthy transformer[7]. This may be loaded up to the post outage short time load limit, 180%, for a short period (less than thirty minutes). However, the overload should be reduced to or below the post outage long-time cyclic load limit (which is the firm capacity of the station) within the specified time, either by transferring load on the MV network, utilising any contracted flexibility services if applicable, or shedding load in extreme cases. The long-time cyclic overloading may then be carried for a sequence of daily load cycles extending up to a few weeks, but as much load as possible should be transferred to neighbouring networks to reduce transformer damage / loss of life.

However, short time overloads approaching 180% should be very infrequent and should be curtailed as quickly as possible as there is a significant increase in risk of transformer failure at 180% loading.

Transformer circuit breakers, connecting cables, CTs, etc, should be rated to carry the maximum (post outage short time) transformer overload.

3.1.3 Load Profiles

The normal load limits permitted are determined by the load expected to be required when feeding under standby requirements and the overload limits by thermal considerations. These limits relate to typical load profiles. Where there is specific information on an atypical load profile on a transformer, or the load includes an industrial / commercial component, or other load with a non-cyclic profile, then the overall load profile should be assessed, and specific overload limits assigned to the transformer using the IEC 60076 Loading Guide, or calculations based on this guide. The impact of any flexibility service on the peak demand and the load profile should be considered.

3.1.4 220/110kV Transformers

Distribution 220kV/110kV transformers should not be loaded in excess of the peak load limits indicated in Table 8.

Table 8: Distribution 220/110kV transformer maximum load limits

Season	Normal Load Limit	Post Outage Load Limits	
		Long Time Cyclic	Short Time (<30 minutes)
Winter	75%	100%	150%
Summer	75%	100%	150%

3.1.5 110kV/MV Transformers

110kV/MV transformers should not be loaded in excess of the peak load limits indicated in Table 9.

Table 9: 110/MV transformer maximum load limits

Season	Normal Load Limit	Post Outage Load Limits	
		Long Time Cyclic	Short Time (<30 minutes)[8]
Winter	90%	150%	180%
Summer	90%	145%	180%

[7] Prior to any load transfer, a number of operational factors are considered, including but not limited to, prior loading of transformer, transformer age / condition, ambient temperature, etc.
[8] Where 2 x 31.5MVA 110kV/MV transformers are operated at 10kV, the post outage short time loading may need to be reduced from 180% to comply with busbar current ratings.

3.1.6 110/38kV Transformers

110/38kV transformers should not be loaded in excess of the peak load limits indicated in Table 10.

Table 10: 110/38kV transformer maximum load limits

Season	Normal Load Limit	Post Outage Load Limits	
		Long Time Cyclic	Short Time (<30 minutes)
Winter	90%	140%	180%
Summer	90%	135%	180%

3.1.7 38/MV Transformers:

38kV/MV transformers should not be loaded in excess of the peak load limits indicated in Table 11.

Table 11: 38kV/MV transformer maximum load limits[9]

Season	Normal Load Limit	Post Outage Load Limits	
		Long Time Cyclic	Short Time (<30 minutes)
Winter	90%	150%	180%
Summer	90%	135%	180%

3.1.8 20/10kV Interface Transformers

Interface transformers may be located in HV stations, or at points in the MV network, interfacing between networks operating at 10kV and 20kV.

Existing 5MVA and 3MVA 20/10kV interface transformers should not be loaded in excess of the peak load limits indicated in Table 12.

Table 12: 20/10kV Interface transformer maximum load limits

Season	Normal Cyclic Load Limit	Overload Load Limits	
		Long Time Cyclic	Short Time <30 minutes)
Winter	130%	145%	180%
Summer	120%	135%	170%

4MVA 20/10kV interface transformers have similar load limits but based on 50% prior loading.

3.2 Station Busbars

Station busbars should be rated such that the required loading levels of the transformers are not restricted.

3.3 Switchgear

Circuit breakers shall be rated to interrupt a fault up to the maximum prospective fault level[10] for the circuit under both normal and standby feeding conditions. Load Break Fault Make (LBFM) switchgear shall be rated to interrupt the full load rating of a circuit and to make connection onto a fault up to the maximum prospective fault level for the circuit.

System short circuit levels by voltage level are listed in the Distribution Code.

[9] A legacy practice differentiating load limits for urban and rural locations is no longer considered.
[10] Circuit breakers where the fault level approaches 90% of their rating should be considered for replacement.

Switchgear should be assessed for suitability for installation on circuits with high capacitive current such as fully cabled circuits.

3.4 Circuits

Existing 38kV and MV circuits should be loaded to comply with thermal rating limits and voltage drop requirements. 38kV and MV back-bone circuits should carry standby capacity to cover for outages in neighbouring networks. In this context, a circuit is defined as the connection from one station busbar to another station busbar and no individual component in this circuit should restrict the rating of the underground cable or overhead line element of the circuit. New conductors should be sized taking losses into account.

3.4.1 Overhead Lines

Overhead Lines shall have no overload rating, i.e. the thermal rating shall not be exceeded.

3.4.2 Underground Cables

Underground Cables shall have no overload rating for non-cyclical loads, i.e. the thermal rating shall not be exceeded. An overload for cyclic load conditions may be applied to specific cables in certain circumstances, including but not limited to voltage level, cable type, prior loading, duration of overload required, installation conditions.

The current ESB Networks Company Standard, '38kV MV LV Civil Ducting Standards' DOC-090217-CMY, states that all underground cables are to be ducted. In busy underground rights of way, spare duct capacity should be provided where possible. The impact of ducts on cable ratings should always be assessed. Cables in proximity, e.g. in a cluster leaving a HV station, should be de-rated for proximity effects.

Further guidance can be found on the ESB Networks Publications Page.

3.5 Short-Circuit Ratings

Station transformers should be capable of sustaining, without damage, the maximum three-phase short circuit fault levels for a period of 2 seconds.

Network conductors, lines and cables, should be capable of sustaining, without damage, the maximum three-phase short circuit fault levels at their location under normal feeding conditions for the duration of fault clearing times provided by local protection. Note that distributed generators contribute to local network fault levels and should be included in any assessment of fault levels.

For distribution 110kV networks, system earthing should be arranged to ensure that the 110kV system remains effectively earthed. The system is effectively earthed when the maximum phase to earth voltage during an earth fault does not exceed 80% of the phase to phase voltage.

In some locations, in proximity to autotransformers, the maximum single-phase short circuit current is higher than the maximum three-phase symmetrical short circuit current. In all cases, the higher of the two short circuit currents shall be used in studies.

4. Security of Supply Standard

4.1 Security of Supply Standard

The distribution network shall be planned to maintain the security of supply standards for Group Demand (GD) levels indicated in Table 13.

Table 13: Security of supply standard

Group Demand (GD)	Typically	Standby Provision	Restore at least within			
			60 seconds	15 minutes	3 hours	Repair Time
0 – 1 MVA	Network Transformer	None	–	–	–	GD
>1 – 10 MVA	MV Feeder: Urban / Rural	N – 1[11]	–	–	GD – 1 MVA	GD
>10 – 30 MVA	38kV Station 38kV Feeder	N – 1	–	GD – 10 MVA	GD	–
>30 – 100 MVA	110kV Station	N – 1	–	GD – 30 MVA	GD	–
>100 MVA[12]	110kV Networks in Dublin	N – 1	GD	–	–	–
		N – 1 – 1 (Outage for Maintenance + Fault)	⅔GD	–	–	GD

Group Demand (GD) is the aggregate peak load supplied by a network element or combination of elements under study, e.g. the load supplied by a network transformer, an MV feeder, a distribution station, a 38kV feeder, a bulk supply point, etc. GD is the load that could be impacted by a contingency involving the network element.

N – 1 refers to a capability to provide standby, without exceeding the rating of remaining plant or a network voltage limit, in the event of unavailability of a single item of plant, such as an overhead line circuit, an underground cable circuit, busbar section[13] or a transformer, arising from a fault or because of maintenance.

N – 1 – 1 refers to a scenario where one item of plant is switched out for maintenance and a fault occurs on another item of plant.

No standby provision is required for group demands of 1MVA or less. Normally open interconnections between LV networks may be installed where these can be provided economically.

Connections of distributed generators are not covered by the security of supply standard and can be considered on a firm access or non-firm access basis.

Additional security of supply may be provided in certain areas for High Impact Low Probability (HILP) events with societal impacts if justified and as agreed with CRU.

4.2 Contribution of Distributed Generation to Security of Supply

The contribution of non-contracted generation to security of supply should be accounted for statistically in the development of medium and long-term network development plans and in Load Indices calculations.

This contribution is proposed for use in investment timelines and it is not intended for use in operational decisions.

[11] In certain situations where a loop connection is particularly difficult, loads in excess of 1MVA may be tolerated without standby provision. However, these situations should be avoided as far as possible and should be remedied at the earliest opportunity.

[12] For GD > 100 MVA, the network should be planned such that supply can be restored to ⅔ GD in 60 seconds in an N-1-1 scenario. Supply should be restored to the remaining customers when either the fault is repaired, or the maintenance is cleared and the plant that was being maintained is switched back in. Where demand during the maintenance period is greater than ⅔ GD, consideration should be given to planning the network such that supply can be restored to all customers within 60 seconds in an N-1-1 scenario.

[13] The requirements in Table 13 do not apply to the unavailability of certain types of busbar sectionalisers.

The contribution takes the form of an appropriate F-Factor, applied to the capacity of a distributed generator, using an approach to be developed, suitable for the Irish distribution system, informed by the principles as set out in Energy Networks Association (ENA) documents EREP130 and EREP131, to take into account the passive contribution of distributed generation on a probabilistic basis.

The impact of the above may be a change in the timing of the medium to long term forecast reinforcement needs expected for the development of the network.

5. Power Quality Standard

Distribution networks shall be planned to provide supply in compliance with the supply quality as per the European Standard EN50160 Voltage Characteristics of Electricity Supplied by Public Distribution Systems.

5.1.1 Short Circuit Capacity

Short circuit capacity levels on the MV network should not be less than the values in Table 14.

