Chapter

Protection of Microgrids

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Abstract

The concept of microgrids goes back to the early years of the electricity industry although the systems then were not formally called microgrids. Today, two types of microgrids can be seen: independent and grid connected. The protection requirement of these two types differs as the protection needs of an independent microgrid are intended for protecting components and systems within the microgrid, whereas a grid connected microgrid demands both internal and external protection. The first part of this chapter is dedicated to independent microgrids. How protection devices such as residual current circuit breakers, miniature and moulded case circuit breakers, and surge protective devices should be selected for an example microgrid is discussed while referring to the relevant standards. In the next section, the protection of a grid connected microgrid is discussed. Particularly, micro-source protection, microgrid protection, loss of mains protection and fault ride-through requirements are discussed while referring to two commonly used distributed generator connection codes. An example with simulations carried out in the IPSA simulation platform was used to explain different protection requirements and calculation procedures. Finally, grounding requirements are discussed while referring to different interfacing transformer connections and voltage source inverter connections.

Keywords: microgrid, micro-sources, protection, grid connected, independent, islanding

1. Introduction

Remote locations which are far from grid electricity and islands have developed independent grids to supply power to the local populations. Even though they were not formally called microgrids, they met most of the criteria for today's microgrid systems. With the advancement of renewable energy technologies and energy storage, the concept of microgrid emerged mainly for grid connected systems that are controlled and operated as a smaller grid.

WG6.22 of CIGRE [1] defines microgrids as "electricity distribution systems containing loads and distributed energy resources (such as distributed generators, storage devices, or controllable loads), that can be operated in a controlled, coordinated way either while connected to the main power network or while isolated." A microgrid can offer a number of benefits to those connected to the microgrid as well as to the local utility. As micro-sources are connected closer to loads, the distribution network losses are reduced considerably. The optimum use of Distributed Energy Resources (DERs) within a microgrid further increases the efficiency of their operation. Further, microgrid connected facilities can continue in operation during a grid outage thus increasing the reliability and quality of supply. They can relieve grid congestion and improve operation of the utility grid.

Based on the purpose and regulatory regime in which they operate, microgrids can be categorise as:

a. "Off-grid" or "independent" – a microgrid that is not connected to the utility grid and serves a remote location or an island;

b. "Campus" or "Customer" – a microgrid connected to the local grid, supply power to one or more premises, and maintain some level of service in isolation from the grid; and

c. "Community" or "Utility" – a microgrid integrated into the utility network serving multiple customers within a community.

In this chapter, for the purpose of protection, "independent" (category a) and "grid-connected" (category b or c) will be used. When the microgrid is in "independent" mode, its protection should disconnect the faulty portion of the microgrid with minimum disruption to the loads connected to the microgrid. When a microgrid is in the "grid connected" mode, it should protect microgrid components when a fault is within the microgrid and isolate or provide fault ride through when a fault is in the utility network to which it is connected. Further, the microgrid protection should be coordinated with the utility network protection while having minimum impact on network protection.

2. Fundamental requirements of protection of a microgrid

Protection is installed to detect fault occurrence and isolate the faulted equipment. This is achieved by a fuse or a circuit breaker (CB). When using a fuse and/or CB for protecting a circuit, the following should be considered:

- Selectivity or discrimination: This is the ability of the protection system to disconnect only the faulted section of a plant and to leave the rest of the power system operating.

- Stability: This refers to the requirement of a protection scheme not to operate for remote or "out-of-zone" faults.

- Speed of operation: Fast protection reduces the risk of damage to plant and personnel, but it is more difficult to make fast-acting protection stable for out-of-zone faults and to provide correct discrimination.

- Sensitivity: This is the level of over-current at which the CB will operate.

- Main protection: This is the primary protection system on any circuit or item of the plant.

- Backup protection: This protection is design to operate in the event of failure of the main protection and to cover certain items of plant, which have a low probability of failing. Backup protection is generally slower than main protection and may isolate more than one circuit.

The example circuit shown in **Figure 1** is used to describe the above in more detail. For a fault at the location shown, it should be cleared by fuse F1 not by CB3. This is called ***selectivity***. F1 and CB3 should be able to discriminate whether the fault

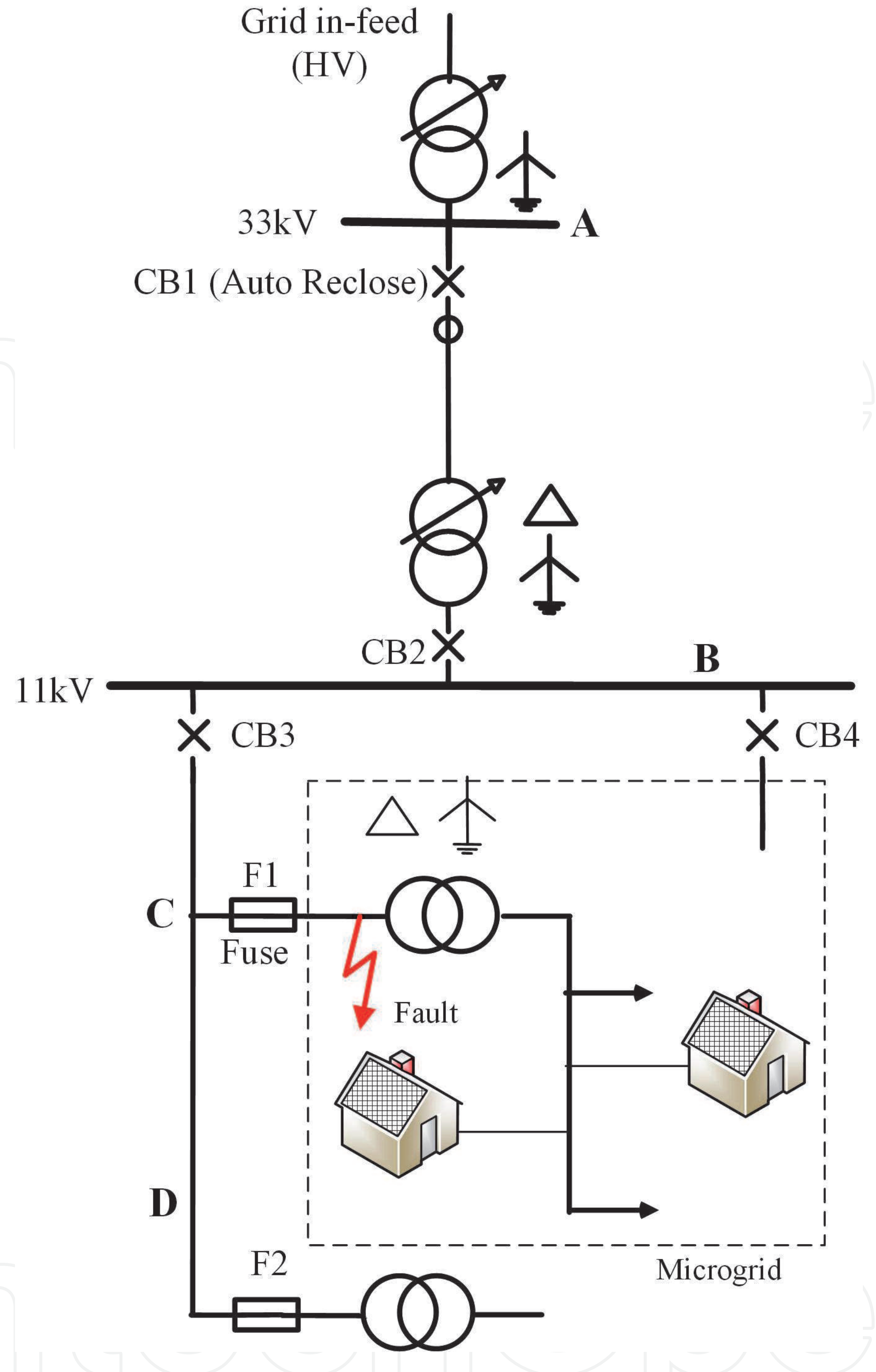


Figure 1.
Grid connected microgrid.

is in its jurisdiction or not. This jurisdiction (or region of operation) of a fuse or a CB is called the ***zone of protection***. CB3 should be able to detect that the fault shown in the figure is ***out-of-zone***. Further, CB3 should provide ***backup protection***, in case F1 is unable to clear the fault.

3. Fault current contribution of different micro-sources and implications for protection

Microgrids utilise hybrid energy sources consisting of renewable energy sources and conventional power plants such as combined heat and power and diesel gensets. In contrast, conventional power plants usually employ synchronous generators.

During a fault, as shown in **Figure 2**, if the microgrid is connected to the utility grid, then there will be fault currents from the utility grid and also from the micro-sources (marked in red lines with arrows). In an independent microgrid that is not connected to the utility grid then the only sources of fault current will be the micro-sources.

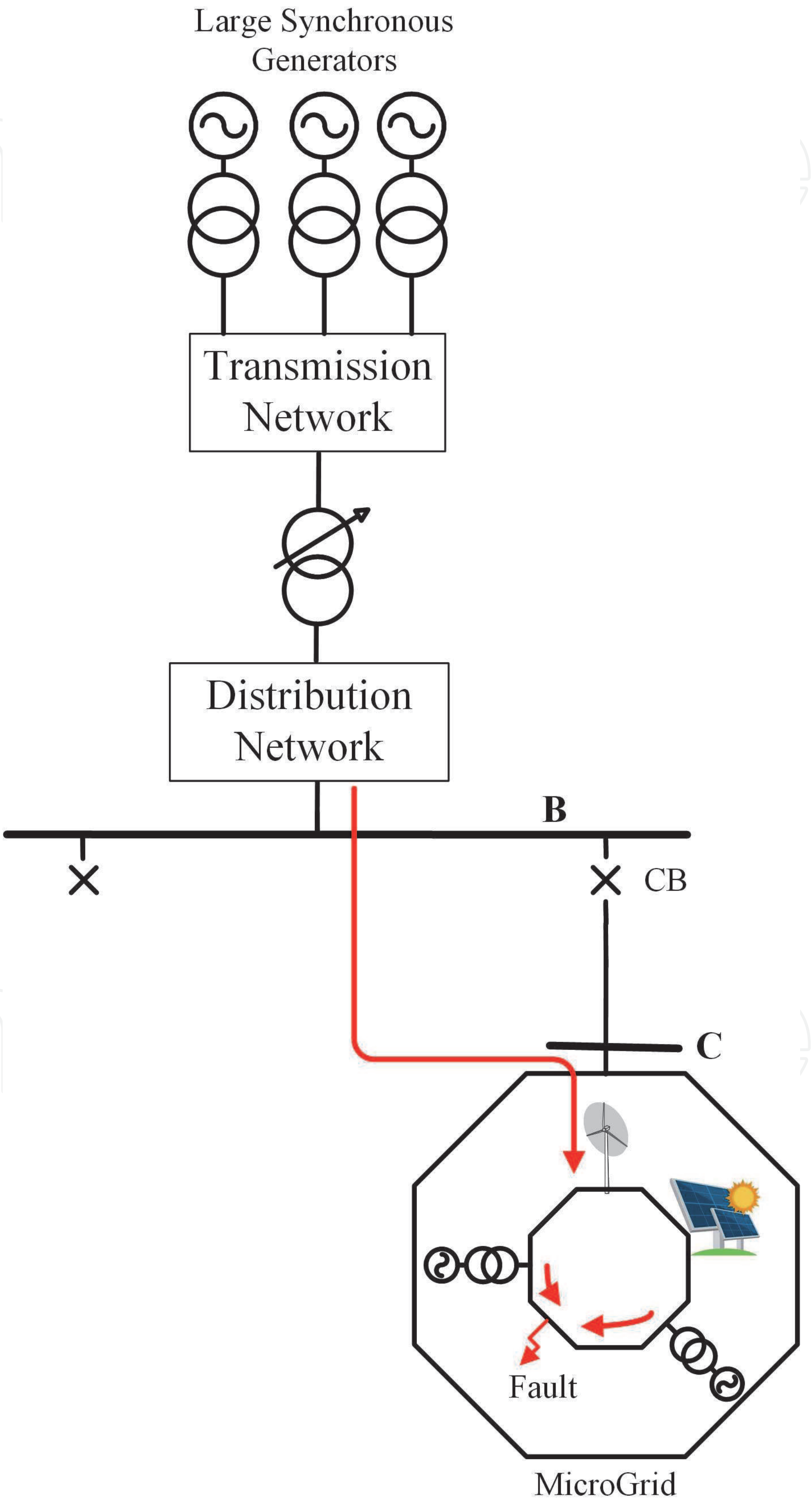


Figure 2.
Fault current within a grid-connected microgrid.

3.1 Fault current contribution from synchronous generators

The fault current contribution from a synchronous generator decreases exponentially after the fault occurs and settles down to a steady-state level. The fault current of a synchronous generator into a three-phase fault depends on the rotor construction. For a cylindrical pole machine, the direct axis has the same value of reactances as the quadrature axis and the fault current contribution to a three-phase fault is usually described by an expression of the form [2–4]:

$$I(t) = \mathrm{E_F}\left[\frac{1}{\mathrm{X}} + \left(\frac{1}{\mathrm{X}'} - \frac{1}{\mathrm{X}}\right)e^{-t/\mathrm{T}'} + \left(\frac{1}{\mathrm{X}''} - \frac{1}{\mathrm{X}'}\right)e^{-t/\mathrm{T}''}\right]\cos(\omega t + \lambda) - \frac{\mathrm{E_F}}{\mathrm{X}''}e^{-t/\mathrm{T_a}}\cos(\lambda) \tag{1}$$

where.

