Marlborough Lines Network Standard

DN016 – LV DG Connection and Operation Standard

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1 General

1.1 Purpose

This connection and operation standard details the requirements for connecting Low Voltage Distributed Generation (LV DG) to the Marlborough Lines (MLL) Network.

MLL is required to comply with a broad range of obligations relating to safety and reliability. Prior to connecting any DG system to the network, MLL must assess the requirements of all relevant regulations and standards, as well as the system's potential to impact:

- safety of our staff and contractors working on our network
- the quality of supply to all customers on the local low voltage (LV) network
- correct operation of the DG
- the customer's point of supply
- network protection

1.2 Scope

Embedded Generation (EG) is considered as one or more generating units embedded within an installation. The term EG will be used throughout this standard as it is specific to generation at one location. Distributed Generation (DG) is considered as the collection of EG, distributed throughout MLL's network.

The voltage at the point of connection to MLL's network determines which standard applicants shall follow. This standard covers low voltage (LV) connected DG. Connection requirements for high voltage (HV) connected generators are defined in Marlborough Lines' HV DG Connection and Operation Standard.

This standard applies to new (or modifications of any) LV EG with a total system capacity no greater than 1000 kVA and capable of operating in parallel with any part of the distribution network. This could include Inverter Energy Systems (IES) – with energy sources such as solar, wind, hydro, energy storage systems (batteries) or electric vehicles (where export capable) – or rotating machines such as grid-tied diesel generators.

This standard does not cover standby generators isolated from the distribution network nor any other isolated generation. If there is a closed electrical circuit between MLL's network and the output of the generator, then the system is defined as operating in parallel to the network irrespective of whether it is exporting power or not.

This document shall be read in conjunction with DN014 DG Connection Policy.

This standard is approved for external release.

1.3 References, Standards and Codes

The following documents are referred to in this standard or provided background material for the development of this standard:

MLL Document	Description
DN005	Network Connection Standard
DN014	DG Connection Policy
DN015	DG Congestion Management
DN017	HV DG Connection and Operation Standard
MLL F36	LV DG Connection Application Form (200kW and less)
MLL F126	LV DG Connection Initial Application Form (> 200kW)
MLL F127	LV DG Connection Final Application Form
MLL F37	LV DG IES Commissioning Form (200kW and less)

External Document	Description
AS/NZS 3000	Electrical installations (known as the Australian/NZ wiring rules)
AS/NZS 3010	Electrical installations - Generating Sets
AS/NZS 4777.1:2016	Grid connection of energy systems via inverters. Part 1: Installation Requirements
AS/NZS 4777.2:2020	Grid connection of energy systems via inverters. Part 2: Inverter Requirements
AS/NZS 5033	Installation and safety requirements for photovoltaic (PV) arrays
AS/NZS 5139	Safety of battery systems for use with power conversion equipment
AS/NZS 61000.3.3	Electromagnetic compatibility (EMC) Part 3.3 Limits - Limitation of voltage changes, voltage fluctuations and flicker in public LV supply systems, for equipment with rated current less than or equal to 16A per phase and not subject to conditional connection.
AS/NZS 61000.3.5	Electromagnetic compatibility (EMC) Part 3.5 Limits - Limitation of voltage fluctuations and flicker in LV supply systems, for equipment with rated current greater than 16A.
AS/NZS IEC 62116	Utility-interconnected photovoltaic inverters – Test procedure of islanding prevention measures
CEC Inverter List	Australian Clean Energy Council Approved Inverter List. Found here.
Electric Vehicle Charging Safety Guidelines	Worksafe Guidelines for safe electric vehicle charging.
Electricity Safety Regulations (ESR)	NZ Regulations to ensure the health and safety of members of the public and prevent damage to property. Found here.
Electricity Industry Participation Code (EIPC)	The Electricity Authority's Electricity Industry Participation Code 2010 (the Code) governs how the electricity market operates. In particular, Schedule 6.1 (of Part 6) describes the processes for obtaining approval to connect distributed generation.

EEA Guide	EEA Guide for the connection of Small-Scale Inverter Based Distributed Generation 2018

1.4 Definitions and Abbreviations

The following definitions are referred to in this information pack:

Definition	Explanation
Anti-islanding Protection	A protection system to detect islanded conditions and disconnect embedded generating systems from the distribution network.
Certificate of Compliance (COC)	Registered electrical workers must audit their own work and fill out a certificate of compliance as proof that they have complied with electrical safety standards and codes. A customer should request the COC from their electrical contractor when work is completed. MLL will need to see the COC before connecting the electrical installation to our distribution network.
Distributed generation (DG)	Generation installed at a customer's installation that is capable of exporting electricity back into the local network. When viewed from MLL's perspective the generation is distributed throughout our network.
Energy Storage System (ESS)	A system comprising one or more batteries (or alternative technology) that store electricity generated by Distributed Energy Resources (DER) or directly from the grid, and that can discharge the electricity to loads.
Embedded Generating System (EG)	One or more generating units embedded behind an installation control point (ICP).
Installation Control Point (ICP)	A point of supply on a local network or an embedded network which the distributor nominates as the point at which a retailer will be deemed to supply electricity to a customer.
Installation	A complete electrical installation from the point of a service main connection to the network, to the most remote circuit supplied by the switchboard.
Inverter Energy System (IES)	A system comprising one or more inverters together with one or more energy sources (which may include an ESS) and controls, where the inverter(s) satisfies the requirements of AS/NZS 4777.2.
Maximum aggregate system capacity	The sum of nameplate ratings for all EG within an installation.
Point of Connection (POC)	A point at which electricity may flow into or out of our network.
Point of Supply	The point at which electricity equipment that exclusively supplies a property crosses that property boundary.
Single Wire	Parts of the electrical high voltage distribution network that use a single live conductor with the earth as the return current path. All

Earth Return (SWER)	premises are supplied at LV either as single-phase or split-phase electric power.
Total System Capacity	The aggregate nameplate rating (kVA) of all individual EG systems behind the Point of Connection.

The following abbreviations are referred to in this information pack:

Abbreviation or Acronym	Definition
CEC	Clean Energy Council
COC	Certificate of Compliance
DER	Distributed Energy Resources
DRM	Demand Response Mode
DG	Distributed Generation
EG	Embedded Generation
ESS	Energy Storage System
GPR	Grid Protection Relay
HV	High Voltage (> 1kV)
IES	Inverter Energy System
ICP	Installation Control Point
L-N	Line to Neutral Voltage
LV	Low voltage (≤ 1kV)
PV	Photovoltaic
ROI	Record of Inspection
SSDG	Small Scale Distributed Generation (≤ 10kW)
SWER	Single Wire Earth Return
THD	Total Harmonic Distortion

2 Technical Requirements

2.1 Labelling and Signage

All LV EG systems shall comply with AS/NZS 3000.

Labels and signs on IES, including cables, shall meet the requirements of AS/NZS 4777.1, AS/NZS 5033 and AS/NZS 5139.