Table 14: Minimum MV short circuit capacity requirements

Voltage	Element	Minimum Short Circuit Capacity
10kV	Three-phase Network	5 MVA / 275A
20kV	Three-phase Network	10 MVA / 275A

5.1.2 Disturbing Loads

The impact of disturbing loads, e.g. industrial, generators, etc. calculated by ESB Networks using data provided by customers on their demand load / generation requirements shall be evaluated using ESB Networks Disturbing Load Guidelines[14] to ensure compliance with the Distribution Code.

The required data on the disturbing load(s) shall be provided by the customer on their application form and / or separately, if necessary, during the technical assessment of the application.

This assessment primarily assesses:

- Voltage fluctuations and flicker
- Voltage unbalance
- Harmonic distortion

Network reinforcements or reconfiguration may be required to accommodate the disturbing load(s), which shall be detailed in the connection agreement. Additionally, any special conditions applicable (such as limits on motor starting frequency, or other limitations) shall be detailed in the connection agreement.

Power quality monitoring equipment may be installed to ensure compliance with the Distribution Code.

Harmonic levels on distribution networks should not exceed the indicative planning levels for harmonic voltages, as set out by voltage level, in Annex B.

5.1.3 Power Factor

The power factor of demand load as seen by the network shall be between 0.90 (importing reactive power) and unity, typically 0.95.

The power factor of a distributed generator shall be within the allowed range, as per the generator type as defined in the Distribution Code, unless otherwise specified in the connection agreement.

[14] To be published on the ESB Networks Website.

6. Network Development

6.1 HV Network Development

Sub-transmission (38kV & distribution 110kV) networks shall be planned to have full standby cover for a network or transmission station fault. Some of this standby cover may be provided by neighbouring MV networks, provided they can be switched in time to meet the security of supply standards in Section 4.

The voltage levels and transformer configurations used on the distribution HV network may be reviewed at intervals for long term development of the network, e.g. use of 3 winding transformers, potential voltage uprating of 38kV.

6.1.1 Bulk Supply Points (BSP)

A Bulk Supply Point (BSP) on the network is defined as a major interface point between the transmission and distribution system.

For major BSPs (> 100MVA), the networks shall be planned to maintain supply or restore supply for the full load almost immediately (within 60 seconds) in the event of any single fault outage. This may be achieved by closed loop operation (meshes) or fast automatic changeover (ACO) switching. Furthermore, in the event of a planned or maintenance outage, the networks shall be planned to maintain supply or restore supply for the load during the maintenance period, based on two thirds (⅔) of Group Demand (GD), in the event of any additional (fault) outage. The maintenance outage shall be cleared to restore supply to the full load as quickly as possible. This is a partial double contingency (N - 1 - 1) provision.

6.1.2 HV Networks

Rural 38kV networks should be operated in an open loop arrangement between neighbouring 110kV stations. The normally open (NO) points may be equipped with auto changeover (ACO), auto open (AOP), auto close (ACL) facilities. Any automatic arrangements may be assessed as part of a new development and installed where appropriate.

Urban 38kV networks may be operated as closed loops on the same 110kV station with appropriate protection.

6.1.3 Tee Connections from HV Networks

A maximum of one 38kV tee connection to an existing 38kV overhead line is permitted between 38kV cubicles fitted with standard 38kV protection unless protection studies indicate unacceptable breaches of protection performance.

Where such a tee is part of a Least Cost Technically Acceptable (LCTA) connection method (see Section 8) fed by overhead lines, a minimum of two SCADA enabled 38kV Load Break Fault Make (LBFM) switches shall be installed at the tee points. If operational requirements dictate, three such switches may be required.

In the event that the method of connection changes, for any reason, from overhead line to fully underground cable, an alternative connection (e.g. a looped connection) shall be required.

A tee connection is not permitted on distribution 110kV lines. As part of a staged development towards a fully looped connection, a tee may be considered as an interim measure, subject to operational and technical acceptability.

6.2 MV Network Development

6.2.1 Distribution Stations feeding MV Networks

Distribution stations (38kV/MV & 110kV/MV) shall be designed to maintain supply to the load on loss of the largest transformer in the station. Most of the standby cover should come from available transformer capacity (including overload) in neighbouring transformer(s) in the station. It is acceptable to provide some of the standby cover from neighbouring MV networks, provided these can be switched in time to meet the security of supply standards in Section 4.

6.2.2 MV Networks

MV main (>1MVA three phase backbone) feeders should have standby cover, by way of normally open interconnection(s) to neighbouring feeders. They should provide standby cover for their load in the event of a fault, within the standby volt drop allocation.

Main MV networks should be operated in an open loop arrangement. Standby cover is not required for branches with less than 1MVA of demand, although this can be provided where costs are low. MV networks should be sectionalised into blocks of load with demand of 1MVA or less. Rural MV backbone feeders should be sectionalised approximately every 5km. These sectionalising points should be equipped for remote operation.

MV networks should only be planned for single contingency (N – 1) events, with the exceptions of:

1) Locations where higher supply security is negotiated with certain major customers or special loads; or
2) Where higher security is required for reasons of national importance.

6.3 Consideration of Losses

Electrical losses on the network impose a significant cost and should be managed. Accordingly, losses are taken into account in determining the optimum development of the network for expected load growth involved by assessing investments on the Total Cost of Ownership or an equivalent basis.

The setting of overall design parameters for the network takes account of the economic loading of plant so that the long-term economic impact is optimised.

6.4 Power Factor

In planning for the optimal development and operation of the distribution system, a power factor for demand load in the range of 0.9 to unity is assumed, typically 0.95, except in the case where more specific information is available.

7. Customer Connections

The customer shall provide the details of the demand load and / or generation to be connected to enable assessment of the connection requirements.

Typical connection capacities at distribution voltages as are set out in Table 15.

Table 15 Connection capacities

Voltage Level	Range limits
MV – 10kV	500kVA - 10MVA
MV – 20kV	500kVA - 20MVA
HV – 38kV	>5MVA – 40MVA[15]
HV – 110kV	>5MVA

The above capacity range limits are dependent on a number of factors including load profile, transformer sizes, circuit capacities, location of customer relative to substation, impact on the timescale to provide capacity for further customer connections, life cycle costing of network development and on how the network can be developed in the future.

New connections over 500kVA shall be made at MV or higher. MV connections may also be considered for new connections under 500kVA.

Increases in existing LV demand load connections should not result in a Maximum Import Capacity (MIC) greater than 500kVA.

There may be a requirement for a terminal substation (HV, MV or MV/LV) and details for this scenario are set out in Annex C.

7.1 Information Required from Customers

Details of the information required from demand load customers and generators seeking connections or extensions to the distribution system are included in the following sections.

7.1.1 Geographical location

Site location maps and site layout plans in order to determine the location of the proposed development in relation to the existing network.

7.1.2 Maximum Import Capacity (MIC) and/or Maximum Export Capacity (MEC)

Maximum Import Capacity (MIC) required, the size and nature of the load, diversity of the load and proposed phasing of the development i.e. the pace at which the load is expected to ramp up to full demand. In the case of generators; the Maximum Export Capacity (MEC), the size and nature of the export required and the proposed phasing of the development, etc.

[15] Higher MECs can be considered for distributed generation connections at 38kV to generator only HV stations or transformers, subject to equipment rating limits and other technical limitations.

7.1.3 Nature of the Demand Load and Embedded Generation

Details of all loads, including any disturbing elements for demand applications are required such as:

- Large motors – details of starting arrangements for all large motors.
- Disturbing Loads, e.g. electric welding, and details of the nature and usage pattern of the disturbing load.
- Electric Vehicle charging requirements.
- Any other significant load classes and their load characteristics.
- Any PV or other generation.
- Harmonics - details of any non-linear equipment likely to produce harmonics on the distribution system and any filtering arrangements which the customer may have already in place. The customer should also provide details of compensation or balancing equipment connected.
- Unbalanced Loads – Where a customer has a three-phase supply, load should be balanced as evenly as possible over the three phases.
- Power Factor – The power factor of demand load as seen by the network shall be between 0.90 (importing reactive power) and unity.

The above is an example of the information which may be requested. Depending on the size and complexity of the load, additional information may also be requested.

7.1.4 Multi-Unit / Multi-Connection development versus Single Unit / Connection

Whether the application is for infrastructure to facilitate load connections to multiple end-customers within a development or is for connection of a single load customer.

7.1.5 Distributed Generation Connections

Generation applications shall provide details and characteristics of the plant proposed for connection and data to facilitate modelling the impact of this plant on the wider electricity system.

7.1.6 Demand Load Diversity

The customer should apply an appropriate diversity factor to each component of the load, as well as to the overall load in order to assess the capacity required from ESB Networks. Diversity factors vary depending on the nature of the load. Diversity factors applied may be requested by ESB Networks.

7.1.7 Specific Requirements

Details of any specific customer requirements for connection.

7.2 Demand Load Connection Assessment Criteria

7.2.1 Evaluation of Network Limitations

When deciding on the method of connection, it should first be established that the existing network has adequate thermal and voltage capacity. If this is not the case, then it shall be necessary to upgrade the network or construct additional network to facilitate the new connection.

Networks are assessed to determine:

- Voltage levels
- Line / cable loading under normal and standby feeding conditions
- Substation loading under normal and standby conditions
- Power quality

In general, the most onerous scenarios are studied for the particular parameters being assessed. In the majority of cases, in assessing the impact of a new demand load, this is under winter peak conditions, however some stations and networks have summer peak conditions.

Any new demand load connection in excess of a given threshold[16] shall be referred to the TSO for assessment.

The planning and design of the network does not allow any plant or network to be loaded beyond its normal rating, as specified by the manufacturer, except in emergency situations designated by ESB Networks.

7.2.2 Voltage Drop

Demand load connections shall be assessed to ensure that voltages outlined in Table 4, are not exceeded.

7.2.3 Transformer Capacity for New Demand Load

Where the available transformer capacity is not adequate to take the additional demand load, consideration should be given to the uprating of the existing transformer capacity in the substation or the construction of a new substation.

