NETWORKS

Public Consultation on the *Smarter HV and MV Customer Connections* Project

New Approaches to Distribution Planning and Security of Supply Standards

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Foreword

ESB Networks is committed to playing its part in leading Ireland's transition to a low carbon future powered by clean electricity. The challenge of an Ireland powered by secure, affordable and zero carbon electricity will take far more than the technologies, techniques and business models we use today. At ESB Networks, we understand the importance of working cooperatively with many stakeholders to develop, test and implement innovative solutions. The challenge of enabling a low carbon Ireland powered by clean electricity builds on our history of innovation, bringing light, heat and power, safely and reliably, to every Irish home, business and community since 1927.

To us, in ESB Networks, the purpose of innovation is to develop and implement new ideas with enduring benefits for our customers.

Consistent application of this principle has been the foundation for one of the most progressive electricity networks in the world. This network has enabled Ireland to become a world leader in industry and technology, and a location of choice for foreign direct investment. Over the past ten years, together with EirGrid, we have innovated to connect and sustain a system with over 4,000 MW of renewable generation producing over 30% of Ireland's electricity during 2018. Our network developments have played a central role in the emergence of a new industry, supporting 540 MW of hi-tech datacentre load. We have done this while introducing new technology and techniques to improve network resilience as we experience, respond to, and learn from the increasing frequency of adverse and extreme weather events.

We are very clear that a key challenge in enabling the network of the future, together with the delivery of the recent National Climate Action Plan, is how we innovate to improve the connection of HV and MV customers to the electricity system, i.e. increasing the volume of renewable generation connected; to increase the speed with which customers (e.g. new generation, demand, flexibility etc.) are connected; to improve network resilience and security of supply; and to continue to connect in an economic manner. To that end, we set up a project called ***Smarter HV and MV Customer Connections*** to look at how we plan to connect customers to the network of the future and we have engaged with key stakeholder groups at different stages of the project.

This consultation as part of that project seeks views on our proposals to more innovatively connect customers in the future. We want to continue to work collaboratively with our many stakeholders and to that end, we welcome your comments and feedback on the proposals detailed in this document.

1. Introduction

The electricity industry is undergoing unprecedented change, facilitating our country's transition to a low carbon energy system, while providing secure supplies of competitive and affordable energy to our homes and businesses. This will be achieved through increasing renewable connections and distributed energy resources as well as the electrification of heat and transport, all of which requires complex integration with the existing electricity grid. A key challenge is to support the efficient transition of these technologies onto the electricity network and examine their impact on our future electricity network while maintaining resilience and security of the network. ESB Networks needs to establish how our approach to connecting customers' should transform to satisfy these challenges.

We believe innovation is vital to embracing the current challenges and delivering effective solutions. Our definition is that innovation is *implementing new ideas* for *enduring benefits* for our customers and business. Our Innovation Strategy has a balanced portfolio of projects centred on eight roadmaps: Connecting Renewables; Customer Engagement; Electrification of Heat and Transport; Asset Optimisation; Flexibility on our Networks; Operational Excellence; Network Resilience and Working with the TSO.

The *Smarter HV and MV Customer Connections* project is a flagship initiative to deliver the Connecting Renewables roadmap successfully. Traditionally the Distribution Planning and Security of Supply Standards are reviewed at regular intervals in the course of business-as-usual however the *Smarter HV and MV Customer Connections* project goes significantly further as it is a fundamental review of the <u>*baseline philosophy*</u> of ESB Networks distribution network planning to ensure that Ireland's energy policy objectives can continue to be met economically and sustainably and that the network's security of supply is appropriate as the country moves to increased levels of electrification of heat and transport.

To date there has been good stakeholder engagement on the project, ranging from project-specific events such as seeking feedback to inform terms of references and project approaches, sharing updates on project progress and plans to disseminating knowledge and learnings from the project to the wider industry through industry fora or hosted events. For example, the aims and scope of the *Smarter HV and MV Customer Connections* project (previously referred to as Planning and Security of Supply Standards Project) were agreed with stakeholders and were published on ESB Networks website in January 2019[1]. A project update was provided in the public consultation on Innovation in ESB Networks in August 2019[2]. Additionally, in July 2019, ESB Networks held a public consultation on an early output from the project, i.e. the proposed approach to Load Indices. This work has been incorporated into the proposed approach for connecting future customers.

This consultation as part of the *Smarter HV and MV Customer Connections* project seeks views on the proposals outlined in this document to transform how ESB Networks connect HV and MV customers.

Note that in this integrated public consultation document we have included significant amount of detail and explanations on the overall approach that we propose would be adopted by network planners in transforming how we would connect HV and MV customers to the distribution network of the future. However, we envisage a suite of more succinct documents will supersede the current Distribution Planning and Security of Supply Standards (DOC-399414-BTC) to be published as key outputs of this project. For the avoidance of doubt, it is not our intention that all the detailed explanations included in this consultation document be included in the innovation project's final suite of documents.

Please send your comments to **innovationfeedback@esbnetworks.ie**

[1] https://www.esbnetworks.ie/who-we-are/innovation/our-innovation-strategy/connecting-renewables
[2] https://www.esbnetworks.ie/tns/publications?sortBy=date-recent

2. 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 supply in compliance with power quality, safety and environmental standards at minimum overall cost over the medium to long term. The planning horizon for network development is medium term, i.e. 5 years with an outlook for up to 10 years. Strategic system development, network re-structuring, e.g. voltage conversion, system optimisation, etc. looks to a longer-term horizon of 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 in order 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 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
- with a view to the needs of customers and the network in the transition to a low carbon future
- in a way that is technically acceptable.

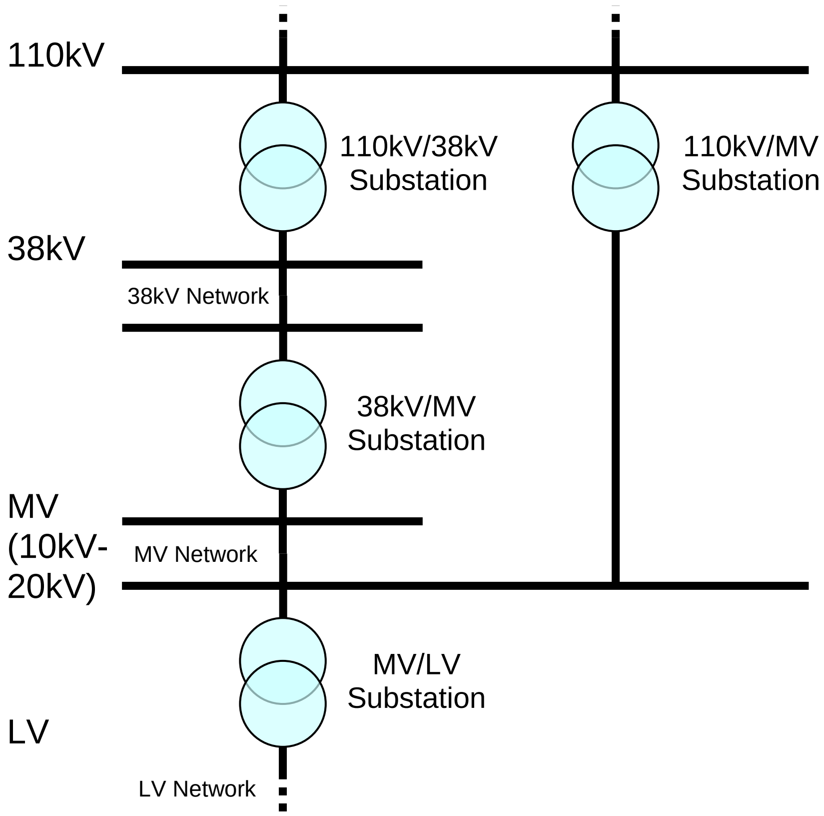
3. Voltage

3.1 Voltage Levels

There are a number of standard voltages in use on the distribution system and customers will be connected at one of these levels. Voltage levels at which a connection can be provided are set out in Table 1.

The standard configuration of the Distribution System is as illustrated schematically in Figure 1.

Figure 1: Representation of the Distribution System



The distribution system shall be designed to maintain the operating voltages within the ranges specified in Table 1.

Table 1 : 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 Generator Site
Medium Voltage (MV)	10,000 Volts (10kV)	11.0kV	10.70kV	10.1kV - 11.1kV	9.5kV - 11.1kV	11.1kV	11.3kV
	20,000 Volts (20kV)	21.0kV	21.40kV	20.1kV - 22.1kV	19.1kV-22.1kV	22.1kV	22.5kV
High Voltage (HV)	38,000 Volts (38kV)	40.0kV	41.6kV	36.5kV - 43.0kV	34.8kV-43.0kV	43.0kV	43.8kV
	110,000 Volts (110kV)	110.0kV	Generally TSO Controlled	105.0kV - 120.0kV	99.0kV - 120.0kV	120.0kV	120.0kV

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 in Public Distribution Systems.

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

For the purposes of this consultation, Annex A Guidance on Voltage Control has been included in this document to provide an explanation of how the permitted voltage drops and voltage rises ensure that voltages remain within the permitted ranges in Table 1.

3.1.1 Permitted Voltage Drop

In order to maintain the voltage performance summarised in Table 1, the voltage drops along the networks should not typically exceed the limits indicated for normal and for contingency operating conditions, as shown in Table 2.

Table 2 : Permitted voltage drops

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

The allocation of voltage bandwidth is based on economic development of the network and may change over time.

Main source voltages on the 110kV networks are generally controlled by TSO. Permitted voltage drops on distribution 110kV networks shall be determined on a case by case basis however volt drop assessments shall maintain the receiving voltage on all distribution 110kV and lower voltage busbars within the ranges specified in Table 1 and shall take account of the operating voltage range on the TSO interfacing 110kV bus.

Where MV network volt drop frequently exceed voltage standards limits, network voltage regulators (regulators) may be used to compensate. 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. Please refer to Annex A Guidance on Voltage Control for further guidance on the use of regulators.

3.1.2 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 1. Interfacing equipment at the generator site shall be rated to handle voltages up to the levels indicated in Column 8 of Table 1 as part of normal operations. This relates in particular to the tapping range for transformers and the insulation rating for circuits and equipment.

3.1.3 Voltage Unbalance

Loads should be balanced across the phases on three-phase distribution networks so that the voltage phase 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.