Examples of signage and labelling required for IES installations are provided in AS/NZS 4777.1, Appendix A. Marking requirements for inverters are detailed in AS/NZS 4777.2, Section 7.

2.2 Maximum System Capacity and Export Limits

The maximum network capacity shall be verified by MLL at the time of application. Where there is no constraint identified, the maximum aggregate system capacity for a standard LV embedded generation connection shall be 1000 kVA.

Where there are multiple generating systems at a premise connected to a single ICP, the system capacity will consider the aggregate of the existing and proposed systems.

Limiting export does not necessarily permit the installation of a larger system to offset onsite load. The disconnection of an EG system can cause site load to rapidly transfer over to the network. This can cause step changes in voltage on both the network and the customer's point of supply, which can affect other customers' quality of supply. As the size of such voltage fluctuations increases with the capacity of the EG system, it is essential to assess the potential impacts on the shared LV network based on the full capacity of the proposed system, rather than on export limits.

2.2.1 Standard Connection - Export Limits at Point of Connection

Most connections will be considered standard. The exceptions are covered in Section 2.2.2

2.2.1.1 LV EG ≤ 10kW

The export limits for EG (≤ 10kW) are fixed and detailed in Table 1 below.

Table 1 EG (≤ 10kW) Standard Connection Export Limits

Network Type	Export Limit	Technical Study Required
Single Phase[1]	≤ 5 kW	No
Two Phase[1]	≤ 5 kW per phase[2]	No
Three Phase	≤ 3.3 kW per phase[2]	No

Note 1: Split-phase transformer connections are to be considered single phase.
Note 2: Multi-phase IES shall meet phase balance requirements in Section 2.3.2.

2.2.1.2 LV EG > 10kW

The export limit shall be assessed and determined during application review. It will be based on:

1. Penetration of DG on the distribution network
2. Asset capacity limits on the distribution network
3. Power quality checks on the distribution network

4. Voltage regulation impacts on the distribution network
5. Distribution network protection impacts

Where technical studies are required to be undertaken, these shall be as per Section 3.

2.2.2 Non-standard Connection - Export Limits at Point of Connection

The following networks are considered non-standard when connecting EG to them.

SWER Networks. These are designed to be low capacity, long radial distribution lines and have technical constraints which limit the capacity of EG connections on LV networks supplied by SWER.

Isolated Networks. These are networks not connected to the main grid and are instead supplied by dedicated remote area power stations (RAPS). The capacity of EG connected to these networks needs to be determined on a case-by-case basis.

The export limits for these types of connections are detailed in Table 2 below.

Table 2 Non-standard Connection Export Limits

Network Type	Export Limit	Technical Study Required
SWER	≤ 2 kW > 2 kW	No Yes
Isolated Network	Any	Yes

2.3 Generation Control

2.3.1 Export limits at Point of Connection

IES shall have a soft limit export control function available. It may be integrated into the inverter(s) or via an external device.

Export limits for different connection types are shown in Section 2.2.1 and 2.2.2. Location specific export limits based on modelled hosting capacity are defined in DN015 - Distributed Generation Congestion Management on MLL’s website.

Where the net export limit is exceeded, the export control function shall operate to ensure the IES meets the export conditions within 15 seconds. For configurations where an inverter provides the power limitation capability, the total cumulative export of all the inverters shall not exceed the approved export limit.

The ability of the customer’s IES to export at the limits described above are not guaranteed and will depend on the characteristics of the distribution network, which may change over time. For example, inverter power output may change where power quality response modes are in operation.

2.3.2 Phase Balance

The IES must have a balanced input and output. The imbalance between phases (with respect to its rating and tolerance) must be no more than 5kVA between any phases as per AS/NZS 4777.1 at the IES point of connection. This imbalance is judged on nameplate capacity.

The addition of a battery inverter to one phase will not be considered in the calculation of phase imbalance.

Multiphase connections shall include phase balance protection where required under Section 2.8.2.1 of this standard.

2.4 Inverter Energy Systems

2.4.1 General

The following requirements apply to IES connecting to MLL's LV network:

1. IES shall be tested by an authorised testing laboratory and be certified as being compliant with AS/NZS 4777.2:2020 (or later) with an accreditation number.
2. IES shall comprise of inverters that are registered with CEC as approved grid connect inverters.
3. The inverters shall be tested and certified by an authorised testing laboratory as being compliant with AS/NZS IEC 62116 for active anti-islanding protection.
4. IES shall comprise of inverters installed in compliance with AS/NZS 4777.1.
5. The inverters shall have both volt-var and volt-watt response modes enabled and be capable of operating the modes concurrently, as per Section 2.11.1 of this standard.

2.4.2 Energy Storage System (ESS)

The connection of an ESS (such as batteries) capable of supplying electricity to an electrical installation or the distribution network is considered grid-connected, unless the inverter is connected behind a break-before-make switch.

Where the ESS is grid-connected:

1. the ESS shall be subject to the requirements of this standard including the same general requirements outlined in Section 2.4.1;
2. the installation of the ESS shall comply with AS/NZS 5139;
3. ESS are either externally DC coupled to an AC inverter or packaged as a product into an integrated system with its own AC inverter. The following requirements shall apply to ESS inverters:
    a. the inverter capacity for any ESS inverter will be included in the total system capacity;
    b. the export limit for the ESS inverter will be considered as part of the export limit at the point of connection.

The installation and commissioning of ESS shall be certified as compliant by a registered electrical worker.

2.4.3 Electric Vehicles

Electric Vehicle Supply Equipment that is only capable of charging from the grid is not considered an EG. An electric vehicle shall be considered an EG and subject to the requirements of this standard, where:

1. it is capable of exporting energy into the customers premises but not the distribution network (also referred to as Vehicle-to-Building or V2B);
2. it is capable of exporting energy into the distribution network (also referred to as Vehicle-to-Grid or V2G); or
3. the electric vehicle charger being installed has the capability to export electricity into either the customers premises or the distribution network.

WorkSafe New Zealand has published Electric Vehicle Charging Safety Guidelines 2019, and AS/NZS 3000:2018, Appendix P, provides guidance for circuits intended for Vehicle-to-Grid export.

2.5 Network Connection and Isolation

An EG system shall only connect to the MLL network via a single point of connection. This may be supplied through a shared or dedicated transformer arrangement.

IES network connection and isolation requirements shall be in accordance with AS/NZS 4777.1.

In addition, the following requirements shall apply.

1. Mechanical isolation shall be in accordance with AS/NZS 3000. The isolator must always be readily accessible.
2. Any means of isolation, where lockable, shall be able to be locked in the open position only.

This isolation switch is for the use of personnel working on the distribution network as means of isolating the IES when required. It shall be located in an accessible place to approved Marlborough Lines contractors at all times.

It is the customer's responsibility to provide an isolation device and all associated protection controls and ancillary equipment. The isolation device shall be capable of disconnecting the whole of the EG system from the distribution network. Where an EG system is a combination of smaller EG units distributed across an installation, multiple isolation points may be required. These must be clearly identified and labelled on site.

