Protection of Power Systems with Distributed Generation: State of the Art

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Abstract

The integration of distributed sources into existing networks brings up several technical, economical and regulatory questions. In terms of physical integration, protection is one of the major issues. Therefore new protection schemes for both distributed generators (DG) and utility distribution networks have been developed in the recent years, but there are still open questions.

This document is the result of a literature study and intends to give an overview of issues and current state concerning protection of DG. The first part gives a basic introduction to distributed generation and power system protection. In section 2 protection issues concerning DG are outlined, then the current practice is described in section 3. In section 4 some new approaches in this field are reported and finally section 5 concludes with an outlook.
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<td>Alternating Current</td>
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<td>AEPS</td>
<td>Area Electric Power System</td>
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<td>AM</td>
<td>Asynchronous Machine</td>
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<td>APS</td>
<td>Adaptive Protection System</td>
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<td>CHP</td>
<td>Combined Heat and Power</td>
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<td>DER</td>
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<td>DG</td>
<td>Distributed, Decentralized, or Dispersed Generation</td>
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<td>Voltage Vector Shift</td>
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1 Introduction

1.1 Distributed Generation

Distributed, dispersed, decentralized or embedded generation (DG, EG) are keywords for an upcoming probable paradigm shift in electric power generation.\(^1\) As mentioned in [1], there is no standing international definition for these terms, but there are a number of legal definitions in several countries. A proposal for a definition of distributed generation is given in [4]. However, many distributed power sources have some characteristics in common:

- Their rating is small compared to conventional power plants,
- they are often privately owned,
- they are not centrally dispatched,
- they are connected to MV or LV distribution networks,
- they do not contribute to frequency or voltage control,
- and usually they were not considered when the local grid was planned.

Hence, there are infrastructural needs as, for example, means of communication.

Two major reasons for an increased utilization of DG are liberalized markets which are now opened for various kinds of participants, and the global trend of reducing greenhouse gas emissions, which leads to more renewable, CO\(_2\)-neutral sources which are normally small-scaled. Further reasons are discussed in [1] and others.

Besides a number of benefits, there are some technical, economical and regulatory issues with DG. In terms of market regulation, licensing, government aid and privacy are typical concerns. Economical considerations display a possible cost increase not only for generation but also for transmission and distribution. Finally, there is the technical point of view, and protection turned out to be one of the most problematical technical issues since its malfunction could cause serious risk for people and components.

1.2 Power System Protection

Basic power system protection principles are outlined in standard literature [13, 14]. The primary purpose of power system protection is to ensure safe operation of power systems, thus to care for the safety of people, personnel

\(^1\)Surveys about DG are given in [1, 2, 3].
and equipment. Furthermore, the task is to minimize the impact of unavoidable faults in the system.\textsuperscript{2} From an electrical point of view, dangerous situations can occur from

- overcurrents and
- overvoltages.

For example, an asynchronous coupling of networks results in high currents. Earth faults can cause high touch voltages and therefore endanger people. The general problem is always voltage and/or current out of limit. Hence, the aim is to avoid overcurrents and overvoltages to guarantee secure operation of power systems.

For the safety of the components it is also necessary to regard device-specific concerns, for example oil temperature in transformers, gas pressure in gas insulated components etc. These points are not directly related to electrical values, but, as mentioned, they always come from or lead to unallowed high voltages or currents.

Another issue is mechanical stress. Whenever power is converted electromechanically, one has to consider not only the electrical but also the mechanical equipment. An example is mechanical resonance of steam turbines due to underfrequency.

Nowadays, electromechanical protection devices are replaced by microprocessor based relays with a number of integrated features. Currents and voltages are suitably transformed and isolated from the line quantities by instrument transformers and converted into digital form. These values are inputs for several algorithms which then reach tripping decisions. Further information about computer relaying can be found in \cite{13,14}.

For the design and coordination of protective relays in a network, some overall rules have become widely accepted:

**Selectivity:** A protection system should disconnect only the faulted part (or the smallest possible part containing the fault) of the system in order to minimize fault consequences.

**Redundancy:** A protection system has to care for redundant function of relays in order to improve reliability. Redundant functionalities are planed and referred to as backup protection. Moreover, redundancy is reached by combining different protection principles, for example distance and differential protection for transmission lines.

**Grading:** For the purpose of clear selectivity and redundancy, relay characteristics are graded. This measure helps to achieve high redundancy whereas selectivity is not disabled.

\textsuperscript{2}Avoidable problems such as system instabilities are subjected to Special Protection Schemes (SPS) as reported in \cite{15}.

4
Security: The security of a relay protection system is the "ability to reject all power system events and transients that are not faults so that healthy parts of the power system are not unnecessarily disconnected" [16].

Dependability: The dependability of a relay protection system is "the ability to detect and disconnect all faults within the protected zone" [16].

