# State-of-the-art of large scale DG impacts in MV networks

Sami Repo, Anna Kulmala and Ontrei Raipala

Tampere University of Technology, Finland

## Table of contents

# 1 Introduction

Distributed Generation (DG) has different impacts on electricity system dependent on generation type and time scale considered in assessment studies. The Figure 1.1 represents impacts in two-dimensional space where time scale and impact area are the coordinates. DG has local impact (power quality, voltage management and distribution efficiency) in distribution network. However the amount of DG connected might become large enough to have regional (grid stability, transmission efficiency, congestion management and adequacy of grid) and also system wide impacts (reserves, hydro/thermal efficiency, emissions and adequacy of energy/power). This kind of scenarios has already happened in Germany, Denmark, Spain, Italy, Portugal and Ireland due to wind power, solar power and combined heat and power units.

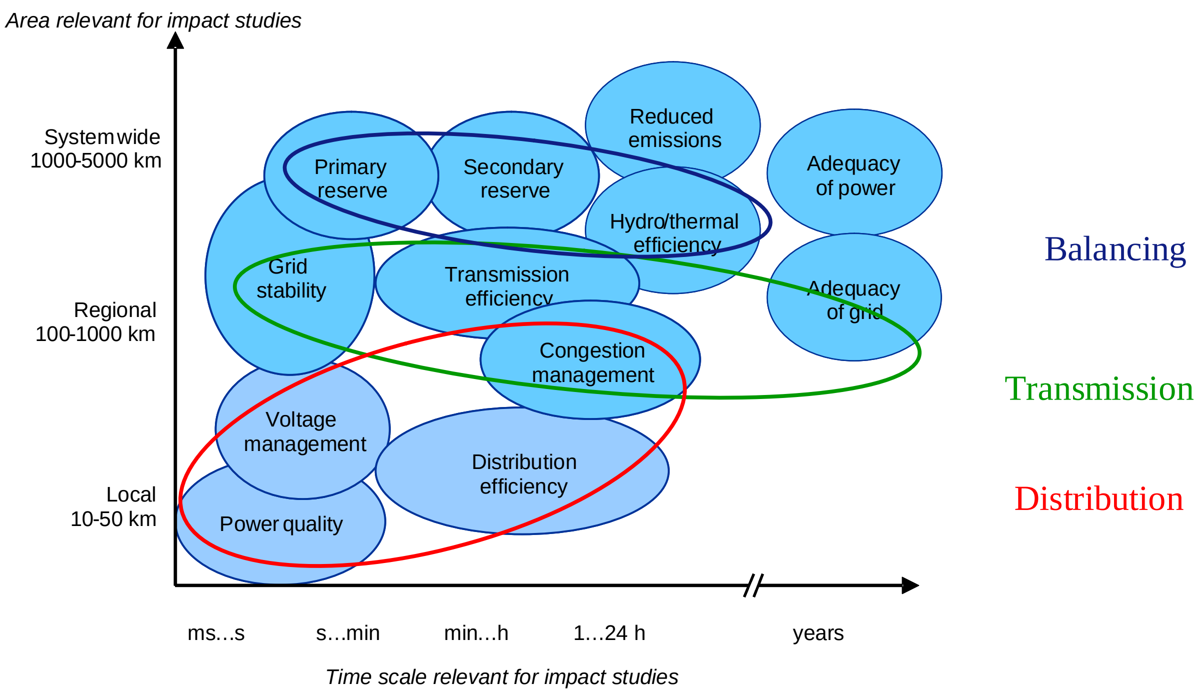


Figure 1.1. Impacts of DG on electricity system. [Hol07]

The electricity system regulation is realized by load following principle. Control reserves are needed to consider load and production forecasting errors which always exists. When the amount of intermittent power production increases that probably increases also production forecasting errors which will impact on control reserves. However the smoothing effect of e.g. wind power is stronger when large control area is considered over long time horizon. This means that local wind farm power variations are not directly influencing on electricity system regulation. DG might have impact on disturbance reserves if a fault in transmission network effects on huge number of DG units and they disconnect at the same time. Fault ride through requirements are a typical method to avoid this unfavorable event. Another scenario might be a storm which might cause a shutdown of major part of wind power in few hours from nominal to zero power.