7.2.4 Losses

Losses on the distribution system have a financial and technical impact on the system. In the assessment of new demand load connections, losses associated with the connection method options considered are accounted for in the determination of the Least Cost Technically Acceptable (LCTA) connection method (see Section 8).

7.2.5 Reinforcements

The addition of a new or increased demand load at one voltage level may result in reinforcement being required at that voltage level, or at higher voltage levels. In some cases, planned reinforcement, not required at present, may have to be done sooner than previously planned as a result of the new / additional demand load.

For larger loads, transmission reinforcements may also be required, and this would be specified by the TSO.

7.2.6 Typical Demand Load Connection Arrangements

Typical connection arrangements for major MV or HV demand customers are listed below and described in ESB Networks Company Standard 'Conditions Governing Connection to the Distribution System' DTIS-250701-BDW.

- **Single radial connection** – a single service connection, i.e. no standby customer connection, although there may be standby in the network at the tap off point.
- **Looped connection** – customer connected to an MV or HV circuit, with a normally open point, which may be located at the substation at the customer site, or elsewhere on the circuit.

[16] Currently 4MVA, unless otherwise agreed with TSO for particular locations.

- **Dual radial MV connection** – two independent MV service connections possibly with the load sectionalised between them for switching load to the healthy feeder for an outage of one of the feeders. The customer busbar is equipped with a 2 out of 3-way circuit breaker interlocking scheme to avoid paralleling the feeders. It is equipped with summation metering.
- **A dual radial connection** may not require dedicated feeders from the HV station but shall require a ring main unit (RMU) on each connecting circuit, housed in an MV substation building. The connections can be tapped from networks supplying other load.
- **Closed looped connection** – two normally closed (typically HV) feeders supplied from independent sources and equipped with directional over-current protection so that no load is dropped on an outage of one of the feeders. It is equipped with summation metering.

The above connection configurations are dependent on a number of factors including load profile, transformer sizes, station outlet availability, circuit availability and capacities, location of customer relative to substation, impact on the timescale to provide capacity for further customer connections and on how the network can be developed in the future.

7.3 Distributed Generator Connection Assessment Criteria

The following criteria are considered in the planning of a distributed generator connection.

7.3.1 Evaluation of Network Limitations

When deciding on the method of connection, it should first be established that the existing network has adequate thermal and voltage capacity. If this is not the case, then it shall be necessary to upgrade the network or construct additional network to facilitate the new connection.

Connections for distributed generators greater than 0.5MW are studied by group processing with the resultant outcome being the Least Cost Technically Acceptable (LCTA) connection method for the group (see Section 8).

Networks are assessed to determine:

- Voltage levels
- Line / cable loading under normal and standby feeding conditions
- Substation loading under normal and standby conditions
- Voltage fluctuations
- Short circuit requirements
- Power quality

In general, the most onerous scenarios are studied for the particular parameters being assessed. In the majority of cases, in assessing the impact of a generator connection, this is under minimum load conditions but can be occasionally under maximum load conditions.

Any new distributed generator connection in excess of a given threshold[17] shall be referred to the TSO for assessment.

The planning and design of the network does not allow any plant or network to be loaded beyond its normal rating, as specified by the manufacturer, except in emergency situations designated by ESB Networks.

[17] Currently 1MVA, unless otherwise specified by TSO for particular locations.

7.3.2 Voltage Rise

Generator connections shall be assessed to ensure that voltages at the PCC and the generator site, outlined in Table 4, are not exceeded.

7.3.3 Demand Customers Applying to Install Export Capacity

Existing demand customers should note that their MIC does not necessarily equate to an inherent symmetrical MEC. Studies shall be carried out to determine the voltage rise, impact on customers sharing point of common coupling and upstream (higher voltage) systems. Customers installing a generator but where the proposed MEC is zero are required to make an application to ESB Networks. The connection shall be assessed as such generation may impact on short circuit level, power quality, voltage disturbances, etc.

7.3.4 Reinforcements

The addition of a new or increased capacity or connected generation at one voltage may result in reinforcement being carried out at the voltage level above. This could occur, e.g. where an MV generation connection feeds through the 38kV/MV substation and resultant power flow on the 38kV network exceeds the 38kV conductor capacity. In some cases, planned reinforcement, not required at present, may have to be done sooner than previously planned as a result of the new / additional generation.

Transmission reinforcements may also be required, and this would be specified by the TSO.

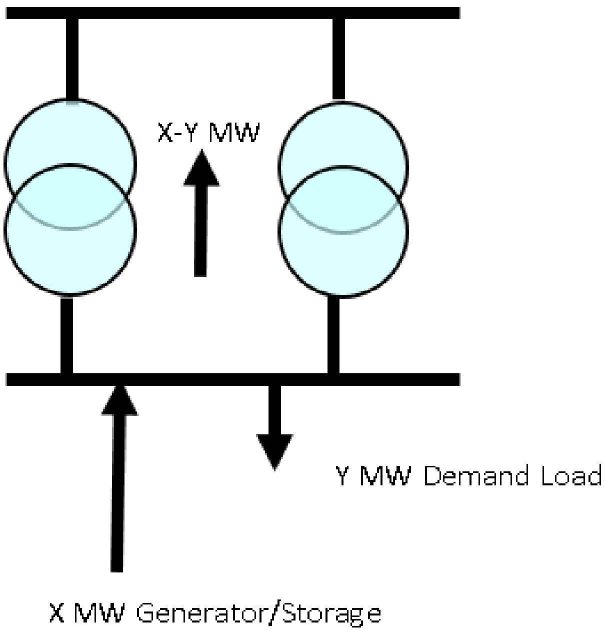
7.3.5 Transformer Capacity for Generation in Existing Substations

In assessing a proposed connection of a generator or generators to a busbar of an existing station, the ability of the existing transformer or transformers to accommodate the flow of power due to the presence of the generators should be assessed. The following principles and guidelines are used in such assessments.

7.3.5.1 Use of Minimum Load

In assessing available transformer capacity for a firm access connection, a minimum load value is taken into account. This is illustrated in the simplified example in Figure 2.

Figure 2: Use of Minimum Load



There is X MW power flowing into the busbar and Y MW of demand load on the station. Therefore, the power through the transformers is X – Y MW. Therefore, for a given amount of generation, the power flowing through the transformers from the generation is at a maximum when the load at the station is a minimum.

Minimum load is not accounted for in Non-Firm Access capacity calculations.

7.3.5.2 Consideration of Reactive Power (VArs)

Each transformer has a rated capacity which is expressed in apparent power (in VA), but more specifically in rated current (A). In order to reflect this, it is necessary therefore to consider reactive power (in VAr) as well as real power (in W). Demand load generally tends to import reactive power. Generation may, depending on several factors, operate importing or exporting reactive power. For the former case, the reactive power of the demand load and generation would add as opposed to netting off as with real power.

7.3.5.3 Transformer Rating Allowance for Wind Generation

When assessing a new generator connection, it should be determined whether the additional generated power would cause the transformer's rated capacity to be exceeded. There is an allowance of 10% in addition to the rated capacity for wind generation applicable for outdoor located transformers[18]. This 10% allowance assumes that highest generation from wind occurs in winter, with lower ambient temperatures, rather than in summer and that the wind may also have a cooling effect on the transformer. No allowance is made for solar PV where highest generation occurs in summer when ambient temperatures and solar gain are higher. No allowance is made for other forms of generation.

[18] The 10% rating allowance does not represent an overload, as it is expected, under the environmental conditions listed, that the transformer operates within the parameters of the IEC 60076 Loading Guide.

7.3.5.4 Two Transformer Stations

Where in an existing demand station, there are two transformers normally connected in a station, the capacity available for firm access connection of generation takes account of only one (the lower rating, if applicable) of the transformers. This allows one of transformers to be taken out of service if required, without causing an outage for the firm access generator(s).

7.3.6 Existing or Committed Generation Connections

Any generators already connected or committed to connect shall also be considered when determining available system capacity. The impact of photovoltaic (PV) based generation at LV (e.g. microgeneration) shall be taken into account.

7.3.7 Loss of Feeder and Voltage Change

If the generator trips for any reason, then a step change in voltage may be experienced by any existing demand customers at the PCC. In order to minimise the effect on other customers, the step change in voltage shall be limited to 10%.

7.3.8 Power factor

The power factor of the distributed generator shall be studied as per the generator type as defined in the Distribution Code. Operation at a specific power factor, or tighter range, within the specified range may be permitted, and in this case, the range shall be defined in the connection agreement.

7.3.9 Losses

Losses on the distribution system have a financial and a technical impact on the system. As a consequence, and acknowledging that Distribution Loss Adjustment Factors (DLAF)[19] are applied to generation connections, losses are not usually a technical constraint for networks used for dedicated generation connections.

Based on the DLAF, the applicant may assess the energy sales implications of the connection method offered. In the event that the applicant, having assessed such implications, determine that their interests would be better served by an alternative connection method involving less losses but most likely a higher capital cost, a modification to their connection can be requested.

For networks shared by two or more generators, ESB Networks shall, subject to all other technical criteria being satisfied, offer a conductor size which in ESB Networks' view yields the most efficient use of that asset over the lifetime. However, should all parties sharing the network request a modification to a higher conductor size then, subject to the connection method being technically acceptable, a revised connection method may be offered.

7.3.10 Use of Normal and Standby Circuits

Where the method of connection for a given generator is to an existing 38kV demand station which is interconnected, it shall be possible to accommodate the full MEC on normal and standby 38kV circuits.

[19] See ESB Networks' Distribution Loss Adjustment Factor Document DOC-140105-AIL.

This would also extend to consideration of the capacity of 110/38kV transformers in the 110/38kV station on the standby circuit(s).

7.3.11 Impact on System Short Circuit Levels

In assessing a generator connection, the impact of the proposed generator(s) on the existing short circuit levels shall be evaluated.

Where an impact is identified such that there are safety implications, for example where the generator would cause the prevailing short circuit level at the location of ESB Networks operated circuit breakers to exceed their interrupting capabilities, the generator cannot connect until the issue has been resolved.