Different network topologies require different protection schemes. In the following paragraphs some typical systems should be described shortly. The simplest network structure to protect are radial systems, therefore simple relays are used [13]. Normally, time-dependent, graded overcurrent protection is installed regarding redundancy (backup protection). More sophisticated relays are used for the protection of rings and meshed grids. Impedance relays trip due to a low voltage-current quotient. Since these relays allow to determine the position of the fault on the line, they are also called distance relays. Detailed descriptions are given in [1, 13, 14]. A very common principle for the protection of generators, transformers, busbars and lines is differential protection. The trigger criteria is, simply speaking, a certain difference between input and output current. Furthermore, a number of other techniques are used, also device-specific ones.

1.3 Generation and Interconnection Systems

Common distributed generators and network interfaces should be outlined in the following paragraphs. Overviews are given in [1, 17, 18, 19, 20].

1.3.1 Machines

Synchronous Machines (SM) are widely used for larger water, steam and combustion engine driven plants, for instance Combined Heat and Power (CHP) plants. By varying the excitation current, it is possible to control the reactive behavior of the SM, i.e. to regulate the voltage. The possibility of voltage control is a major benefit and makes island operation possible.

Asynchronous or Induction Machines (AM, IM) are primarily used for wind and smaller hydro plants. Since these machines derive their excitation from the network, they always consume an inductive current and therefore behave as reactive loads even if they are providing active power. Hence, voltage control and island operation is normally not possible with AM. An additional fact to consider is that these machines normally run with a low power factor. The fault behavior of AM is determined by a low positive and negative sequence impedance. With AM in the network, the fault current level is normally increased.

\footnote{The fault current level is defined in section 2.1.}
In order to increase the power factor, AM are sometimes equipped with Power Factor Correction (PFC) [17, 21, 22]. So-called PFC-AM are able to continue operation if the main supply is lost, but voltage and frequency will not be stable.

For modern wind power stations double-fed induction machines are used. The relation between the network frequency $f_n$, the rotor current frequency $f_r$ and the mechanical frequency of the shaft $f_m$ in such machines is

$$k2\pi f_m + f_r = f_n$$  \hspace{1cm} (1)

where $k$ is an integer constant due to the machine design. This equation explains how the machine can operate with various mechanical speed whereas the network frequency $f_n$ is constant: The rotor circuit has to be fed with a corresponding frequency $f_r$. This method enables wind turbines to run in a wider range of speed and therefore to optimize efficiency.\(^4\)

DC Machines are rarely used as generators because they need to be connected to the AC system via an expensive inverter. Another disadvantage is that the brushes have to be serviced frequently.

### 1.3.2 Transformers

Whenever machines or inverters are connected to networks of different nominal voltage, transformers are needed. The high voltage winding of the transformer is usually used to meet the grounding requirements of the utility. Delta-wye configurations are commonly installed for isolated generators. In terms of protection, the transformer connection is important since the zero sequence impedance depends very much on the winding type (delta/wye) and also on the earth connection. Reference [19] compares five common transformer connections outlining their problems and benefits.

### 1.3.3 Power Electronic Interfaces

Whenever primary power is not transformed via a rotating AC machine, power electronic devices are used as a utility connection. Also wind power stations are often connected via converters. In large wind parks a common DC busbar collects the power and delivers it to the utility grid via one rectifier and one transformer [23].

Microturbines usually drive a synchronous machine at very high speed (due to efficiency). The high frequency has to be converted to the nominal utility frequency. Photovoltaic panels and fuel cells directly produce DC power which has to be converted.

An advantage of power electronic converters is their controllability. Anyway, a converter has to be equipped with a controller that can be used to

\(^4\)This method is also used for pump storage hydro stations because the most efficient speed of Pelton turbines varies with the head.
achieve a number of functionalities. Voltage or reactive power control could be integrated in converters as an additional feature [20].

In terms of protection, it is a clear disadvantage of semiconductor devices that their valves are almost not overloadable, i.e. overload can not be accepted for a longer time. Therefore converter controls are designed to prohibit high currents what leads to a lack of short circuit power which is necessary to trip protection. In section 2.1 the fault level is discussed. This fault level may be low in networks with a large contingent of converter-connected power sources.

1.3.4 Interconnection System View

Reference [24] gives a review of DG interconnection systems and states some trends and research needs. Also the commercial status of interconnection equipment (list of manufacturers, cost and pricing, etc.) is outlined. Interconnection systems are defined as “the means by which the DER unit electrically connects to the outside electrical power system and provides protection, monitoring, control, metering and dispatch of the DER unit,” where DER are Distributed Energy Resources [24]. Network interfaces are described from a system point of view using functional schemes as shown in figure 1. Several typical schemes and configurations are outlined according to:

1. Does the system use an inverter?
2. Does the system have a parallel connection to the local grid?
3. Can the system export power to the local grid?
4. Is the system remotely dispatchable?

A test report of a Universal Interconnection (UI) device is given in [25]. The device that was designed by General Electrics connects the DG with the local load as well as with the grid. The UI device is further described in section 3.3.4.