Voltage unbalance on the MV bars 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.

For the purposes of this consultation, Annex A Guidance on Voltage Control has been included in this document to provide further guidance.

4. Security of Supply

4.1 Security of Supply Standard

The distribution network shall be planned to maintain the security of supply standards indicated in Table 3.

Table 3: 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[1]	–	–	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[2]	110kV Networks in Dublin	N – 1	GD	–	–	–
		N – 1 – 1 (Outage for Maintenance + Fault)	2/3 GD	–	–	GD

[1]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.

[2] For GD > 100 MVA, the network shall be planned such that supply can be restored to 2/3 GD in 60 seconds in an N-1-1 scenario. Supply will 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 2/3 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.

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 in the event of a loss of a single item of plant 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.

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 shall be sectionalised into blocks of load with demand of 1MVA or less. Rural MV backbone feeders shall be sectionalised approximately every 5km. These sectionalising points should be equipped for remote operation. MV and, where relevant, LV networks should only be planned for single contingency (N – 1) events, with the exception of where higher supply security is negotiated with certain major customers or special loads.

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.

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.

Rural 38kV networks should be operated in an open loop arrangement between neighbouring 110kV stations. The normally open (NO) points should be equipped with auto changeover facilities. Urban 38kV networks can be operated as closed loops on the same 110kV station with appropriate protection.

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 / maintenance outage, the networks shall be planned to maintain supply or restore supply for the load during the maintenance period, based on two thirds (2/3) 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.

Note: Connections to Distributed generators are not covered by the Security of Supply standard.

Additional security of supply may be provided in certain areas for High Impact Low Probability 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 shall be accounted for statistically in the development of medium and long term network development plans.

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

This will take the form of an F-Factor approach, taking into account the passive contribution of distributed generation on a probabilistic basis. The F-Factor will be generation type specific and will vary based on the intermittency of the generation, ie whether the generator is in control of its fuel source.

A staged approach is proposed, as follows:

1. Adoption of established GB F-Factors on an initial basis
2. Compilation of country specific F-Factors for Ireland, taking into account differing circumstances that prevail here, over GB, such as:
    a) Common practice of non-coupling of distribution connected wind generators with demand load (e.g. through standalone HV transformers, Group Processing Application (GPA) ‘hub’ stations)
    b) Specific wind regimes for Ireland
    c) Lower numbers of non-intermittent generation installations with typically lower Maximum Export Capacity (MEC)
    d) Impact of Non-Secured Access on expected availability of generation under certain network fault conditions
3. Adoption of the Ireland F-Factors in future security of supply considerations and load indices calculations

The impact of the above would be a reduction in **the Medium/Long term forecast costs** expected for the development of the network. Actual budget costs on an individual network circuit immediately prior to investment would be based on more specific criteria and the economic consequences to customers should an outage not be mitigated by the F-Factor expected.

4.3 Specific Network Provisions

For the purposes of this consultation, we have included the following considerations used by network planners in their network connection studies however, it is not our intention nor is it appropriate to include such detail in the suite of Planning and Security of Supply Standards documents that will be published as a final output of the *Smarter HV and MV Customer Connections* project.

In line with transmission design criteria, the load that would be isolated for the loss of two 110kV lines shall not exceed four 110kV stations supplying distribution networks or 80MW of distribution load.

38kV networks should be developed as:

- Closed loops supplied from the same 110kV station, typically town loops.
- Closed meshes supplied from the same Bulk Supply Point, e.g. Dublin City.
- Radial lines between neighbouring 110kV stations, capable of interconnection through a Normally Open (NO) point. These NO points may be equipped with ACO switching where appropriate.

Two transformer 110kV/MV and 38kV/MV stations should have a main and standby supply at HV. This can take the form of looping on the 110kV or 38kV network.

A tail or singly fed 38kV station is acceptable as a stage in development towards a fully looped station or where specific loads do not justify the cost of a looped development, provided the following conditions are met:

- There should be sufficient standby cover in underlying MV networks to support the load on loss of the 38kV feeder.
- The development is compatible with long term development plans, towards a looped supply.
- No more than two stations should be planned for on a single tail feeder.

A tail fed station may be supplied by a tee connection from the main HV feeder. In such a case the tee connection must be equipped with at least 2 way and preferably 3 way load break fault make (LBFM) type switches at the tee off point from the main feeder. The requirement is to be able to isolate a faulted section and restore supply to the remainder of the network. These switches shall be capable of remote operation. On 38kV networks and subject to a protection implication assessment, there shall be no more than one tee connection between any two protected points. Such tee connections are not preferable however as they limit operational flexibility. For distribution 110kV lines, a tee connection is not allowed and instead shall have a switching station at the tee point.

Under normal feeding conditions, protection / automatic switching arrangements should be such that a single fault will not result in loss of supply to a 38kV line length x station load combination of greater than 200 MW.kms unless justified by a specific study.

Under normal or standby feeding conditions, protection / automatic switching arrangements should be such that a single fault will not isolate more than 2 looped stations.

110kV/MV stations should be considered, where there is sufficient concentration of load to justify the transformer sizes, e.g. in urban areas and for commercial or industrial parks. These avoid a layer of transformation and reduce congestion problems on 38kV networks.

Two transformer HV/MV stations are preferable to provide firm capacity for loss of a transformer. Single transformer stations are acceptable provided the load can be transferred over neighbouring MV networks to meet the security requirements of Table 3 for loss of the transformer. As the loading approaches a level where there is insufficient stand-by capabilities over the MV networks, the station shall be upgraded with a second transformer. All single transformer stations should be developed with a view to upgrading to two transformer operation in the future. It is acceptable for single transformer stations to be tail fed.

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

Network reliability shall be assessed when evaluating network development options. Network developments should seek to optimise supply reliability.

4.4 Supply Quality

Distribution networks shall be planned to provide supply in compliance with the supply quality standard EN50160 Voltage Characteristics in Public Distribution Systems.

4.4.1 Short Circuit Capacity

Short circuit capacity levels should not be less than the values in Table 4.

Table 4: Minimum Short Circuit Capacity Requirements

Voltage	Element	Min S/C Capacity
10kV	Three-phase Network	5 MVA
20kV	Three-phase Network	10 MVA

4.4.2 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 will be evaluated using ESB Networks Disturbing Load Guidelines 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 D Harmonic Levels.

4.4.3 Power Factor

In planning for the optimal development and operation of the distribution system, a power factor in the range of 0.9 to unity is assumed, typically 0.95.

4.5 Consideration of Losses

Electrical losses on the network impose a significant cost and must 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 a Total Cost of Ownership (TCO) 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.

5. Equipment Loading / Rating

Networks and equipment should normally be sized for expected peak loading conditions over the investment timeframe.

5.1 HV Station Transformers

Current standard distribution transformer sizes are indicated in Table 5.

Table 5: Current standard Distribution Transformer Sizes

Voltage Level	Size (MVA)
220/110kV	250
110/38kV	63 31.5
110kV/MV[1]	31.5[2] 20
38kV/MV[1]	15[3] 10 5
20/10kV Inter-Tie	4

[1] Larger transformer sizes of 63MVA 110/20kV and 31.5MVA 38/20kV are available for distributed generator only hub stations.
[2] Where 2 x 31.5MVA 110kV/MV transformers are operated at 10kV, the short time emergency loading may need to be reduced from 180% to comply with busbar current ratings.
[3] A 15MVA transformer is permissible where appropriate to local conditions

On loss of a transformer in a typical two transformer station the full load transfers to the remaining healthy transformer. This may be loaded up to the Short Time Emergency load limit, e.g. 180%, for a short period. However, the overload must be reduced to or below the Long Time Emergency load limit within the specified time limit, either by transferring load on the MV network or shedding load in extreme cases. The Long Time Emergency 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.

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. Certain transformers may be de-rated and may have reduced emergency loading capability below these levels.

Note: Special load limits may apply to specific transformers due to associated ancillary equipment, in addition to equipment age, fault history, etc.

Where the industrial / commercial component of load on a transformer reaches or exceeds 50% of the total load then the 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.

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

5.1.1 38/MV Transformers:

38kV/MV transformers should not be loaded in excess of the peak load limits indicated in Table 6. These values are in percentage of name-plate rating, e.g. 5MVA, 10MVA, etc. Normal loading needs to be restricted below these values to provide standby cover for loss of a transformer. The normal load limits are determined by 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 or transformer, rating calculations shall be performed to assign specific normal and emergency load limits to that transformer. This situation may arise for major industrial customers with very flat load profiles, i.e. high load factors.

Table 6: 38kV/MV Transformer Maximum Load Limits

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

5.1.2 110/38kV Transformers:

110/38kV transformers should not be loaded in excess of the peak load limits indicated in Table 7.

Table 7: 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%

5.1.3 110kV/MV transformers:

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

Table 8: 110/MV Transformer Maximum Load Limits

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

5.1.4 220/110kV Transformers

Distribution 220kV/110kV transformers shall not be loaded in excess of the peak load limits indicated in Table 9:

Table 9 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%

5.1.5 20/10kV Interface Transformers

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

Table 10: 20/10kV Interface Transformer Maximum Load Limits

Season	Normal Cyclic Load Limit	Emergency 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.

5.2 Station Busbars

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

5.3 Switchgear

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

Short circuit levels are as listed in the Distribution Code.

5.4 Circuits

Existing 38kV, MV and LV 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. New MV and LV conductors shall be sized taking losses into account

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

Underground Cables in proximity, e.g. in a cluster leaving a station, shall be de-rated for proximity effects. Cables can have a modest over load for cyclic loading conditions, but shall have no overload rating.

The current ESB Networks policy is to duct all underground cables. 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.

5.5 Short-Circuit Ratings

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

Network conductors, lines and cables, shall 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 110kV networks, system earthing shall be arranged to ensure that the 110kV system remains effectively earthed and that single-phase to earth fault currents do not exceed the maximum three-phase symmetrical short circuit fault current levels at any point in the network. 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.

6. Customer Connections

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

Connection capacities at distribution voltages as are set out in Table 11.

Table 11 Connection capacities

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

The above capacity ranges limits are dependant 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 and on how the network can be developed in the future.

New connections over 500kVA shall be made at MV or higher. Increases in existing LV demand connections should not result in an MIC greater than 500kVA.

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

6.1 Information Required from Customers

Details of the information required from demand customers and generators seeking connections or extensions to the distribution system can include:

6.1.1 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.