X	synchronous reactance
X'	transient reactance
X''	sub-transient reactance
$\mathrm{E_F}$	pre-fault internal voltage
T'	transient short circuit time constant
T''	sub-transient short circuit time constant
$\mathrm{T_a}$	armature (dc) time constant
λ	angle of the phase at time zero
ω	system angular velocity

The armature time constant ($\mathrm{T_a}$) is not a fixed value but depends on the location of the fault. It is given by

$$\mathrm{T_a} = \frac{(\mathrm{X}'' + \mathrm{X_e})}{\omega(\mathrm{R_a} + \mathrm{R_e})} \tag{2}$$

where.

$\mathrm{X_e}$	external reactance (to the fault)
$\mathrm{R_e}$	external resistance (to the fault)
$\mathrm{R_a}$	armature resistance

The first three terms of Eq. (1) represent a symmetrical decaying ac fault current and the fourth term a dc offset.

Table 1 shows the parameters of a large ($\mathrm{G_L}$) and a small ($\mathrm{G_S}$) synchronous generator. The main difference is the resistance of $\mathrm{G_S}$ is much higher than that of $\mathrm{G_L}$ and the time constants of $\mathrm{G_S}$ is much lower than $\mathrm{G_L}$. For a three-phase fault at the terminal of the machine, the armature time constant of $\mathrm{G_L}$ is 163 ms and that of $\mathrm{G_S}$ is 5.9 ms. **Figure 3** shows the envelope of the current immediately after the terminal fault for both machines. As can be seen $\mathrm{G_S}$ has a shorter transient compared to $\mathrm{G_L}$. However, as $\mathrm{G_L}$ is connected far away from the microgrid, its contribution for a three-phase fault within the microgrid is much smaller and the presence of $\mathrm{R_e}$ and $\mathrm{X_e}$ minimises the armature time constant and the period of transient.

Parameter	Larger generator (G_L)	Smaller generator (G_S) [5]
Rated voltage	15 kV	400 V
Rated Apparent Power	21.4 MVA	16 kVA
Base impedance (Ω)	10.5	10
X (pu)	2.04	3.82
X′ (pu)	0.36	0.26
X″ (pu)	0.22	0.1
R_a (Ω)	0.045	0.54
Field Resistance (Ω)	0.18	9.79
T′	1.4 s	41 ms
T″	18 ms	6 ms

Table 1.
Comparison of parameters of a large and small synchronous generator.

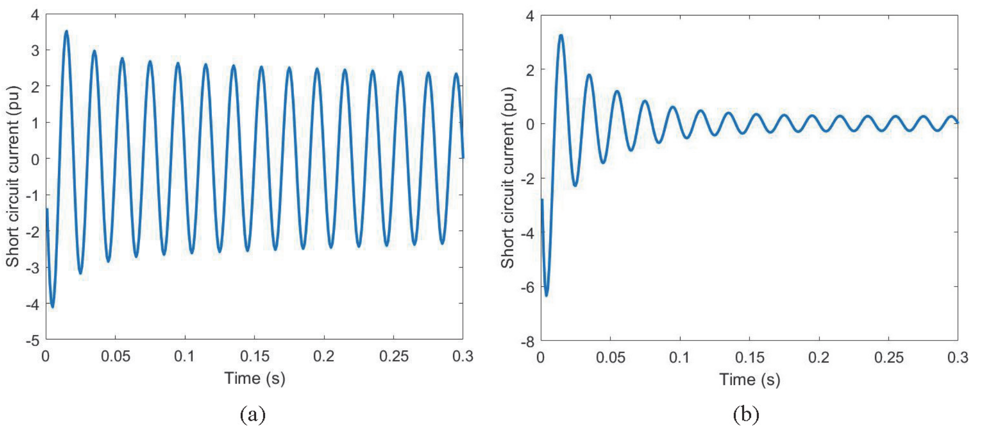


Figure 3.
Fault current at the terminal of the synchronous generator. (a) for G_L and (b) for G_S.

During the fault, the generator terminal voltage decreases rapidly, and as the field current is usually derived from the generator terminal, the field current also decreases. This limited field current capability reduces the airgap flux thus reducing the fault current contribution of the synchronous generator. The fault current will fall to zero within a fraction of a second or within a few seconds at the most, thus generator protection device such as a moulded case circuit breaker (MCCB) may not detect the fault. This fault current without field forcing is shown by the red line in **Figure 4**. For the correct operation of the protective devices, field forcing, which is maintaining the field current throughout a fault condition, is often required. Fault current with field forcing is shown by the blue line. Reference [6] highlights a number of field forcing methods such as shaft mounted permanent magnet generator as a pilot exciter and auxiliary winding design that enables to obtain the field current from both current and voltage of the generator.

3.2 Fault current contribution from asynchronous generators

Fixed speed wind farms and some small hydro plants employ asynchronous (induction) generators as their power source. In these generators, the airgap flux is formed by the induction effect, and when the stator supply is lost, the airgap flux also diminishes. Therefore, as **Figure 5** shows typical fault current shows a high initial current and a rapid decay to zero. Eq. (3) is used to describe the fault current contribution of an asynchronous generator to a three-phase fault at its terminals.

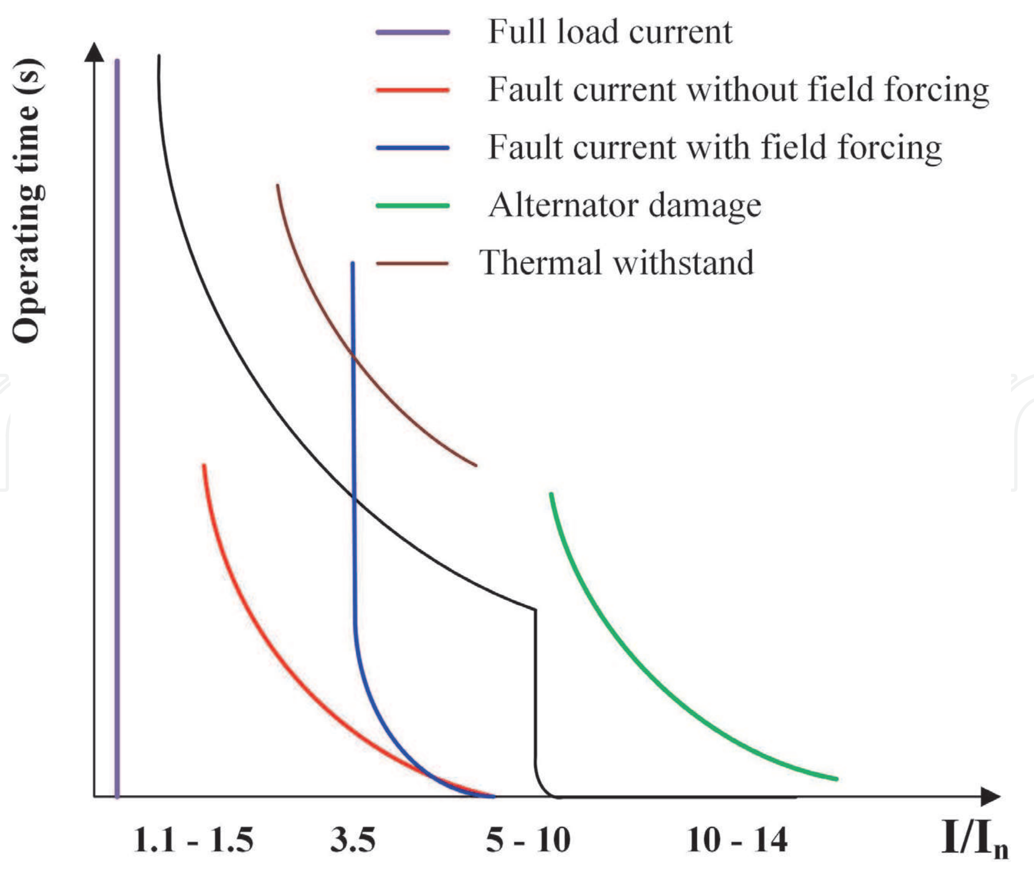


Figure 4.
Characteristic of the generator protection for terminal faults [6].

$$I(t) = \frac{V_1}{X''}\left[\cos(\omega t + \lambda)e^{-t/T''} + \cos(\lambda)e^{-t/T_a}\right] \tag{3}$$

where.

$X'' = X_1 + \frac{X_2' X_m}{X_2' + X_m}$; $T'' = \frac{X''}{\omega R_2'}$; $T_a = \frac{X''}{\omega R_1}$.	
R_1	is the stator resistance.
X_2' and R_2'	are the stator referred rotor reactance and resistance.
X_m	is the magnetising reactance.
V_1	is the magnitude of the network voltage.
$\omega = (1 - s)\omega_s \approx \omega_s$	(as s is very small).

Any external impedance involved must be added to the stator impedance.

3.3 Fault current contribution of converter connected sources

Solar plants and variable speed fully rated wind farms are interfaced to the microgrid through a voltage source converter (VSC). The VSC effectively creates a synthesised ac voltage behind an inductor. The VSC employs an inner control loop which is usually a current controlled regulator. During a network fault, in between the time of disconnecting the upstream protection and islanded detection of VSC, the inner control loop of the VSC regulates the positive-sequence component of its output current to a constant value. Therefore, most short circuit analysis platforms such as ASPEN. CAPE, and ETAP model VSCs as a voltage controlled current source [7].

VSC usually employs Insulated-gate bipolar transistors (IGBTs) and these will be damaged even when short duration high currents flow through them. When a

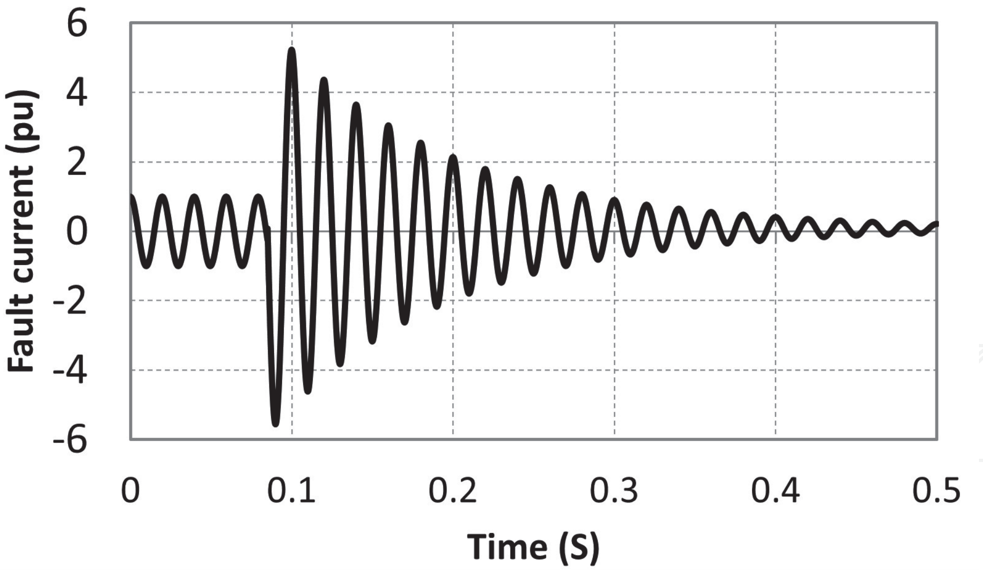


Figure 5.
Fault current of an induction generator with a three-phase fault at its terminals (phase shown with minimum DC offset).

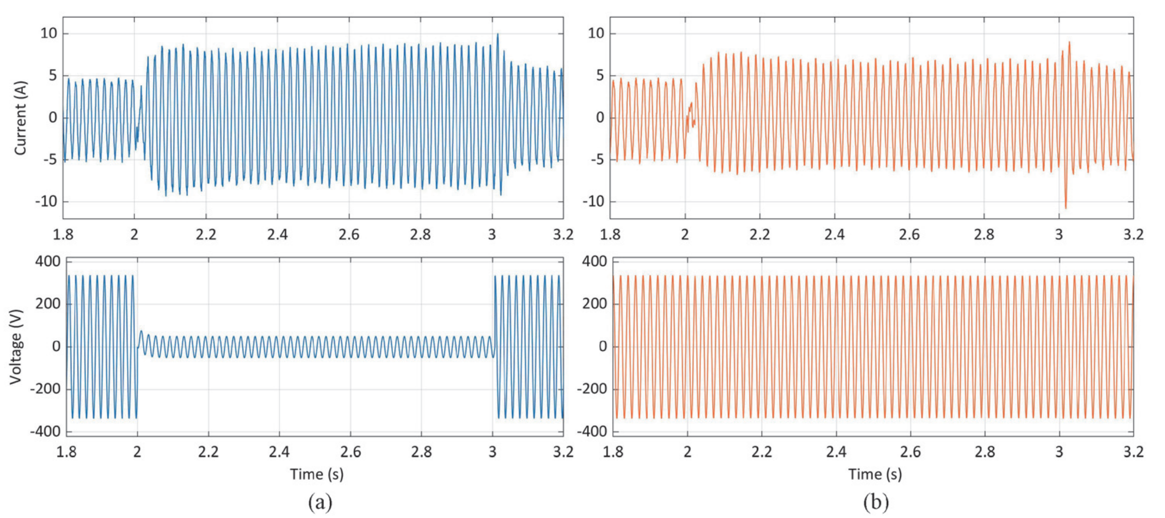


Figure 6.
The solar inverter fault current for a line-to-ground fault (fault is from 2 to 3 sec). (a) Inverter current (A) – Top and terminal voltage (V) – Bottom of the faulty phase. (b) Inverter current (A) – Top and terminal voltage (V) – Bottom of the healthy phase.

transient current approaches a damaging level, the IGBTs are protected by controllers that turn off the IGBTs. Therefore, the fault current contribution from a converter connected distributed generator is very low.

The VSC's response to negative-sequence imbalance, such as a line-to-line or line-to-ground fault, depends on the inverter's control algorithms. Often the VSC provides a constant positive sequence current with very little negative and zero sequence current. This is shown in **Figure 6**, obtained from a line-to-ground fault near a 2 kW solar PV plant (simulated using a MATLAB/SIMULINK model).