2 Protection Issues with DG

The overall problem when integrating DG in existing networks is that distribution systems are planned as passive networks, carrying the power unidirectionally from the central generation (HV level) downstream to the loads at MV/LV level. The protection system design in common MV and LV distribution networks is determined by a passive paradigm, i.e. no generation is expected in the network [20].

With distributed sources, the networks get active and conventional protection turns out to be unsuitable. The following sections will outline the most important issues.
2.1 Short Circuit Power and Fault Current Level

The fault current level describes the effect of faults in terms of current or power. It gives an indication of the short circuit current or (apparent) power boost. In [1] the fault level in p.u. is defined as

$$fl = i = \frac{1}{\|Z_{th}\|}$$

whereas $i$ is the fault current related to the nominal current and $\|Z_{th}\|$ is the inner impedance of the Thevenin representation of the network in p.u. Examples for this value are given in [1], typical fault levels in distribution networks are in a range of 10–15 p.u., where 1 p.u. corresponds to the rated current.

This is, phase-phase or phase-earth faults normally result in an overcurrent which is significantly higher than the operational or nominal current.\(^5\) This is a very basic precondition for the function of (instantaneous) overcurrent protection. The fault current has to be distinguishable from the normal operational current. To fulfill that, there has to be a powerful source providing a high fault current until the relay triggers. This is not the case for all kinds of generation devices (see section 1.3). Especially power electronic converters are often equipped with controllers that prevent high currents. If, for example, a remote part of a distribution network is equipped with large PV installations, it could happen that in case of a failure there is almost no significant rise of the phase current and the fault is therefore not detected from the overcurrent protection system. The question arises, why one needs to care about a fault if there is no fault current. The answer is that dan-

\(^5\)The amplitude of the fault current is dependent on the fault impedance, for phase-earth faults it is also highly dependent on the grounding.
dangerous touch voltages may occur even if the current is low. Furthermore permanent faults may spread out and destroy more equipment.

With DG in the network, the fault impedance $z_{th}$ can also decrease due to parallel circuits, therefore the fault level increases and there could be unexpected high fault currents in case of a failure. This situation puts components at risk since they were not designed to operate under that circumstances.

For correct operation it is also important that the relay measures the real fault current which was expected and taken under consideration when the relay was configured. Figure 2 shows a distribution feeder with an embedded generator that supplies part of the local loads. Assuming a short circuit at point $a$, the generator will also contribute to the total fault current

$$I_f = I_{nw} + I_{dg}$$

but the relay R will only measure the current coming from the network infeed $I_{nw}$. This is, the relay detects only a part of the real fault current and may therefore not trigger properly. As mentioned in [26, 27] there is an increased risk especially for high impedance faults that overcurrent protection with inverse time-current characteristic may not trigger in sufficient time.

One can find another influence of DG on fault currents when assuming a short circuit at the busbar b2. In this case, the fault current contribution from the generator passes the relay in reverse direction what could cause problems if directional relays are used. DG can also affect the current direction during normal operation, this issue is explained in section 2.3.

Concluding the issues concerning short circuit faults it can be stated that dispersed generation affects the

- amplitude,
- direction and
- duration (indirectly)
of fault currents. The last point is a result of inverse time-current characteristics (or grading respectively).

2.2 Reduced Reach of Impedance Relays

The phenomena of reduced reach of distance relays due to embedded power infeed is mentioned in [26, 27, 29] and other references. In [14] this problem is considered for conventional power systems.

The reach of an impedance relay is the maximum fault distance that triggers the relay in a certain impedance zone, or in a certain time due to its configuration. This maximum distance corresponds to a maximum fault impedance or a minimum fault current that is detected.

Considering figure 2, one can calculate the voltage measured by the relay R in case of a short circuit at a:

\[ U_r = I_{nw} Z_{23} + (I_{nw} + I_{dg}) Z_{3a} \]  

(4)

where \( Z_{23} \) is the line impedance from bus b2 to bus b3 and \( Z_{3a} \) is the impedance between bus b3 and the fault location a. This voltage is increased due to the additional infeed at bus b3. Hence, the impedance measured by the relay R

\[ Z_r = \frac{U_r}{I_{nw}} = Z_{23} + Z_{3a} + \frac{I_{dg}}{I_{nw}} Z_{3a} \]  

(5)

is higher than the real fault impedance (as seen from R) what corresponds to an apparently increased fault distance. Consequently, the relay may trigger in higher grading time resp. in another distance zone.

For certain relay settings which were determined during planning studies, the fault has to be closer to the relay to operate it within the originally intended distance zone. The active area of the relay is therefore shortened, its reach is reduced. Note that the apparent impedance varies with \( I_{dg}/I_{nw} \). A possible solution to this problem is outlined in section 4.1.

2.3 Reverse Power Flow and Voltage Profile

Radial distribution networks are usually designed for unidirectional power flow, from the infeed downstream to the loads. This assumption is reflected in standard protection schemes with directional overcurrent relays. With a generator on the distribution feeder, the load flow situation may change. If the local production exceeds the local consumption, power flow changes its direction [30]. Reverse power flow is problematic if it is not considered in the protection system design. Moreover, reverse power flow implies a reverse voltage gradient along a radial feeder.