6.1.2 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.

6.1.3 Nature of the 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 motor(s).
- Electric Vehicle charging requirements.
- Disturbing Loads i.e. electric welding, and details of the nature and usage pattern of the disturbing load.
- Any other significant load classes.
- 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 the customers load as seen by the network shall be between 0.90 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.

6.1.4 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.

6.1.5 Specific Requirements

Details of any specific customer requirements for connection.

6.1.6 Demand Diversity

The customer shall apply 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 will vary depending on the nature of the load.

6.1.7 Generation Customers

Generation applications will need to 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.

6.2 Typical Connection Arrangements

Typical connection arrangements for major MV or HV demand customers are listed below and described in 'Conditions Governing Connection to the Distribution System'[3] and include:

- **Single radial supply** – a single service connection, i.e. no standby customer connection, although there may be standby in the network at the tap off point.
- **Dual radial supply** – two independent service connections possibly with the load sectionalised between them and normally with an ACO facility for switching load to the healthy feeder on loss of one of the feeders. The customer bus bar is usually equipped with a 2 out of 3 way circuit breaker interlocking scheme to avoid paralleling the supplies. It is normally equipped with summation metering.
  A dual radial supply does not require dedicated feeders from the station. The connections can be tapped from networks supplying other load.
- **Looped supply** – two normally closed feeders supplied from independent sources and equipped with directional over-current protection so that no load is dropped on loss of one of the feeders. It is also normally equipped with summation metering.
  The above connection configurations are dependant 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.

[3] www.esbnetworks.ie/docs/default-source/publications/conditions-governing-connection-to-the-distribution-system

6.3 Generation Connection Considerations

A generator connection must ensure that the network capabilities in terms of thermal and voltage limits, power quality limits, short circuit capacity, and connected in a manner consistent with the long term development of the electricity network in the area.

The future growth of embedded generation at LV could reduce the headroom on voltage and thermal capacities for upstream generation connections, and this should be reflected by an allocation of the available upstream capacities to cover this impact. This is being kept under review and currently the impact is not material.

Currently generator connections are planned using conventional connection methods that ensure the distribution planning limits are not exceeded as set out in Section 6.5, it is now proposed to consider the application of Non-Secured Access to ensure that the generation connection meets the criteria but modification of the generation output will be used to ensure the criteria are met.

Initially it is proposed to consider Non-Secured Access to transformer capacity, with a view to extending to address other connection limitations.

6.4 Non-Secured Access General Principles:

Implementation of Non-Secured Access (‘NSA’) requires the identification of the limitations that restrict access and then the constraining of the generator so that the limitation is not breached.

The methods by which the limitations can be identified and the generator constrained vary from simple, involving an absolute constraint on generation when a limitation is expected to be breached, to complex, involving constraining off generation in proportion to what is required to ensure that the limitation is not breached.

However actual operational experience with any sophisticated NSA scheme at Distribution voltage levels is limited.

It must also be realised that more than one generator may wish to have NSA to the same network and this could lead to excessive complexity and deterioration in the reliability of the network.

Furthermore the risk associated with operating networks at their limits increases the likelihood that a maloperation of the scheme could result in extensive damage to the network and disruption to demand customers and other generators. This is because NSA involves the connection of generation in excess of the network capacity available.

Costs, including those associated with the day to day operation of such schemes, should be allocated appropriately amongst customers.

The implications of the above are that:

a) NSA schemes should not unduly infringe on rights of existing generators.

b) NSA should be initially applied in simple schemes and should be limited so that interactions between different schemes do not occur e.g. application at 38kV and above would be simpler than further downstream.

c) NSA should be applied where it will provide the greatest return in terms of enabling greater generation connection capacity on a ‘Whole of System’ basis.

d) Risk and costs associated with the implementation of NSA schemes should not be borne by demand users or generators not associated with the NSA scheme.

e) NSA schemes should not initially require centralised and should operate automatically with fail safe procedures from a local HV station controller.

f) NSA schemes should be designed in such a way that they facilitate the future development of more complex schemes which would provide increased benefits to the system.

g) A feature of a NSA scheme is that in the event of planned maintenance on a particular network component or circuit, the generator will be impacted for the duration of the works, and this time period may be extensive (up to several months).

h) ESB Networks will develop rules for the provision and allocation of NSA to cater for:
   (i) Treatment of existing Secured-access generation in relation to increases in installed generation.
   (ii) Treatment of NSA generation in relation to conversion to Secured access if network is reinforced.
   (iii) Possible approaches to matching NSA generation to network limitations in the event of interactions.
   (iv) Interactions between different RES. The NSA scheme should operate to maximise renewable energy output.

6.5 Connection Assessment Criteria

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

6.5.1 Evaluation of Network Limitations

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

Connections for distributed generators greater than 0.5MW are typically studied by group processing, the resultant outcome being the least cost technically acceptable connection method for the group.

Networks are assessed to determine:

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

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.

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.

6.5.2 Voltage Rise

Generator connection shall be assessed to ensure that voltages at the PCC and the generator site, outlined in Table 1, are not exceeded.

6.5.3 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 will need to be carried out to determine the voltage rise, impact on customers sharing point of common coupling and upstream (higher voltage) systems.

6.5.4 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.

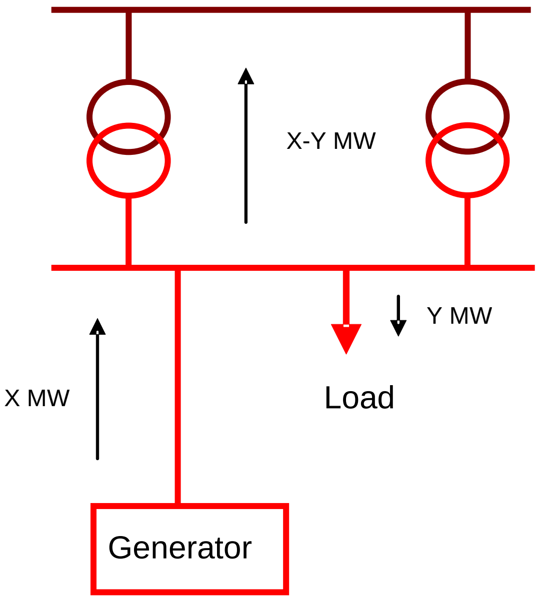
6.5.5 Transformer Capacity for Generation in Existing Substations

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 must be assessed. The following principles and guidelines are used in such assessments.

6.5.5.1 Use of Minimum Load

In assessing available transformer capacity, a minimum load value is taken into account.

Figure 2 Use of Minimum Load



The reason for this is illustrated the example in Figure 2, there are X MW being generated. There is Y MW of load on the station. Therefore, the power flowing through the transformers is then X – Y MW. Therefore, for a given amount of generation, the power flowing through the transformers from the generation will be at maximum when the load is at the station is a minimum.

6.5.5.2 Consideration of Reactive Power (VArs)

Each transformer has a rated capacity which is expressed in apparent power (VA). 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 a number of 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.

6.5.5.3 Transformer Overload 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.

6.5.5.4 Two Transformer Stations

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

This is the area in which it is proposed to initially apply NSA.

6.5.6 Existing or Committed Generation Connections

Any generators already connected or committed to connect must also be considered when determining available system capacity. Currently the impact of photovoltaic (PV) based generation at LV is not considered material but this may change in the future.

6.5.7 Loss of Feeder and Voltage Change

If the generator trips for any reason, then a step change in voltage will 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%.

6.5.8 Losses

As set out previously, losses on the distribution system have a financial rather than a purely technical impact on the system. As a consequence and acknowledging that Distribution Loss Adjustment Factors (DLAF) are applied to generation connections, losses are not a technical constraint for networks used for dedicated generation connections. Based on the DLAF, it will be for the applicant to 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, then they are within their rights to request a modification to their connection in the normal way.

For networks which will be shared by two or more generators, ESB Networks will, subject to all other technical criteria being satisfied, offer a conductor size which will in ESB Networks' view yield 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.

6.5.9 38kV Connected Tees

A maximum of one 38kV tee connection to an existing 38kV overhead line is typically allowed between 38kV cubicles fitted with standard 38kV protection. When protection studies indicate unacceptable breaches of protection performance, this option will not be feasible.

Where such a tee is part of a LCTA connection method fed by overhead lines, a minimum of two 38kV Load Break Fault Make Switches (LBFM) 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 all UG cable; a tee connection will no longer be technically acceptable and alternative approaches will be looked at.

6.5.10 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 must be possible to accommodate the full MEC on normal and standby 38kV circuits.

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

6.5.11 Impact on System Short Circuit Levels

In assessing a generator connection, the impact of the proposed generator[s] on the existing short circuit levels should 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.

6.5.12 Harmonic Distortion Limits

A schedule of individual harmonic distortion limits shall be provided to the generator.

6.5.13 Additional consideration for Battery Energy Storage Facilities

The import and export components of a battery energy storage application shall be studied separately. Export from battery energy storage shall be treated similarly to Distributed Generation in terms of technical study, with additional technical requirements to ensure compliance with the potential voltage fluctuation levels associated with activation of the facility. The import component of the battery energy storage facility may on a non-secured basis and this will be defined in the Connection Agreement.

The mode of operation of the facility will depend 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 will be based only for the system service(s) applied for by the Applicant. Provision of different system service will 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, a more detailed study may need to be performed, and more stringent individual limits may be applied, as the cumulative impact of operation is what will be experienced by the system.

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. This maximum power swing shall apply regardless of whether the facility is importing power, fully charged (and neither importing nor exporting power) or exporting power, at the time of activation.

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.

6.5.14 Security Implications

Indicative and illustrative security implications for distributed generators are shown in Annex E.

6.5.15 Impact on Distribution System Stability

Where there are concerns that a large generator (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 identify necessary changes to, for example, protection operating times or drive specific remedies, these must be in place before the generator in question is connected.