2.6 Installation Design

The overall voltage rise from the point of connection to the inverter AC terminals shall not exceed 2% of the nominal voltage at the point of connection, according to AS/NZS 4777.1, Clause 3.3.3.

If over-voltage problems are occurring at either the point of connection or at the IES, the size of cabling between these points should be considered as one possible cause of the over-voltage.

2.7 Earthing

The earthing requirements shall be in accordance with the relevant standards. These include, but are not limited to:

1. For IES, AS/NZS 4777.1
2. For ESS, AS/NZS 5139
3. For PV systems, AS/NZS 5033
4. For Generating Sets, AS/NZS 3010
5. For all the above, AS/NZS 3000

2.8 Protection

Fault levels shall not exceed the equipment rating of the EG system, distribution network equipment, associated switchgear and protection equipment. Where the EG system may contribute to fault levels, MLL shall:

- Conduct fault studies which includes the fault contribution from the EG system; and
- Provide the customer with the existing fault levels and protection equipment ratings to assess whether the design of the EG system will exceed relevant equipment ratings.

Where it is determined the design of the EG system has the potential to raise the fault levels on the distribution network beyond the capacity of MLL's equipment, the customer shall meet the cost to upgrade the network equipment. The customer must ensure that their switchboard and equipment can withstand the total prospective fault currents.

Where required, the customer shall provide adequate protection and metering CT cores for protection systems and VT reference signals as specified by MLL.

2.8.1 Inverter Integrated Protection

Inverter integrated protection requirements shall be as per AS/NZS 4777.1 and AS/NZS 4777.2 (Section 4) for LV EG connections.

2.8.1.1 Anti-islanding

Passive anti-islanding settings shall be set to the values given in Table 3 below.

Table 3 Integrated Protection - Mandatory Passive Anti-islanding Settings

Protection function	Settings	Trip Delay	Maximum disconnection time
Undervoltage 2 (V < <)	70 V_{l-n}	1 s	2 s
Undervoltage 1 (V <)	180 V_{l-n}	10 s	11 s
Overvoltage 1 (V >)	260 V_{l-n}*	1 s	2 s
Overvoltage 2 (V > >)	265 V_{l-n}*	-	0.2 s
Underfrequency (F <)	45 Hz	1 s	2 s
Overfrequency (F >)	52 Hz*	-	0.2 s
Minimum reconnection time	60 seconds		

*differs from AS/NZS 4777.2: 2020 Table 4.1 and 4.2.

Active anti-islanding requirements shall apply as per AS/NZS 4777.2, clause 4.3.

The IES reconnection procedure is detailed in AS/NZS 4777.2, section 4.7.

2.8.2 Central Protection

Central protection is the coordination of EG at one site, providing protection for the entire installation. It is very important to preserve safety of grid personnel and the general public. It is additional to inverter integrated protection.

Table 4 Central Protection Requirements

Central Protection Requirements (ANSI)	IES ≤ 5kVA	IES > 5kVA & ≤ 30kVA	IES > 30kVA	Non IES (Rotating machines)
Phase balance protection (46)	No	Yes	Yes	Yes
Passive anti-islanding protection (27P, 59P, 81U, 81O, 81R)	No	No	Yes	Yes
Overcurrent and earth fault (51P, 50N)	No	No	Yes	Yes
Directional power (32)	Yes[1]	Yes[1]	Yes[1]	Yes[1]

Note 1: Directional power protection may be required on some EG systems, refer 2.8.2.4.

Where the EG system comprises multiple inverters, all inverters on all phases of the EG system shall simultaneously disconnect from the distribution network in response to the operation of protection or automatic controls.

Where a Grid Protection Relay (GPR) is installed, it shall be located as close to the main switch (grid supply) of the installation as practicable and shall provide the central protection function.

The GPR shall be integrated in a fail-safe manner, e.g. the EG system shall disconnect whilst the GPR is out of service.

2.8.2.1 Phase Balance Protection

Phase balance protection shall meet the central protection requirements of Clause 3.4.4.2 of AS/NZS 4777.1. It is required where:

1. inverters are connected across more than one phase at an installation;
2. one or more inverters are single-phase; and
3. one or more phases has greater than 5 kVA of aggregate single-phase inverter capacity.

EG shall be configured to minimise imbalance between phases. Where an EG causes imbalance greater than 5kVA between phases, as measured by the GPR, the phase balance protection shall respond by disconnecting all EG from the installation within 30 seconds.

All phases of an IES must simultaneously disconnect from, or connect to, MLL's distribution network in response to protection or automatic controls (e.g. anti-islanding trip and subsequent reconnection).

Where multiple single-phase inverters are connected to more than one phase, the inverters must be interlocked and configured to behave as an integrated multi-phase inverter providing balanced output across all connected phases whilst connected to MLL's distribution network.

2.8.2.2 Passive Anti-islanding Protection

Passive anti-islanding protection shall be provided by the GPR. This protection is in addition to any inverter integrated settings (Section 2.8.1.1) and can be considered as backup protection.

The following two tables outline required settings for IES and Rotating Machine central protection relays.

Table 5 Central Protection - IES Passive Anti-islanding Settings

Protection function	ANSI Code	Settings	Trip Delay
Undervoltage 2 (V < <)	27P	70 V_{l-n}	1.0 s
Undervoltage 1 (V <)	27P	180 V_{l-n}	10 s*
Overvoltage 1 (V >)	59P	260 V_{l-n}*	1.0 s*
Overvoltage 2 (V > >)	59P	265 V_{l-n}*	0.2 s*
Underfrequency (F <)	81U	45 Hz	2.0 s
Overfrequency (F >)	81O	52 Hz	2.0 s
Rate of change of frequency (ROCOF)	81R	± 4 Hz/s	0.25 s

*differs from AS/NZS 4777.1: 2016 Table 2.

Table 6 Central Protection - Rotating Machine Passive Anti-islanding Settings

Protection function	ANSI Code	Settings	Trip Delay
Undervoltage	27P	207 V_{l-n}	10 s
Overvoltage	59P	253 V_{l-n}	1.0 s
Underfrequency	81U	45 Hz	2.0 s
Overfrequency	81O	52 Hz	2.0 s
Rate of change of frequency (ROCOF)	81R	± 4 Hz/s	0.25 s

2.8.2.3 Overcurrent and Earth Fault protection

This protection must coordinate/discriminate with all relevant protection, including the distribution network protection and any other customers' protection.

2.8.2.4 Directional Power (Export Limit)

Directional power protection is required when an export limit has been set for the point of connection and the IES does not employ "soft" controls as described in Section 2.3.1. It may be used as a backup in addition to a central export monitoring device.

Any generating system with a maximum export limit may be required to include directional power protection to detect and prevent the inadvertent exceeding of the agreed export limit to the network.