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6Load currents are neglected for this consideration.
Dispersed generation always affects the voltage profile along a distribution line. Beside power quality issues, this could cause a violation of voltage limits and cause additional voltage stress for the equipment. The voltage increase/drop $\Delta U$ due to power in-/outfeed can be approximated with $[1, 29, 31]$

$$\Delta U \approx \frac{P_{dg}R_{th} + Q_{dg}X_{th}}{U_n}$$  \hspace{1cm} (6)$$

where $U_n$ is the nominal voltage of the system, $R_{th} + jX_{th}$ is the line impedance (Thevenin equivalent respectively) and $P_{dg} + jQ_{dg}$ is the power infeed of the DG.

An analytical method of calculating the influence of DG on the voltage profile of distribution feeders is presented in $[32, 33, 34]$.  

Figure 3 pictures the voltage gradient along a distribution feeder with and without embedded generation. The power flow direction corresponds to the sign of the voltage gradient. In this situation the power flow direction between bus b2 and b3 is changed due to the infeed at bus b3.

Especially in highly loaded or weak networks dispersed generation can also influence the voltage profile in a positive way and turn into a power quality benefit.

Reference $[35]$ describes another issue concerning the voltage profile on distribution feeders. Usually tap-changing transformers are used for the voltage regulation in distribution networks which change the taps, i.e. their
turns ratio, due to the load current. If the DG is located near the network infeed (e.g. at bus b2 in figure 3), it influences tap-changing because the DG infeed decreases the resulting load for the transformer. Hence tap-changing characteristics will be shifted, the infeed voltage will not be regulated correctly.

2.4 Islanding and Auto Reclosure

Critical situations can occur if a part of the utility network is islanded and an integrated DG unit is connected. This situation is commonly referred to as Loss Of Mains (LOM) or Loss Of Grid (LOG). When LOM occurs, neither the voltage nor the frequency are controlled by the utility supply.

Normally, islanding is the consequence of a fault in the network. If an embedded generator continues its operation after the utility supply was disconnected, faults may not clear since the arc is still charged.

Small embedded generators (or grid interfaces respectively) are often not equipped with voltage control, therefore the voltage magnitude of an islanded network is not kept between desired limits, and undefined voltage magnitudes may occur during island operation.

Another result of missing control might be frequency instability. Since real systems are never balanced exactly, the frequency will change due to active power unbalance. Uncontrolled frequency represents a high risk for machines and drives.

Since arc faults normally clear after a short interruption of the supply, automatic (instantaneous) reclosure is a common relay feature. With a continuously operating generator in the network, two problems may arise when the utility network is automatically reconnected after a short interruption:

- The fault may not have cleared since the arc was fed from the DG unit, therefore instantaneous reclosure may not succeed.
- In the islanded part of the grid, the frequency may have changed due to active power unbalance. Reclosing the switch would couple two asynchronously operating systems.

Extended dead time ($t_i$ in figure 4) has to be regarded between the separation of the DG unit and the reconnection of the utility supply to make fault clearing possible. Common off-time settings of auto reclosure relays are between 100 ms and 1000 ms. With DG in the network, the total off-time has to be prolonged. Reference [27] recommends a reclosure interval of 1 s or more for distribution feeders with embedded generators.

A linear approximation for the frequency change during island operation is given in [1, 36]. The rate of change of frequency is expressed as a function
of the active power unbalance

\[ \Delta P = \sum P_{dg} - \sum P_l \]  

(7)

the inertia constant of the machine \( H \), the machines’ rated power \( S_n \) and
the frequency before LOM \( f_s \):

\[ \frac{df}{dt} = \frac{\Delta P f_s}{2S_n H} \]  

(8)

It is straight forward to calculate the frequency change

\[ \Delta f = \frac{\Delta P f_s}{2S_n H} \cdot t_i \]  

(9)

This approach does only consider the frequency change due to islanding, the fault is not regarded.

Figure 4 shows an example for an auto reclosure procedure where an embedded generator is not disconnecting although it is islanded with the local grid. Here it is assumed that there is a lack of active power after islanding, i.e. \( \sum P_{dg} < \sum P_l \), therefore the island frequency decreases.

LOM and automatic reclosure are some of the most challenging issues of DG protection and therefore a lot of research has been done in that area. The only solution to this problem seems to be disconnecting the DG unit as soon as LOM occurred. Thus it is necessary to detect islands fast and reliably. Several islanding detection methods are presented in section 3.1.

2.5 Other Issues

Besides the issues mentioned in the previous sections, there are some other problems concerning the integration of DG. These issues are already known from experience with conventional power systems.

2.5.1 Ferroresonance

As described in [26, 27], ferroresonance can occur and damage customer equipment or transformers. For cable lines, where faults are normally permanent, fast-blowing fuses are used as overcurrent protection. Since the fuses in the three phases do not trigger simultaneously, it may happen that a transformer is connected only via two phases for a short time. Then, the capacitance of the cable is in series with the transformer inductance what could cause distorted/high voltages and currents due to resonance conditions.