4. Protection of independent microgrids

4.1 Protection for safety

When designing and implementing an electrical installation of a microgrid, the safety of the people or livestock occupying that buildings or houses connected to the microgrid, the safety of equipment connected to the microgrid, and the safety of the electrical installation of the microgrid should be considered.

In order to provide protection against electric shock resulted from contact with a conductor which forms part of a circuit and would be expected to be live, basic protection such as the insulation of live parts, the provision of barriers, obstacles or enclosures to prevent touching, and placing out of reach are commonly employed.

4.2 Over-current and short circuit protection

A protective device should automatically interrupt the supply to the line conductor or equipment in the event of a fault. For automatic disconnection, a Residual Current Device (RCD) such as a Residual Current operated Circuit Breaker (RCCB) or an over-current protective device such as fuses, Miniature Circuit Breakers (MCB), Moulded Case Circuit Breakers (MCCB) or Residual Current operated Circuit Breaker with integral Over-current protection (RCBO) could be used.

4.2.1 Commonly used protective devices

4.2.1.1 Fuses

A High Breaking Capacity (HBC) or High Rupturing Capacity (HRC) fuse is used to protect various equipment in a microgrid. When the fault current flows through the fuse, it's fuse wire heats up and melts. The time that corresponds to this process is called pre-arcing time. Even if the fuse wire melts, the current continues to flow in the form of an arc. That time is called the arcing time. In an HBC fuse in order to quench the arc, a powered filling is used, as shown in **Figure 7**.

When selecting a fuse for microgrid equipment, two currents should be considered:

- Rated current: The current that the fusing element can take without melting.

- Breaking capacity: The maximum current the fusing element can break without any damage to the fuse.

Figure 8 shows the time-current characteristic of a fuse. As can be seen, the operating time is inversely proportional to current.

4.2.1.2 Miniature circuit breakers (MCB)

An MCB has a magnetic coil and a bimetal strip (**Figure 9**). For a prolonged over-load current, the bimetal strip starts bending and breaks the circuit after some time. A magnetic coil is an instantaneous element that breaks the circuit immediately after a high current is detected. This acts on a short-circuit current.

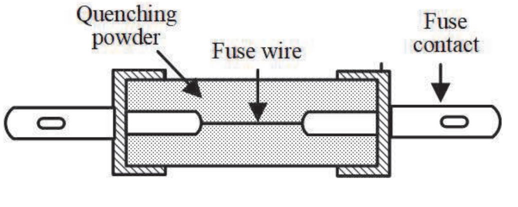


Figure 7.
HBC fuse.

Due to the presence of bi-metal strip and magnetic coil, an MCB shows two different characteristics for over-load and short-circuit currents, as shown in **Figure 10**. In that figure, the PQ characteristics are due to the bi-metal strip and the QR characteristics are due to the magnetic coil.

4.2.1.3 Residual current devices

Residual current devices are used for rapid disconnection of the source of electricity. Their sensitivity can be 10, 30, 100 or 300 mA. **Figure 11** shows part of the operating mechanism in an RCCB. The current in the live wire passes through coil A and that of neutral wire passes through coil B. If phase current and neutral currents are equal, then the flux produced by coils A and B will cancel out. If an earth fault occurs in part of the installation or a person or animal comes into contact with the live wire, the current in one coil differs from that of the other. Then the flux of the two coils will be out of balance resulting in a net magnetic flux in the toroid. This resultant flux links with the fault detection coil and the emf induced will cause the circuit breaker to break the circuit.

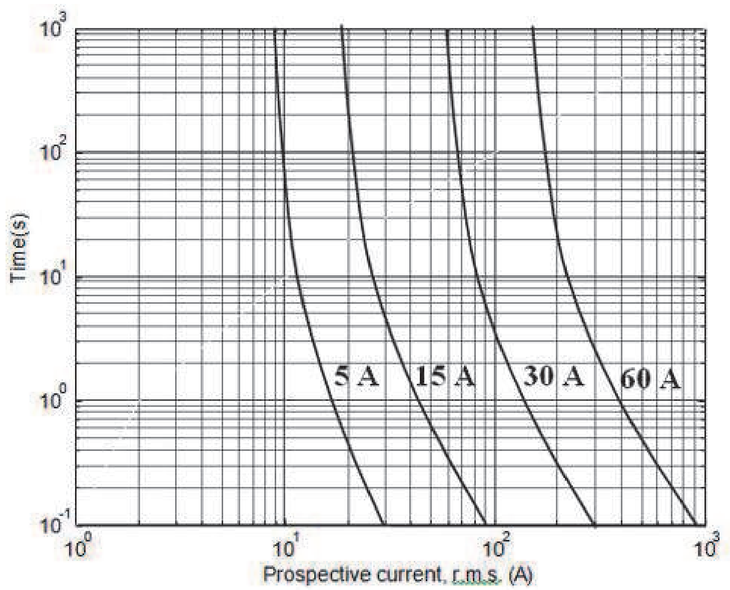


Figure 8.
Operating characteristic of a fuse.

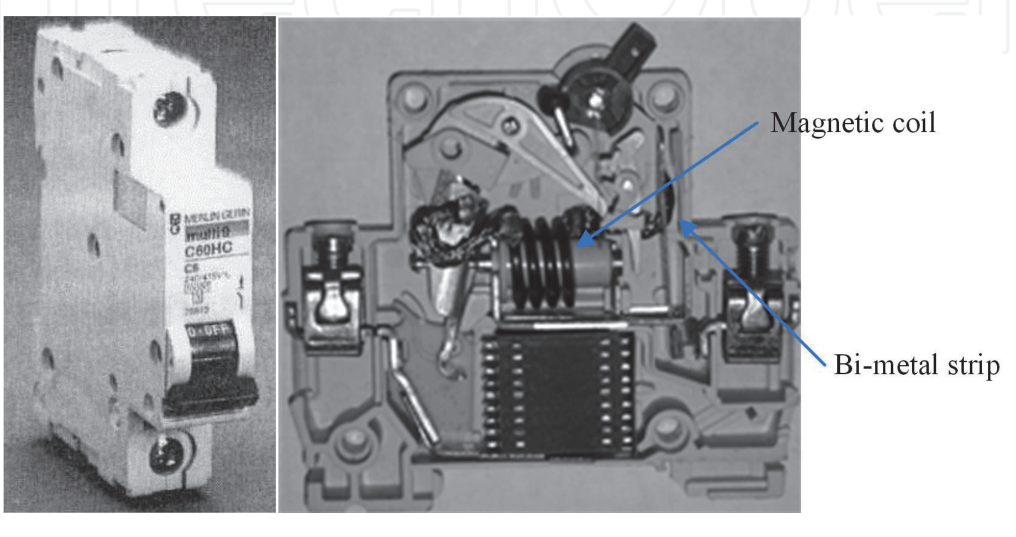


Figure 9.
Open-up section of an MCB.

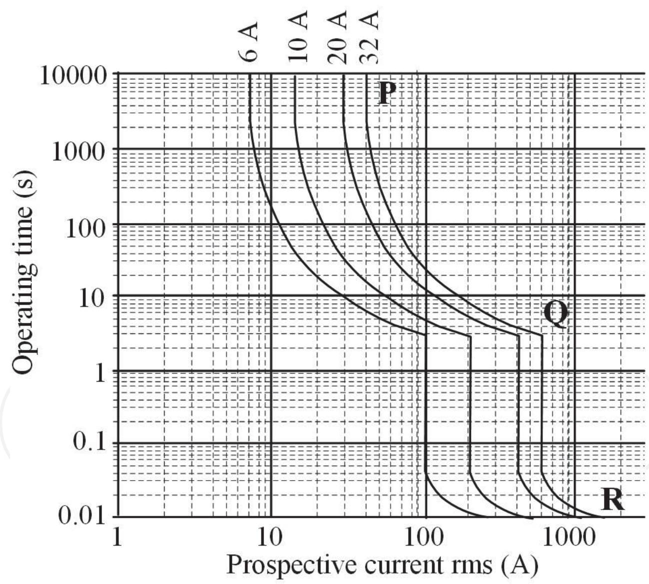


Figure 10.
MCB characteristics.

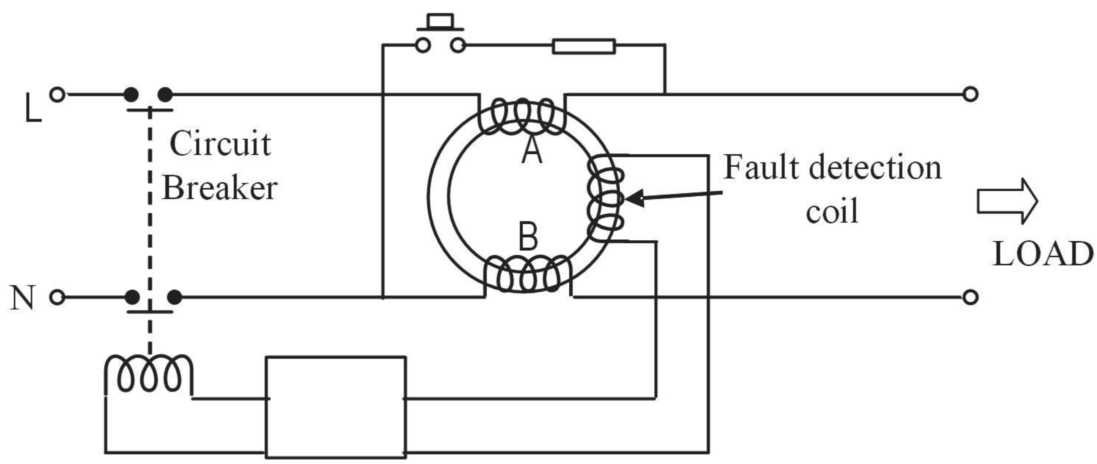


Figure 11.
Simplified diagram of an RCCB.

4.2.1.4 Moulded case circuit breaker (MCCB)

Functionally an MCCB is very similar to an MCB, except the rated current and breaking capacity is much higher. MCCBs are available in three types: Type B, C and D. Type B is used when the power factor of the equipment being protected is closer to 1. Type C is used for inductive loads and Type D is used for motor loads. **Figure 12** shows the symbol of an MCCB and its time-current characteristics. As indicated in the symbol, the MCCB has a circuit breaking element (), a thermal element for over-current protection (), and a magnetic element for short circuit protection (). A modern MCCBs comes in various frame sizes, and the current a frame can normally carry is the rated current of the MCCB.

4.2.2 Protection of solar plants

Figure 13 shows a typical medium-size solar PV plant. The dc circuits are protected by array fuses, and string fuses and disconnectors. A string fuse with a disconnector should be employed for each string. As the fuses used in the strings are subjected to constant sun irradiance and high temperatures, they should be de-rated in many applications by applying the temperature correction factor specified by the

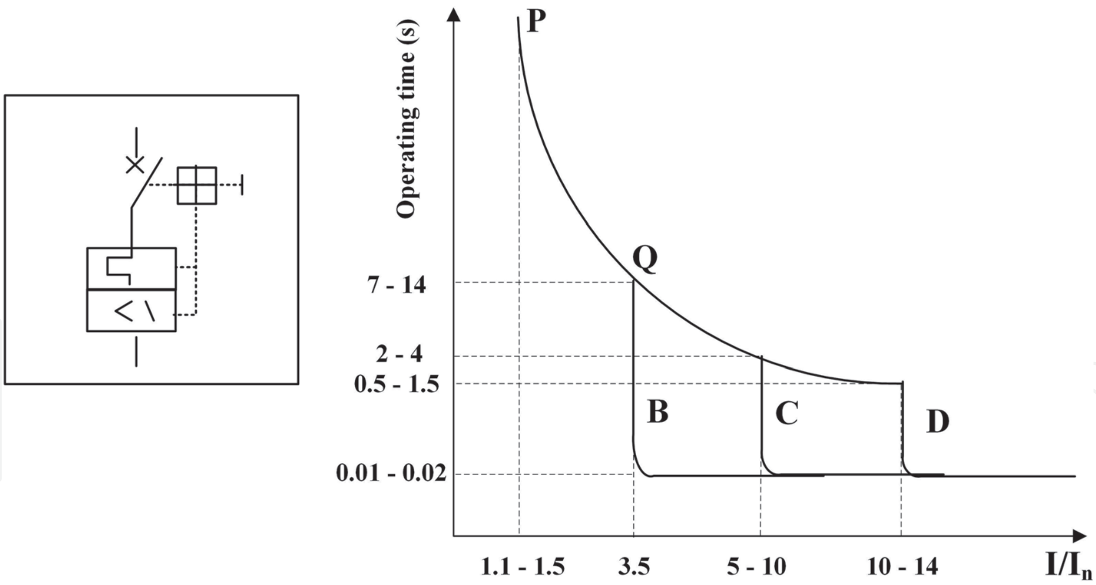


Figure 12.
Symbol of an MCCB and its time-current characteristics.