6.6 Description of Non-Secured Access Arrangements for Transformer Capacity

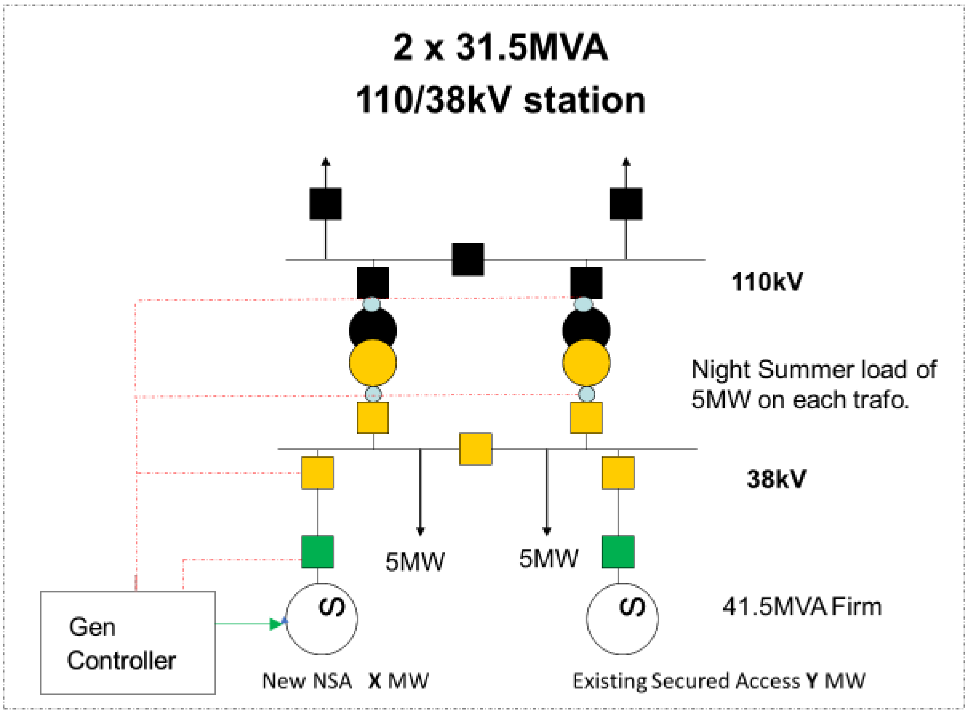


Figure 3 Arrangements for NSA Transformer Capacity in 38/MV Station looped from 110/38kV Station

In Figure 3, a typical 2 x 31.5MVA 110/38kV Station is shown, feeding generation at 38kV via dedicated 38kV circuits.

There are 2 x 31.5MVA Transformers installed and a minimum load of 10MW on the station.

An existing generator of capacity Y MW is already connected.

The available capacity in the 110/38 station for generator connection is 41.5MVA based on the fact that even with the loss of 1 x 31.5MVA transformer, generator output of up to 41.5MVA could be accommodated, with 10MW being absorbed by station minimum load and the remaining 31.5MVA being transferred upstream through the remaining 31.5MVA transformer.

However, no further generation can be accommodated at the station without overloading the remaining 31.5MVA transformer.

A simplified description of the 'Non-Secured Access (NSA)' Arrangement proposes that the available generation capacity which could be accommodated would be assessed based on the Total Transformer Capacity plus Minimum Load *prior* to the loss of a transformer. This means that in normal circumstances a further 31.5MVA of generation could be accommodated at the station (assuming no other constraints upstream).

In order to ensure that the remaining 31.5MVA transformer was not overloaded in the event of loss of one transformer, the NSA Generator would have its generation restricted by tripping off immediately (Option 1), or in a more sophisticated approach (Option 2) ramping output down to match the capacity available.

A loss of either transformer is detected by signals from the Transformer Circuit Breakers ('CB's) with the signal paths shown by the dotted red lines.

Option 1:

Signals are received by a 'Generator Controller' which trips the NSA Generator CB and removes it from the network. In the event that the Generator CB does not operate a backup signal is sent to ESB Networks CB in the 110/38 Station which trips the 38kV circuit feeding the generator.

Option 2:

Signals are received by the 'Generator Controller' but the signal received indicates the capacity level to which the NSA generator must ramp down. In this situation the NSA Generator does not trip but continues for export albeit at a reduced level. Similar to Option 1, if the Generator does not ramp down sufficiently ESB Networks CB is tripped to remove the generator.

In both Options 1 & 2 loss of the signal from the Generator Controller due telecommunications issues disconnects the generator from the station, so the reliability of the communications system is critical and duplicate communication paths are likely to be required.

Option 2 is more complex than Option 1 to implement although it has the advantages of minimising generation restrictions and avoiding abrupt voltage changes. However it would need to be set up such that variations in generator output associated with matching the remaining capacity available did not lead to instability of overshooting of target levels.

Accordingly, it is proposed that initially Option 1 is trialled by ESB Networks and Option 2 developed following successful operational performance of Option 1.

Furthermore, in more complex arrangements with multiple generators it is proposed that available capacity is allocated 'pro-rata' amongst all NSA Generators, regardless of the order in which they received their Connection Agreements, so that operation of the system is simplified and more generator capacity can be connected (this is covered in more detail overleaf).

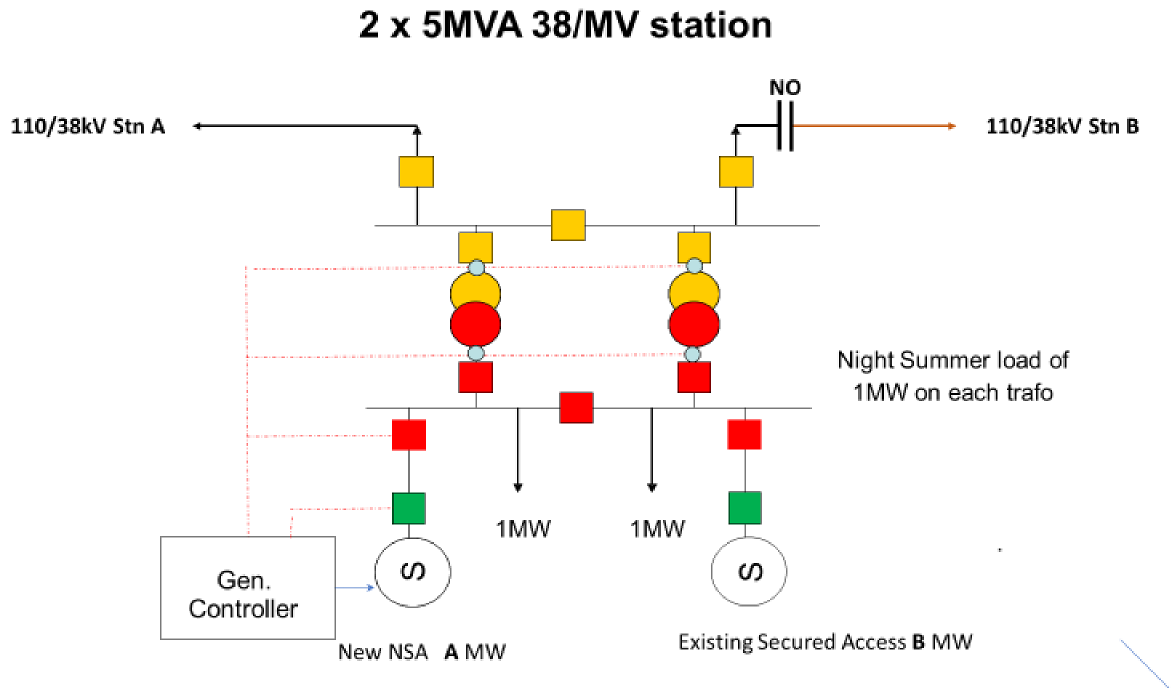


Figure 4 Arrangements for NSA Transformer Capacity in looped 38/MV Station

In Figure 4, a typical 2 x 5MVA 38/MV Station is shown, fed at 38kV from 110/38kV Stn A and with standby from 110kV Stn B.

There are 2 x 5MVA Transformers installed and a minimum Load of 2MW on the Station.

An existing Generator of Capacity B MW is already connected.

The available capacity in the 38/MV Station for Generator connection is 7MW, based on the fact that even with the loss of 1 x 5MVA transformer, generator output of up to 7MVA could be accommodated, with 2MW being absorbed by station minimum load and the remaining 5MW being transferred upstream through the remaining 5MVA Transformer.

However no further Generation can be accommodated at the station without overloading the remaining 5MVA Transformer.

In the proposed 'Non-Secured Access (NSA)' Arrangement the available generation capacity which could be accommodated would be assessed based on the Total Transformer Capacity plus Minimum Load *prior* to the loss of a transformer. This means that in normal circumstances a further 5MVA of generation could be accommodated at the station (assuming no other constraints upstream).

In order to ensure that the remaining 5MVA transformer was not overloaded in the event of loss of one transformer, the NSA Generator would have its generation restricted by tripping off immediately (Option 1), or in a more sophisticated approach (Option 2) ramping output down to match the capacity available.

A loss of either transformer is detected by signals from the Transformer Circuit Breakers ('CB's) with the signal paths shown by the dotted red lines.

Option 1:

Signals are received by a 'Generator Controller' which trips the NSA Generator CB and removes it from the network. In the event that the Generator CB does not operate a backup signal is sent to the ESB Networks CB in the 38/MV Station which trips the circuit feeding the generator.

Option 2:

Signals are received by the 'Generator Controller' but the signal received indicates the capacity level to which the NSA generator must ramp down. In this situation the NSA Generator does not trip but continues for export albeit at a reduced level. Similar to Option 1, if the Generator does not ramp down sufficiently the ESB Networks CB is tripped to remove the generator.

In both Options 1 & 2 loss of the signal from the Generator Controller due telecommunications issues disconnects the generator from the station, so the reliability of the communications system is critical and duplicate communication paths are likely to be required.

Accordingly, it is proposed that initially Option 1 is trialled by ESB Networks and Option 2 developed following successful operational performance of Option 1.

Furthermore, in more complex arrangements with multiple generators it is proposed that available capacity is allocated 'pro-rata' amongst all NSA Generators, regardless of the order in which they received their Connection Agreements, so that operation of the system is simplified and more generator capacity can be connected (this is covered in more detail below).

NSA under 'real world' considerations:

As can be seen from this description it is very similar to the operation proposed in Fig 1 for 38kV connections to 110/38kV stations and this is because in these simplified descriptions the impact of upstream capacity issues has not been considered.

In current generator connections capacity upstream cover other contingencies such as back feeding from the 38kV circuit and 110/38kV transformer capacity. However, in the NSA proposals this capacity is not considered as a requirement and in the event of an upstream contingency the NSA Generators will also trip/be restricted.