2.5.2 Grounding

In [18, 19, 26, 27, 37] possible grounding problems due to multiple ground current paths are mentioned. If a DG unit is connected via a grounded delta-wye transformer, earth faults on the utility line will cause ground currents
Figure 4: Auto reclosure procedure: fault occurs at $t_f$, disconnection of at $t_d$, reconnection at $t_r$, reclosure interval $t_i$; state of utility switch $S$, utility synchronous frequency $f_s$, island frequency $f_i$, frequency drop $\Delta f$.

in both directions, from the fault to the utility transformer as well as to the DG transformer. This is normally not considered in the distribution system ground fault coordination.

In [37] the problem of Loss Of Earth (LOE) for single point grounded distribution systems is demonstrated. Whenever the utility earth connection is lost, the whole system gets ungrounded.

3 Current Practice

3.1 Island Detection

The difficulties with islanded DG have been outlined in section 2.4. To prevent island operation, the protection system has to detect islands quickly and reliably. This is the task of loss of mains protection. References [21, 38] divide island detection into passive and active methods. Some of them will be outlined in the following sections.

3.1.1 Passive Methods

These methods detect loss of mains by passively measuring or monitoring the system state.

Under-/Overvoltage A clear indication of lost utility supply is very low voltage. If there are uncontrolled generators in the network, the voltage
can also rise (for example due to resonance) and exceed the upper limit. Therefore, under- and overvoltage relays are a simple islanding protection method. In larger islands the voltage collapse will take some time, therefore this kind of LOM protection is often too slow.

**Under-/Overfrequency** As mentioned, real systems are never balanced exactly. After LOM happened, the frequency in the island changes due to equation (8). Hence frequency out of limits can indicate island operation. The frequency does not change instantaneously but continuously, thus frequency relaying is a rather slow method.

**Voltage Vector Shift (VVS)** This method is outlined in [1] and others, it is also referred to as phase displacement [38] or phase jump [25] method. Figure 5 shows the situation when part of the load is fed from an embedded generator and the rest is supplied from a distribution network. The distribution network and the embedded generator are represented by equivalent circuits, both operating on the local load. After the utility switch S disconnects, the local load has to be supplied from the generator G. Assuming constant load, the transmission angle, i.e. the voltage phase difference be-

Figure 5: Voltage vector shift after islanding. Thevenin equivalent of the network with $E_{nw}$, $Z_{nw}$ and of the generator with $E_{dg}$, $Z_{dg}$ respectively.
between the generator and the load terminal has to rapidly increase due to the sudden power flow increase. This increased transmission angle is shown in figure 5. Dotted lines represent parallel supply, solid phasors show the situation after islanding. Figure 6 pictures the situation in the time domain. Due to the vector jump, the duration of the concerned period is extended. Voltage vector relays monitor the duration of every half cycle and initiate tripping if a certain limit is exceed. Common voltage vector shift relays trip with $\vartheta_{\text{pickup}} = 6 \ldots 12^\circ$ [1, 17].

**Rate of Change of Voltage** Loss of mains detection due to the rate of change of voltage is introduced in [39]. Usually voltage changes are slow in large interconnected power systems. If a distribution system gets separated, a rate of change of voltage occurs that is significantly higher than during normal operation. Therefore rate of change of voltage can be used to detect island operation. A major handicap of this method is that it is sensitive to network disturbances other than LOM.

**Rate of Change of Frequency (ROCOF)** As discussed in section 2.4, the frequency in an island will change rapidly due to active power unbalance. The corresponding frequency slope can be used to detect loss of mains. Whenever $df/dt$ exceeds a certain limit, relays are tripped. Typical pickup values are set in a range of 0.1 to 1.0 Hz/s, the operating time is between 0.2 and 0.5 s [1, 17]. A problem with ROCOF protection is unwanted tripping resulting from frequency excursions due to loss of bulk supply, for example faults in the transmission grid. Another reason for malfunction is phase shifts caused from other network disturbances.
Rate of Change of Power and Power Factor Loss of grid algorithms based on the rate of change of the generator active power output are outlined in [38, 40]. In [40] the instantaneous power is derived from the generator voltages and currents and then the rate of change of power is used in a limiting function that prohibits mal-function due to system disturbances. The results of the studies in [40] show that the algorithm needs at least six cycles (120 ms) to detect LOM what is rather slow compared with other LOM detection methods. Reference [39] presents simulation results arguing that the most sensitive variables to system disturbances are time derivative of voltage, current, impedance, absolute change of voltage, current, current angle, impedance and changes in power factor, whereas some of these are redundant. Certain situations are studied and a suitable logic for a LOM relay is derived using the rate of change of voltage and changes in power factor.

Elliptical Trajectories Whenever a fault occurs on a line, the corresponding voltage an current changes at the sending end are related to each other by an elliptical trajectory [41]. The trajectory of voltage and current change (in combination with scaling factors) is described by an orbital equation. The investigations in [41] show that the shape of this trajectory changes significantly after islanding.