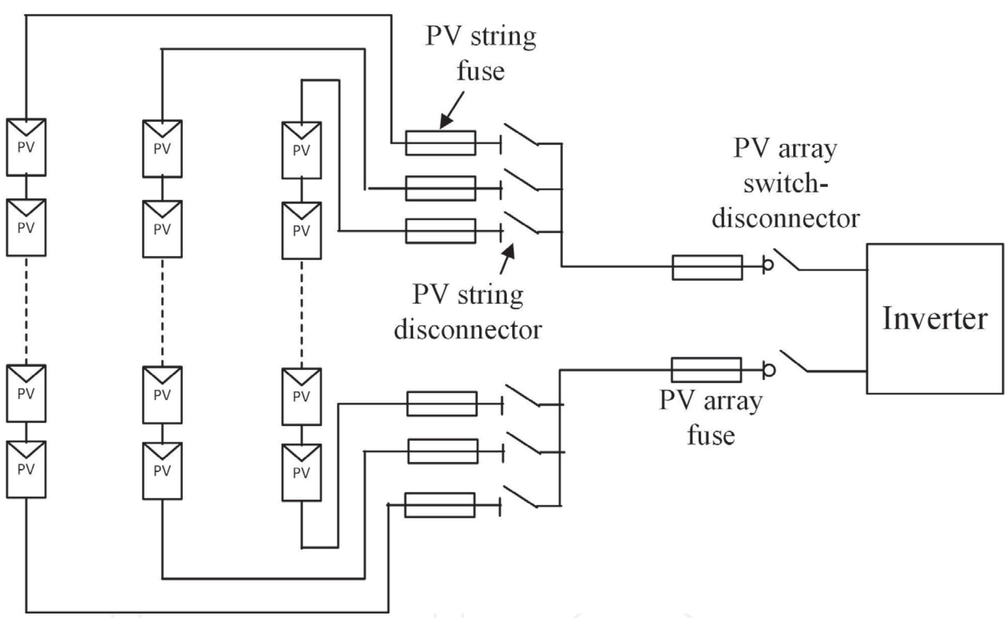


Figure 13.
Typical protection arrangement for a PV plant.

manufacturers. A PV array fuse is only required if there is another source of short circuit current such as a battery system.

IEC 62548 [8] and IEC60364–7-712 [9] provide guidance for protection against over-currents in solar plants. When there are more than two strings in a PV plant, a fuse is required to protect a string from reverse currents due to a short circuit of part of that string. The above IECs state that if $(N_s - 1) \times I_{SC}$ (where N_s is the number of parallel strings and I_{SC} is the short circuit current of a PV sub-array at standard test conditions) is greater than the series fuse rating specified in the manufacturer's data sheet (as per IEC 61730–2 [10]), then string fuses should be employed. String fuses should be selected such that $1.5 \times I_{SC} < I_n < 2.4 \times I_{SC}$ and $I_n \leq$ string fuse rating (where I_n is the rating of the fuse).

4.2.3 Protection of wind power plants

The electrical protection of small wind turbine generators is addressed in IEC61400–1 [11]. The wind turbine generator should have a disconnection switch and the rated current of fuses or the setting current of other over-current protective devices such as MCB and MCCB should be selected as low as possible but adequate for starting the wind turbine generator. Further, the rated short-circuit breaking capacity should be at least equal to the prospective fault current at the point of installation. The action of the bi-metallic strip in MCBs and MCCBs should introduce a time delay that affords the generator time to start and settle into the normal running current without unnecessary tripping.

4.3 Surge protection

Lightning or switching surges can enter into different expensive equipment in a microgrid and destroy or cause it to mal-function. To provide protection against surges, surge protection devices (SPD) are employed. An SPD is a metal oxide varistor or an avalanche breakdown diode or a gas discharge tube. An SPD diverts the surge into the ground, thus providing protection to the device to which it is connected.

4.4 Case study

An islanded microgrid installed in the north of Sri Lanka that feeds power to a remote island that has 120 families is considered. The microgrid has a wind farm, ground-mounted solar plant, battery bank with a grid forming inverter and a backup diesel generator. Some photos from the microgrid are given in **Figure 14** and the rating of these components is given in **Table 2**.

A simplified diagram was created from the single line diagram of Eluvithive microgrid and **Figure 15** shows this simplified network and associated protective devices.

In the event of a network fault, the dc link voltage of the wind turbine will rise rapidly because the inverter is prevented from transforming all the active power coming from the wind generator. Therefore, in order to maintain the dc link voltage below its upper limit, the excess power is dissipated in a chopper circuit shown. Here the excess energy is dissipated into a resistor connected to the dc link as heat. When the dc-link voltage reaches a critical value, the dc-link is short circuited for a short period of time through the chopper. During the activation of the chopper, the dc-link discharges keeping the dc-link voltage below a critical value.

As can be seen from the figure, the wind turbine is protected by a 3 pole over-current protective device (MCCB 1). Each wind turbine is rated at 220 V, 50 Hz but operating at a variable voltage and variable frequency mode. According to the wind turbine specification (WINDSPOT 3.5 kW [12]), the power generation at the cutout wind speed (25 m/s) is 4214 W. The corresponding current is $4214/\left(\sqrt{3} \times 220\right) =$ 11.06 A. The current rating of MCCB 1 was selected as 125% of generator rated current, i.e. 13.8A. Even though a 16 A MCB is adequate when considering the load current rating, the wind turbine manufacturer uses a 25 A MCCB. The selection was based on the short circuit capability of MCBs. They have a breaking capacity less than 5 kA and at the terminal of the generator, the short circuit current may be higher than that. Therefore, the smallest MCCB, having a rated current of 25 A and a braking capacity of 10 kA, is employed. Also, note that as the current from the generator has a variable frequency, an MCCB suitable for operating at variable frequency was selected.

Since the grid side of the wind turbine is a single phase, the maximum current on that side is 19.15 A, thus requiring an overcurrent protective device of 23.9 A (1.25 x 19.15). Therefore, an MCCB having a rated current of 25 A and a braking capacity of 10 kA was used for MCCB 2.

Figure 14.
Some photos from Eluvithive microgrid. (a) Map of the island, (b) distance view of the island, (c) solar panel and microgrid assembly, (d) solar inverters, (e) solar inverters and multi-cluster panel, (f) diesel generator, wind turbine inverters and dump loads, (g) wind turbines, and (h) Li-ion batteries.

Table 3 provides the specifications of the solar panels that are essential for determining the protective devices. In that table STC stands for standard test condition, i.e. irradiance of 1000 W/m^2 and ambient temperature of 25°C.

As there are three parallel-strings, as described in Section 3.2.2, $(N_s - 1) \times I_{SC}$ = 2 x 8.81 = 17.62 A. As this is greater than PV module's series fuse rating, 15 A, string fuses are required. The current rating of the fuse should be such that $13.2\,(1.5 \times 8.81) < I_n < 21.1\,(2.4 \times 8.81)$. Therefore 15 A fuses are employed.

The output current of the inverter is $15 \times 10^3/\left(\sqrt{3} \times 400\right) = 21.6$ A, and the MCCB rating was selected as greater than 125% of the output current, i.e. 27 A. Therefore, for MCCB 3, 32 A, 4 pole, 10 kA, MCCB was used. A similar procedure was used to select MCCBs for other places.

Source	Unit capacity	Number of units	Total capacity
Diesel Generator	30 kW	1	30 kW
Wind Plant	3.5 kW	6	21 kW
PV plant	250 Wp	180	45 kWp
Li-ion batteries	13 kW/27.5 kWh	4	52 kW/110 kWh

Table 2.
Different sources and capacity of microgrid components.

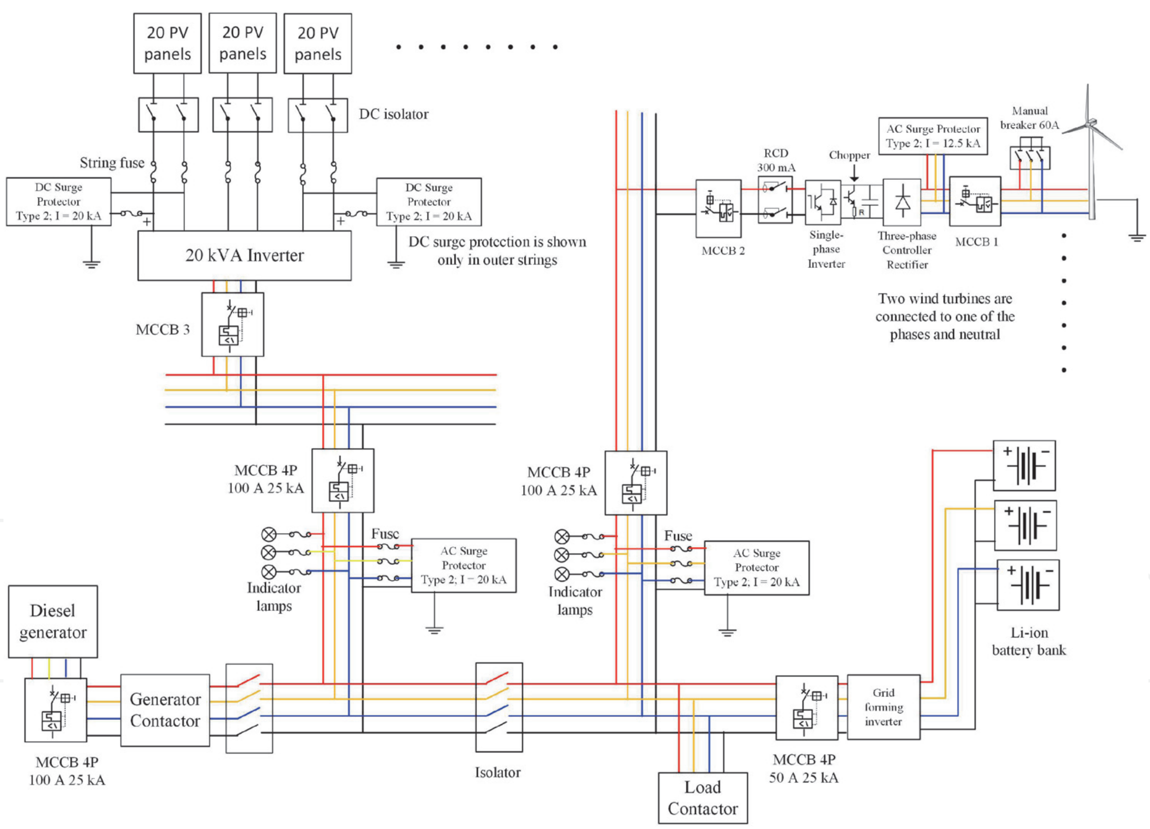


Figure 15.
Example isolated microgrid.

STC Power (Wp)	250
STC Open circuit voltage Voc (V)	37.6
STC short circuit current Isc (A)	8.81
Series string fuse rating (A)	15

Table 3.
Details of each of the solar panels.

	At junction box		Inverter dc side	Inverter ac side	
Criteria	Ldc < 10 m	Ldc > 10 m		Lac < 10 m	Lac > 10 m
Type of SPD	No need	SPD1 Type 1	SPD2 Type 2	No need	SPD3 Type 2

Table 4.
SPD requirement [7].

As shown in the figure, Surge Protection Devices (SPD) are employed to protect sensitive electrical equipment like the inverter, monitoring devices and PV modules. Their requirement depends on the length of the dc cable between the array and inverter (L_{dc}) and the length of the ac cable between the inverter and main distribution board (L_{ac}). **Table 4** specifies these requirements.

5. Protection of microgrids operating in parallel with the grid

There should be adequate protection to ensure the safe operation of the components within a microgrid and external circuit to which the microgrid is connected. As discussed in Section 3, fuses, MCBs, MCCBs, and RCCBs are used for small microgrids. For large microgrids protection relays and associated circuit breakers are used. A typical microgrid connection with associated protection is shown in **Figure 16**.

In **Figure 16**, a number of fault locations could be identified:

- Fault F1: This is a fault within the micro-source, and the generator protection should clear the fault.

- Fault F2: For a feeder fault within the microgrid, both micro-sources and the main grid will provide fault currents. Fault current provided by MS2 is cleared by the relays associated with CB8. Fault current from the grid and MS1 is cleared by the relays associated with CB6. As the coordination of relays should maintain for grid connected and islanded modes, careful studies should be carried out to ensure proper coordination. Two alternative settings could be used with modern numerical relays, one for the grid connected mode and the other for the islanded mode.

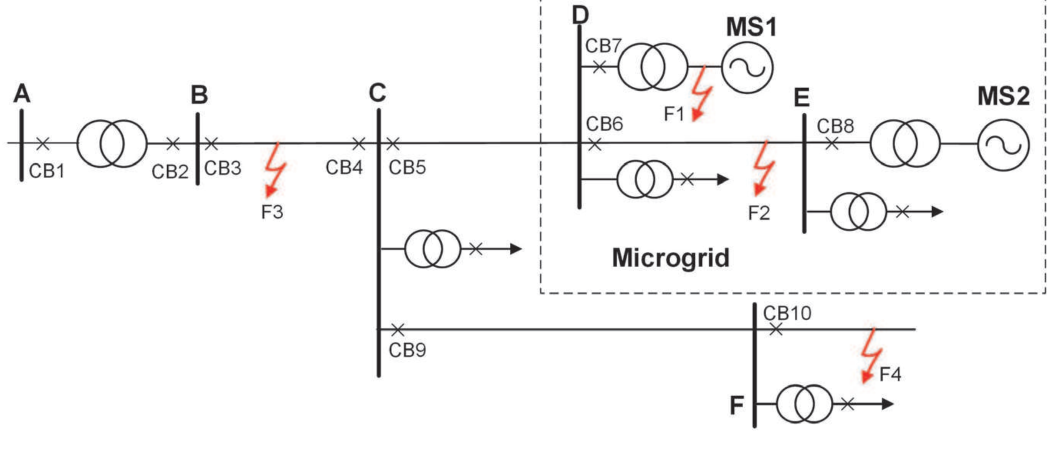


Figure 16.
Protection of grid connected microgrid.

- Fault F3: When a fault occurs in the main grid at the location shown, it is detected by the overcurrent relays associated with CB3 and CB4 and isolates the fault by switching these two circuit breakers. Under such condition, the microgrid experiences a Loss of Mains (LoM) and adequate LoM protection should be employed to isolate the microgrid from the main grid.

- Fault F4: As the fault is at the far end of the radial network, the protection relay CB10 will clear the fault with considerable time delay. During this period the voltages of the busbar C and D may experience voltage dips, and the micro-sources should be able to ride-through the fault and come back to normal operation when CB10 isolates the fault.