This approach is necessary as otherwise:

a) The NSA approach requires extra cost and delay in ensuring extra capacity on upstream networks.
b) The NSA approach would require upstream capacity to be continuously available, although the main connection to the NSA would be less reliable. In effect this could result in upstream (higher voltage) Generator connections incurring extra costs to secure capacity that was being reserved for occasional use by downstream NSA Generators.

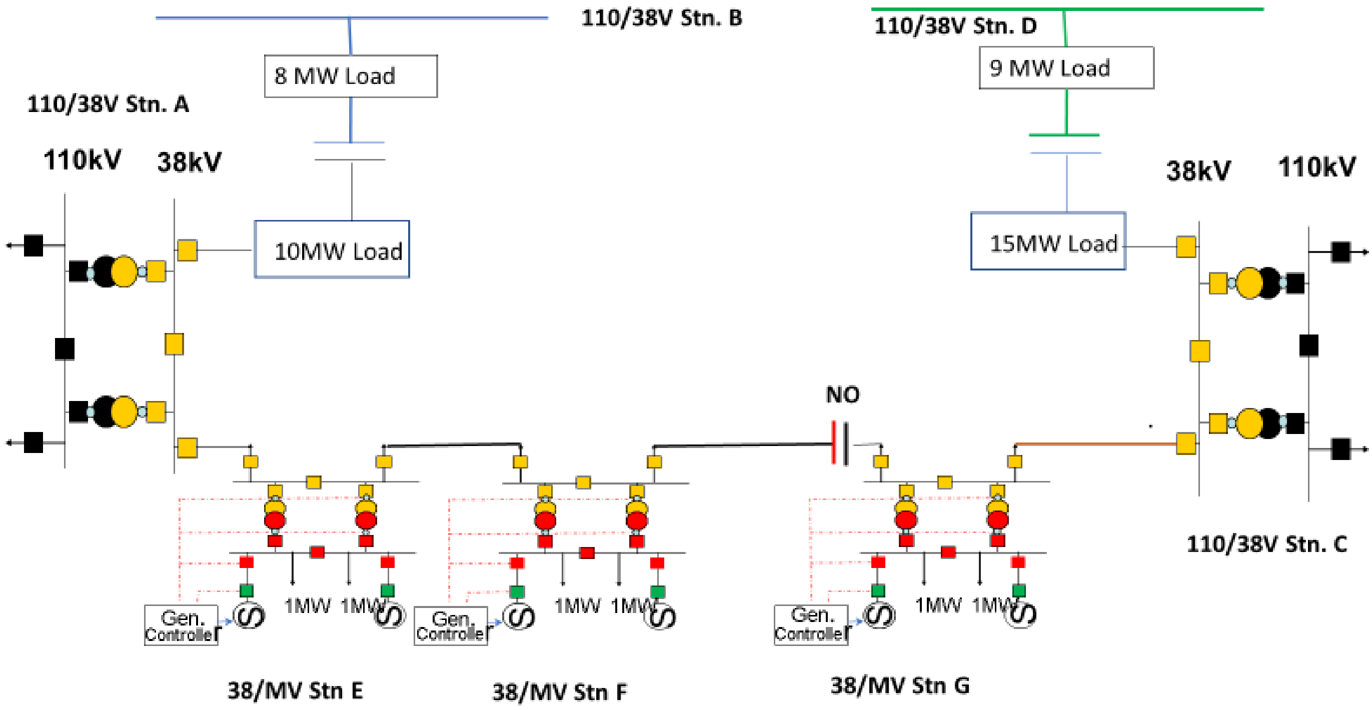


Figure 5 Implementation of NSA in actual Network conditions

In Figure 5, a more complete description of a typical network is provided.

There is a 38kV circuit shown between 110/38kV stations A and C, on which three 38/MV Stations are looped, with 38/MV stations E and F fed from 110kV Station A, and 38/MV Station G fed from 110/38kV Station C. There is a Normally Open Point on the 38kV circuit between the 38kV stations F and G.

Each of the 38/MV Stations also has an NSA Generator connected.

Additionally, 110/38kV Station A has another 38kV circuit feeding 10MW of load/generation with standby from 110/38kV Station B via a 38kV Station carrying 8MW of load/generation.

There are similar arrangements between 110/38kV stations C and D which are interconnected by a 38kV circuit carrying 15 and 9MW of Load/Generation.

<u>Next consider the situation where the Customers described as 'Load' on the diagram are actually Generation.</u>

So the additional issues now arising are as follows:

- If there is a fault on the 38kV Circuit between 110kV Stations A and C, then all the 38kV Stations and their associated NSA Generation will now be transferred to either 110kV Station A or 110/38kV Station C, and the associated 38kV Circuit will carry the full amount of normal and NSA generation connected to 38kV Stations E, F and G.

  If the 38kV Circuit is then overloaded then NSA generation must be reduced, so that communications are required between the 38kV Feeders at 110/38kV Stations A and C and every NSA Generator & 38kV Station on the full 38kV Circuit (Station's E, F & G), both normal and standby.

- If there is a fault on the 38kV Circuits between 110kV Station A and B, or between 110kV Stations C and D, then extra generation will be added to the 110/38kV Transformers in these Stations and if the 110/38kV

Transformers are overloaded then the NSA Generators on any 38kV circuits fed from the 110/38kV Station must be restricted.

This requires communication between 110kV Stations A and every 38kV Station with NSA Generation on every 38kV Circuits fed from 110kV Station A. Similar requirements are required for 110kV Station B.

As can be appreciated from the example above, the level of complexity has increased exponentially and as failure to respond to such scenarios will cause overloading and damage to plant (as well as associated safety issues), all such eventualities must be addressed by the system installed.

Furthermore, it can be seen that attempting to apply any disconnection order is increasingly complex as the NSA Generators involved may now be fed from circuits and transformers to which they were not normally connected. This means that the simplest and most effective response is simply to ramp down all NSA generators to the capacity available, so that order of connection to a particular set of assets is not an issue.

For the purpose of establishing the feasibility of NSA Generator connections in relation to Transformer Capacity it is initially proposed to only trial such connections <u>where there are no relevant restrictions on either the 38kV Circuits or the 110/38kV Stations</u>. This simplifies the initial arrangements and allows time to develop the more sophisticated communications systems required to appropriately manage contingencies with greater amounts of NSA Connections.

For the avoidance of doubt, NSA Generator connections in such a trial will not have 'Secured' connections for issues on 38kV Circuits and 110/38kV Stations, just that in the initial trial such restrictions are not likely to arise and pose restrictions. When more sophisticated communications systems are installed these NSA Generators will be restricted for issues on associated 38kV Circuits and 110/38kV Stations.

Further Considerations:

- **Connection of additional NSA Generation can also lead to Voltage Rise Issues under contingency feeding arrangements, so that the creation of excessive voltage rise at points on the network will also require reduction of NSA Generator output to mitigate the effect. This will require additional communications and control.**

- **Voltage disturbances caused by switching NSA loads could become an issue but could likely be mitigated by ramping changes in NSA output rather than simple disconnection.**

- **Increases in Short Circuit levels may also become an issue, although less likely in rural areas where impedances are high due to circuit lengths.**

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

7.1 Least Cost Technically Acceptable Solution

In the context of demand connection projects and network development projects, the Least Cost Technically Acceptable (LCTA) solution is defined as the option which is technically acceptable, which results in the minimum charge to the customer (or the End-User, as appropriate) and which facilitates the long term development of the electricity network in the area.

In the context of generation, and in particular in a group processing approach, the LCTA solution will take account of the sub-group as a whole, where applicable.

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

7.2 Non-Wires Alternatives:

Having arrived at an LCTA for a conventional reinforcement, a Non-Wires Alternative (NWA) solution is automatically considered as an option for demand customer connections and distribution network demand reinforcement.

In general, it is proposed that the following framework be used to assess the suitability of NWA solutions.

The first stage in the assessment is against specific exemption criteria to rule out unsuitable projects. For example:

- Assets with a Load Index of LI5 will not be considered for a NWA solution.
- Where the reinforcement is into an asset that requires replacement for condition or obsolesce reasons that supersede the demand rationale.

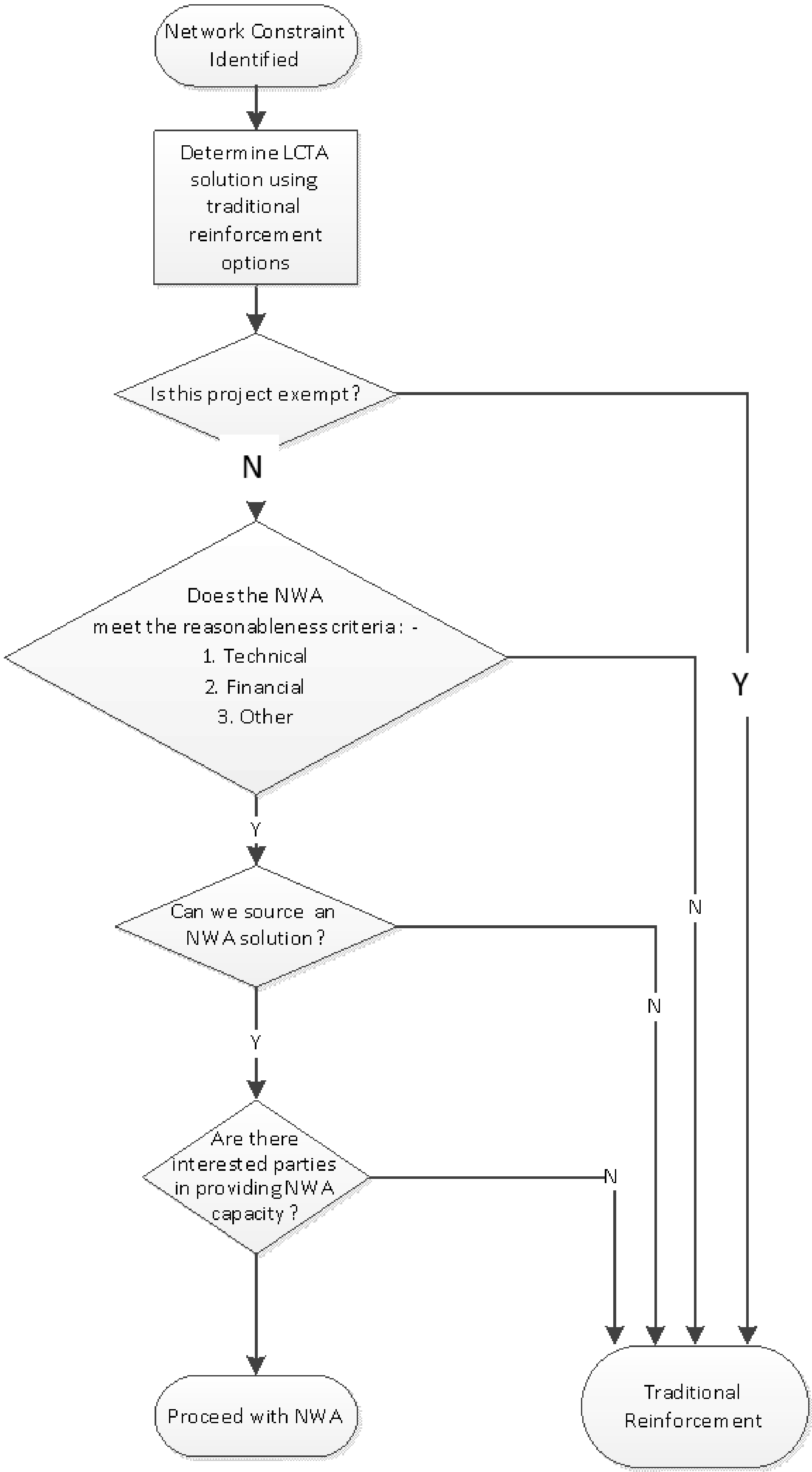
However, consideration of temporary NWA solutions during the construction phase of other projects may be sought to reduce potential planned outage difficulties or to facilitate project progression.