3.1.2 Active Methods
Beside passive measurements and monitoring, there are active methods of LOM detection where the detection system (relay) is actively interacting with the power system in order to get an indication for island operation.

Reactive Error Export This highly reliable means of LOM detection is shortly discussed in [21]. For this method, the generator is controlled on a certain reactive power output. Whenever islanding occurs, it is assumed that it is not possible to deliver the specified amount of reactive power to the local grid since there is no corresponding load. This reactive export error is taken as an indicator for LOM.

Fault Level Monitoring The fault level in a certain point of the grid can be measured using a point-on-wave switched thyristor [21]. The valve is triggered close to the voltage zero crossing and the current through a shunt inductor is measured. The system impedance and the fault level can be quickly calculated (every half cycle) with the disadvantage of slightly changed voltage shape near the zero crossover.

System Impedance Monitoring In [21] a method is introduced that detects LOM by actively monitoring the system impedance. A high frequency
Figure 7: System impedance monitoring. The meter M will measure an increased HF signal when the utility network is disconnected.

source (a few volts at a frequency of a few kHz) is connected via a coupling capacitor at the interconnection point. As pictured in figure 7, the capacitor is in series with the equivalent network impedance. When the systems are synchronized, the impedance $Z_{dg}$ is low, therefore the HF-ripple at coupling point is negligible. After islanding, the impedance increases dramatically to $Z_{nw}$ and the divided HF-signal is clearly detectable.

**Frequency Shift** Inverter-interfaced DG can be protected against LOM using frequency shift methods [42, 43]. The output current of the converter is controlled to a frequency which is slightly different to the nominal frequency of the system. This is done by varying the power factor during a cycle and re-synchronization at the begin of a new cycle. Under normal conditions, the terminal frequency is dictated by the powerful bulk supply. If the mains supply is lost, frequency will drift until a certain shutdown level is exceed.

**Voltage Pulse Perturbation and Correlation** In [43, 44] two methods of islanding detection for inverter-connected DG are presented that use a perturbation signal of the output voltage. For the first method, the inverter output is perturbed with a square pulse. This square pulse appears in both the inner voltage of the source and the voltage at interconnection point. If islanding happens, the apparent impedance at the generator terminal increases and therefore the perturbation can be measured at the point of common coupling (similar to system impedance monitoring). The second method uses a correlation function to detect LOM. The inner voltage of the source is randomly perturbed and correlated with the voltage change at the interconnection point. During normal operation, the apparent impedance is low and the voltage waveform at the interconnection point will not reflect the perturbation signal. After islanding the modulation signal will appear in both the inner voltage and the voltage at the interconnection point what
Figure 8: Protection scheme for a generator embedded in an MV utility grid [1]. Relay numbers are explained in table 1.

results in a strong correlation.

3.2 Interconnect vs. Generator Protection

Protection concerns both the distribution grid as well as the distributed generator itself. Therefore protection schemes have to be implemented on both sides of the Point of Common Coupling (PCC). In [18, 19] the whole protection system is split into two parts:

Interconnect protection: It protects the grid from the DG unit, i.e. it provides the protection on the grid-side for parallel operation of the DG and the grid. The requirements for this part are normally established by the utility.

Generator protection: It is installed at the generator-side of the PCC and protects the DG from internal faults and abnormal operating conditions. Usually, the utility is not responsible for this kind of protection.

A typical multifunction interconnect relay configuration is outlined in [19], whereas [1] presents some generator protection schemes.

Figure 8 pictures a typical relay configuration for a generator embedded in a MV utility grid [1]. This system protects the generator from internal faults and abnormal operating conditions. The relay function numbers are listed in table 1 on page 20. Figure 9 shows the assembly of functionalities included in a typical multifunction interconnect relay.

3.3 Examples of State-of-the-Art Relays

A number of companies are offering generator protection and control systems [24]. Three examples of generator protection devices are presented in this section.
Table 1: Explanation of relay numbers [1, 46].

<table>
<thead>
<tr>
<th>Number</th>
<th>Application</th>
</tr>
</thead>
<tbody>
<tr>
<td>21</td>
<td>distance</td>
</tr>
<tr>
<td>25</td>
<td>synchronizing</td>
</tr>
<tr>
<td>27</td>
<td>undervoltage</td>
</tr>
<tr>
<td>27N</td>
<td>neutral undervoltage</td>
</tr>
<tr>
<td>32</td>
<td>directional power</td>
</tr>
<tr>
<td>40</td>
<td>loss of excitation</td>
</tr>
<tr>
<td>46</td>
<td>neg. seq. current</td>
</tr>
<tr>
<td>47</td>
<td>neg. seq. voltage</td>
</tr>
<tr>
<td>50</td>
<td>instantaneous overcurrent</td>
</tr>
<tr>
<td>50N</td>
<td>neutral instantaneous overcurrent</td>
</tr>
<tr>
<td>51N</td>
<td>neutral time overcurrent</td>
</tr>
<tr>
<td>51V</td>
<td>voltage-restrained overcurrent</td>
</tr>
<tr>
<td>59</td>
<td>overvoltage</td>
</tr>
<tr>
<td>59I</td>
<td>instantaneous overvoltage</td>
</tr>
<tr>
<td>59N</td>
<td>neutral overvoltage</td>
</tr>
<tr>
<td>60FL</td>
<td>voltage transformer fuse failure</td>
</tr>
<tr>
<td>67</td>
<td>directional overcurrent</td>
</tr>
<tr>
<td>79</td>
<td>reclosing</td>
</tr>
<tr>
<td>81</td>
<td>frequency (under and over)</td>
</tr>
<tr>
<td>81R</td>
<td>rate of change of frequency</td>
</tr>
<tr>
<td>87</td>
<td>differential</td>
</tr>
<tr>
<td>LOM</td>
<td>loss of mains</td>
</tr>
</tbody>
</table>
3.3.1 Integrated Generator Protection