The different protection requirements under the above fault conditions are specified in country-specific standards. In the UK, the basic protection requirements for microgrids containing micro-sources of 16 A or less and connected to LV distribution networks are spelt out in the Engineering Recommendation G98 [13]. The protection requirements for a larger microgrid but with less than 50 MW sources and connected to distribution MV networks are given in the Engineering Recommendation G99 [14]. For all distributed energy resources (DER) connected to distribution networks in the USA, the protection requirements are given in IEEE1547: 2018 [15]. G99 specify protection requirements under four generator types classified based on the rated power and the connection point voltage. These categories are given in **Table 5**. IEEE 1547 also categorises generators as category I, II and III based on the abnormal operating performance, mainly voltage and frequency ride-through capabilities. As the recommended protection arrangement varies with the connection arrangement of the transformer and the generator, the readers are directed to the relevant standard for more details.

5.1 Protection of micro-sources

For an internal fault in a large generator, differential protection is usually employed. **Figure 17(a)** shows that if both ends of the stator windings are accessible, differential protection provides phase and earth fault protection. If only one side of the stator is accessible, earth fault protection can be achieved as shown in **Figure 17(b)**. In some cases, differential protection covers both generator and generator transformer. In such a case, a fault F1 shown in **Figure 16** is cleared by the differential protection scheme.

5.2 Protection of the microgrid

For a fault at location F2 of **Figure 16**, micro-sources MS1 and MS2 deliver fault current. As shown in **Figure 18**, an overcurrent relay (marked as 51) associated with the micro-sources can clear the fault. Suppose the micro-source is a small

Type	Output Power	Voltage to which the DER is connected
A	0.8 kW to 1 MW	< 110 kV
B	1 MW to 10 MW	< 110 kV
C	10 MW to 50 MW	< 110 kV
D	> 50 MW	> 110 kW

Table 5.
Different types defined in G99.

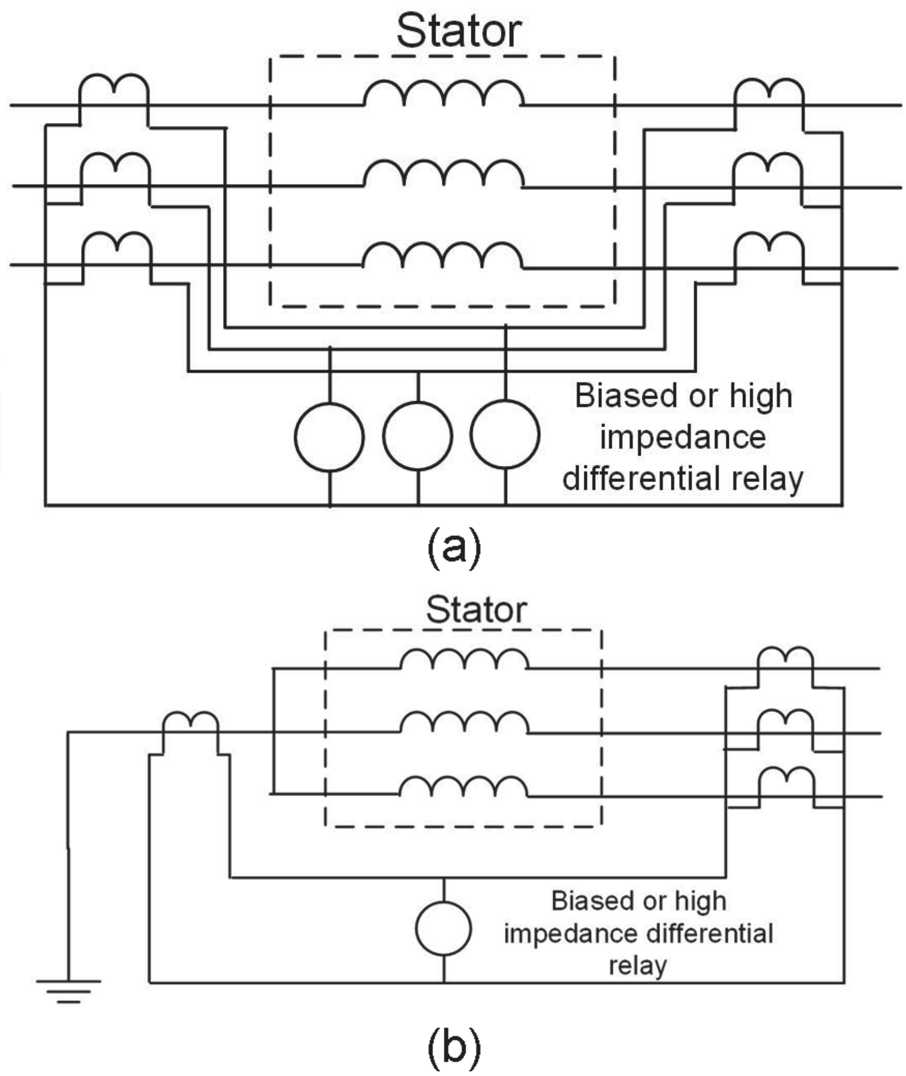


Figure 17.
Differential protection of generator. (a) Earth and phase fault protection and (b) restricted earth fault protection.

synchronous generator. In that case, as discussed in Section 2.1, excitation should be maintained during a fault using a field forcing technique for the over-current protection to work satisfactorily.

A better scheme for providing over-current protection of the network from a small generator is to use a voltage-restrained or voltage-controlled over-current relay (51 V) (also shown in **Figure 18**). This relay requires both current and voltage signals to operate. The voltage restrained approach causes the pick-up current to decrease with decreasing voltage, as shown in **Figure 19(a)**. When the voltage is at its rated value, the pick-up setting of the relay is high. As the voltage decreases (due to a fault), the pick-up value of the relay is decreased proportionally. The voltage-controlled approach has a high pick-up value when the voltage is above a preset voltage, and the pick-up current is reduced to a lower value for voltage below the preset voltage (**Figure 19(b)**).

5.3 Protection for LoM

When the microgrid becomes disconnected from the grid due to an external fault as F3 in **Figure 16**, IEEE 1547 and G99 specify a number of ways to provide LoM protection. Some of the protection functions are associated with generators, whereas some other functions are associated with interface protection associated

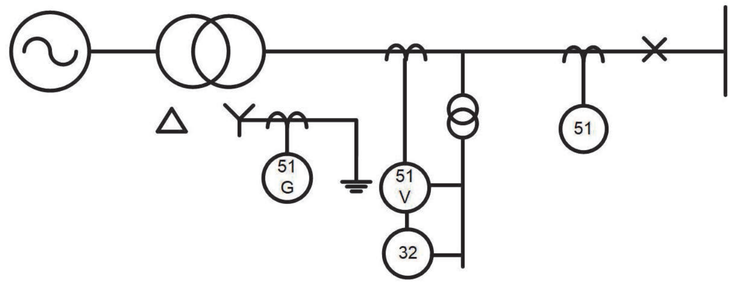


Figure 18.
Overcurrent protection for phase and earth fault protection.

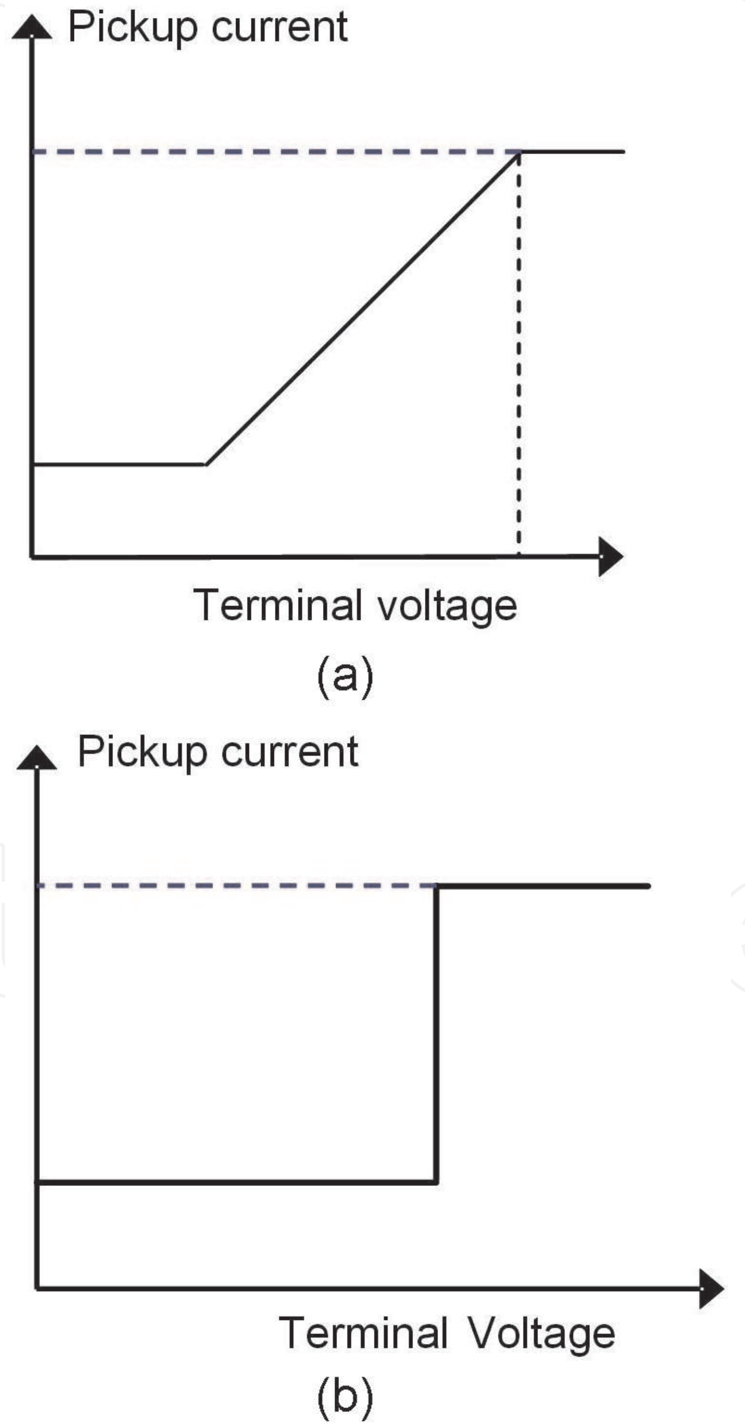
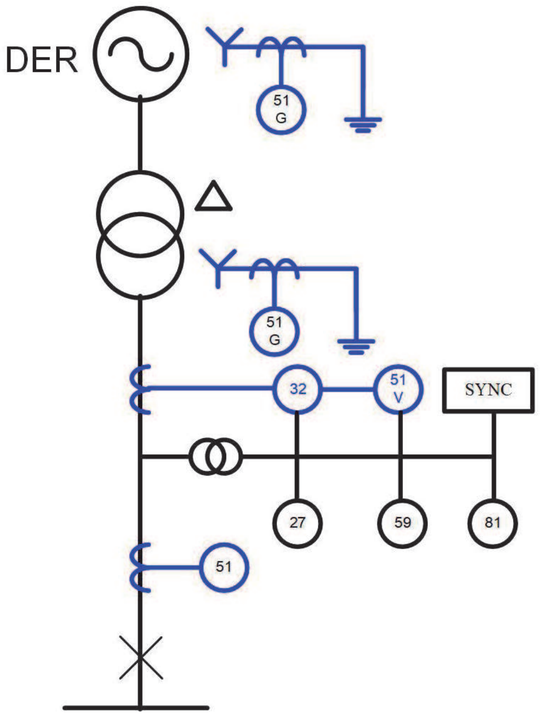


Figure 19.
Operating characteristic of voltage restrained and voltage controlled relays. (a) Voltage restrained and (b) voltage controlled.



27	Under-voltage
32	Reverse Power
51	Over-current (phase)
51G	Over-current (ground)
51V	Over-current (voltage controlled or voltage restraint)
59	Over-voltage
81	Under and over frequency
SYNC	Synchronising

Figure 20.
Typical protection requirement for DER.

with the utility-tie CB at the point of connection or point of common coupling. **Figure 20** shows the typical LoM protection functions associated with the generator as specified in G99. For completeness, the protection functions described under the previous section are also included in the figure by blue colour lines.

Parameter		IEEE1547:2018			G99	
		Category	Setting (pu & Hz)	Time delay (sec)	Setting (pu & Hz)	Time delay (sec)
Under-voltage (pu)	Stage 1	I	0.70	2.0	0.80	2.5
		II	0.70	10.0		
		III	0.88	21.0		
	Stage 2	I & II	0.45	0.16		
		III	0.50	2.0		
Over-voltage (pu)	Stage 1	I & II	1.10	2.0	LV – 1.14 HV – 1.10	1.0 1.0
		III	1.10	13.0		
	Stage 2	I, II, III	1.20	0.16	LV – 1.19 HV – 1.13	0.5 0.5
Over-frequency (Hz)	Stage 1	I, II, III	62	0.16	52	0.5
	Stage 2	I, II, III	61.2	300		
Under-frequency (Hz)	Stage 1	I, II, III	58.5	300	47.5 Hz	20
	Stage 2	I, II, III	56.5	0.16	47.0	0.5
					LV: 50–1000 V ac LL HV: > 1000 V LL	

Table 6.
Over and under voltage and frequency limits.

Loss of Mains may cause frequency or voltage to be outside the normal operating ranges. When the voltage and frequency are outside the limits defined in **Table 6**, the micro-source is tripped within the respective clearing time. For this, under-voltage (27), over-voltage (59), under-frequency (81/O), and over-frequency (81/U) protection relays are used.

As per the G99, interface protection includes over, and under-frequency relays operating for the 2nd stage settings (**Table 4**), over and under-voltage relays operating for the 2nd stage settings, and a special relay employed for LoM protection.