Intermittent power production has also impact on other conventional production units. Here the interest is on how the conventional capacity is run and how the variations and prediction errors of wind power change the unit commitment: both the time of operation and the way the units are operated (ramp rates, partial operation, starts/stops). On the longer time scale the adequacy of power generation is also interesting question. Wind power's aggregate capacity credit during peak load situations, high energy capacity energy storages and generation companies' willingness to maintain rarely used reserve units affect on adequacy of power generation.

The presence of DG can have many positive impacts on the distribution network usage which are listed in table 1.1. The realization of these positive impacts, which are often called "system support benefits", is, however, not self-evident but depends on the reliability, location, size and controllability of DG resources. [Bar 00] Voltage support, for instance, is largely dependent on the type of the DG unit but also on the way that the DG units are required to be operated. The voltage control capabilities of directly coupled wind turbines using induction generators are very poor, whereas, converter connected DG units have relatively good abilities for supporting network voltages provided that the dimensioning of the converter allows this. [Ack 05] The larger the DG production in a feeder, the more important is the coordination of the DG operation and feeder operation strategies. [Bar 00] In the EU, there is, however, no obligation for the DG unit owners to collaborate with the network utility. DG can sometimes also increase the reliability of the supply by enabling the supply restoration on a larger area than what would be possible without DG. This, however, is questionable in case of DG units that have low availability on demand.

Table 1.1.Positive impacts of distributed generation on distribution networks [Bar 00]

| Positive impacts of DG on distribution network |
|---|
| Voltage support and improved power quality |
| Loss reduction |
| Improved system reliability |
| Transmission capacity release |
| Postponed network infrastructure upgrades |

The presence of DG, however, also raises many new challenges. The most serious of these are probably related to network protection and voltage levels. In the traditional electric power system design the flow of electric power has been unidirectional, namely from the transmission grid towards lower voltage levels as explained earlier. Unidirectional power flow has enabled relatively simple network design especially from protection perspective. The presence of distributed generation is, however, now changing this simple basis. [Jen 00, Mäk 07]

# 2 Protection of network and DG

The addition of DG into distribution networks raises new challenges to the protection of distribution networks. For instance, protection sensitivity, - selectivity, unintentional islanding and failed autoreclosing problems may occur as a result of connecting DG. These risks should always be assessed when connecting new a generating unit to distribution network. This chapter briefly presents the most significant protection issues related to DG.

## 2.1 Protection blinding

Distribution feeders are connected to primary substations via circuit breakers. The circuit breakers, which are controlled by protection relays, are meant to be closed during normal operating conditions. However, once the relay detects a fault on the feeder it is set to protect, it controls the circuit breaker to open its contacts thus disconnecting the faulted feeder from the feeding substation. Non-directional overcurrent protection is the most commonly utilized method for feeder protection due to its low cost and simplicity. Directional earth fault protection is, however, additionally needed in isolated or compensated distribution systems.

The reach of an overcurrent relay is determined by the minimum fault current that causes the relay to trip. This minimal current setting should be such that the reach of the overcurrent relay extends to the next recloser or covers the whole radial network downstream from the circuit breaker controlled by the overcurrent relay in case if no reclosers are used. [Dug01] The presence of DG affects the reach of relays in certain situations. A situation where the operation of a protective relay is delayed or even completely hindered because of the fault current contribution of a DG unit is called protection under-reach or protection blinding. This may occur when a DG unit is feeding fault current parallel with the supplying substation as presented in figure 2.1. This being the case, the current seen by the relay protecting the feeder is reduced due to the fault current contribution of the parallel feeding DG unit. [Mäk05]

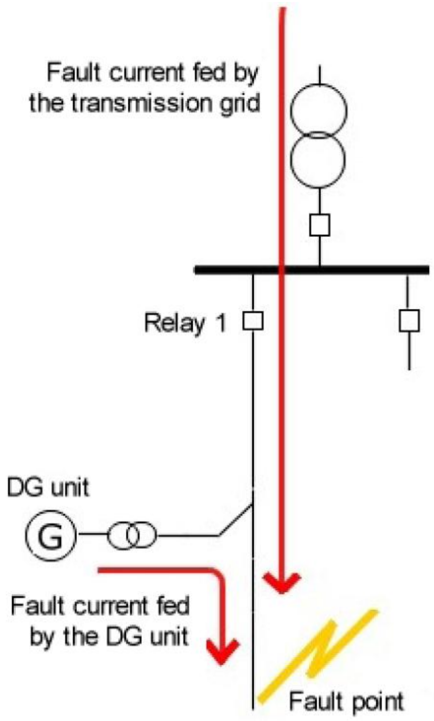


Figure2.1. DG unit causing protection blinding [Mäk05]