The digital generator protection DGP54BABA from General Electrics Industrial Systems is an integrated generator protection with all features of classical protection [47]: overvoltage, under-/overfrequency, loss of excitation and overexcitation, unbalanced current, differential protection etc.

The device offers remote programming and data acquisition via a RS-232 serial interface. Fault reports of the last three faults are stored in the internal memory.

3.3.2 Loss of Mains Relay

Tyco Electronics offers the loss of mains protection relays 246-ROCL and 256-ROCL which are designed for applications where generators are running in parallel with a mains supply [48].

Both rate of change of frequency and voltage vector shift measurement are integrated to detect disconnection of a generator.
The user can adjust the setting for

- VVS from 2 to 24° in steps of 2°,
- ROCOF from 0.10 to 1.00 Hz/s in steps of 0.05 Hz/s, and
- startup delay from 2 to 12 s.

Phase steps and rate of change of frequency can be monitored continuously using the fibre-optic digital data and status output. The response time for phase angle shifts is up to 2 cycles, for frequency rate changes it is within 32 cycles. A relay time of 5 ms has to be added.

In [48] it is mentioned that voltage vector shifts correspond to rates of change of frequency, what has to be considered in the relay settings. Otherwise it is not possible to get a clear distinction between ROCOF and VVS trips.

3.3.3 Integrated Genset Control Device

Woodward offers the Easygen-1000 genset control for single unit operation [49]. The device integrates a number of features for measurement, protection and control.

In terms of protection it provides voltage, frequency, overload, reverse and reduced power, load imbalance, definite and inverse time-overcurrent, ground fault and loss of mains detection.

3.3.4 General Electric Universal Interconnection Device

General Electric has developed a universal interconnection device for the interconnection of distributed energy resources (also mentioned in section 1.3.4) [25]. Its main components are:

- A so-called Intelligent Electronic Device (IED), based on existing relay technology, that provides protection, control and other features, also remote control.
- Two switches that enable operation of the DG in parallel to the grid or on the local load.
- Two circuit breakers for emergency protection.
- Measurement transformers for metering and monitoring.
- Power supply for the IED, the contact relays, and a battery charger.

The test report of this device especially emphasizes the issue of LOM [25]. It is mentioned that passive detection methods fail if the frequency/voltage deviation after islanding does not exceed a certain threshold. This results in a so-called Non-Detection Zone (NDZ) of the relay. This problem can be solved by adding a directional power protection.
3.4 International Recommendations, Guidelines and Standards

Besides a number of national and utility-specific interconnection rules, there are several international standards and recommendations published [20, 50, 51]. The probably most important are:

- IEEE 929-2000 Recommended Practice for Utility Interface of Photovoltaic (PV) Systems [53]
- IEEE 242-2001 Recommended Practice for Protection and Coordination of Industrial and Commercial Power Systems [46]
- IEEE 1547 Series of Standards for Interconnection [54] (in progress)

4 New Approaches

4.1 Adaptive Protection Systems

Adaptive protection is an "online activity that modifies the preferred protective response to a change in system conditions or requirements. It is usually automatic, but can include timely human intervention" [55]. An adaptive relay is "a relay that can have its settings, characteristics or logic functions changed online in a timely manner by means of externally generated signals or control action" [55].

In other words, adaptive protection systems are systems which allow to change relay characteristics/settings due to the actual system state. For example, the primary zone pickup value of a distance relay can be changed online according to power infeed from a T-connected generator (see section 2.2).

There are several adaptive techniques proposed in [55] which use online information of the system to optimise the protection system function. Some examples are:

- Adaptive system impedance modeling (an up-to-date impedance model of the network that provides input data for a relay)
- Adaptive sequential instantaneous tripping (for faults near the remote station)
- Adaptive multi-terminal distance relay coverage (regarding infeed from T-connections in the relay settings)
- Adaptive reclosure (prevent unsuccessful reclosure for permanent faults, high-speed reclosure in case of false trips).
In [56] it is proposed to use real-time synchronized phasor measurements of bus voltages and line currents as a source of information for adaptive relays.