7.3.12 Harmonic Distortion Limits

Distributed generator connections may add to or amplify existing background harmonic distortion levels, particularly where long underground cable circuits can alter system characteristics, by altering system resonant points.

A schedule of individual harmonic distortion limits shall be provided to the generator, in order to maintain the planning levels outlined in Annex B.

7.3.13 Impact on Distribution System Stability

Where there are concerns that a large DG (including energy storage) could pose a localised threat to the stability of the distribution system, for example rotor angle stability, ESB Networks reserve the right to carry out or otherwise initiate, specific stability studies to quantify such impacts.

Where the outcome of such studies identifies necessary changes to, for example, protection operating times or drive specific remedies, these shall be in place before the generator in question is connected.

7.3.14 Typical Distributed Generator Connection Arrangements

Typical (non-exhaustive) connection arrangements and security implications for firm access distributed generator connections are shown in Annex D.

7.3.15 Impact on System Protection

The impact of the distributed generator connection on existing HV system protection configuration and operation is assessed and any upgrades required as a result are included as part of the connection.

7.4 Non-Firm Access (NFA) for Distributed Generation Connections

To facilitate and maximise the connection of further distributed generation[20] to the distribution system, a distributed generator connection can be offered on a non-firm access (NFA) basis.

A NFA distributed generator connection shall reduce its export to a reduced level (which may be to zero) or disconnect from the distribution system for a defined network event, such as an outage of an item of plant (e.g. a transformer or circuit).

[20] As the aim of NFA is to maximise the connection of further distributed generation, energy storage is not considered eligible for a NFA connection.

The conditions are set out in the ESB Networks' 'Non-Firm Access Connections for Distribution Connected Distributed Generators' Guide DOC-190220-FOT.

7.5 Energy Storage Connection Assessment Criteria

7.5.1 General

The import and export components of an energy storage (e.g. battery) facility shall be studied separately.

The technical study criteria for an energy storage facility shall be similar to those applied to a distributed generator, with additional technical considerations to ensure compliance with the potential voltage fluctuation levels associated with activation of the facility. The import component of the energy storage facility may be contracted on a non-firm basis, and this shall be defined in the connection agreement.

7.5.2 Additional Considerations for Energy Storage

The mode of operation of the facility depends on the system service being provided (e.g. energy arbitrage, peak shaving, operating reserve, fast frequency response, reactive power response, ramping margin response, etc). The technical study carried out shall be based only for the system service(s) applied for by the applicant.

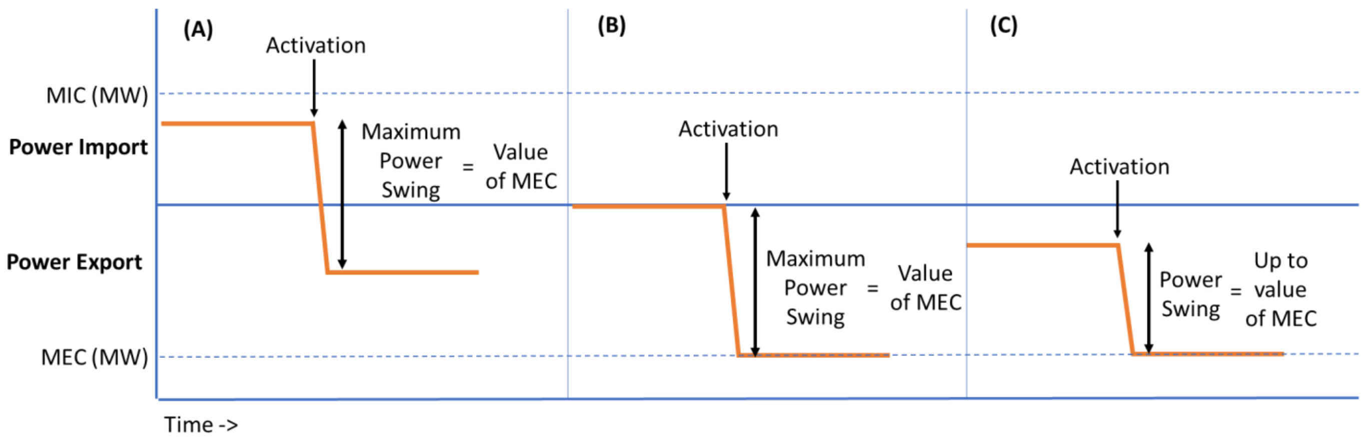
Provision of a different system service(s) shall require an application for modification of the connection agreement and a further technical study.

Certain fast acting system services may result in frequent voltage fluctuations or step changes at the point of connection on the distribution system. In order to minimise effects on other users of the distribution system, the voltage step change on activation of the facility for fast acting service provision shall not exceed 3%.

Where multiple facilities providing system services are interacting, the cumulative impact of operation shall be studied and more stringent individual limits may be applied.

The maximum power swing studied on activation of the facility shall be studied as the value of the MEC at the relevant power factor range. With reference to Figure 3, this maximum power swing shall apply regardless of whether the facility is (A) importing power, (B) fully charged (and neither importing nor exporting power) at the time of activation. In the event the facility is (C) exporting power at the time of activation, the power swing shall be such as to not exceed the MEC.

Figure 3: Activation of energy storage for fast acting system services



The power factor of the facility shall be studied as per the generator type (PPM) as defined in the Distribution Code.

Where compliance with the voltage fluctuation limit cannot be achieved across the full power factor range, operation at a specific power factor within the specified range may be permitted, and in this case, the range shall be defined in the connection agreement.

8. Determining the Least Cost Technically Acceptable (LCTA) Solution

8.1 Least Cost Technically Acceptable Solution

8.1.1 Network Development

In the context of network development projects, the LCTA solution is defined as the option which is technically acceptable, and which results in the minimum charge to the end-user, taking into account the long-term economic development of the electricity network in the area.

8.1.2 Demand Load Connections

In the context of demand load connection projects, the LCTA solution is defined as the option which is technically acceptable, most economic, including an estimate of costs incurred at the customer end of the connection, taking into account the long term economic development of the electricity network in the area.

8.1.3 Distributed Generator Connections

In the context of distributed generation connection projects, and in particular in the context of the group processing approach under the approved connection offer processing policy, the LCTA solution takes account of the sub-group as a whole, as applicable.

8.1.4 Additional LCTA Considerations

When assessing a customer connection, the medium to long term development needs of the network and connecting station(s) should be prudently assessed, taking wider system developments, potential MV voltage conversion and the possibility of future customer connections into account. In the case of a distributed generator connection, such an assessment may result in a 'system operator preferred' connection method, or build, as defined in the 'Joint TSO/DSO Group Processing Approach Charging and Rebating Principles' document DOC-310810-AZK.

Additionally, when assessing customer connections or network development as part of a wider planned programme of work, efficiencies for the programme itself (for instance in construction time or outage requirement reduction) or other standardisation benefits (for instance in designs or specification and use of materials) may be accounted for in the determination of the LCTA solution.

Any costs incurred by ESB Networks in providing a customer connection or installing infrastructure which are deemed by ESB Networks to be over and above the LCTA solution, and which are at the request of the customer are borne in full by the customer.

8.2 Non-Wires Alternatives (NWA)

Having arrived at a LCTA for a conventional reinforcement, a Non-Wires Alternative (NWA) option may be considered.

The process by which this is considered is set out in the ESB Networks' 'Non-Wires Alternatives to Network Development' Guide DOC-140220-FOL.

Annex A. (Informative) Voltage Control

A.1. 38kV Network Volt Drop Allocations

Voltage on the 38kV sub-transmission system should be maintained within limits such that the 38kV/MV transformers with their tapping range can step the voltage down to within the 10.6 – 10.8kV[21] operating range or its 20kV equivalent for the MV busbars. This should be achieved under all loading conditions and station locations, i.e. close in to or remote from the 110kV station. See Table 16 for Standard 38kV Volt Drop Allocation.

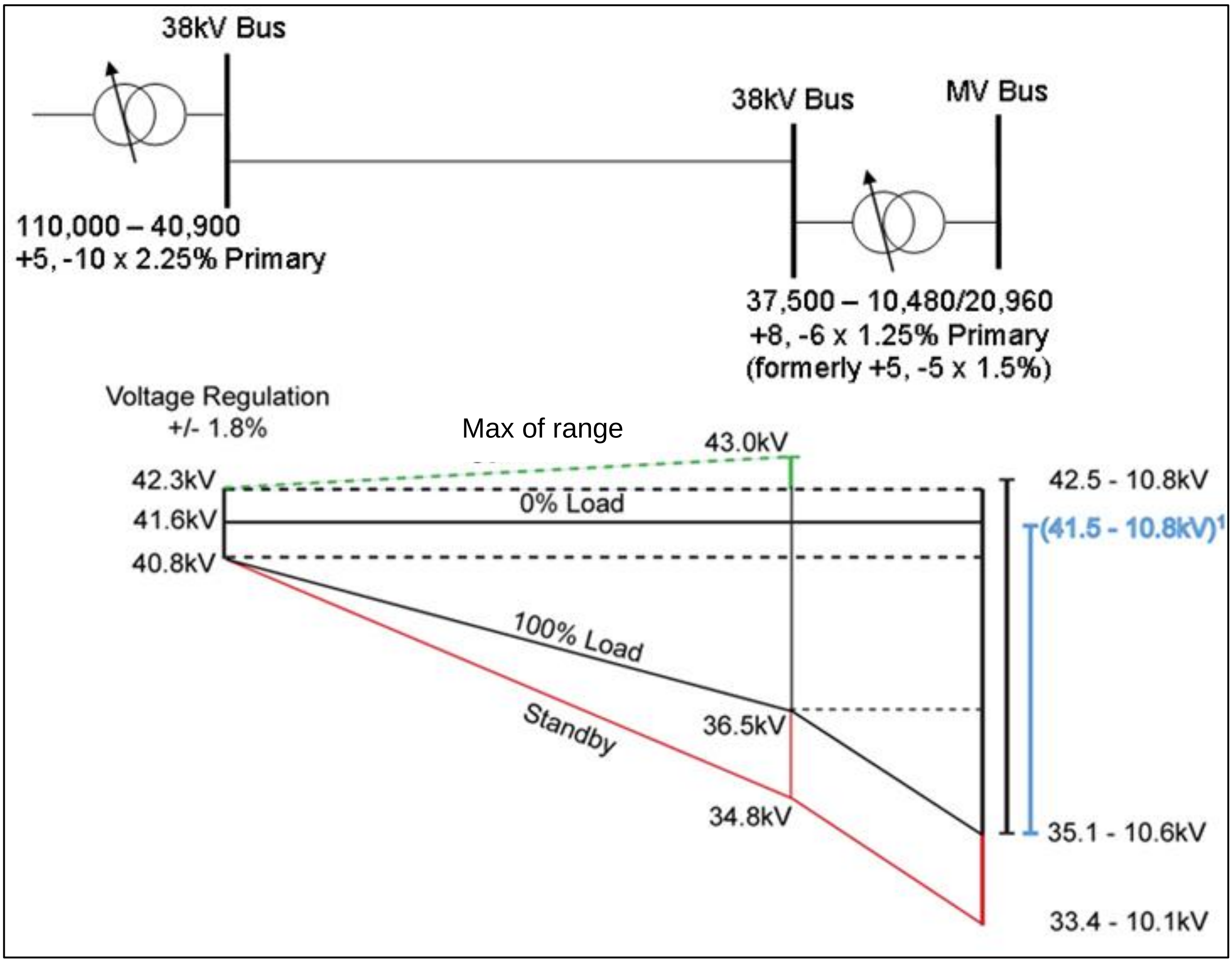
Table 16: Standard 38kV Volt Drop Allocation