2.8.2.5 Wireless Export Limiting Signal Transfer

Where an EG's GPR or export monitoring device is remote from the EG's automatic disconnection device (whether external or inverter integrated), a wireless communication system may be used. The system shall meet the following requirements:

1. have a supervised wireless communications link;
2. have a communication delay that does not exceed 0.5 seconds; and
3. disconnect the EG from the distribution network for any loss of communications longer than 5 seconds.

2.8.3 Feeder Automatic Re-closing

MLL employ an automatic feeder re-closing scheme on the majority of our distribution network. Automatic re-closing of the feeder involves open and closing (after a predefined "dead time") the upstream circuit breaker in an attempt to clear temporary faults. This may happen up to three times and be as quick as 1.0 seconds depending on the location.

EG shall disconnect within the dead time to ensure safe restoration and to avoid damage to the EG equipment.

It may be appropriate to set a fast acting undervoltage element on rotating machines to ensure they isolate before the reclose is attempted. This requirement can be discussed with MLL on a case-by-case basis.

2.9 Operating Voltage and Frequency

All LV connected EG shall have a nominal voltage of 230V (400V) at 50Hz.

2.9.1 Automatic disconnection

In accordance with AS/NZS 4777.2, Clause 4.5.2, an IES shall operate its automatic disconnection device within 3 seconds when the average voltage for a 10-minute period exceeds $V_{nom\text{-}max}$, where $V_{nom\text{-}max}$ is 249V (Phase to Neutral) in New Zealand.

2.9.2 Frequency range

The EG shall be capable of supplying rated power for frequencies between 45 Hz and 52 Hz.

IES shall maintain continuous operation for frequency variations within the limits specified in AS/NZS 4777.2, Table 4.4 and respond as defined in Table 4.5 under the New Zealand row.

2.10 Metering

An import/export meter is required for installations with grid-connected EG. This metering must be certified and comply with the requirements of Part 10 of the Code. The installation of metering is to be arranged by the customer with their electricity retailer.

2.11 Power Quality

The generating system must not negatively impact on the quality of supply to MLL's distribution network or other customers.

2.11.1 IES Power Quality Response Modes

The Volt-VAr and Volt-Watt response modes, as specified in AS/NZS 4777.2 Clause 3.3.2.3 and Clause 3.3.2.2, shall both be enabled for all inverters within an IES. Setpoints shall be configured as per Table 7 and Table 8 of this standard.

The Volt-VAr response mode varies the reactive power absorbed or supplied by an inverter in response to the voltage at its AC terminals. Figure 2-1 provides a graphical representation of the Volt-VAr response.

Table 7 Volt-Var response mode settings

Reference	Voltage (L-N) (Volt-Var)	Max Reactive Power % of Rated IES Output
V_{V1}	207	60% supplying
V_{V2}	220	0%
V_{V3}	235	0%
V_{V4}	244	60% absorbing

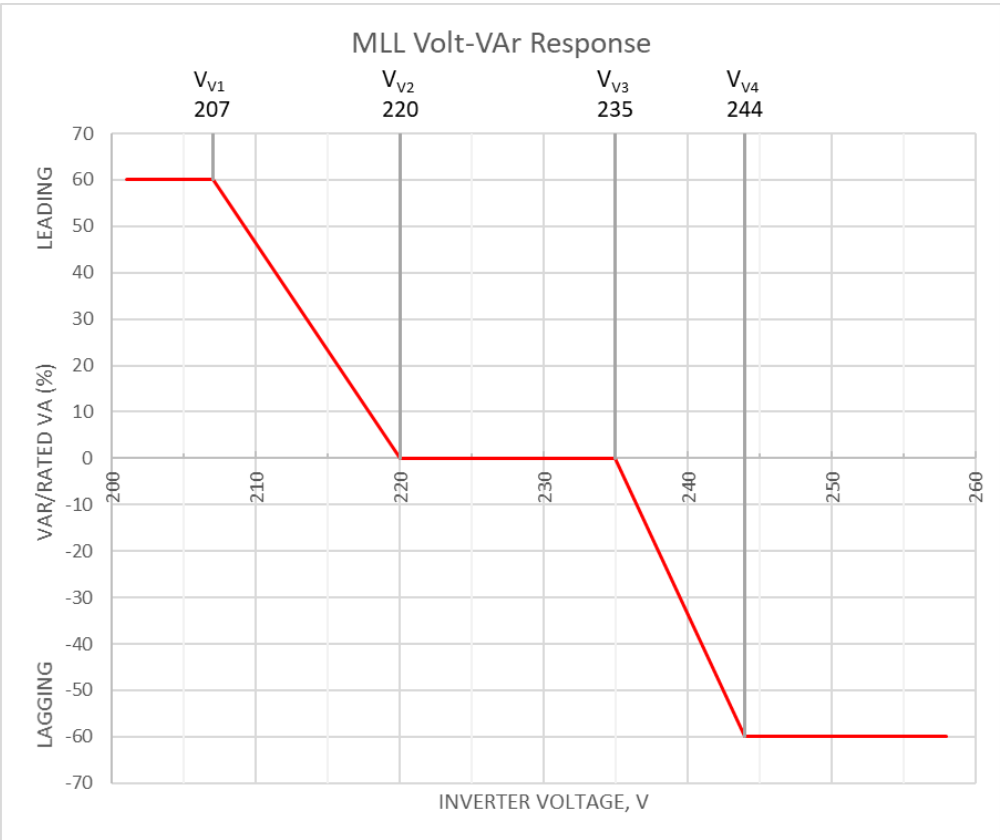


Figure 2-1 Function for NZ Volt-Var response mode

The Volt-Watt response mode varies the maximum active power output level of the inverter in response to the voltage at its AC terminals. Figure 2-2 provides a graphical representation of the Volt-Watt response.

Table 8 Volt-Watt response mode settings

Reference	Voltage (L-N) (Volt-Watt)	Max Active Power
V_{W1}	242	100%
V_{W2}	250	20%