A feasibility study for adaptive protection of a part of a real distribution system is demonstrated in [57]. The paper shows the basic requirements for implementing adaptive relaying concepts:

1. Microprocessor-based relays
2. Appropriate software for relay modelling, relay coordination and communication
3. Appropriate means of communication

A relay coordination software model as shown in figure 10 is introduced which makes real time changes of relay configurations possible.

In [58] adaptive and conventional reach settings for distance relays are compared for a certain network structure. The simulation results show differences between conventional settings due to offline worst case studies and optimal adaptive reach settings of about 10%.

An adaptive scheme for optimal coordination of overcurrent relays is presented in [59]. The sum of the first zone operating times $T_{ii}$ of $n$ relays is taken as an objective function to minimize, whereas the coordination time interval between the zones $\Delta T$ builds the constraint. The optimization problem is then formulated as

$$\text{minimise } F = \sum_{i=1}^{n} T_{ii}$$

with $T_{ji} \geq T_{ii} + \Delta T$ \hspace{1cm} (11)

$T_{ii}$ is assumed to be a function of certain relay parameters which are results of the optimization. After a change in the network, the optimization was executed and relay settings have been updated with the optimal parameters. The algorithm was successfully applied to the IEEE 30-bus test system.
Figure 11: Block diagram of PMU [60]. After the analog voltage and current signals are transformed and filtered, they are converted into digital form and represented as phasors.

4.2 Synchronized Phasor Measurement

A power systems’ state can be determined using so-called Phasor Measurement Units (PMU). Such PMUs provide synchronized measurement of terminal voltage and current phasors in time intervals down to 20 ms [60]. Synchronisation of the phasors is achieved using the Global Positioning System (GPS). A block diagram of a PMU is pictured in figure 11.

In so-called Wide Area Protection Systems, the measured voltage and current phasors are transferred to a central computer where they are processed and used for monitoring, state estimation, protection, control and optimization [15, 61]. Such systems offer great opportunities for protection and control. The possibility of using PMU measurement data for adaptive protection schemes is outlined in [62].

A possible application of synchronized phasor measurements could be LOM detection. The data gathered from PMUs installed at either side of the coupling point (PCC) could be used for real-time phasor comparison (a kind of phase differential protection). However, PMUs are quite costly devices (up to EUR 10’000 and more), therefore this technically feasible alternative will hardly be economically justifiable for this application.

4.3 Intelligent Systems

Reference [63] gives an overview of intelligent systems in electric power delivery. Autonomous systems and computational intelligence are proposed as possible solutions for decentralized control.

An adaptive distance protection using an artificial neural network is demonstrated in [64]. In this case adaption is reached by training the neural network to a certain performance, i.e. characteristic. As pictured in figure
Figure 12: Adaption of an impedance relay characteristic to fault impedance by the use of artificial neural networks. Solid line: normal relay characteristic; dotted line: trained characteristic for high impedance faults [64].

12, the neurons can be trained in such a way that the normal behavior (circle) is adapted for high impedance faults. In [64] the relay errors are significantly reduced with the described method.

5 Conclusion and Future Work

Much literature is available concerning protection of distributed generation. Many publications demonstrate the same problems and issues, but solutions are rare. A general approach is still missing, but first steps are visible [24].

In [29] it is discussed that the numerical relations of typical values such as line impedances, generator ratings etc. are equal in different networks (HV, MV, LV) if per-unit values are considered. The scaled system aspects in terms of power flow are almost the same for small-scaled distributed generation and for large-scaled centralized plants. This point indicates once more that the key issues concerning integration of DG are related to infrastructural items such as data acquisition, operation, protection and control. Adequate infrastructure, as it is commonly installed in HV transmission networks and conventional, centralized power plants, is missing.

From the authors’ point of view, there are three key issues to solve:

1. Information: Integrating DG into existing distribution networks is an issue because data acquisition systems are not available. The installation of an information system such as as the Supervisory Control And Data Acquisition (SCADA) system (usually installed in transmission systems) would help to solve many problems. The internet is already easily accessible, therefore it could be a great chance to utilize it for the purpose of power system operation [65].

2. Coordination: Proper coordination is a fundamental requirement for satisfying operation of protective relays. System studies and analysis
have to be performed case-by-case to properly coordinate the protection settings. Software could be implemented that offers special coordination features for the integration of DG in distribution systems.

3. Adaptation: As mentioned in [64], the implementation of adaptive protection is a challenging task since information which is normally not available in distribution networks is needed to update the relay settings.

Visions, future trends and expected developments in the field of electric power delivery are presented in [66, 67, 68, 69, 70]. The general view is that distributed generation is expected to play an important role in future energy systems.

Future work could be related to the points discussed in the previous paragraphs, whereas three major questions arise:

- How should future distribution systems be designed to simplify integration of DG (towards a plug-and-play system)?
- How can islanded parts of distribution systems be operated and resynchronized?
- How can DG be dispatched centrally (if wanted), and what data infrastructure is needed to achieve this?

References


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