IEEE 1547: 2018 and G99 state that under and over frequency and under and over voltage relays will not provide adequate protection for LoM, and additional means is required. G99 states that additional LoM protection is required for Type A, B and C power generating modules. Depending on the situations, rate of change of frequency (ROCOF), reverse active power, and reverse reactive power relays may be applied to provide LoM protection. However, if reverse power occurs during normal operation, then the reverse power relay cannot be used for LoM protection. Further, if the microgrid contains micro-sources that can generate reactive power and reverse reactive power flows are experienced during normal operation, then the reverse reactive power relay cannot be used for LoM. Then the ROCOF relay is the only relay that remains for protecting against LoM.

ROCOF relay senses df/dt over a number of cycles and operates when it is greater than a predetermined value. The ROCOF relay should ignore slow changes of df/dt and only should respond to rapid changes. The rate of change of the frequency is determined by the inertia constant[1] of the distributed generator and captive load and governed by the following equations:

$$\frac{d\omega}{dt} = \frac{1}{J}(T_m - T_e) \tag{4}$$

The inertia can be expressed in per unit as an H constant

$$H = \frac{\frac{1}{2}J\omega_S^2}{S_{rated}} \text{ [Ws/VA]} \tag{5}$$

where S_{rated} is the base MVA.

ω_S is the angular velocity (rad/s) at synchronous speed.

Thus

$$\frac{d\omega}{dt} = \frac{{\omega^S}_2}{2HS_{rated}}(T_m - T_e) = \frac{\omega_s}{2H}(P_m - P_e) \tag{6}$$

where $\frac{\omega_s T}{S_{rated}} = P$ is the per unit (pu) power.

Since $\omega_s = 2\pi f$, from (6) the ROCOF can be obtained as:

$$\frac{df}{dt} = \frac{f}{2H}(P_m - P_e) \tag{7}$$

where P_m and P_e are pu quantities on generator base.

A sudden connection or disconnection of a load and a fault in the network may cause a sudden shift in the terminal voltage vector of a DER with respect to its

[1] Inertia constant is the ratio between the kinetic energy and the apparent power of the rotating machine.

normal operating voltage. A relay that measures the voltage phase changes in consecutive cycles and compares the value with a preset value could be used to provide LoM protection. Such relay is called a vector shift relay. Even though the voltage vector shift relay is recognised in G98 as an acceptable method of providing LoM protection, it can be over-sensitive and operate incorrectly. Present revisions of G99 state that the voltage vector shift technique is not an acceptable LoM protection.

5.4 Fault ride-through for remote faults

As discussed before, a remote fault (such as fault F4 in **Figure 16**) may create temporary voltage disturbances. Under such conditions, the micro-sources should ride the fault and resume operate immediately after the remote fault is cleared. As per IEEE 1547, if the temporary voltage is between the lower and upper red lines in **Figure 21**, then the micro-source should ride-through the fault by maintaining synchronism with the grid and without tripping the generator breaker. When the remote fault is cleared, the active current output should be restored to at least 80% of the pre-disturbance active current level within 0.4 s. A similar requirement is specified in G99. The ride-through requirement for G99 Type C & D generators is also shown as the blue line in **Figure 21**.

IEEE 1547 also specifies a rate of change of frequency (ROCOF) ride-through. Micro-sources should ride-through and not trip for frequency excursions having magnitudes of ROCOF less than 0.5 Hz/s for Category I, 2.0 Hz/s for Category II and 3.0 Hz/s for Category III DERs.

5.5 Case study

An example microgrid is shown in **Figure 22**. In that network all the line impedances are given on 200 MVA, 11 kV base. The transformer reactances and generator impedances are given on their own base. This network is used to demonstrate the operation of the microgrid under different faults.

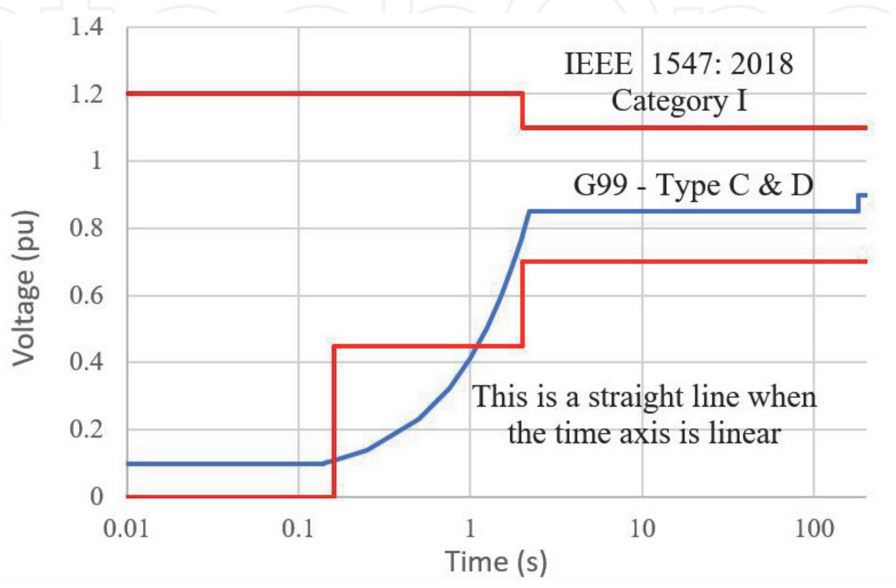


Figure 21.
Fault-ride through requirements.

5.5.1 Fault on utility network: Islanding of the microgrid

A fault at F3 (at 1 s) is cleared by CB3 and CB4 and the microgrid may continue to operate depending on the active and reactive power balance within the microgrid. **Table 7** gives the voltages of different busbar before and after islanding. As can be seen from the table, even after islanding, the voltages of the busbars will be maintained within limits.

Figure 23 shows MS1 terminal voltage and generator frequency when the microgrid is islanded due to a fault at F3. During islanded operation, the total generation within the microgrid is P = 5 MW and Q = 1.5 Mvar whereas the total demand is P = 4.3 MW and Q = 1.5 Mvar. Therefore, the surplus of generation (without considering the losses) after islanding is 700 kW. For MS1 on 5 MVA base, the inertia constant is 2.5 MWs/MVA. From Eq. (7), the rate of change of frequency can be calculated as follows:

$$\frac{df}{dt} = \frac{f}{2H}(P_m - P_e) = \frac{50}{2 \times 2.5} \times \frac{700}{5000} = 1.4\text{Hz/s} \tag{8}$$

From **Figure 23**, it is computed that the rate of change of frequency is 0.036 Hz/s. This is because, when accounting for the losses surplus is much less that 700 kW. Further, when considering the reactive power balance, there is no significant difference to vary the voltage. Therefore, neither under-voltage or over-frequency relays will detect the islanding situation. Typically, the ROCOF relay on a small microgrid is set to operate for 1–3 Hz/s, and with the penetration of micro-sources are increasing it is reduced. For example, in the GB ROCOF setting has recently

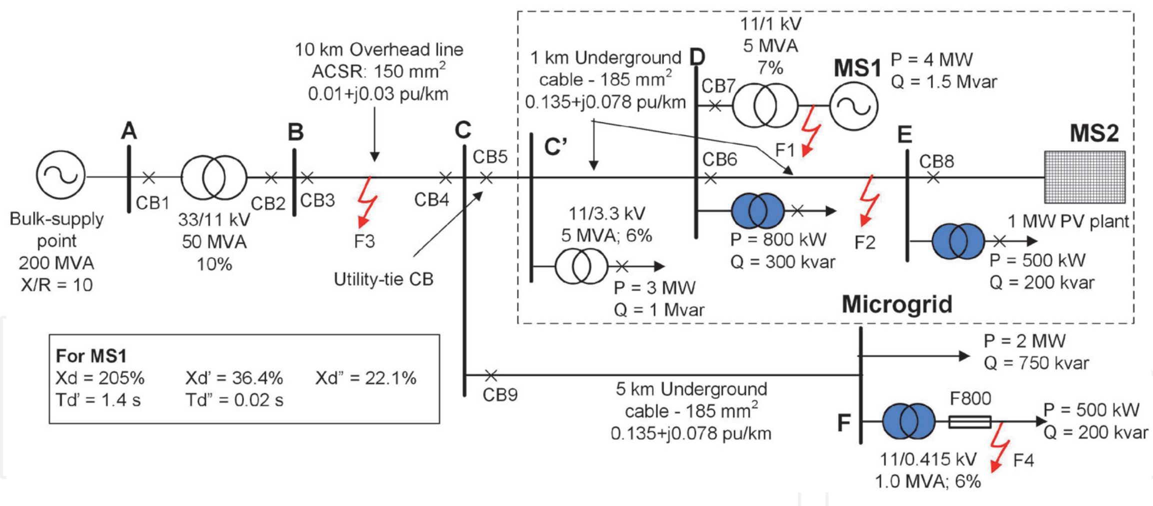


Figure 22.
Example grid-connected microgrid.

Busbar	Voltage (pu) before islanding	Voltage (pu) after islanding
A	1.02	
B	$1.016\angle - 0.06^o$	
C	$1.015\angle - 0.06^o$	$0.966\angle - 3.53^o$ (C′)
D	$1.018\angle - 0.01^o$	$0.969\angle - 3.49^o$
E	$1.018\angle - 0.02^o$	$0.97\angle - 3.47^o$

Table 7.
Voltages of different busbars before and after islanding.

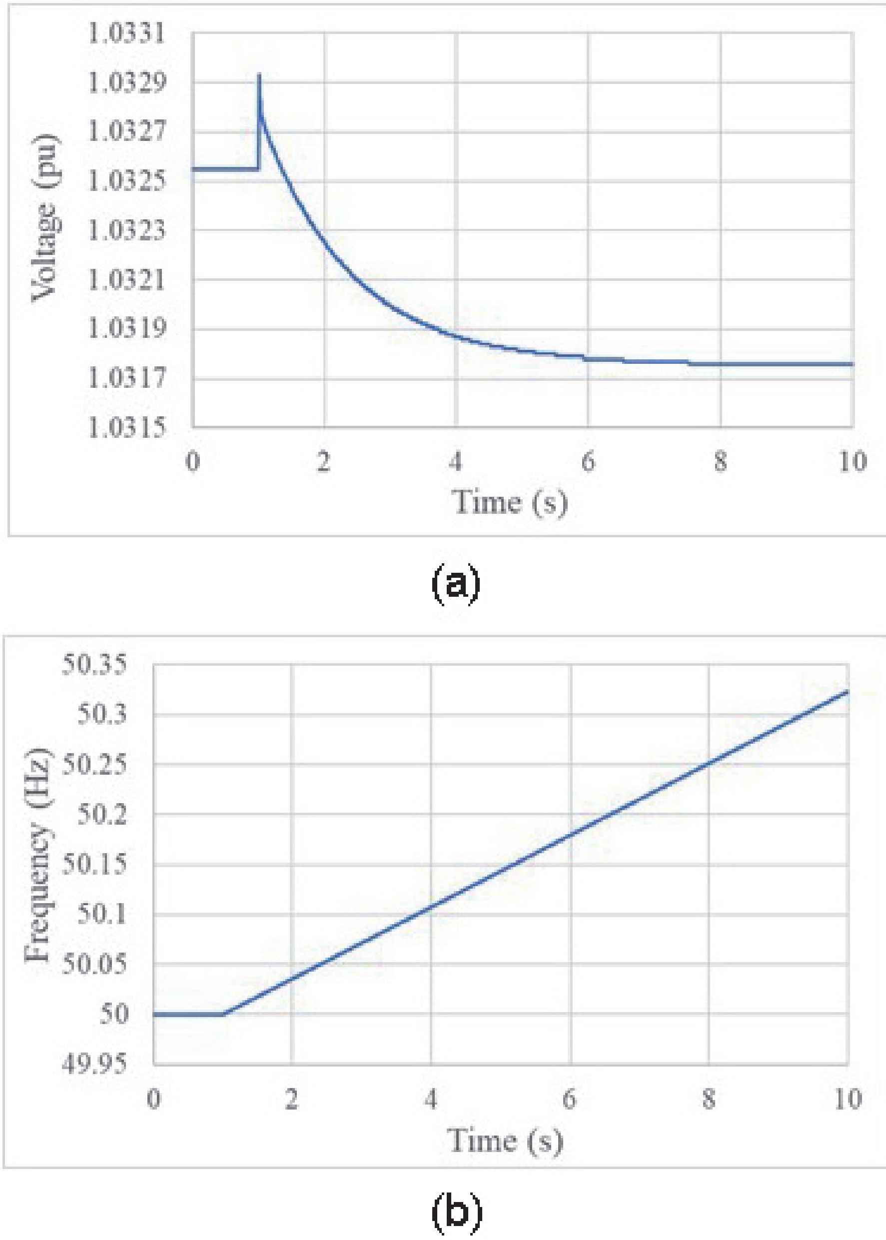


Figure 23.
The voltage and frequency of MS1 terminal. (a) Generator busbar voltage and (b) generator frequency.

changed from 1.25 Hz/s 0.125 Hz/s. With a such setting, the ROCOF relay will not operate. Therefore, the microgrid can continue to operate in islanding mode provided that there is no significant change in the generation and load.

5.5.2 Fault external to microgrid: fault-ride-through of generator in microgrid

Figure 24 shows the voltage at the busbar D for a fault at F4 with grid connection, which is introduced at 1 s and cleared at 2 s. As can be seen, the voltage is well within the ride-through requirements specified in **Figure 21**, and therefore MS1 should ride-through the fault.