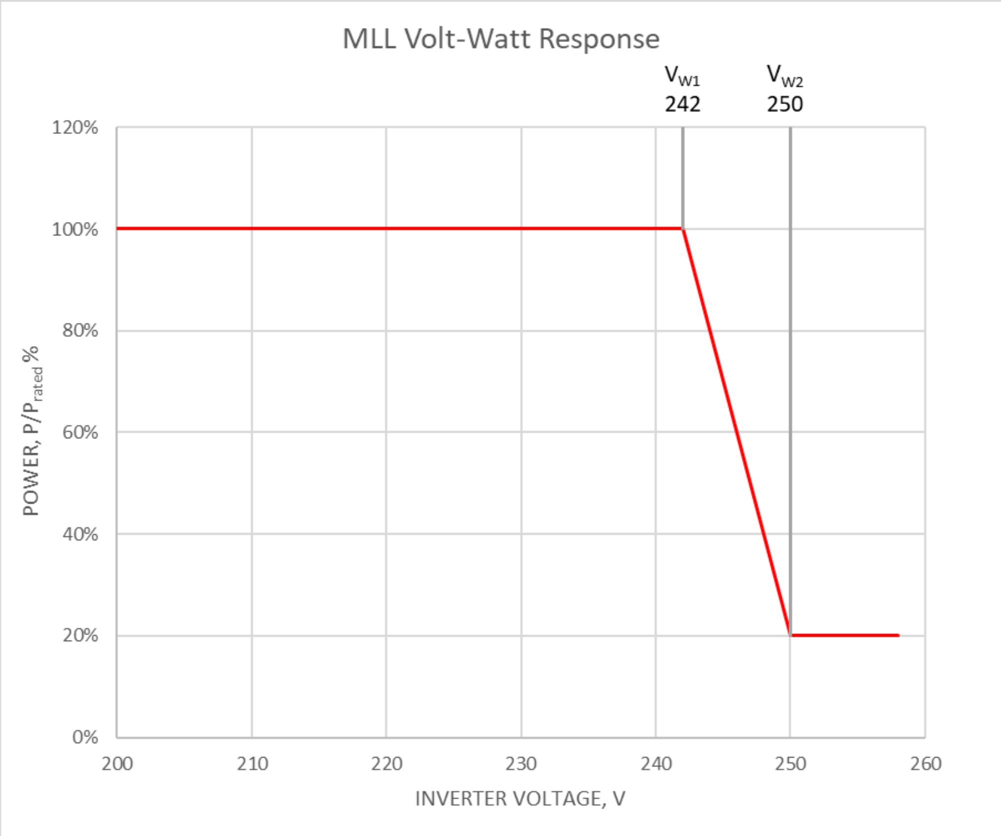


Figure 2-2 Function for NZ Volt-Watt response mode

Volt-Var and Volt-Watt response mode settings shall be programmed into each inverter and protected from unauthorised changes.

2.11.2 Voltage

The customer must ensure that voltage disturbances caused by the generating system, the overall electrical installation or by any appliances, do not result in voltage disturbances to other network users, greater than the limits prescribed in AS/NZS 61000 (part 3.3 or 3.5), at the point of connection.

The IES shall comply with AS/NZS 4777.2, Clause 2.8 with respect to voltage fluctuation and flicker, Clause 2.9 with respect to transient voltage limits, and to Clause 2.10 with respect to DC current injection.

2.11.3 Ramp Rate

To minimise adverse impact on network voltage, the maximum allowable rate at which IES can be loaded and unloaded shall not exceed 16.67% of rated power per minute, as per AS/NZS 4777.2.

In addition, when performing a controlled shut down of any EG, the load on the generating system should be reduced to a minimum before opening any of the generating unit's circuit breakers.

2.11.4 Harmonics

MLL's requirements around harmonics are detailed in Section 6.4 of DN005 – Network Connection Standard available on our website.

Individual harmonic currents produced by IES shall comply with the requirements of AS/NZS 4777.2, Clause 2.7.

MLL may require a network harmonic study to be performed to confirm they meet our requirements.

2.11.5 Power Factor

EG should operate at, or as close as possible to, unity power factor except when required otherwise by power quality response modes, demand response modes (DRM), or other external signal agreed upon with MLL.

IES shall be capable of supplying or absorbing the reactive power required by the Volt-VAr response mode, per Section 2.11.1 of this standard, and in accordance with the IES reactive power capability requirements of AS/NZS 4777.2 Section 2.6.

Non-IES (i.e. rotating machines) shall be designed and operated to adequately control real and reactive power to achieve a power factor at the point of connection of greater than 0.9 lagging or leading.

2.12 Demand Response Modes (DRM)

Where an IES is capable of Demand Response Modes (DRM), they shall be configured as follows:

Table 9 Demand Response Mode Configuration

Inverter Demand Response Modes (DRM)	
Response Mode	Requirement
DRM 0	Operate the disconnection device
DRM 1	Do not consume power
DRM 2	Do not consume at more than 50% of rated power
DRM 3	Do not consume at more than 75% of rated power AND source reactive power if capable
DRM 4	Increase power consumption (subject to constraints from other active DRMs).
DRM 5	Do not generate power
DRM 6	Do not generate at more than 50% of rated power

DRM 7	Do not generate at more than 75% of rated power AND sink reactive power if capable
DRM 8	Increase power generation (subject to constraints from other active DRMs)

IES support for DRM shall be according to AS/NZS 4777.2 – DRM 0 shall be mandatory, DRM 1-8 are optional but should be implemented where available. Note, DRM 1-4 are relevant only to IES with energy storage (ESS) capability.

2.13 UPS or Backup Power Supplies

Generation may be used in conjunction with batteries to provide an uninterruptible, or backup, power supply (UPS) for certain circuits within the premises.

In this instance, no protection device shall interrupt the neutral or earth conductors between the network and the inverter. This prevents the use of residual current devices (RCDs) between the inverter and the network.

3 Technical Studies

Technical studies are required to be conducted at the customer's expense to enable connection to the distribution network. These studies shall be undertaken by an MLL approved Electrical Engineering Consultancy having specialist network modelling, protection and generation experience and is accredited to undertake design work for MLL or Transpower.

Before conducting any technical studies, the scope shall be reviewed and approved by MLL.

The completed technical studies will be reviewed by MLL to confirm settings and suitability against this standard.

The technical studies are outlined in Table 10:

Table 10 Technical Studies Required for LV EG Connections

Technical Studies	IES ≤ 10kVA	IES > 10kVA & ≤ 50kVA	IES > 50kVA	Non IES (Rotating machines)
Voltage Regulation	No	Yes[1]	Yes	Yes
Power Flow	No	Yes[1]	Yes	Yes
Fault Level	No	No	Yes[1]	Yes
Protection Grading	No	No	Yes	Yes

Note 1: These studies may not be required or will be undertaken by MLL on a case by case basis.

4 Inspection, Testing and Commissioning

EG installations require an electrical inspection by a registered Electrical Inspector as defined as high risk prescribed electrical work in the Electricity (Safety) Regulations.

On-site testing and commissioning shall be undertaken in accordance with AS/NZS 4777.1, AS/NZS 3000, AS/NZS 5033 (where applicable), the equipment manufacturer's specifications, other relevant standards and this technical standard.

4.1 Commissioning of EG ≤ 200kVA

For EG systems 200kVA and below the installer shall follow MLL's commissioning test form, MLL F37, to ensure compliance to this standard.

The MLL commissioning form covers tests of importance such as:

1. Operate the main switch (e.g. Inverter Supply) and verify the connection time is greater than 60 seconds.
2. Isolate the main switch (Mains Supply) and verify the EG disconnect time is less than 2 seconds.
3. Where export limiting is required, disconnect the customers load and confirm Export to the grid does not exceed approved limits.
4. Settings are in accordance with this standard and have been password or lock protected.

The commissioned equipment and settings shall not deviate from the approved application form. MLL may require the applicant to produce a site-specific commissioning plan prior to install, but this will be noted in your approval letter.

4.2 Commissioning of EG > 200kVA

For EG systems above 200kVA, installers must submit a commissioning plan to MLL a minimum of 30 business days prior to the commencement of commissioning.