The next stage in the assessment will be against technical, economic, timeline and feasibility criteria. For example:

- Feasibility of a solution being procured and delivered in the required timeline. For instance, it may be more straightforward for a demand response service provider to coordinate a flexibility solution from large or medium industrial or commercial customers than from a larger number of smaller customers.
- Consideration of existing built environment and land use may be taken into account. For instance, a dense urban or a suburban area may not be suitable for a larger utility scale energy storage site, or location of a Distributed Generation unit.
- Cost Benefit Analysis - A NWA solution will be sought where the lifetime economic value of the NWA solution is less than the corresponding value of the deferral or delay to the reinforcement project. This may be based on a number of factors, including:

    - The net value from the NWA solution which is a function of a number of factors, such as investment deferral period, transaction and implementation costs, impact on future reinforcement costs, impact of the deferral on capability of making new connections, etc.
    - The setup and operational cost of the commercial enquiry itself and other administrative costs.
    - Accepted industry costs for provision of NWA solution options (e.g. €/kWh or €/kVA for energy storage, diesel generation, etc.) may be used.

Figure 6 Indicative NWA Process Flowchart



Annex A. Guidance on Voltage Control

A.1. Contingency Operating Range

In the event of voltage dropping outside the contingency operating range, the option of shedding load to avoid damaging customer equipment should be considered.

A.2. 38kV Network Volt Drop Allocations

Voltage on the 38kV sub-transmission system shall 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 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.

The voltage spread is determined by the tapping range of the 38kV/MV transformers. There is an additional margin of flexibility in the MV bandwidth (+/- 1%) that relieves some of the voltage pressure on the 38kV system. Collectively, this translates into allowable voltage drops on the 38kV system. Some of the available voltage drop is required for the 38kV voltage regulation in the 110/38kV stations. Another portion is required for voltage drop in the 38kV/MV transformers. The remainder is available to the 38kV networks. See Table 12 for Standard 38kV Volt Drop Allocation.

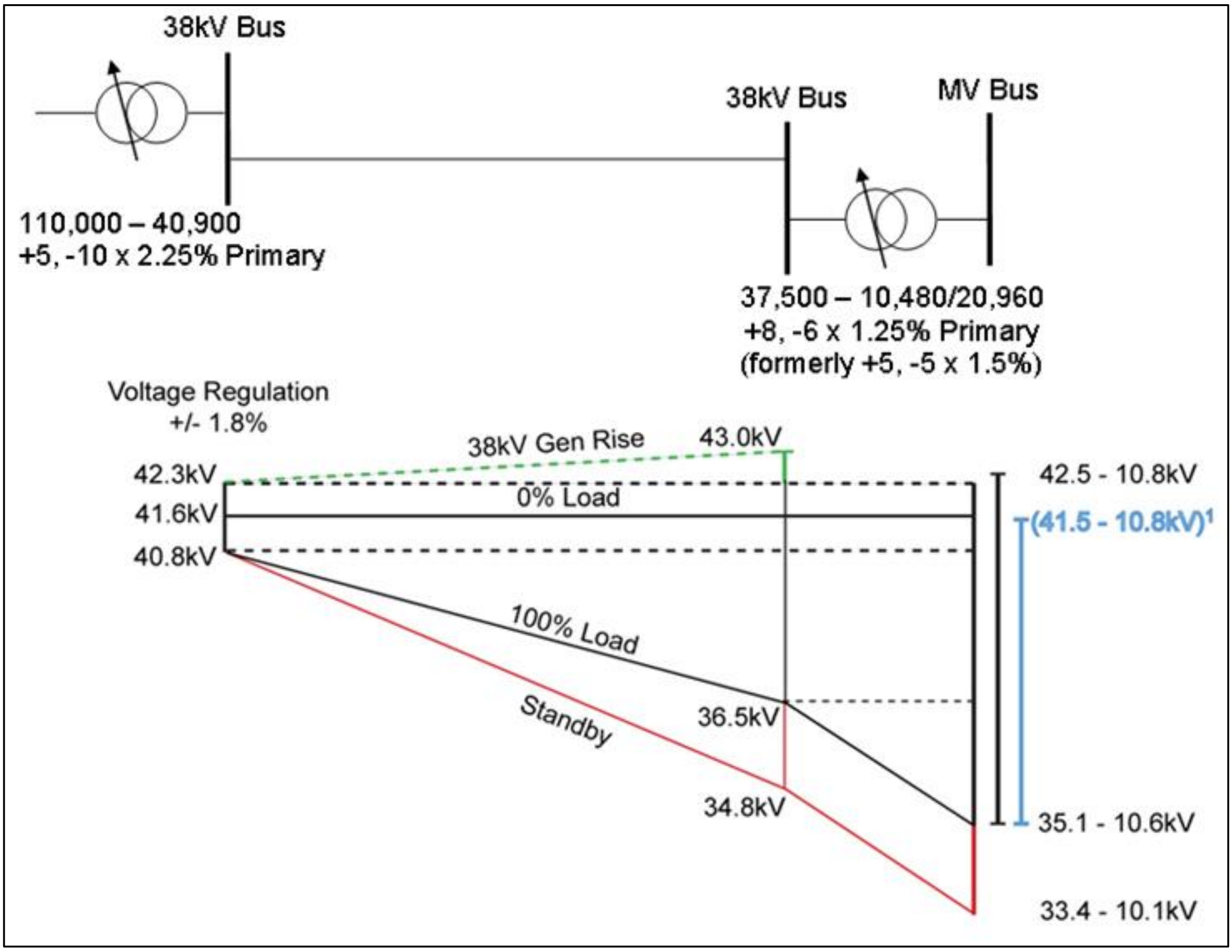
Table 12: Standard 38kV Volt Drop Allocation

Network Element	Normal Allocation	Standby Allocation
Voltage Regulation	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 a MV or LV

The alignment of voltages on the 38kV system is illustrated in Figure 7.

Figure 7: 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.

The tap step width on 110/38kV transformers is 2.25%. So 2 x 80% x 2.25% = 3.6% is needed for voltage regulation. Representative 38kV/MV transformer voltage drops are taken for normal loading at 90% and emergency loading at 180% of load rating. The nominal 38kV/MV transformer ratio of 37,500 – 10,480/20, 960 should be scaled to the actual MV operating voltage, e.g. 38,500 – 10,750/21,500.

The ideal voltage regulation set point for the 38kV bars in 110/38kV stations is 41.6kV. In rural situations, where there is always some voltage drop and little prospect of voltage rise at light load and where the 38kV/MV transformers have an extended tapping range (+8, -6 x 1.25% or +7, -5 x 1.5%), this set point can be used. In urban situations, where voltage rise problems can arise on cabled networks or where the 38kV cables are old or in poor condition, the voltage regulation set point can be dropped to 40.8kV. Also, where there are older 38kV/MV transformers with a reduced tapping range (+5, -5 x 1.5%) near the 110kV station, the voltage regulation set point may need to be dropped to 40.8kV. In all cases, the receiving voltage limits in 38kV/MV stations should remain in kV terms, as indicated in Table 13.

For standby feeding, customer service voltage can drop outside normal standards by a margin 5%. Provided this contingency allocation is not already used on the MV/LV networks, it can be availed of to allow the MV voltage to drop to 10.1/20.2kV on the MV bars in a station. This corresponds to an additional allowed voltage drop on the 38kV bar to 34.8kV. Such contingency conditions shall be limited in extent and duration.

Table 13: 38kV Voltage Limits

Sending Voltage – kV	
Set Point	Range
Nominal - 41.6	40.8 - 42.3
Rural/OH - 41.6	40.8 - 42.3
City Network - 40.8	40.1 - 41.5

Receiving Voltage – kV 38kV Bar
Maximum - 42.5
Minimum Normal - 36.5
Minimum Standby - 34.8

A.3. 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.

A.4. MV Volt Drop Allocations

In order to preserve customer service voltage within supply quality standards, voltage drops on the distribution networks need to be controlled.

Voltage is regulated on the MV busbars. The bandwidth for voltage regulation is typically set to +/- 80% of a transformer tap step width. Thus for a 38kV/MV transformer with 1.25% taps the voltage regulation bandwidth would be +/- 1% about the voltage set point V_S. Thereafter voltage drops within the downstream MV and LV networks have to be kept within the allowed limits to maintain customer service voltage.