Protection blinding is especially problematic when definite time characteristics in overcurrent relays are applied. This is because feeder protection may become completely non-operational in the case of definite time characteristics, whereas, the operation of protection is likely to be only delayed when inverse time characteristic overcurrent is utilized. However, a delayed operation of feeder protection is also a serious issue because it can cause the thermal limits of lines and components to be exceeded. The blinding problem can be mitigated by setting more sensitive tripping values to the relays but this, on the other hand, can cause nuisance tripping during faults on the adjacent feeder, in extreme production / demand conditions or because of the starting currents of DG or other rotating devices. Constraining the DG unit operation and network reinforcements can also be used to mitigate the relay blinding problem but the associated additional costs may sometimes even render the construction DG unit economically unfeasible. Changing the electrical parameters of the DG unit can also be used to tackle the blinding problem but this, of course, can only be done in the planning phase. [Mäk05] Moreover, the DNOs chances of influencing the location and size of the DG unit are minor [Kul09].

## 2.2 Selectivity problems

Distributed generation can sometimes cause unnecessary tripping of the feeder where it is connected to. This may happen when a DG unit is connected to a feeder and a fault occurs in some of the adjacent feeders fed by the same substation. This being the case, the DG unit feeds the fault on the other feeder via the substation bus and thus, as shown in figure 2.2, also through the relay protecting the feeder where the DG unit itself is connected to. If the current fed by the DG to the fault is large enough, the relay, provided that it is not equipped with the directional protection feature, considers that a fault has occurred within its protection zone and trips the DG unit feeder needlessly off. This is phenomenon is called protection selectivity problem or sympathetic tripping problem. Selectivity problems are likely to occur on situations where the generator on the first feeder and the fault on the other feeder are both located close to the substation. [Mäk04] Also the type of the generator strongly influences to the likelihood of this problem. The fault current fed by induction generators usually decays quickly enough not to cause selectivity problems, whereas, synchronous generators can sustain a prolonged fault current which is more likely to cause problems. [Mäk06]

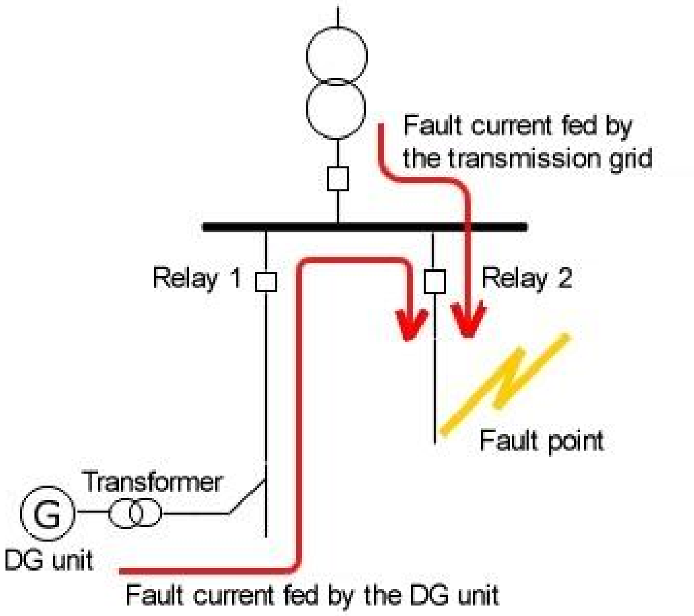


*Figure 2.2. Protection selectivity problem caused by DG* [Mäk06]

Selectivity problems can often be avoided by using proper relay settings. The simplest solution is to increase the fault current tripping thresholds of the problematic relays. However, if the current settings of the problematic relays cannot be changed, the problem can also be solved by utilizing appropriate operation times of the adjacent feeder relays. This can be done by setting the relay protecting the feeder where the DG unit is connected to, to operate slower than the adjacent feeder relays. If the latter alternative is preferred, care has to be taken that the delayed relay operation will not cause any thermal limits of network components to be exceeded. In cases where proper settings for non-directional overcurrent relays cannot be found, selectivity problem can be tackled by utilizing directional relay protection. The replacement of old relays with new ones that have the directional fault current detection included, however, naturally causes additional expenses. [Mäk04]