Network Element	Normal Allocation	Standby Allocation
Voltage Regulation on 38kV busbar in feeding 110kV Station	3.6%	
38kV Network	10.5%	14.5%[1]
38kV/MV Transformer	4%	8%[1]

[1]Only one of these allocations can be used at a time provided the contingency allocation is not already used at MV or LV

The alignment of voltages on the 38kV system is illustrated in Figure 4. Voltages outside of these ranges may exist for short periods of time as per European Standard EN50160 Voltage Characteristics of Electricity Supplied by Public Distribution Systems.

Figure 4: 38kV Voltage Control



[1] Some older 38kV/MV transformers only have a +5, -5 x 1.5% tapping range (11 taps). In this case, the upper end of the 38kV operating voltage is reduced as indicated in brackets.

[21] The nominal sending voltage in urban networks is 10.4kV.

A.2. MV Volt Drop Allocations

Voltage is regulated on the MV busbars. The bandwidth for voltage regulation is typically +/- 1% about the voltage set point V_S.

Thereafter voltage drops within the downstream MV networks should be kept within the allowed limits to maintain customer service voltage.

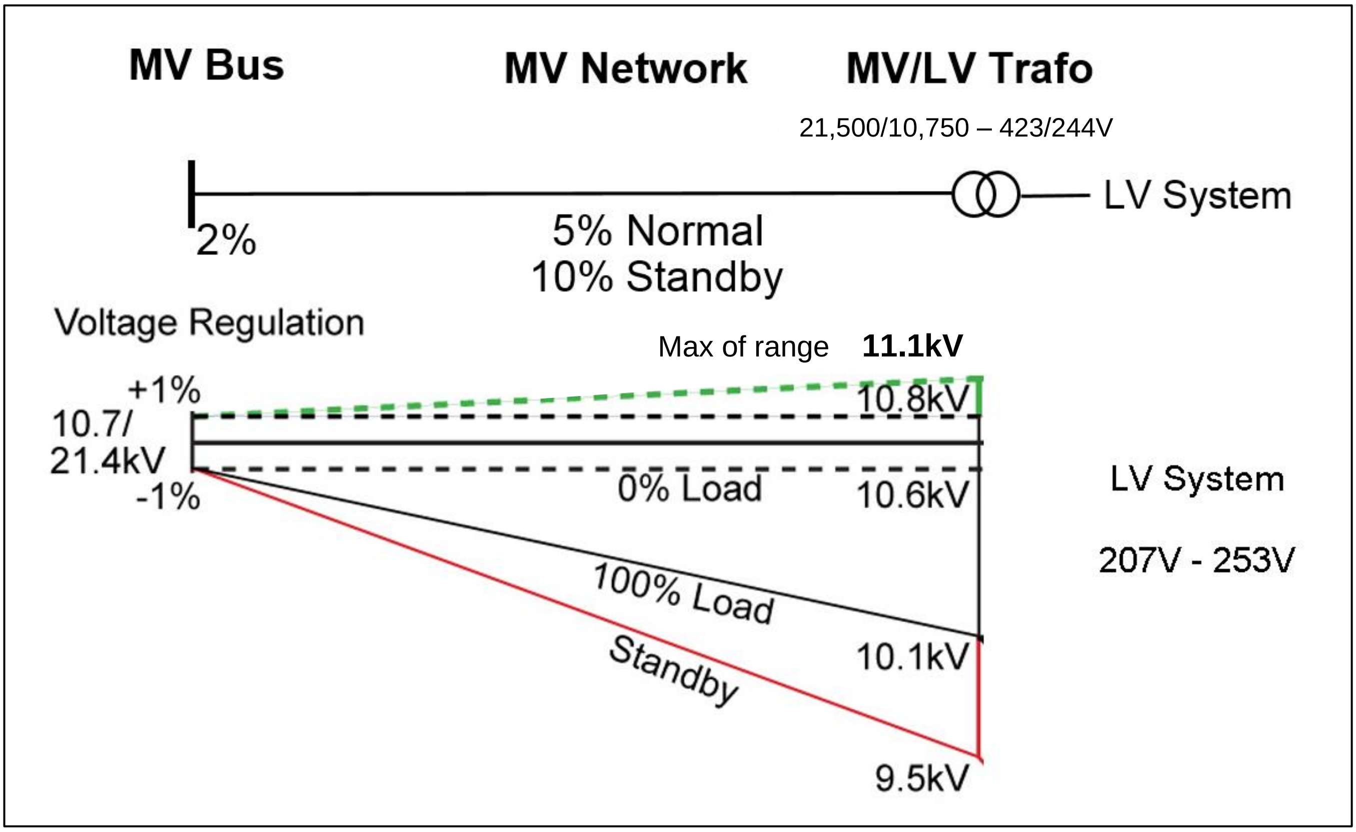
Voltage drops within MV network elements shall be planned to maintain the voltage within the limits defined in Table 17. Thus, for peak design load on networks, the voltage drops should not exceed these limits. Where voltage drops on a three-phase network are determined on a phase by phase basis, the worst phase volt drop should comply with these limits.

Table 17: Standard MV Volt Drop Allocation

Network Element	Normal Allocation	Standby Allocation
Voltage Regulation on MV busbar in feeding HV/MV Station	2%	
MV Network	5%	10%

The alignments of voltages on the MV system is illustrated in Figure 5. Voltages outside of these ranges may exist for short periods of time as per European Standard EN50160 Voltage Characteristics of Electricity Supplied by Public Distribution Systems.

Figure 5: MV/LV Voltage Control



In situations where it is reliably known that the MV network volt drop allocation is not fully utilised under both normal and standby feeding conditions and may not be in the foreseeable future, a portion of the unused MV bandwidth may be used to increase the downstream LV voltage bandwidth available for planning purposes. This situation can arise for example with urban cabled MV networks.

A.3. Use of MV regulators

Where MV network volt drops exceed limits, network voltage regulators may be used to compensate provided that booster rating[22] does not restrict the required throughput of the circuit. Regulators should be limited to no more than one regulator in series in an MV network for normal feeding and no more than three in series for standby feeding[23].

A portion of the voltage boost is lost to compensate for the decrease in input booster voltage caused by the increase in upstream load due to the higher voltage output from the booster. The effective downstream boost is decreased by this amount. For example, if there is a volt drop of 10% and a 10% boost is applied, an effective downstream boost of about 8% only is achieved. Where several regulators are connected in series there is a diminishing return, e.g. the aggregate voltage drop arising from the increased losses can cancel or even exceed the voltage gain in the regulators. Additionally, as boosters are operated in series, 'hunting' may become an issue if more than three boosters are in series.

Regulators should be installed near the point in the network where the volt drop reaches 90% of the allowed limit. Boosters should only be utilised based on reasonably balanced phase loading. Where there is a significant problem with phase unbalance, this should be corrected with load re-balancing rather than relying on a regulator to alleviate the problem.

A.4. Voltage Unbalance

Where voltage drops are determined on a phase by phase basis for three-phase networks, the worst-case volt drop should comply with the volt drop allocations.

It is more advantageous to attempt to resolve the underlying load / network unbalance problems. This entails attention to balancing the single-phase spurs on three-phase MV networks.

Note that feeder phase balancing is assessed for normal feeding conditions only.

A.5. Voltage rise effects on lightly loaded cabled networks

There can be problems with voltage rise at light load on 38kV cabled networks and 110kV networks. This arises from the energy stored in the circuit capacitances. This increases with the presence of cable and with the square of the operating voltage. Network load flow analyses at 38kV and 110kV should model the circuit capacitances. Where there is a significant amount of cable and particularly at 110kV, load flow analyses should be performed using the approved network modelling tool to check for voltage rise at light loads.

The use of reduced voltage levels at certain times to reduce reactive power requirements and voltage rise effects arising from associated cabling at similar or higher voltages can be considered.

[22] The current largest MV regulator size available is 150A, corresponding to 2.7MVA at 10kV and 5.4MVA at 20kV.
[23] Three-tank boosters may be considered where appropriate.