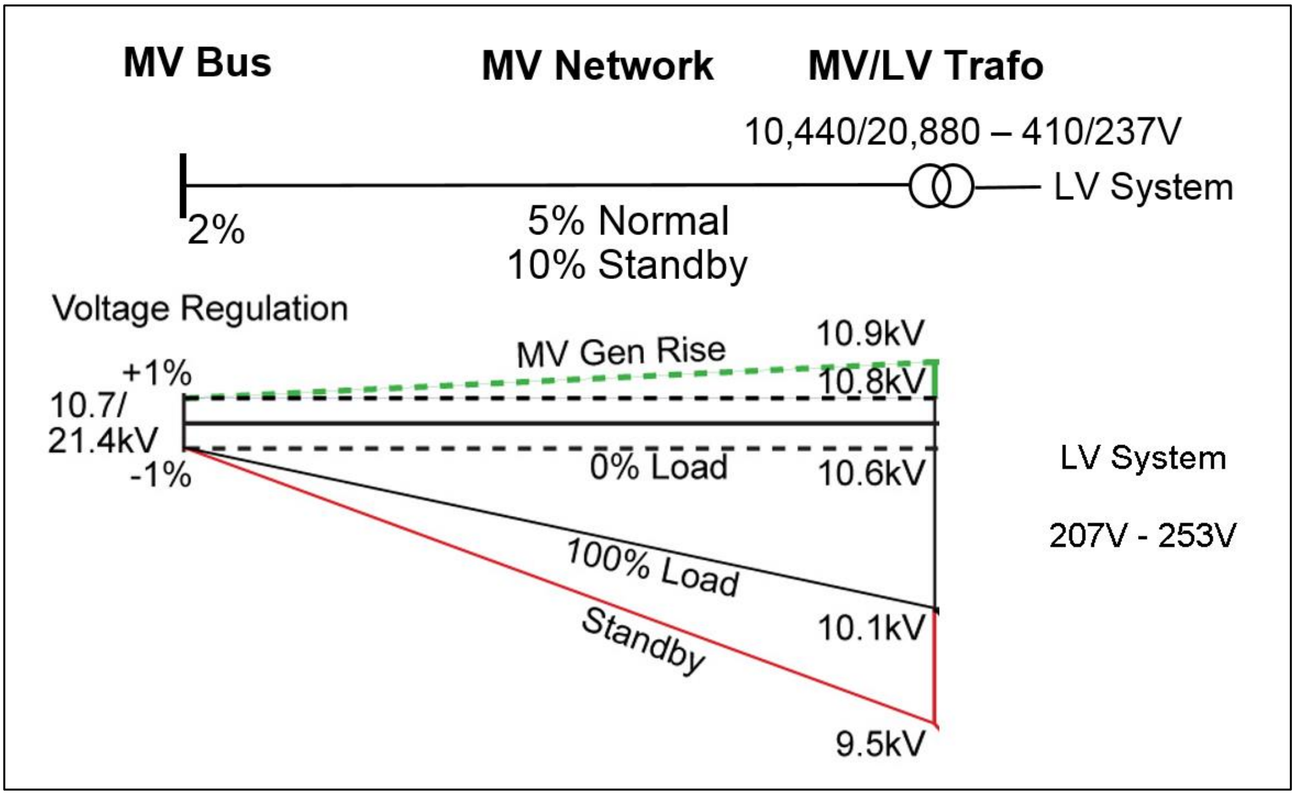
Voltage drops within MV network elements shall be planned to maintain the voltage within the limits defined in Table 14. Thus for peak design load on networks the voltage drops should not exceed these limits. Where voltage drops on a three-phase network are determined on a phase by phase basis, the worst phase volt drop should comply with these limits.

Table 14: Standard MV/LV Volt Drop Allocation

Network Element	Normal Allocation	Standby Allocation
Voltage Regulation	2%	
MV Network	5%	10%

The alignments of voltages on the MV system is illustrated in Figure 8.

Figure 8: MV/LV Voltage Control



The allocations add up to somewhat more than the allowed service voltage spread because some allowance is made for diversity between peak load conditions on the MV and LV networks. For standby feeding, the volt drop allocation on MV networks is doubled.

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 will not be in the foreseeable future, the unused allocation can be used in a downstream LV network. This situation can arise for example with urban cabled MV networks.

Where there is local MV generation on an MV network, the voltage on the MV network is allowed to rise 1% above the top end of the normal voltage range in the absence of generation.

A.5. Use of MV regulators

Where MV network volt drops exceed limits, network voltage regulators may be used to compensate. 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 portion of the voltage boost is lost to compensate for the increase in upstream current. The effective downstream boost is decreased by this amount. For example, if we have a volt drop of 10% and apply a 10% boost we only get an effective downstream boost of about 8%. 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.

Regulators should be installed near the point in the network where the volt drop reaches 90% of the allowed limit. Boosters should be placed on the basis of 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.

Annex B. Guidance on 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.

Annex C. Requirements for a Terminal Substation

A terminal substation may be required at the customer site, depending on a number of factors as set out below. The customer should engage with ESB Networks on the requirements applicable during the early stages of project development.

Demand Connections:

Requirement 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 appropriate 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 will be indoor, whereas those in more rural locations will be outdoor (subject to a suitability study).

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 the table below. Please note that these requirements are in addition to those outlined in 3.2.3 below.

Maximum Import Capacity (MIC)	Customer requirement for the provision of a Substation Building and Site
≥ 5MVA	HV/MV Terminal Substation will be required in most cases 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 planned requirements available on existing substations and on the local MV network • The Customer's future expansion plans

Requirements for a MV Terminal Substation and Site

MV connected customers are required to provide an MV Terminal Substation Building and site to comply with the standard ESB Networks' MV Substation Building Specification in all cases. A customer MV Switchroom housing the customer owned main incoming circuit breaker will be required to be located immediately adjacent to and adjoining the ESB Networks substation building.

Requirements for a MV/LV Transformer Substation

Where an ESB Networks MV/LV transformer substation is required, a customer LV Switchroom housing the customer owned switchgear will be required to be located immediately adjacent to and adjoining the ESB Networks substation building.

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

Generator Connections:

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

Given the additional complexity of group processing, potential interaction between generation connections and other criteria, the specific substation and site requirements for a generator shall be advised during the application process.

Annex D.Harmonic Levels

Table 15: 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 E.Security Implications for Generator Connections

Connection to the Generator via Single Item of Plant

Depending upon the nature and topology of the connection method offered for a generator connection, one or more generators may be connected via a single item of plant, hereinafter referred to as "the single item of plant". An example would be where one or more generators are connected via a new dedicated transformer.

Any fault outage which causes the single item of plant to be unavailable will result in an outage of the Generator.

In the event of a planned outage which causes the single item of plant to be unavailable, this will also result in an outage of the Generator. In such an event, the Generator will be notified as per the Distribution Code DPC 4.4.3.

Examples of these occurrences for various topologies are given in the following Sections.

Tail Fed and Single Transformer Stations

__**Connection to the Generator is Made Through a New Generation Only Tail Fed Transformer Station**__

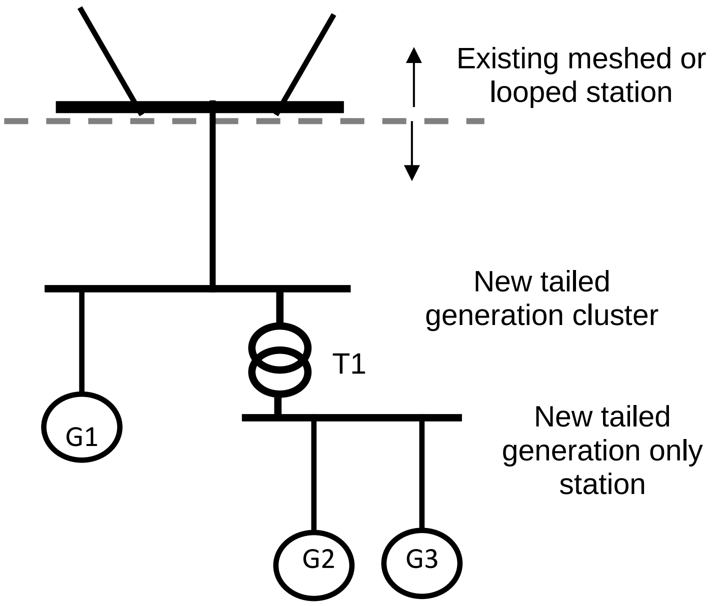


Figure A

- As depicted in Fig A above, any outage to the higher voltage line/cable feeding the tailed station or tailed station busbar will cause an interruption to G1, G2 and G3. A connection will not be restored to the generators in question until such time as the line/cable in question is restored to service.
- As depicted in Fig A above, any outage to the transformer T1 will cause an interruption to G2 and G3. A connection will not be restored to the generators in question until such time as T1 is restored to service.
- In the event of planned outage, the Generator will be notified as per The Distribution Code (DPC 4.4.3).

Connection to the Generator is Made Via an Existing/Proposed Tail Fed or Single Transformer Station, Supplying Demand

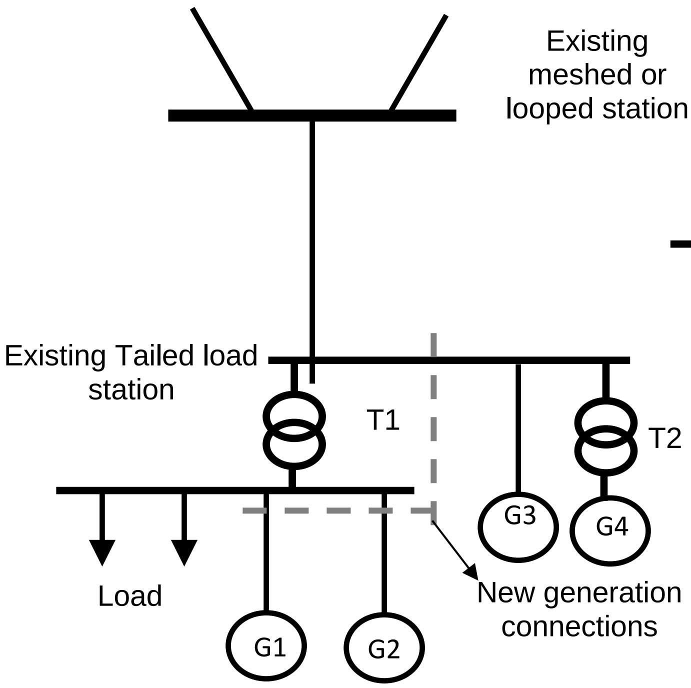


Figure B

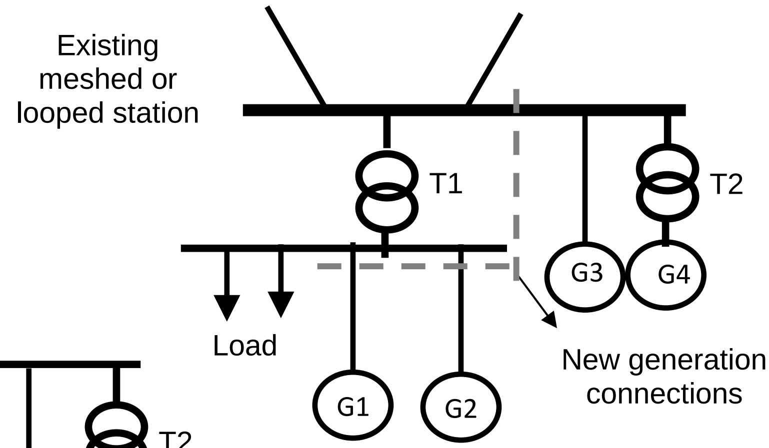


Figure C

- As depicted in Fig B above, any outage to the higher voltage line/cable feeding the tailed station or tailed station busbar will cause an interruption to G1, G2, G3 and G4.
- As depicted in Fig B and C above, any outage to the transformer T1 will cause an interruption to G1 and G2.
- As depicted in Fig C above, if the looped station is single busbar, an outage of the half busbar at the looped station to which G3 and G4 is connected, will cause an interruption to G3 and G4.
- In the event of planned outage, the Generator will be notified as per the Distribution Code.