## 2.3 Unintentional islanding

Islanding refers to a situation where a network area including customer loads and DG becomes separated from the main grid. Unintentional islanding is strictly forbidden (safety regulations G59/1 and IEEE1547) and all DG units therefore need to be equipped with a loss of mains (LOM) protection scheme which ensures that unintentional islanding does not occur. The main reasons for the non-acceptance of unintended islanding are [Brü06]:

- An isolated DG unit can cause safety hazards to utility personnel by back feeding isolated lines that should be de-energized for maintenance purposes
- Customer devices fed by an isolated DG unit can be damaged due to poor power quality in the islanded network section
- DG can cause automatic reclosing failures by maintaining the voltages on a line that should be de-energized
- Network components can be damaged as a result of out-of-phase reclosing

Most of the LOM protection methods are based on detecting the changes in some system quantities such as voltage and frequency. These changes, which usually take place when islanding occurs, are mainly caused by the imbalance between real- and reactive power production and consumption in the island. There is, however, a risk that this imbalance is so small that the transition to island mode does not cause any of the quantities measured by a LOM relay to drift out of the preset limits. In cases like this, LOM protection fails to detect islanding. This blind area of LOM protection in the surroundings of the production- consumption equilibrium is called the non-detection zone (NDZ). [Mäk07] Figure 2.3 shows what the NDZ for traditional overvoltage- (OVP) / undervoltage protection (UVP) and overfrequency- (OFP) / underfrequency protection (UFP) might look like.

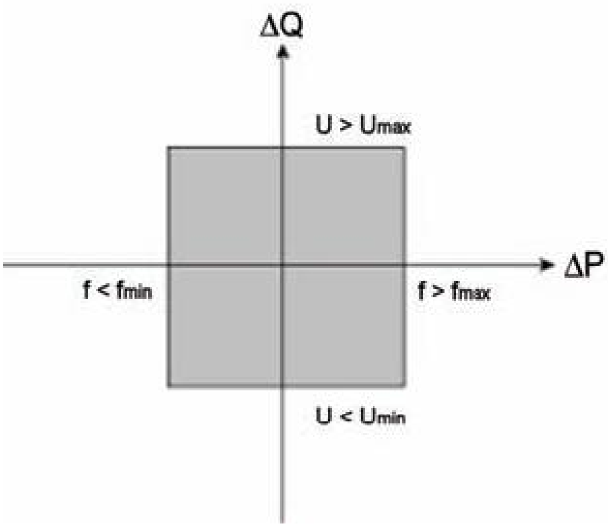


*Figure 2.3. Non-detection zone for traditional voltage and frequency protection [Mäk07]*

The U > Umax marking in the figure refers to the OVP limit, whereas, the U < Umin marking refers to the UVP limit. Respectively, the markings f > fmax and f < fmin refer to the OFP and UFP limits. This kind of traditional voltage and frequency protection is probably the most utilized LOM detection method due to its simplicity.

At present, the common practice in isolated- or impedance earthed systems is to leave the earth fault protection of DG units to be undertaken by the LOM protection. This means that the DG unit will only be disconnected after the formation of an island caused by the opening of the feeder relay. This arrangement can sometimes be problematic because of the NDZ of the LOM protection. [Mäk07] This is especially problematic when fast automatic reclosing is used on the feeder in question. More advanced LOM detection functions, such as the rate of change in frequency, are therefore often added to the LOM relay in order to obtain faster and more reliable LOM protection.