Annex B. (Informative) Planning Levels for Harmonic Voltages

Table 18: Indicative Harmonic Planning Levels for harmonic voltages for 110kV, 38kV, MV, LV studies

IEC 61000-3-6 Ref Values

Harmonic Voltages - % Fundamental

h	110kV	38kV	MV	LV
THD	**3.00%**	**5.625%**	**6.50%**	**8.00%**
2	1.40%	1.70%	1.80%	2.00%
3	2.00%	3.50%	4.00%	5.00%
4	0.80%	0.95%	1.00%	1.00%
5	2.00%	4.25%	5.00%	6.00%
6	0.40%	0.48%	0.50%	0.50%
7	2.00%	3.50%	4.00%	5.00%
8	0.40%	0.48%	0.50%	0.50%
9	1.00%	1.15%	1.20%	1.50%
10	0.35%	0.44%	0.47%	0.50%
11	1.50%	2.63%	3.00%	3.50%
12	0.32%	0.40%	0.43%	0.46%
13	1.50%	2.25%	2.50%	3.00%
14	0.30%	0.37%	0.40%	0.43%
15	0.30%	0.30%	0.30%	0.40%
16	0.28%	0.35%	0.38%	0.41%
17	1.20%	1.58%	1.70%	2.00%
18	0.27%	0.34%	0.36%	0.39%
19	1.07%	1.39%	1.50%	1.76%
20	0.26%	0.32%	0.35%	0.38%
21	0.20%	0.20%	0.20%	0.30%
22	0.25%	0.31%	0.33%	0.36%
23	0.89%	1.13%	1.20%	1.41%
24	0.24%	0.30%	0.32%	0.35%
25	0.82%	1.02%	1.09%	1.27%
26	0.23%	0.30%	0.32%	0.35%
27	0.20%	0.20%	0.20%	0.20%
28	0.23%	0.29%	0.31%	0.34%
29	0.70%	0.86%	0.91%	1.06%
30	0.22%	0.28%	0.30%	0.33%
31	0.66%	0.80%	0.84%	0.97%
32	0.22%	0.28%	0.30%	0.33%
33	0.20%	0.20%	0.20%	0.20%
34	0.22%	0.27%	0.29%	0.32%
35	0.58%	0.69%	0.72%	0.83%
36	0.21%	0.27%	0.29%	0.32%
37	0.55%	0.64%	0.67%	0.77%
38	0.21%	0.27%	0.29%	0.32%
39	0.20%	0.20%	0.20%	0.20%
40	0.21%	0.26%	0.28%	0.31%
41	0.50%	0.57%	0.59%	0.67%
42	0.21%	0.26%	0.28%	0.31%
43	0.47%	0.53%	0.55%	0.63%
44	0.20%	0.26%	0.28%	0.31%
45	0.20%	0.20%	0.20%	0.20%
46	0.20%	0.26%	0.27%	0.30%
47	0.43%	0.47%	0.49%	0.55%
48	0.20%	0.25%	0.27%	0.30%
49	0.42%	0.45%	0.46%	0.52%
50	0.20%	0.25%	0.27%	0.30%

Annex C. (Informative) Requirements for a Terminal Substation

A terminal substation may be required at the customer site, depending on a number of factors, such as those set out below.

The customer should engage with ESB Networks on the requirements applicable during the early stages of project development.

C.1. Demand Connections

C.1.1. Requirements for a HV Terminal Substation and Site

Where the connection voltage is determined to be at 38kV or 110kV, then a HV Terminal Substation and site, to comply with the specification for 38kV or 110kV connection, is required in all cases. The terminal substation may be either indoor or outdoor based on the least cost technically acceptable solution. Typically, substations being developed in urban areas and town centres are indoor, whereas those in more rural locations are outdoor (subject to a suitability study).

C.1.2. Requirements for a HV/MV Transformer Substation and Site

In some cases where a customer is connected at MV, but this load cannot be met by the existing MV network, a HV/MV terminal substation and site may be required. The general guidelines and site requirements for a Terminal Substation and site under these circumstances are shown in Table 19.

Table 19: Requirement for provision of substation building and site

Maximum Import Capacity (MIC)	Customer requirement for the provision of a Substation Building and Site
≥5MVA	HV/MV Terminal Substation may be required for loads greater than this level
<5MVA	A HV/MV Transformer Substation may be required where this is the least cost technically acceptable solution based on: • The MIC (MVA) of the proposed load • Disturbing elements of customer load • The distance from the existing substations to the proposed load • Any spare capacity above the planned requirements available on existing substations and on the local MV network • The customer's future expansion plans

C.1.3. Requirements for a MV Terminal Substation and Site

MV connected customers are required to provide (and transfer to ESB Networks) an MV substation building and site, to comply with the standard ESB Networks' MV substation building specification, or an ESB Networks' approved modularised alternative[24], in all cases.

[24] Alternatives to the MV substation building are under consideration at time of writing.

A customer MV switchroom housing the customer owned main incoming circuit breaker shall be required to be located immediately adjacent to and adjoining the ESB Networks substation building.

C.1.4. Requirements for a MV/LV Transformer Substation

Where an ESB Networks MV/LV transformer substation is required, customers are required to provide (and transfer to ESB Networks) an MV substation building and site, to comply with the standard ESB Networks' MV substation building specification. A customer LV switchroom housing the customer owned switchgear shall be required to be located immediately adjacent to and adjoining the ESB Networks substation with a suitable cable duct provided between the two installations.

A unit substation and site is suitable for low density distributed load developments, i.e. low-medium density residential developments only, and should not be considered for mixed or commercial / industrial high load density type developments.

C.2. Generator Connections

The requirement for a terminal substation and site or transformer substation and site for distributed generator connections is broadly similar to demand load connections, i.e. depending on proposed generation capacity and connection voltage.

MV connected distributed generator customers are required to provide an MV substation building and site, to comply with the standard ESB Networks' MV substation building specification, or an ESB Networks' approved modularised alternative[25] to accommodate the required equipment for the Embedded Generation Interface Protection (EGIP)[26] standard.

Given the additional complexity of group processing, and potential interaction between generator connections at transmission and distribution voltages, and other criteria, the specific substation and site requirements for a generator shall be advised during the assessment process. This may require development of a shared HV substation or other shared infrastructure.

[25] Alternatives to the MV substation building are under consideration at time of writing.
[26] Currently applicable to connections >2MW MEC.

Annex D. (Informative) Security Implications for Firm Access Generator Connections

As it not possible to cover all possible scenarios, the following is a non-exhaustive guide representative of typical connection arrangements, for firm access connections.

The majority of firm access connections remain connected to the distribution system for n-1 events, however an outage may result for n-1 events for some existing or contracted connections (e.g. into single transformer or tail-fed HV stations).

A planned or fault related outage of any part of the dedicated shallow connection for a DG, or the busbar section to which the DG connected shall result in an outage of the DG and connection shall not be restored until the associated works are completed.

In the event of any planned outage affecting a DG, the DG shall be notified as per the Distribution Code, DPC4.4.3.

Whilst every effort should be made to minimise planned outage durations, any works carried out during a planned outage which affects a DG should, unless otherwise agreed, be carried out during normal working hours. In the event that the DG seeks to reduce the duration of the outage through the working of additional hours and / or non-normal working hours, this shall only be done with the prior agreement of ESB Networks and at the DG's cost.

D.1. Generation-Only HV Stations

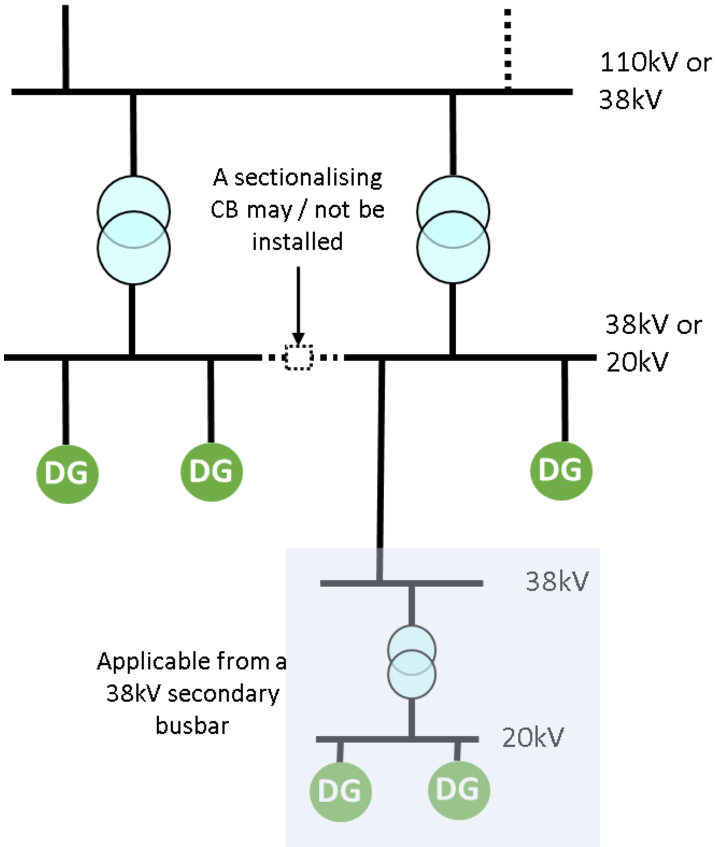
See Figure 6 for a simplified example of a Generation-Only HV Station.

Stations developed for the connection of DG only may be looped, or tail-fed, at HV.

In the case of a of a tail-fed station, a planned or fault related outage of the connecting circuit shall result in an outage of the station and all DGs connected, and the connections shall not be restored until the circuit is reconnected.

Unless otherwise agreed, there is no redundancy in the installed transformer capacity in generation only HV stations, i.e. the transformers operate similar to single transformer stations. In such stations with more than one transformer, a sectionalising circuit breaker cubicle may or may not be installed. If a sectionalising circuit breaker is installed, it shall be operated normally open.

Figure 6: Generation only station



In the event of a planned or fault related transformer outage, where a sectionalising circuit breaker is not installed, the DGs connected to that transformer shall also be subject to an outage, and connection shall not be restored until the transformer is reconnected.