The commissioning plan is to be divided into three parts:

1. Pre-connection off-line testing;
2. Compliance testing; and
3. On-line commissioning.

The commissioning plan shall confirm, at a minimum, the following points:

- What elements of the EG are proposed to be tested;
- The specific steps that the customer proposes to test the above elements;
- The pass/fail criteria for each test, including any settings/values that are to be verified; and
- The proposed timeframe for testing and commissioning.

The customer must compile the test results in a commissioning report and submit this to MLL for review. The commissioning report must confirm that all protection and control systems are functional, and their settings are consistent with information approved by MLL. At a minimum it shall include:

- Copy of Certificate of Compliance (COC);
- Copy of commissioning records in line with AS/NZS 5033;
- Any other applicable testing records, e.g. earthing system tests;
- Protection test results;
- Written confirmation of the anti-islanding protection device tested and compliant with this standard.
- Power quality response modes enabled and their settings.
- Site single line diagram (SLD).

5 Operations & Maintenance

The owner or operator or the EG system is responsible for the following.

- Maintenance and safe operation of the generation system (including inverters, protection devices, cabling and solar panels).
- Ensure the generation system complies with all relevant acts, regulations, standards rules and codes of practice.
- Ensure that any changes to the electrical installation at the supply address are performed by an electrician lawfully permitted to do the work and that the customer holds a Certificate of Compliance issued in respect of any of the changes.
- Seek approval prior to altering the IES capacity or inverter. MLL will advise if additional work is required and the associated cost (if any).
- Operating the system within the generation export limit imposed by MLL (if applicable).

Marlborough Lines may, from time to time, isolate any EG in order to perform certain maintenance tasks or manage the network capacity in accordance with our operational requirements or DN015 Distributed Generation Congestion Management.

6 Records and Information

MLL is responsible for ensuring that it has plans and records of EG installations to ensure the safe and reliable operation of our network. MLL may keep records pertaining to an EG installation within its documentation systems for the lifetime of the installation.

6.1 Initial Application Forms

The LV initial application form is split by EG capacity. There is a form for ≤ 200kW and one for greater than 200kW.

The application form is required for MLL to evaluate LV EG connection to our network. It will provide information such as:

- Customer contact details
- Installation site details

- EG type(s)
- EG capacity
- Battery ESS capacity (where applicable)
- IES specifics and compliance with AS/NZS 4777.2 standards. (e.g. datasheets, certificates)
- Site diagram (refer Appendix B – Site Diagram Example)
- Site Single Line Diagram (refer Appendix C – System SLD Examples)

6.2 Final Application Form

A final application form may only be required for EG systems greater than 10kW.

MLL may conclude that a final application is not required. In this case approval to connect will be clearly provided in our response to your initial application. Otherwise the applicant will need to complete a final application form too.

6.3 As-built information

IES documentation must be stored on site in accordance with AS/NZS 4777.1, Section 7, and available to MLL on request. Non-IES EG shall also store relevant operation and maintenance information onsite.

Upon, or at any time after, completion of the installation of the EG system, Marlborough Lines may request access to the premises to conduct an inspection of the system. This is to verify compliance with this standard and may include checking of:

- Certificate of Compliance (COC)
- Electrical Safety Certificate
- Inspection and Record of Inspection (ROI)
- Generation capacity and phase balance
- Operation of the grid protection device (anti-islanding)
- Power response modes enabled and set correctly (e.g. Volt-VAr and Volt-Watt)

6.3.1 Commissioning results

For EG systems 200kVA and below the installer shall submit a completed commissioning test form, MLL F37, for our records and to ensure compliance to this standard, refer Section 4.1. This shall be returned to MLL within 10 business days of the EG being connected to our network.

The following information shall be included with submission of the test form:

- As-built Site Diagram, refer Appendix B – Site Diagram Example
- As-built System SLD, refer Appendix C – System SLD Examples
- Record of anti-islanding protection settings and passive anti-islanding settings matching those set out in Table 3. Screenshots or photos are required as evidence.
- Record of voltage control modes and settings matching those set out in Table 7 and Table 8. Screenshots or photos are required as evidence.
- Record of export limit settings and how these are managed.
- Copy of the Certificate of Compliance and Record of Inspection.

For EG systems above 200kVA the installer shall submit a completed commissioning test report in line with their approved commissioning plan, refer Section 4.2. The necessary attachments and timeframes will be detailed in the approved plan.

Appendix A – Settings Checklist

The purpose of this settings overview is to assist the customer with the design and commissioning of the inverter(s) by summarising key parameters in one spot. Further information can be found in the relevant sections above.

Protection of the Distribution Network (section 2.8.1.1)

Table 3 Mandatory Passive Anti-islanding Settings

Protection function	Settings	Trip Delay	Maximum disconnection time
Undervoltage 2 (V < <)	70 $V_{l\text{-}n}$	1 s	2 s
Undervoltage 1 (V <)	180 $V_{l\text{-}n}$	10 s	11 s
Overvoltage 1 (V >)	260 $V_{l\text{-}n}$*	1 s	2 s
Overvoltage 2 (V > >)	265 $V_{l\text{-}n}$*	-	0.2 s
Underfrequency (F <)	45 Hz	1 s	2 s
Overfrequency (F >)	52 Hz*	-	0.2 s
Minimum reconnection time	60 seconds		

*differs from AS/NZS 4777.2: 2020 Table 4.1 and 4.2.

Power Quality Response Modes (section 2.11.1)

Default ‘New Zealand’ region settings in Inverter.

Volt-Var

Table 4 Volt-Var response mode settings

Reference	Voltage (L-N) (Volt-Var)	Max Reactive Power % of Rated IES Output
V_{V1}	207	60% supplying
V_{V2}	220	0%
V_{V3}	235	0%
V_{V4}	244	60% absorbing