## 2.4 Failed reclosing

Automatic reclosing (AR) is meant for removing temporary faults automatically without causing an extended interruption in the supply of electricity. This is achieved by opening a circuit breaker connecting the faulted feeder to the supplying grid for a short period of time, and then reclosing the circuit breaker. During the open time (usually from 0.2s to a couple of seconds) of this circuit breaker, there is no source feeding the fault arc which leads to the extinguishment of the arc. Typically, in case if the first reclosing sequence should fail, one or two more reclosings sequences are made before the circuit breaker is ordered into permanent open position for the repair time. [Lak95] AR has a great significance for the reliability of electricity supply since, e.g., in Finland about 90% of faults on overhead lines are temporary in nature [Sen04] and thus also clearable by AR. The situation, however, becomes a bit more complicated in the presence of DG since the fault arc is usually extinguished only after all DG units on the feeder are disconnected. This is because the DG units that remain connected to the feeder during the autoreclosing open time can sustain the voltages and thus also the fault arc on the feeder in question. A certain period during which the voltage is equal to zero is also necessary after the extinguishment of the fault arc so that the ionized gas created by the fault arc has time to disperse [IEE02].

It is also important to pay close attention to the reclosing of the feeder circuit breaker in order to avoid dangerous stresses to the DG unit (caused by out of phase reclosing). This kind of coordination between the feeder protection and LOM relays is, however, quite challenging, especially in case if fast reclosing is applied [Ple03]. Synchro check and dead line voltage relays could, therefore, be a reasonable option for backing up LOM protection. Out of phase reclosings can be avoided this way, but this back up protection, on the other hand, can naturally stop the reclosing attempt and thereby lead to a permanent interruption of supply. [Kum04] Because of the challenging nature of this coordination, it may sometimes be necessary to use longer circuit breaker open times or more sensitive LOM protection settings to ensure correct protection sequence, or sometimes even give up on the use of fast AR. Very sensitive LOM protection settings have the disadvantage that they may cause nuisance tripping of the DG unit during disturbances. [Mäk07] Prolonged AR open times are also disadvantageous because they degrade supply quality and, moreover, the prolonged open time still does not guarantee correct operation of LOM protection in all cases [Kum05]. A failed and a successful reclosing sequence are illustrated in figure 2.4. The left figure illustrates a failed reclosing sequence, whereas, the right figure shows a successful one. In the left figure, a

DG unit connected to the feeder, where the autoreclosure is applied, maintains the voltage during the circuit breaker open time thus causing the reclosing action to fail. In the right figure, on the other hand, the LOM protection disconnects the DG unit in time and the network is thus de-energized resulting in a successful reclosing.

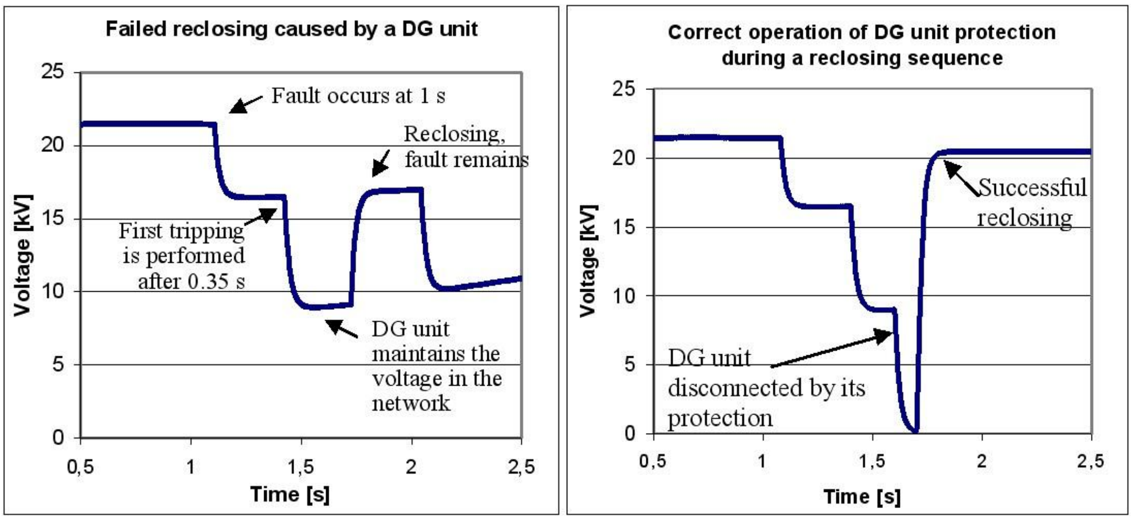


*Figure 2.4. Reclosing problems caused by DG* [Mäk07]