In the event of a planned or fault related transformer outage, where a sectionalising circuit breaker is installed, the DGs connected to that transformer shall also be subject to an outage. Where technically and operationally acceptable, it may be possible to facilitate the energisation of the DG and import of power only (up to the contracted MIC) for the DGs affected by the transformer outage in order to assist maintaining the auxiliary supplies. DGs affected by a transformer outage associated with the connection of new DG, may apply for outage mitigation measures, subject to conditions, limitations and technical acceptability[27]. If approved, this may facilitate a reduced MEC for the duration of the outage. Otherwise the connection shall not be restored until the transformer is reconnected.

[27] See 'Policy for Facilitating Outage Mitigation to Existing Generator Customers'.

D.2. HV Stations with Demand Load

D.2.1. Single Transformer or Tail-Fed HV Stations

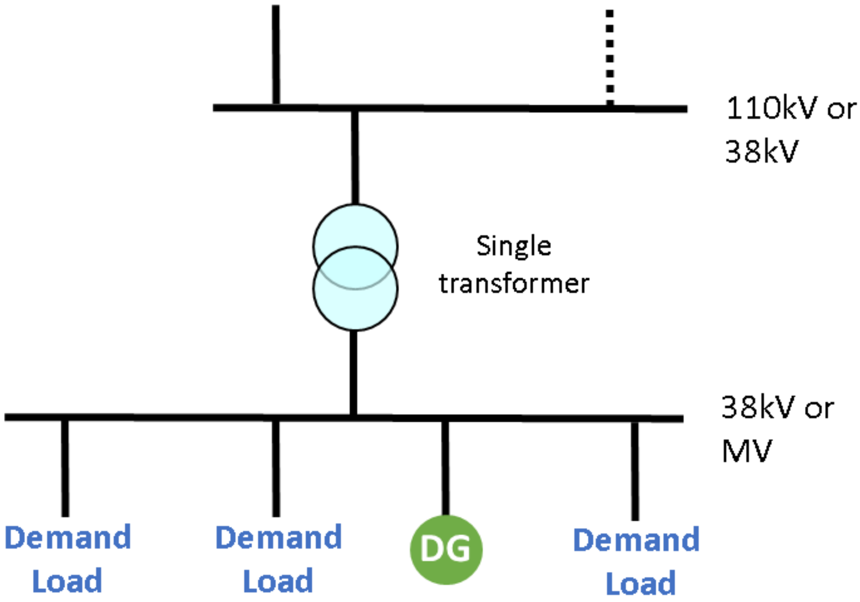
See Figure 7 for a simplified example of a single transformer or tail-fed HV Station.

In the case of a of a tail-fed HV station, a planned or fault related outage of the connecting HV circuit shall result in an outage for any DGs connected to the station. The DGs shall not be reconnected until the HV circuit is reconnected.

Single transformer HV stations may be looped, or tail-fed, at HV.

In the event of a planned or fault related transformer outage in a single transformer HV station, the DGs connected to the station shall also be subject to an outage, and connection shall not be restored until the transformer is reconnected.

Figure 7: Single Transformer or Tail-Fed HV Station



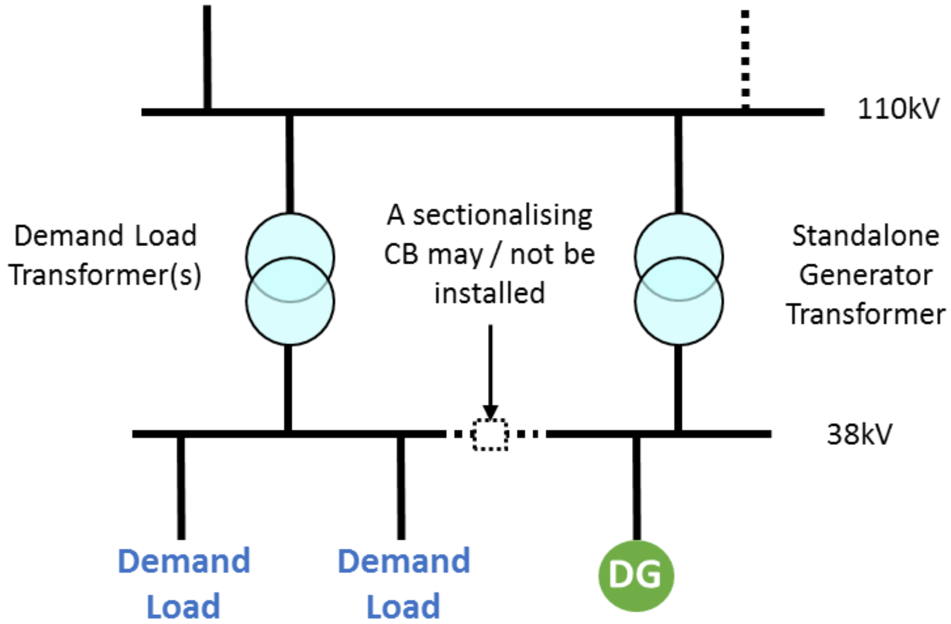
D.2.2. Connection to a Standalone Generator Transformer in HV Station with Demand Load

See Figure 8 for a simplified example of a connection to a Standalone Generator Transformer in a HV Station with Demand Load.

In the event of a planned or fault related transformer outage, where a sectionalising circuit breaker is not installed, the DGs connected to that transformer shall also be subject to an outage, and connection shall not be restored until the transformer is reconnected.

In the event of a planned or fault related transformer outage, where a sectionalising circuit breaker is installed, the DGs connected to that transformer shall also be subject to an outage. Where technically and operationally acceptable, it may be possible to facilitate the energisation of the DG and import of power (up to the contracted MIC) for the DGs affected by the transformer outage in order to assist maintaining the auxiliary supplies. DGs affected by a transformer outage associated with the connection of new DG, may apply for outage mitigation measures, subject to limitations conditions, limitations and technical acceptability[28]. If approved, this may facilitate a reduced MEC for the duration of the outage. Otherwise the connection shall not be restored until the transformer is reconnected.

Figure 8: Standalone Generator Transformer



[28] See 'Policy for Facilitating Outage Mitigation to Existing Generator Customers'.

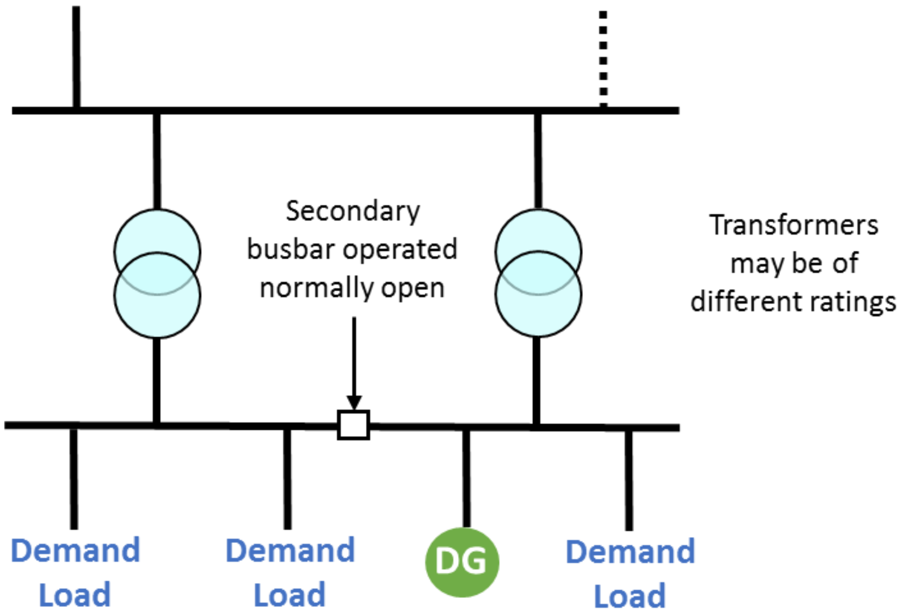
D.2.3. Connection to a HV Station where the Secondary Busbar is Operated with a Normally Open Sectionalising CB

See Figure 9 for a simplified example of a connection to a HV Station where the secondary busbar is operated with a Normally Open Sectionaliser.

A planned outage of the transformer to which the DG is connected should not result in an outage of the DG, unless otherwise part of the connection arrangement and connection agreement (e.g. where the transformers are of different ratings, as a result of a system operator preferred build configuration).

A fault related outage of the transformer to which the DG is connected shall result in a temporary outage of the DG, until the sectionalising CB is closed through operator intervention, unless otherwise part of the connection arrangement and connection agreement (e.g. where the transformers are of different ratings, as a result of a system operator preferred build configuration).

Figure 9: HV station with Normally Open Sectionaliser

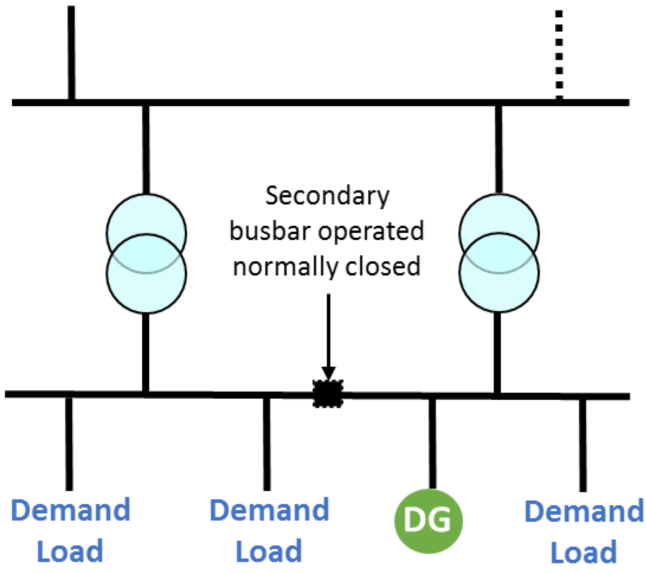


D.2.4. Connection to a HV Station where the Secondary Busbar is Operated with a Normally Closed Sectionalising Cubicle or CB

See Figure 10 for a simplified example of a connection to a HV Station where the secondary busbar is operated with a Normally Closed Sectionaliser.

A planned or fault related outage of a transformer should not result in an outage for the DG.