Connection to Lower Voltage Busbar of New-Build Station for Generation

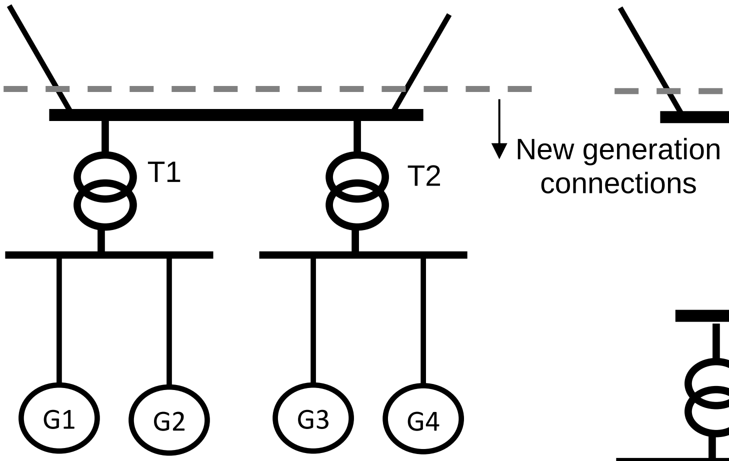


Figure D

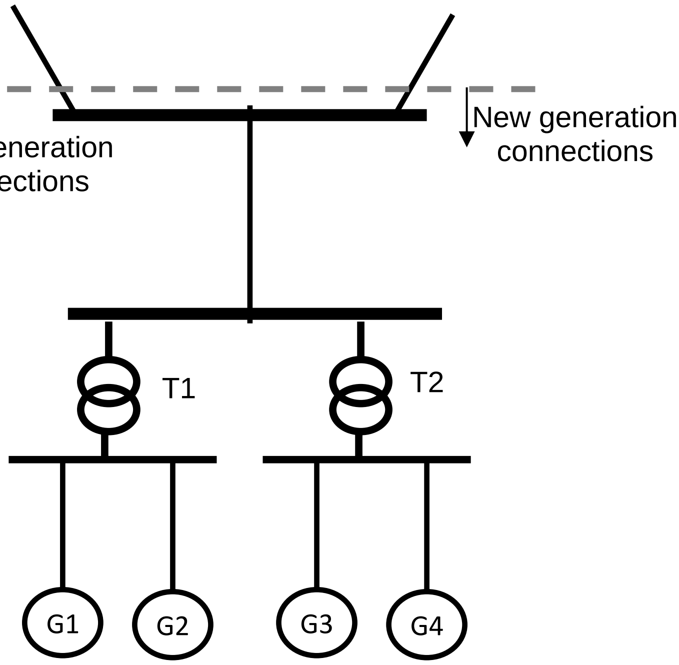


Figure E

- Unless otherwise agreed, redundancy of the transformers is not a consideration in the design of the station. i.e. effectively the transformers in question each operate similar to tail fed single transformer stations and do not provide standby to the other.
- As depicted in Fig D and E above, any outage to the transformer T1 will cause an interruption to G1 and G2. A connection will not be restored to the generators in question until such time as T1 is restored to service.
- As depicted in Fig D and E above, any outage to the transformer T2 will cause an interruption to G3 and G4. A connection will not be restored to the generators in question until such time as T1 is restored to service.
- As depicted in Fig E above, any outage to the higher voltage line/cable feeding the tailed station or tailed station busbar will cause an interruption to G1, G2, G3 and G4. A connection will not be restored to the generators until such time as the high voltage line/cable is restored to service.
- In the event of a planned outage, the Generator will be notified as per the Distribution Code.
- Where there are multiple lower voltage busbar sections, separated by open busbar sectionalising Circuit Breakers, in the event of loss of a transformer due to a fault, adjacent bus sectionalising Circuit Breaker(s) will not be closed through Operator intervention

Connection to Lower Voltage Busbar of a Conventional Transformer Station for Demand with Two Transformers

This section sets out the operational implications of the proposed feeding arrangement. The capacity available is set out in the relevant section above.

<u>Where the Lower Voltage Busbar is Operated Solid</u>

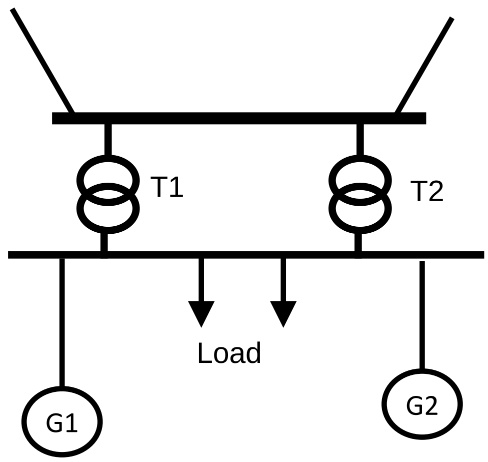


Figure F

- Any individual planned outage of T1 or T2 will not in general result in an outage of G1 or G2.
- A fault on T1 or T2 could result in an outage for G1 and G2.
- Any fault on the lower voltage busbar will result in an outage of the G1 and G2.

Where the Lower Voltage Busbar is Operated with a Normally Open Circuit Breaker in the Station

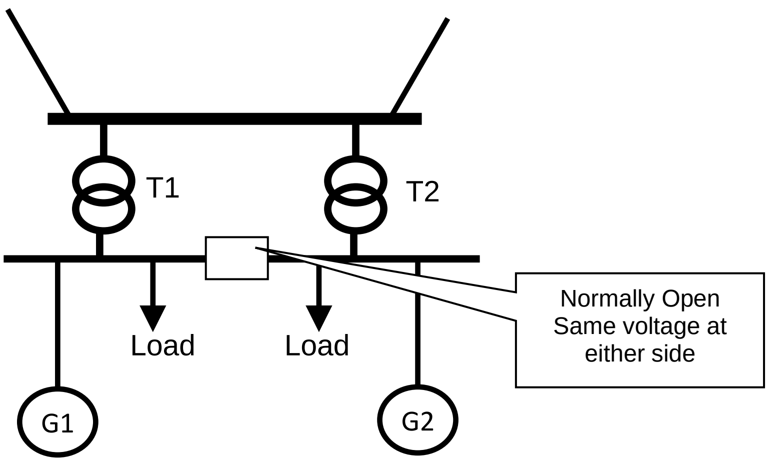


Figure G

- Any planned outage of the transformer or half busbar which normally feeds the Generator will not result in an outage of the Generator, unless otherwise part of the connection arrangement.
- Any fault outage of the transformer which normally feeds the Generator will result in a temporary outage to that Generator until the lower voltage sectionalising Circuit Breaker is closed through Operator intervention, unless otherwise part of the connection arrangement.

Where the Lower Voltage Half-Busbars are Operated at Different Voltages and are Coupled by an Inter-Tie Transformer via a Normally Open CB

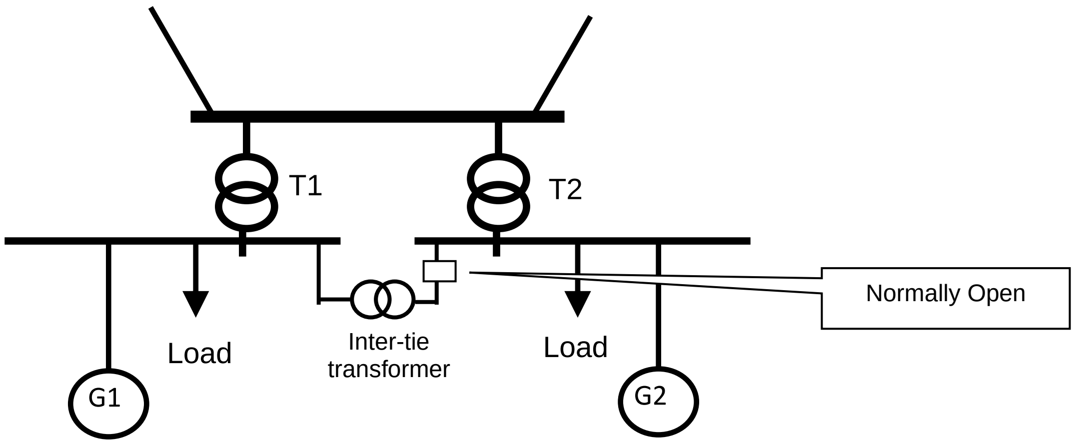


Figure H

- Any fault outage of the transformer which normally feeds the Generator will result in an outage of the Generator.
- A planned outage of T1 or T2 may result in an interruption G1 or G2 depending upon the size of the generation relative to that of the inter-tie transformer.

Planned Outages

Whilst every effort will be made to minimise necessary planned outage time, any works carried out during a planned outage which affects the Generator, shall unless otherwise agreed, be done during normal working hours. In the event that the Generator seeks to reduce the time of the outage through the working of additional hours and/or weekend work, this will only be done with prior agreement of ESB Networks and at the Generator's costs.