## 2.5 DG and rising fault levels

The addition of DG generally causes the fault levels in distribution networks to raise, i.e. increases the magnitudes of the fault currents. High currents may especially be found near to DG units but also at the fault point. This may sometimes lead to exceeding of the thermal limits of certain network components, as for instance switchgear, cable connections and transformers. In particular the combination of delayed feeder protection caused by protection blinding and increased fault current may be hazardous. [Kul09]

Fault level contribution of a DG unit is dependent on a number of factors. The type of the generator and the way it is connected, for example, affect the form and the magnitude of the fault current. Synchronous generators are usually designed to be able to feed prolonged fault currents, whereas, induction generators are not capable of feeding continuous fault current during three phase faults because the reactive power supply required to sustain the excitation of the induction generator is interrupted in such faults [Jen00]. Converter connected generators feed much smaller fault currents compared to directly connected generators. The impedance between the generator and the fault point which is dependent, for instance, on the distance and configuration between the fault point and the generator, also affects the fault current magnitude fed by the generator. [Dti05]

In some areas where the fault levels are already close to the switchgear current ratings, the connection of a DG unit may cause these ratings to be exceeded. The components whose ratings are exceeded can, of course, be changed to components with higher ratings but this is usually costly. The component upgrade costs are often allocated to the DG unit owner which may render the whole DG project uneconomical.

[Jen00] There are also a number of other methods for limiting increased fault levels such as the introduction of additional impedance (e.g. current limiting reactors or one to one ratio transformers), fault current limiters and certain active network management methods. See [Dti05] and [Rai09] for more information concerning fault level mitigation.

## 2.6 Challenges related present planning tools

Distribution network planning is typically carried out with the help of dedicated planning software which is called network information system (NIS). In Nordic thinking, a typical NIS includes network component data and plenty of calculation functionalities combined to a graphical interface. A NIS usually shows the geographical image of the area in question on the background to help the planning engineers to visualize the network area better. The ability to analyze both technical and economical aspects of network planning is an essential feature of NIS. [Mäk07]

NISs are based on steady state calculation and root mean square (rms) values. This approach is, due to its efficiency, more suitable for network planning purposes than programs with time domain. The currently available NISs are, however, not able to take DG adequately into account. In the fault analysis of the present NISs, DG can be taken into account as a constant short circuit source. This is sufficient for large synchronous generators but not for other types of generators or converter connected units which are being widely applied today. This deficiency of present NIS software could be fixed by "stretching" the steady-state calculations. The "Stretching" means that the short circuit calculations are looped in such a fashion that the effect of DG can be taken into account. This looping is possible because the short circuit calculations do not require substantial calculation power. During each loop the fault current fed by a DG unit is altered while the other component values are left untouched as steady state values. [Mäk07]

There can still be some complicated simulation cases where more advanced simulation tools are needed. For such studies, it would be beneficial to develop a standard interface between NIS and the more advanced simulation program utilized in order to minimize manual data transfer. It must, however, be noted that the modeling of network components in present NISs is considerably more simplified compared to advanced simulation tools. Present NISs also lack the data required for dynamic simulation studies. This means that there would still be manual work to be done when transferring the network model from NIS to the other program.

# 3 Network operation and management

The controllability of DG units may be utilized in electricity distribution network operation and management. The separation of network and power production businesses however increases the complexity of this kind of thinking in many countries. Ancillary service contract between service provider and distribution network operator will probably be the most probable method at distribution network level to organize the utilization of DG units in network management. The contract defines a standard requirement for the performance of controllable resource and the payment basis for the availability and use of service. If certain ancillary service is required from almost every DG unit, it is better to include that into DG connection requirements i.e. grid codes. Distribution network level ancillary services are e.g. power flow management, reactive power support and voltage control. The amount of customer owned controllable resources which participate in network management will increase in the future.