Volt-Watt

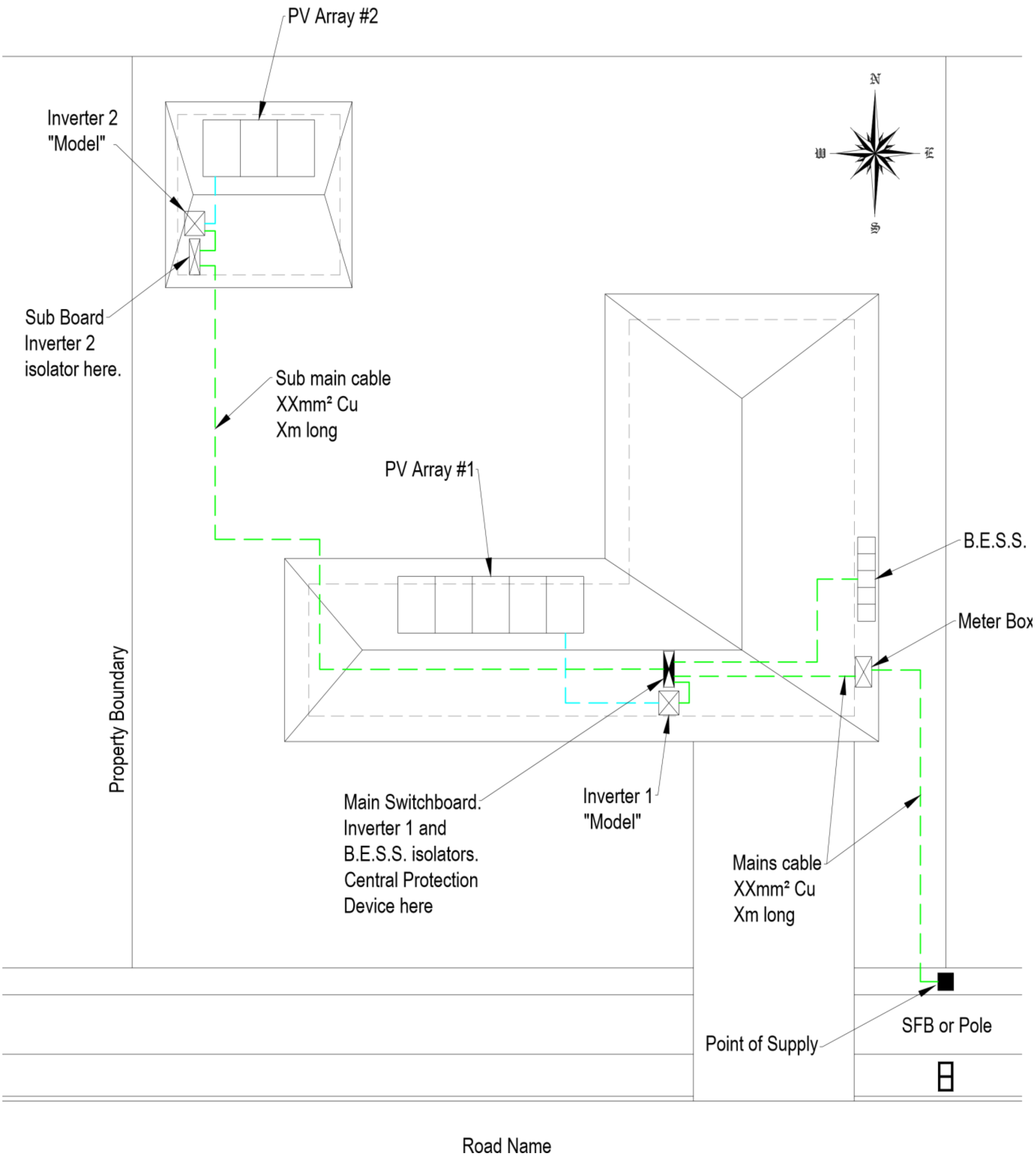
Table 5 Volt-Watt response mode settings

Reference	Voltage (L-N) (Volt-Watt)	Max Active Power
V_{W1}	242	100%
V_{W2}	250	20%

Appendix B – Site Diagram Example

Please provide a sketch (or aerial photo) of the property with the following items identified:

- Point of Connection (PoC)
- Mains cable type, route, and length.
- Meter box, main switchboard, distribution boards, sub cables.
- Inverter(s), inverter(s) isolator, PV array and central protection device location.



Appendix C – System SLD Examples

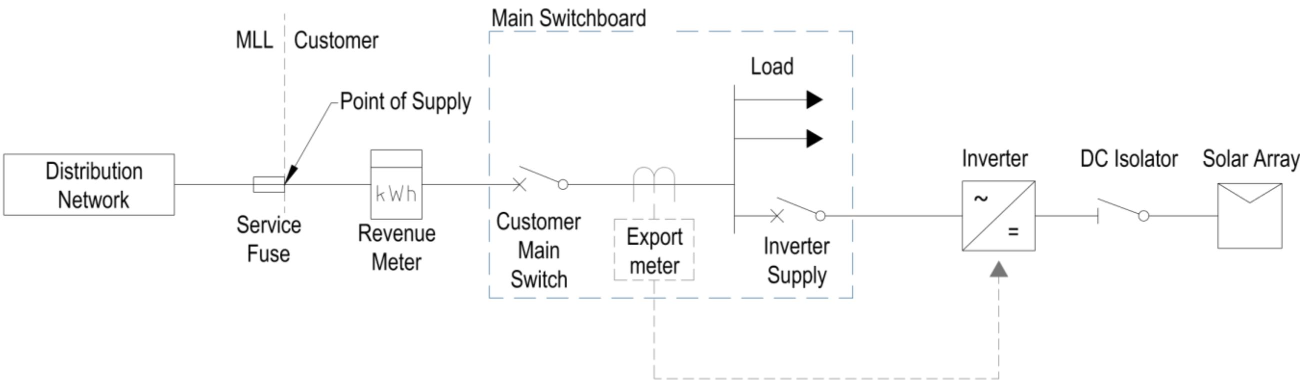
A single line diagram (SLD) needs to contain information on the installation wiring from the point of connection off the Marlborough Lines network, through to all the inverters on site, including where the customer's load is connected.

It shall contain information on all protection devices and switches, as well as any communications required to achieve the desired operation of the system (i.e. export limit, central protection etc.).

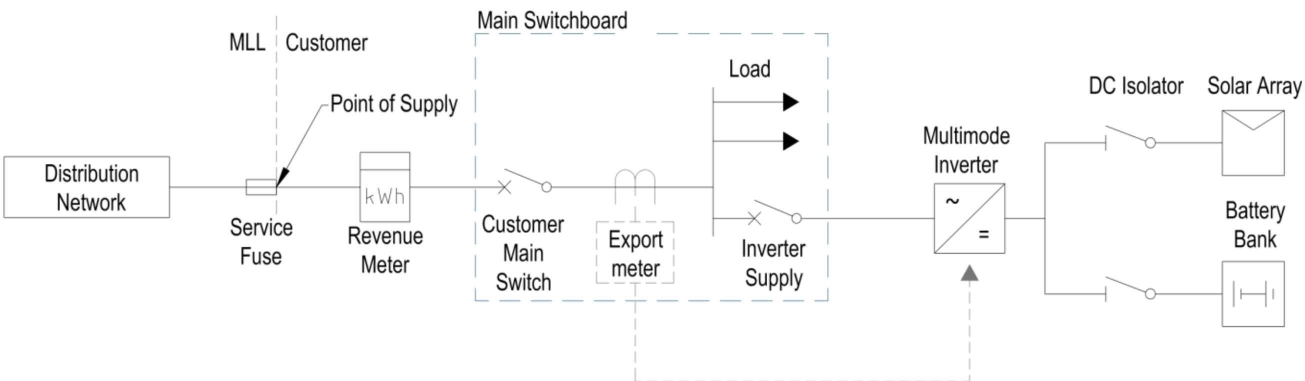
SLDs must use correct symbols (referenced from AS/NZS 3000:2018) and shall contain at least the following information:

- Point of Connection (PoC)
- Revenue Meter
- Main switch/CB
- Main switchboard and any distribution boards
- Load(s)
- Inverter(s)
- Inverter isolators and/or protective devices
- Energy Source, i.e. PV array, battery
- Communication paths i.e. export limit, central protection
- Monitoring equipment i.e. current transformers

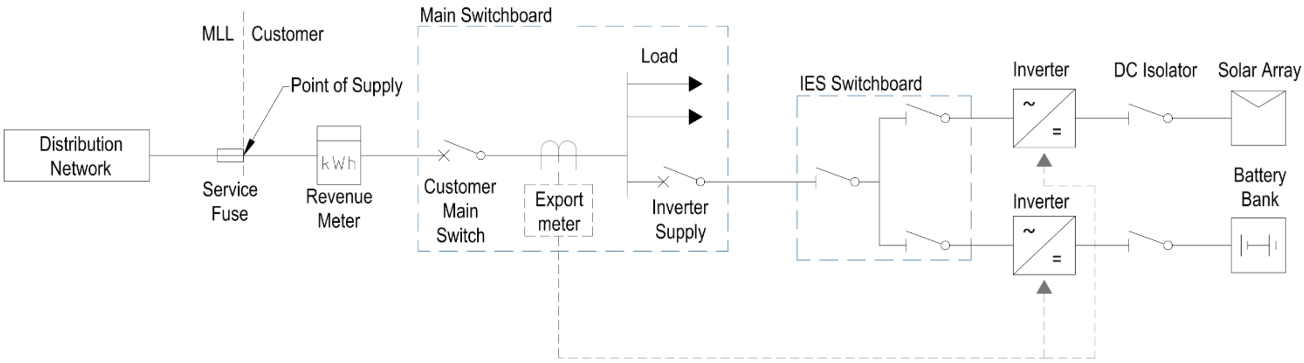
Example 1 – Single PV inverter connection



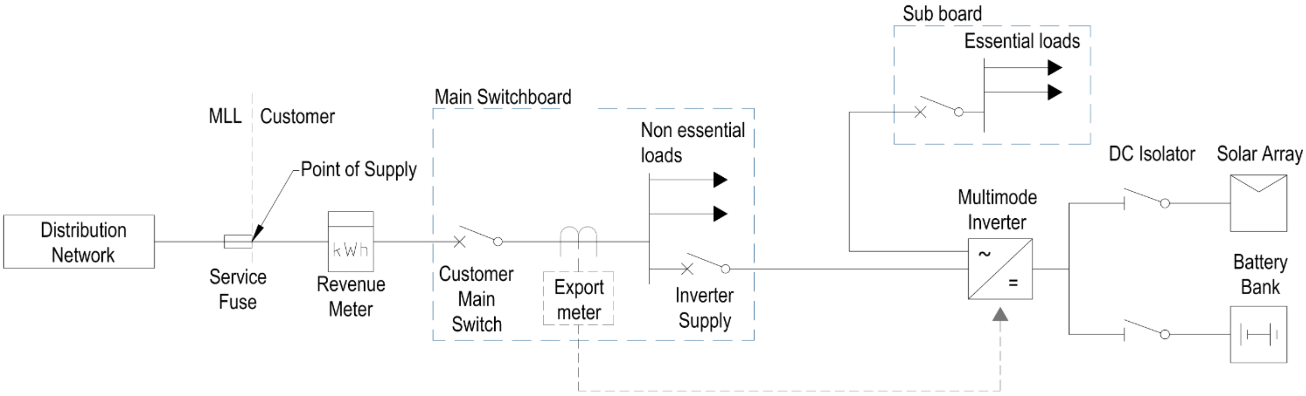
Example 2 – DC coupled PV and Battery through single inverter connection



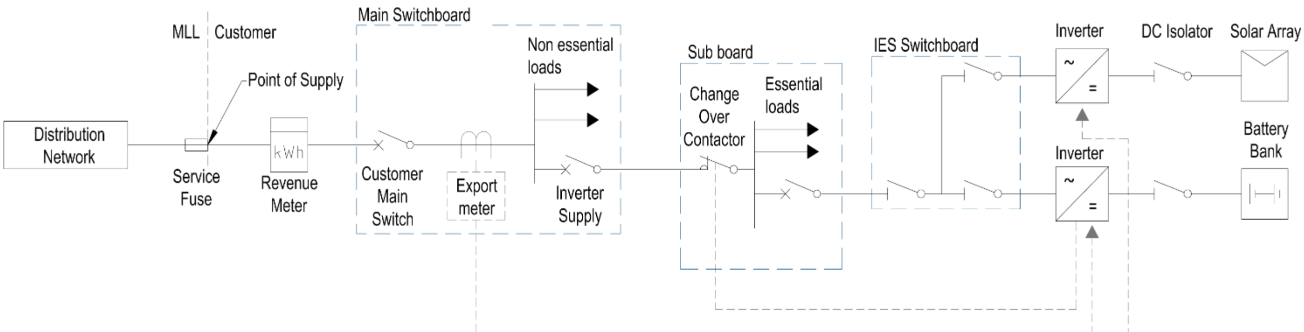
Example 3 – AC coupled PV and Battery with two inverter connections



Example 4 – IES with stand-alone functionality with single inverters



Example 5 – AC coupled PV and Battery with stand-alone functionality with two inverters



Appendix D – Determining an Installations export capability

Check the voltage

Measure the phase to neutral voltages at the installation's main switchboard, while the switchboard is unloaded, and at a time when the network load is expected to be low. Record the voltages, the date, and the time.

If any of the voltage readings are 244 volts or above, please advise Marlborough Lines. There may be other distributed generation nearby, transformer tap settings or LV neutral issues that need to be resolved first.

Determine the Supply Loop Impedance

Measure the phase-neutral and phase-phase supply loop impedances for each phase at the installation's main switchboard.

Calculate the phase-neutral and phase-phase impedances of the circuit from the main switchboard to the proposed inverter terminals. Or measure from the proposed location of the inverter if the wiring already exists. Add these two together to provide the total loop impedance for each phase combination seen by the inverter.

Calculate the Network Impact Product

Multiply the inverter kVA rating by the loop impedance to calculate the Network Impact Product.

$$NIP = P_{Inverter} \times Z_{Loop}$$

Where; $P_{Inverter}$ is the inverter per phase nameplate rating in kVA.
Z_{Loop} is the phase-neutral loop impedance seen by the inverter

Example: A 3kVA single phase inverter is connected to the main switchboard at an installation with a phase-neutral loop impedance of 0.5 Ω. Therefore $NIP = 3 \times 0.5 = 1.5$

The NIP can be improved by lowering the loop impedance or spreading the inverter kVA across phases. A balanced load will also help.

Recommended NIP thresholds

Where the calculated NIP is lower than the threshold in the table below, the IES will have the best chance of operating over its full range. If the NIP is above the threshold, voltage rise may occur and limit output of the IES.

IES Configuration	NIP Threshold (unbalanced load)	NIP Threshold (balanced load)
Single Phase	-	2.4
Two Phase	2.4	3.2
Three Phase	2.4	4.8