5.5.3 Fault internal to microgrid: operation of protection in grid-connected and islanded mode

For a fault at F2 (busbar E), the fault current through CB6 without MS1 is 4.5 kA, and with MS1, it is 7.76 kA. Therefore, the micro-source MS1 aid the protection by reducing the operating time of CB6. With the protection coordination settings for

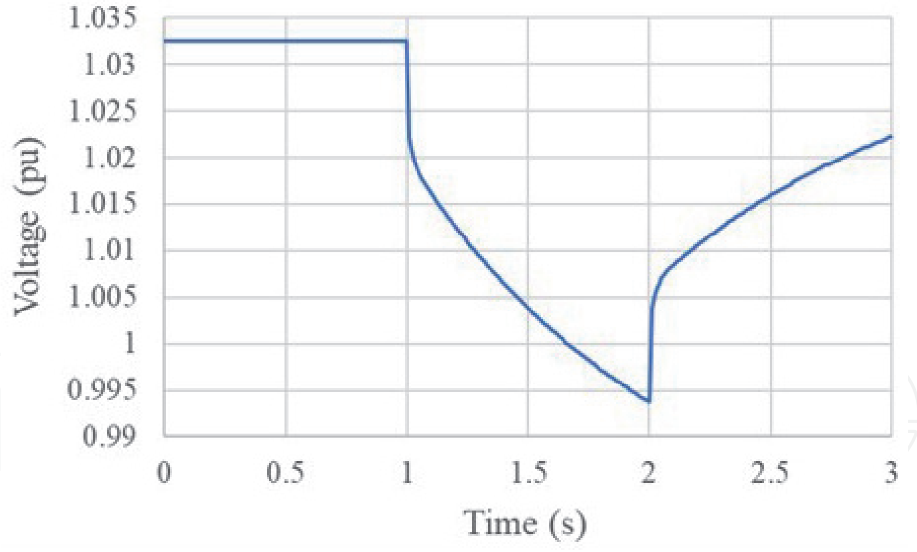


Figure 24.
Voltage at busbar D.

grid connected mode, the protection of CB6 may have mal-operate if the microgrid becomes islanded. In islanded mode, the fault current flowing through CB6 for a fault at F2 reduces to 3.38 kA. The following section explains this issue further.

In grid connected operation, relays at CB9 and CB3 should be coordinated with the fuse F800, which is a 800 A fuse. Then CB5 and CB6 should be coordinated with CB3. These settings are given in **Tables 8** and **9**.

In **Table 8**, full load current in line BC was obtained using load flows carried out in IPSA simulation platform with MS1 and MS2 disconnected. This is the case that introduces the highest current through the line. Similarly, the current through CF was obtained. The possible fault currents at each end of lines (neglecting load currents) was obtained by applying faults at busbars B, C and F. In order to select the primary current rating of the current transformer (CT), and overload current of 125% was considered. The secondary current rating is based on the relay to which the CT is connected and assumed as 5A. Usually, the plug setting (PS) is selected higher than the overload current and less than the fault current and 100% is selected for both relays, i.e. relay at CB3 and CB9. Plug setting multiplier (PSM) is the fault current divided by the plug setting, and it is calculated for each relay for faults at the sending and receiving end of the line.

CB9 should be coordinated with the 800 A fuse, the fuse operating current was obtained for a LV side fault at busbar F. That is for a fault current of 28.83 kA on the LV side of the transformer, from the fuse characteristic, it was found that the operating time is 5 ms. Assuming a grading margin of 0.25 s, the minimum operating time of relay at CB9 is 0.255 s (0.25 + 0.005). Assuming an extremely inverse characteristic [16] for the relay at CB9, the operating time of the relay CB9 was calculated as follows.

$$\begin{aligned}\text{The operating time of the relay} &= 80 \times TMS/\left[PSM^2 - 1\right] \\ &= 80 \times TMS/\left[28.3^2 - 1\right] = 0.255\ \text{s}\end{aligned} \tag{9}$$

where 28.3 is the PSM of the relay at CB9 for a fault at F (see **Table 8**).

Therefore the time multiplier setting (TMS) of the relay = 2.55.

As the maximum possible TMS for a typical overcurrent relay is less than 1.5, the PS of the relay was increased to 130%. Then the PSM = 5650/(1.3 x 200) = 21.7 and the new TMS = 1.49. Select TMS as 1.5 (in many relays, TMS can set only in discrete steps; for this example, it was assumed that the step size is 0.025).

Line	BC		CF	
Line End	**B**	**C**	**C**	**F**
Full load current (A)	382.3 A (when MS1 and MS2 are not operating)		142.4 A	
Fault current (kA)	8.46	8.07	8.07	5.65
CT ratio[1]	500:5		200:5	
Plug setting (PS)	100% = 500 A		100% = 200 A	
PSM = FC/PS	16.9	16.1	40.4	28.3

[1]*Assuming 125% of overload current.*

Table 8.
Data for selecting the relay for the coordination path F800-CB9-CB3.

Line	CD		DE	
Line End	**C**	**D**	**D**	**E**
Full load current (A)	195 A (when MF1 and MF2 are operating)		28 A	
Fault current (kA)	8.16	8.09	8.09	7.52
CT ratio[1]	300:5		50:5	
Plug setting (PS)	90% = 270 A		90% = 45 A	
PSM=FC/PS	30.2	29.9	179.8	167.1

[1]*Assuming 125% of overload current.*

Table 9.
Data for selecting the relay for the coordination path CB3-CB5-CB6.

With PS of 130% and TMS of 1.5, the operating time of the relay at CB9 for a fault near busbar C was calculated as follows.

$$\text{PSM} = 8070/(1.3 \text{ x } 200) = 31.0 \tag{10}$$

$$\text{Operating time of the relay} = 80 \times 1.5/\left[31^2 - 1\right] = 0.125 \text{ s} \tag{11}$$

By considering the grading margin of 0.25 s, the operating time of the relay at CB3 for a fault near the busbar C should be 0.375 s. Assuming the relay is very inverse [16], the TMS was calculated as follows.

$$\begin{aligned} \text{The operating time of the relay} &= 13.5 \times TMS/[PSM - 1] \\ &= 13.5 \times TMS/[16.1 - 1] = 0.375 \text{ s} \end{aligned} \tag{12}$$

TMS = 0.419, select 0.425.

Even though the above settings work ok for the given fault, when implementing the protection coordination system in the IPSA simulation platform, the curves of relays at CB9 and CB3 intercept. Therefore, the PS of the relay at CB3 was increased to 150%, and the resultant curves are shown in **Figure 25**.

Table 9 shows the PSM calculation for lines CD and DE for a fault at F2 (busbar E).

With the setting of the relay at CB3 calculated for the previous coordination, the operating time of that relay for a fault at C is 0.58 s. To maintain the correct grading margin, for a fault at the end C, the relay at CB5 should operate at less than 0.33 s, i.e. 0.58–0.25 s. Then assuming that CB5 is a very inverse relay, the TMS was calculated as follows.

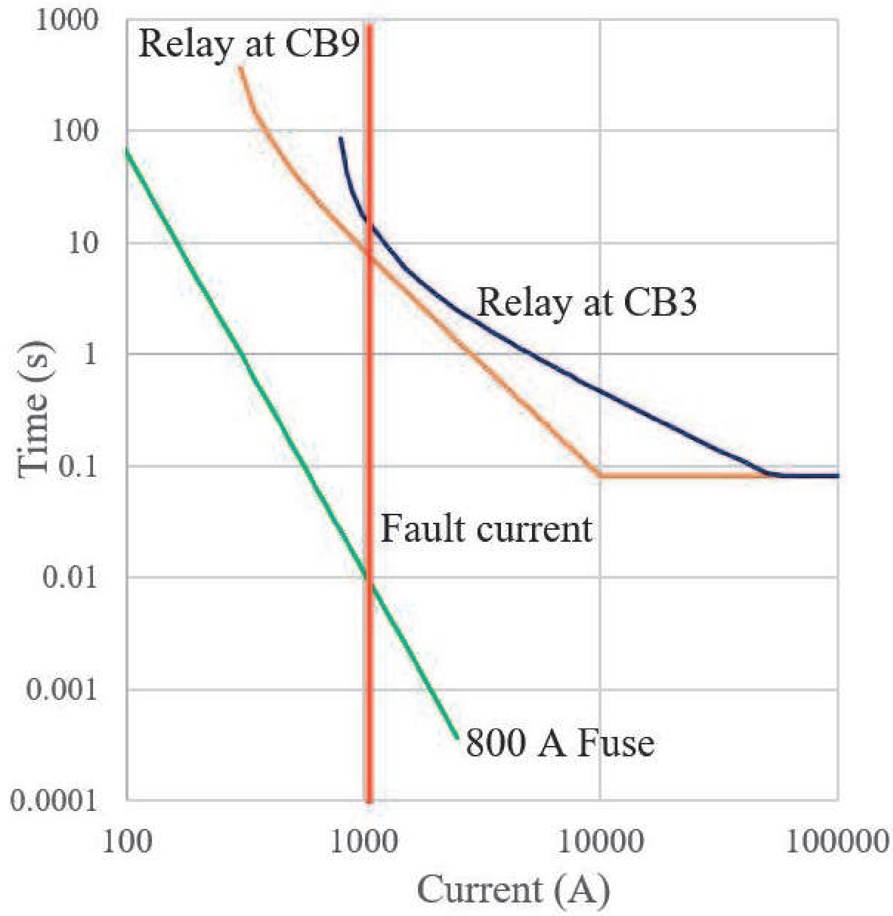


Figure 25.
Relay and fuse characteristic for a fault after 800 a fuse.

$$\begin{aligned} &13.5 \times TMS/[30.2 - 1] < 0.33 \\ &\therefore TMS < 0.71 \end{aligned} \tag{13}$$

Therefore, TMS was selected as 0.7.

With the calculated setting of the relay at CB5, the operating time of the relay for a fault at D was calculated as $13.5 \times 0.7/[29.9 - 1] = 0.33$ s. Then the relay at CB6 should operate less than 0.077 s (0.33–0.25 s) for a fault at busbar D. Assuming that CB6 is a very inverse relay, the TMS was calculated as follows.

$$\begin{aligned} &13.5 \times TMS/[179.8 - 1] < 0.077 \\ &\therefore TMS < 1.02 \end{aligned} \tag{14}$$

Select TMS as 1.0.s.

Figure 26 shows the coordination of CB3-CB5 and CB6. Also shown the operation of CB6 when MS1 is in operation when MS1 is not in operation, and during an islanded mode for a fault at F2. As can be seen, the operating time of the relay under islanded condition is highest.

6. Earthing requirements

6.1 Effective earthing approaches for transformer connected micro-sources

Micro-sources are operated in parallel with the utility grid and are connected through a transformer. It is important that the proper earthing of this interfacing

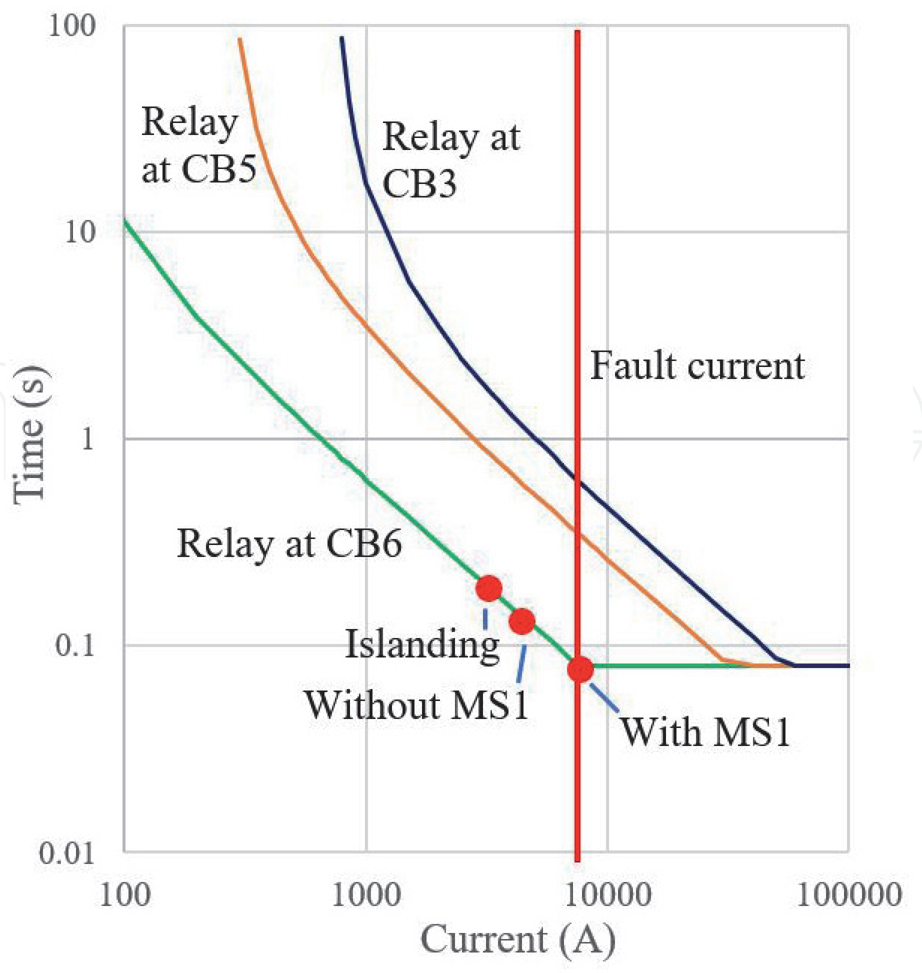


Figure 26.
Relay coordination.

arrangement. **Figure 27** shows possible transformer connection arrangements. It was assumed that the generator is star earthed in all four configurations.

6.1.1 Earthed star: delta connection

This is connection A shown in **Figure 27**. This arrangement provides isolation of the generator from microgrid/utility side ground faults. As discussed in Ref. [17], high zero sequence impedance resulting from this configuration may interfere with the normal flow of fault currents on the microgrid, thus upset protection coordination, nuisance fuse operations, and false operations of upstream protective devices. These problems can be reduced by using a grounding-impedance in the neutral grounding connection of the transformer as per IEEE/ANSI C62.92 [18]. The grounding-impedance should be selected such that the ratio of zero sequence reactance (X0) to positive sequence reactance (X1) less than or equal to 3 and the ratio of zero sequence resistance (R0) to positive sequence reactance less than or equal to 1. This can be easily achieved if the utility side of the interfacing transformer is star-earthed.