## 3.1 Control resources

### 3.1.1 Frequency control

Different types of power production units all have their own technical and economical characteristics, which govern the way they are used. The amount generation dispatched each hour is based on load predictions that are made one day in advance for every hour of the following day. The hourly load predictions are relatively accurate but there will usually still be some unbalances between the production and consumption. In order to balance these deviations, generators are dispatched more precisely for every 15 minute period one hour in advance. These power deliveries are handled in special regulating market. Changes in the load occurring faster than in 15 minute periods, however, are not predicted at all. The balancing of these deviations, which should be relatively small, is left for the frequency control. [Ple 03]

Frequency control consists of two components, namely primary and secondary control. The power plants participating in the primary control all have to be equipped with turbine governors with automatic frequency controllers. These controllers are fast and their gain is selected in such a way that the power required is divided between the participating generators proportionally to their capacities. [Ple 03] If a deviation in the power balance of the system should take place, the rotational masses of all the generators will either absorb or release kinetic energy, which results in a change in the system frequency. This is called the inertial response. If the frequency deviation is large enough, the primary frequency control will be activated. [Mor 06] After the primary control has compensated this power unbalance, there will still be a small deviation in the system frequency. If this deviation is large enough, secondary control reserves are activated which will bring the frequency back closer to its nominal value, and thereby free the activated primary reserves for prospective needs. In the Nordic synchronous system (includes the Finnish, Swedish, Norwegian and the eastern part of the Danish power system [Nor 08]) primary control is automated whereas secondary control is manual. [Ple 03]

There will also have to be additional control reserve for contingencies where a generation unit or an interconnection is suddenly lost. The size of the required control reserves for disturbances is determined by the largest generation unit or the interconnection with the largest imported power flow. [Ple 03] Load control, which will be presented later in this report, has very favourable characteristics for being used as this kind of contingency reserve. By using load control as reserve capacity the generators allocated for reserve capacity could be liberated from this task to be used for power production. [Kir 99]

### 3.1.2 Frequency control in power systems having large DG penetration level

The protection of the DG units is generally adjusted to trip as soon as voltage or frequency deviates from normal operation values. These kind of tight protection settings guarantee good protection for the DG unit and thus please their owners. Sensitive protection settings of DG also please the DNO because they guarantee good protection for other network equipment and ensure that problems related to unintended islanding are not to occur. This sort of protection settings have also been tolerated by the system operator as long as the penetration of DG has been low. The amount of DG is, however, now rapidly growing and it can be anticipated that they are likely to replace some of the conventional generation. This has made the operators realize that they might not be able to maintain the power balance if single contingencies, such as a single short-circuit or a loss of a single generating unit will cause vast amounts of tripping. Many system operators, such as the Swedish Svenska Kraftnät and the Danish Energinet.dk, are now making new more demanding operation requirements for wind farms, and it is anticipated that similar requirements shall also be made for DG units in the future. [Ple 03]

Wind power is problematic in the sense that its production is difficult to predict and that the production does not correlate with the demand. This leads to the fact that additional reserve capacity is needed if the proportion of wind power is high. If wind power is to replace some conventional power plants it may be necessary that wind power has to become a part of the control reserve. In order to be able to control the frequency up and down, wind power must be set to operate on lower than full capacity. This, of course, is a waste of energy and thus increases the cost of the energy produced by wind power. Another option is to maintain control reserves in other production units like hydro units which also have additional costs. The use of energy storages with adequate capacity, as for instance pumped hydro energy storage and large scale storage of hydrogen combined with fuel cells, could solve this problem. Present hydrogen storages combined with fuel cells unfortunately have the disadvantage that the efficiency of their charge-discharge cycle is less than 50 percent. [Ple 03]

Many DG units are connected to the network through power electronic converters. These sorts of units are separated from the system frequency and are, therefore, allowed to operate on whatever speed is optimal for them as, for example, the variable speed wind turbines and the micro-turbines do. Some DG units, like fuel cells or photovoltaic, have no rotational parts at all. Units with a power electronic converter connection, therefore, require special arrangements in order that they could participate to frequency control. Such arrangements are presented in [Mor 06], where the frequency control capabilities of different kinds of DG units are also examined. Wind turbines cannot participate in the primary frequency control in the classical sense, unless they are operated on lower than full output power as explained earlier, but they are capable of rapidly releasing their rotational energy to the system and thus contributing to the frequency control for a short period. Fuel cells, on the contrary, are not capable of rapid power output changes, whereas, it can sustain slow power output changes. In that sense, these two are of somewhat complementary. Micro-turbines, which are basically small gas turbines, are, of course, capable of primary frequency control as long as they are not operating at their full power. [Mor 06] Small-scale hydro-generation is well suitable for frequency control provided that the unit includes a reservoir of a considerable capacity. Without considerable storage capacity the output of hydro-generation unit is dependent on the river flow and is thus likely to undergo large variations. [Jen 00] Small scale CHP unit are usually set follow the heat demand and the electricity is thus only a by-product that is being produced in proportion to the heat production. The produced heat and electricity in a CHP unit including a heat accumulator can, however, be decoupled to some extent depending on the capacity of the accumulator. [Ple 03] All in all, there should be a mixture of different kinds of DG units in order that the DG could obtain a good contribution to the primary frequency control. [Mor 06]