Figure 10: HV station with Normally Closed Sectionaliser



D.2.5. Connection to a HV Station where a standby transformer is installed

See Figure 11 for a simplified example of a connection to a HV Station where a standby transformer is installed.

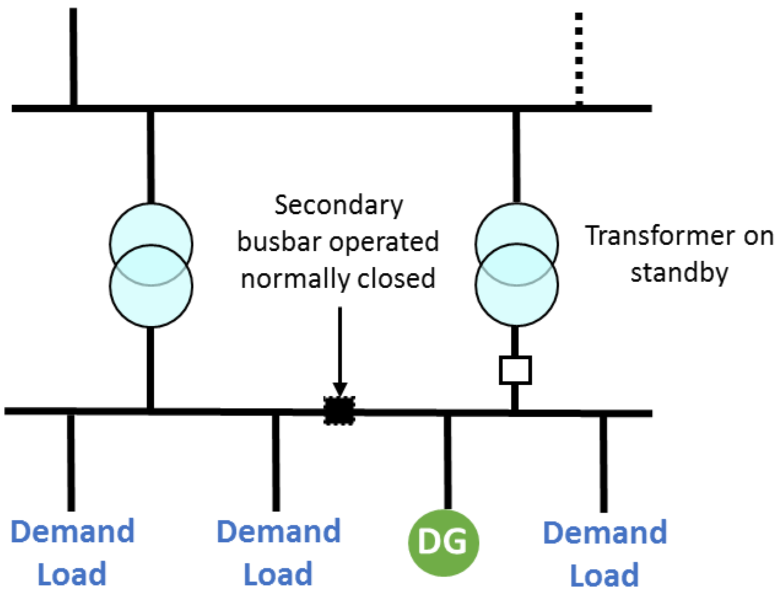
A standby transformer[29] is one which is not normally in service, but which can be switched in as required.

Where the capacity of the standby transformer is required to maintain security of supply for demand load customers connected to the station (e.g. non-transferrable load), its capacity shall be accounted for as set out in Section 7.3.5.

A planned outage of the transformer normally in service, may result in a temporary outage of the DG, until the standby transformer is switched in through operator intervention.

A fault related outage of the transformer normally in service shall result in a temporary outage of the DG, until the standby transformer is switched in through operator intervention.

Figure 11: HV station with standby transformer



[29] A standby transformer may be of a different rating to the transformer(s) normally in service.

Derogations

No Derogations are recorded against the Requirements of this document.

Terms and Definitions

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

Table 20: Terms and Definitions

Term	Definition
Shall	Designates a Company Requirement, hence conformance is mandatory.
Should	Designates a Company Recommendation where conformance is not mandatory but is recognised as best practice.
May	Designates a Permissive Statement - an option that is neither mandatory nor specifically recommended.
Auto Changeover (ACO)	Automatic Changeover systems are designed and implemented to monitor and maintain continuous supply to customers by using one infeed to supply load, and another standby infeed available should alternative feeding arrangements be required to supply the load.
Bulk Supply Point (BSP)	A transmission station that feeds into the sub-transmission system usually at 38kV.
Circuit Breaker (CB)	A switching device which can be operated manually or automatically (by protection relays) for interrupting the flow of electrical current thereby energising or de-energising an electrical circuit.
The Commission for Regulation of Utilities (CRU)	The government body with responsibility for regulating the energy and water industry in Ireland.
Distributed Generation (DG)	Generation capacity connected to the distribution networks, e.g. CHP, wind farms, small hydro, etc.
Distribution System	The aggregate of HV/MV stations, MV and LV networks that takes energy from the sub-transmission system and supplies it to MV and LV customers.
Distribution System Operator (DSO)	The licensed operator of the Distribution System. ESB Networks Ltd. in its capacity as the licensed operator is responsible for the ownership, maintenance and development of the Distribution System under its DSO Licence.
Embedded Generator Interface Protection (EGIP)	Embedded Generator Interface Protection is designed to disconnect the generator from the network during abnormal system conditions by tripping a dedicated circuit breaker or recloser, located as close as practically possible to the interface between the Independent Power Producers (IPP) equipment and the ESBN distribution network.
Extra High Voltage (EHV)	The lower limit varies but for distribution systems this is normally a class of nominal system voltages in excess of 138kV, i.e. associated with bulk transmission systems.
Firm Capacity of Station	The full emergency / contingency load rating of all remaining transformers after loss of the largest transformer in a station. A single transformer station thus has no firm capacity.
Group Demand (GD)	Group Demand is the aggregate peak load supplied by a network element or combination of elements under study, e.g. the load supplied by a network transformer, an MV feeder, a distribution station, a 38kV feeder, a bulk supply point, etc. It is the load that could be impacted by a contingency involving the network element.
High Voltage (HV)	The lower limit varies but for distribution systems this is normally a class of nominal system voltage in excess of 35kV and up to 138kV.
Load Break Fault Make (LBFM)	A switch rated to break load current but rated to close on to a fault.
Least Cost Technically Acceptable (LCTA)	In the context of network development projects, the LCTA solution is defined as the option which is technically acceptable, and which results in the minimum charge to the end-user, taking into account the long-term economic development of the electricity network in the area.
Load Factor	The ratio of average to peak load on a power system or element over a defined time period, typically a year.

Load Indices (LI)	A load index is a measure of peak loading on a HV station against its firm capacity. A five-point scale is used to assign a Load Index between 1 and 5 to a HV Station; LI1 representing a lightly loaded station and LI5 representing a heavily loaded station.
Loss Load Factor	The ratio of average to peak losses on a power system or element over a defined time period, typically a year.
Low Voltage (LV)	A voltage not normally exceeding 600 Volts AC between phase and earth or 1000 Volts AC between phases. A voltage not normally exceeding 900 Volts DC pole to earth or 1500 Volts DC between poles.
Maximum Demand (MD)	The peak load actually drawn by a customer or group of customers within a certain time period, typically a billing period.
Maximum Export Capacity (MEC)	The maximum power that a customer is permitted to export via their ESB Networks electricity connection.
Maximum Import Capacity (MIC)	The maximum power that a customer is permitted to import via their ESB Networks electricity connection.
Medium Voltage (MV)	The upper limit varies but for distribution systems this is normally a class of nominal system voltages in excess of 1,000 volts up to 35kV.
Negative Sequence Voltage	A set of symmetrical phase voltages, i.e. of equal magnitude and 120° phase angle, having the opposite phase sequence to the source, i.e. the system generation. The term negative sequence may also be applied in the same sense to AC currents, impedances (ratios between negative sequence voltages and currents in a network), etc.
Nominal Voltage	The voltage value, by which a system is designated and to which certain operating characteristics of the system are related.
Non-Firm Access (NFA)	See ESB Networks' 'Non-Firm Access Connections for Distribution Connected Distributed Generators' Guide DOC-190220-FOT.
Non-Wires Alternative (NWA)	See ESB Networks' 'Non-Wires Alternatives to Network Development' Guide DOC-140220-FOL.
Normally Open (NO)	A switching point between two interconnected parts of an electrical network which is left intentionally open.
Phase Unbalance	A measure of asymmetry between phase parameters in terms of magnitude, phase angle or both. This is typically expressed as a ratio of negative (3 wire networks) and or zero sequence values (4 wire networks) to the positive sequence value.
Point of Common Coupling (PCC)	The point at which the supply network dedicated to a customer interfaces with the rest of the power system. Upstream of this point the network will be shared with other customers / loads.
Price Review (PR)	A financial review process ed by the regulator - the Commission for Regulation of Utilities (CRU).
Power Park Module (PPM)	A unit or ensemble of units generating electricity, which is either non-synchronously connected to the network or connected through power electronics, and that also has a single Connection Point to the distribution system. For avoidance of doubt, a Wind Farm Power Station (WFPS) or Solar Farm Power Station (SFPS), are considered to be a PPM. A PPM will comprise at least one Wind Turbine Generator (WTG) or Solar Generator (SG).
Positive Sequence Voltage	A set of symmetrical phase voltages, i.e. of equal magnitude and 120° phase angle, having the same phase sequence as the source, i.e. the system generation. The term positive sequence may also be applied in the same sense to AC currents, impedances (ratios between positive sequence voltages and currents in a network), etc.
Service Connection	The immediate section of network connecting a customer to the local distribution network. It is normally terminated in a customer metering arrangement. A service connection is usually dedicated to a customer, but in certain cases, e.g. housing estates, a service can be shared between neighbouring customers.
Service Voltage	The voltage value at the customer's interface, declared by the power company. This is typically expressed as a voltage range, in terms of a nominal voltage with plus and minus percentage limits of variation, e.g. 230V, +10%, -10%.

Sub-Transmission System	The HV networks that take energy from the transmission stations / Bulk Supply Points and supply it to distribution stations at 38kV or 110kV. Effectively this comprises the 38kV networks and any distribution 110kV networks.
System Voltage	A value of voltage used within a power system. It is typically expressed as a nominal voltage with an upper limit only. This upper limit defines the rated voltage for equipment, e.g. a nominal voltage of 20kV with a rated voltage for equipment of 24kV.
Transmission System	The aggregate of HV and EHV networks and stations that take energy in bulk from major generators and supply it to Bulk Supply Points or major HV customers.
Transmission System Operator (TSO)	The licensed operator of the Transmission System. EirGrid in its capacity as licensed operator of the Transmission System under its TSO Licence.
Voltage (V)	The DC value, or in the case of AC, the root mean square (RMS) value, of the nominal voltage by which a system or part of a system is designated.
Voltage Drop (VD)	The difference in voltage between one point in a power system and another, typically between the supply bus and the extremities of a network. This is typically expressed as a percentage of the nominal voltage.
Voltage Regulator (Booster)	A Voltage Regulator is a transformer used to control the voltage level. It can be used to increase or decrease the voltage to keep it within voltage standards.
Zero Sequence Voltage	A set of phase voltages of equal magnitude and zero phase angle relative to each other. The three-phase values are therefore in phase with each other. The term zero sequence may also be applied in the same sense to AC currents, impedances (ratios between zero sequence voltages and currents in a network), etc.

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