6.1.2 Star-star connection

This is connection B shown in **Figure 27**. In order to provide effective grounding of the generator with respect to the utility grid, $X0/X1 \leq 3$ and $R0/X1 \leq 1$ [18]. In this configuration, interferences, especially triplen harmonics, transfer from the grid side to the micro-source side and vice versa.

6.1.3 Delta: earthed star and Delta–Delta connections

These are connections C and D shown in **Figure 27**. If the network on the utility side is ungrounded or delta, then these configurations might create ground over-voltages during faults. To explain this, a part of the microgrid shown in **Figure 28** is used. If the HV side voltage is interrupted, the substation CB opens, and the microgrid may go into the islanded mode. This was a common incident in the Moragahakanda hydropower plant in Sri Lanka. This particular power plant has 4 generators totalling 25 MW and is connected to a 33 kV network. During the first two years of operation, this power station operated as an island with captive loads when the Naula grid, to which the power station is connected, failed. This was later mitigated using a transfer trip arrangement that sends the tripping command to Moragahakanda when the Naula trips.

During the above operating scenario, during a single phase to ground fault the virtual neutral formed in the delta shifts to the original position of phase C as in the phasor diagram shown in **Figure 29**. Then phases-A and -B may experience an

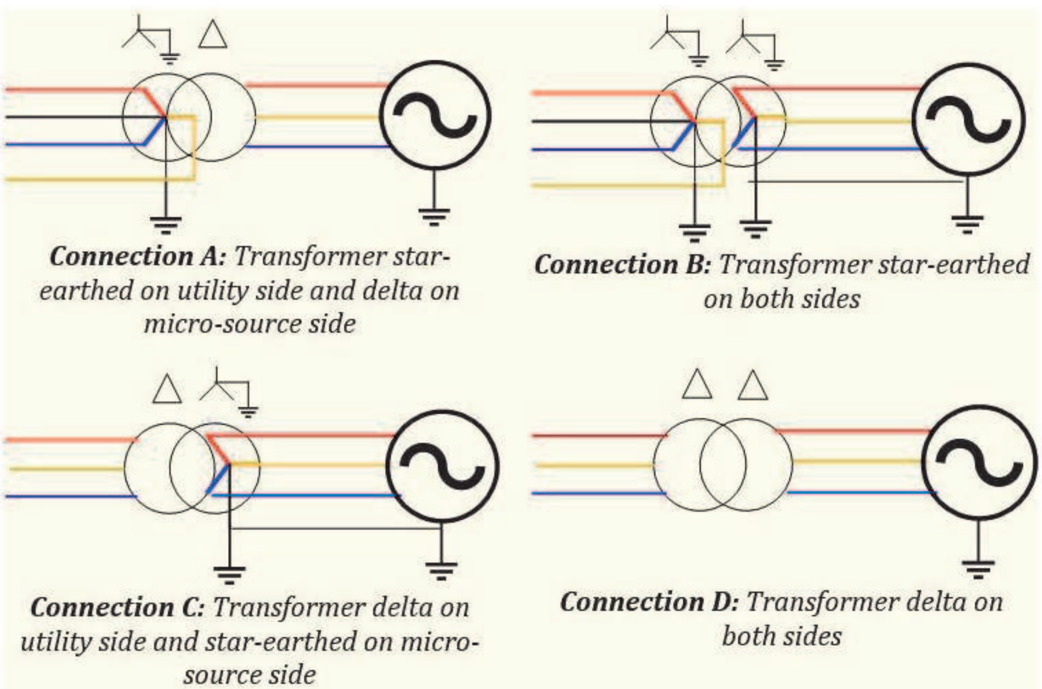


Figure 27.
Possible transformer connection to a micro-source.

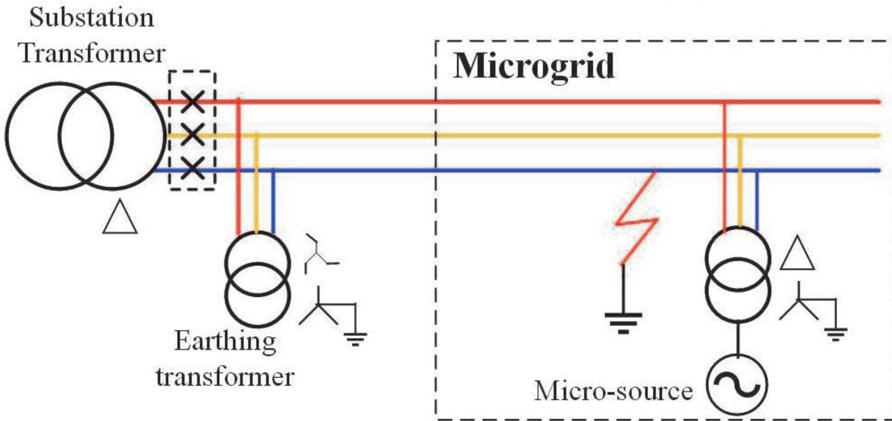


Figure 28.
Single-phase fault on the islanded microgrid.

over-voltage as high as 173% of the original voltage. In practice, this is limited by the faulty impedance and the impedance shown to the fault from the earthing transformer. However, the over-voltages created by such a fault may damage the loads connected to the 33 kV network.

Connection arrangement C can be used with a substation having a Star-earthed, as shown in **Figure 30**. The transfer trip provides fast disconnection of the micro-source, thus preventing any over-voltages appearing on the circuit.

6.2 Effective earthing approaches for VSC connected micro-sources

When paralleled with strong voltage sources (i.e., synchronous generators), VSCs have little impact on neutral grounding, and conventional methodologies of

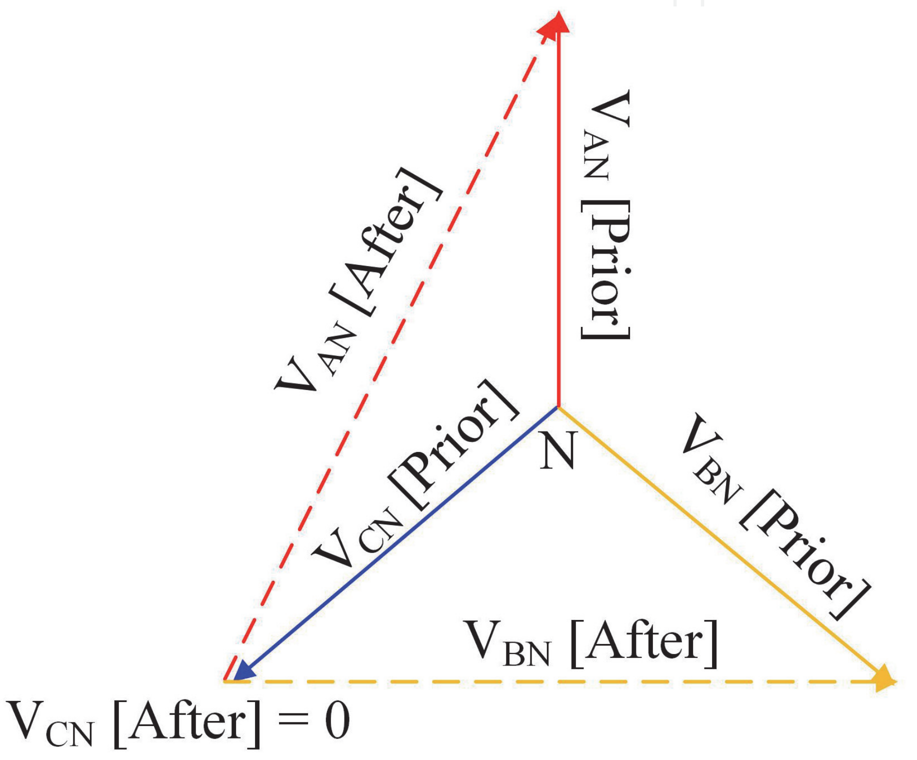


Figure 29.
*Phasor diagram for the situation shown in **Figure 28**.*

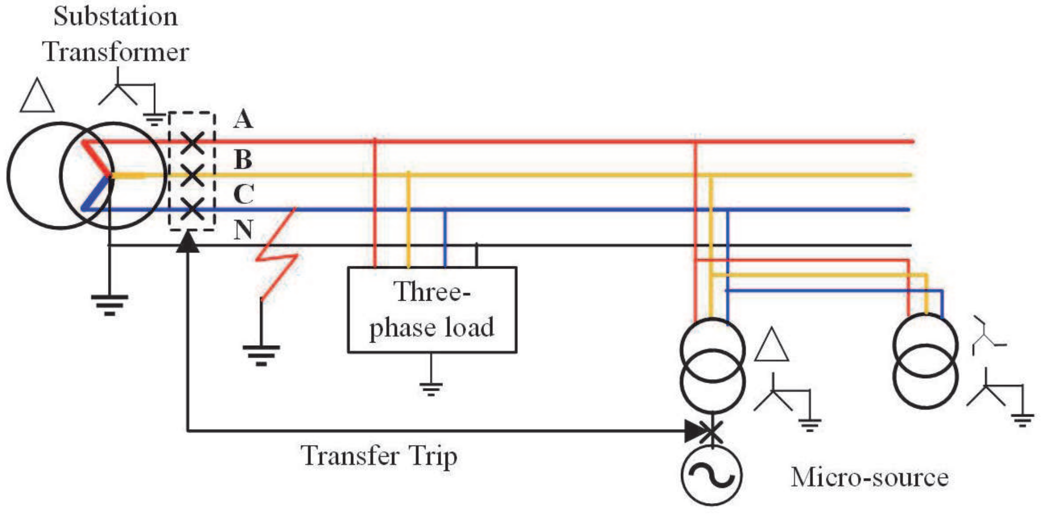


Figure 30.
Typical earthing arrangement for the transformer connection C.

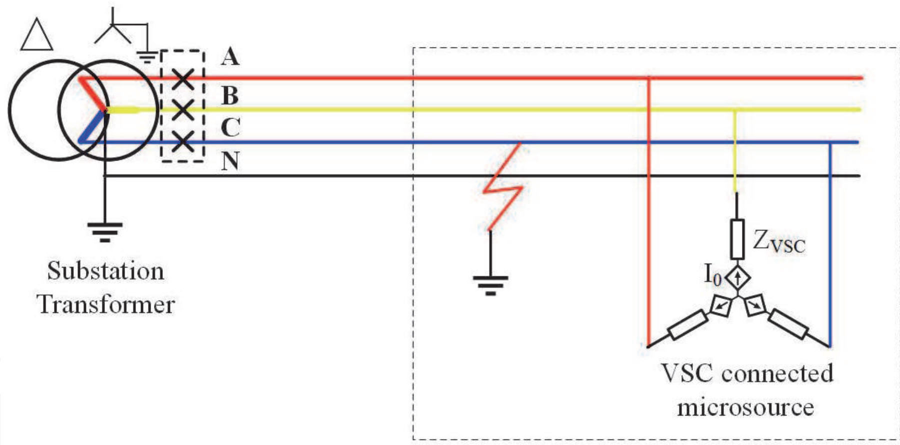


Figure 31.
Representation of a VSC for a single-phase fault on a distribution network.

grounding calculation can be utilised. In most cases, VSCs interconnected with a system providing a strong short-circuit source can be ignored in grounding calculations because of their relatively small short-circuit current contribution compared to that provided by synchronous generators in an interconnected power system. There are certain circumstances where VSCs can become dominant within a sub-system when that sub-system becomes isolated from the main grid. These circumstances involve distribution feeders or systems having sufficient micro-source capacity to support significant energisation of the sub-system when islanded from their normal source.

As most solar inverters are single phase or three-phase three wire, there are no zero sequence currents from them. Therefore, for a transient over-voltage condition that occurs due to single phase fault, it is accurate to assume that the VSC as a positive sequence current source. This is shown in **Figure 31**. Due to the earth fault, if the substation breaker opens and the inverter continues to provide a positive sequence current, then the voltage on health phases is I_0 times the equivalent load impedance between that phase and neutral. A series of tests done on a number of inverters show that this voltage is often greater than 1 pu voltage [19]. When the generation to load ratio is high, a supplementary ground source may be used to reduce the transient over-voltages. IEEE/ANSI C62.92.6 [20] indicates that the supplementary ground sources might interface with the feeder protection coordination, and therefore, case-specific analysis is required.

7. Conclusions

With the formation of generation clusters connected to distribution networks, there is a high possibility of adopting smaller controllable structures such as microgrids operating in parallel to the main utility grid. Even though independent microgrids are in operations since the early ages of electricity generation, the idea of grid connected microgrid immerged more recently.

The protection of independent microgrids is somewhat similar to the protection of special installations. In them, the RCCDs are used to protect against direct and indirect contacts, MCBs or MCCBs are used to protect against overload and short circuit currents, and SPDs are used to protect against over-voltages.

The protection of grid connected microgrids depends on the complexity of the microgrid. Internal faults of micro-sources and their interfacing transformers are protected by a differential protection scheme. Overcurrent protection for faults within the microgrid network and outside is provided by properly coordinated overcurrent protection devices. As micro-sources provide limited fault current voltage operated or voltage restrained overcurrent devices are used. The applicable standards such as IEEE 1547: 2018 and G99 state that under an islanding situation due to a fault outside the microgrid, the microgrid should cease to operate with the times specified in the standards. To provide loss of main protection, under- and over-voltage and under- and over-frequency relays are employed. However, as these relays do not provide adequate protection under LoM, ROCOF relays are used to disconnect the microgrid. For remote faults outside the microgrid, micro-sources should ride-through the fault, and ride-through requirements are specified in the standards.

For correct operation of the microgrid, attention should be paid to the grounding arrangement. The grounding varies with the interfacing arrangement, i.e. transformer connection arrangement or voltage source connection arrangement. In many cases, effective earthing should be maintained as per IEEE/ANSI C62.92.

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