### 3.1.3 Voltage control

The voltage control methods of existing distribution networks are designed based on the assumption of unidirectional power flows. When DG is connected to the network this assumption is no longer valid. DG's effect on voltage quality is one of the most important factors that limit the penetration level of DG. In weak distribution networks the amount of DG is usually limited by the voltage rise effect. Some voltage control methods based on local measurements are already widely used in distribution networks. It may, however, be that the existing voltage control methods will become inadequate if DG penetration reaches considerable levels. Should this be the case, active voltage control offers a wide range of new solutions.

At present, distribution network voltage is automatically controlled using tap changers on the main transformers at the substations. Tap changers are usually controlled by automatic voltage control (AVC) relays. The voltage at the substation is maintained constant or, if line drop compensation is used, the substation voltage depends also on the load current through the transformer. Also capacitors (both at the substation and at the feeder), voltage regulators and distribution transformer tap settings participate in voltage control. [Lak95]

Voltage quality consists of many features including e.g. voltage level and its variations, fast voltage transients, harmonics, voltage dips and interruptions. DG alters the voltage levels in the network, can cause transient voltage variations and might increase or decrease the harmonic distortion of the network voltage. It also increases the network's short circuit power and, therefore, reduces the effect of network disturbances at other parts of the network on customer voltage assuming that it stays connected during the disturbance. [Jen00]

DG raises the voltage level in the network which can be either advantageous or disadvantageous to the network depending on the size, location and time variation of the DG unit. At high load DG supports the voltage and, consequently, improves the network's voltage quality. However, if the DG unit is large enough the voltage rise can become excessive. DG can also affect the operation of existing voltage regulating devices. For instance, if line drop compensation is used at the substation AVC relay [Lak95], connecting DG to the network decreases the current through the transformer and, therefore, lowers the voltages of customers at adjacent feeders.

Changes in the output current of the DG unit affect network voltages. Large transient voltage variations occur especially during DG connection and disconnection. More frequent voltage changes (flicker) can be caused by changes in the primary energy source (e.g. wind) but fortunately these changes tend to be smoother than step changes and are, therefore, less likely to cause nuisance to other customers. Flicker can be caused also by some forms of prime mover or adverse interactions between the DG unit and other existing voltage regulators such as the main transformer tap changer or reactive power compensation capacitors. [Jen00, Bar00]

DG can either increase or decrease the harmonic distortion of network voltage. The effect on harmonics depends on the type of network connection (synchronous machine, asynchronous machine, power electronics) and the design of the DG unit. [Jen00, Bar00]

### 3.1.4 Voltage control in distribution networks including DG

At present, DG is usually considered merely as negative load in distribution network planning and the capacity of connected generation is determined based on two worst case loading conditions (maximum generation/minimum load and minimum generation/maximum load). It is assumed that DG does not participate in distribution network voltage control in any way and that it can produce its maximum output power regardless of the network state (a firm connection). If feeder voltage limits are overstepped in either situation, the network is reinforced (conductor size is increased, a dedicated feeder is built for the DG or the DG is connected to a higher voltage level). In this case, the operational principle of the network remains unchanged but the connection costs of DG can become large. [Jen00]

Active management of distribution networks can also be used to mitigate the voltage rise caused by DG. Voltage rise can be mitigated for instance by controlling the active and reactive power of distributed generators, by controlling load demand or by reducing the substation voltage. Control can be based only on local measurements (e.g. production curtailment when the connection point voltage is above its limit) or be coordinated (e.g. control of AVC relay voltage set point based on maximum and minimum voltages in the network). [Lie02, Rep 05, Kul 07]

Voltage rise caused by DG can be decreased by allowing the generator to absorb reactive power. The usual practice is still to operate DG at unity power factor but also local reactive power has been used in some real distribution network. The reactive power control capability of DG depends on its network interface. Power plants with synchronous generator or power electronic interface are capable of controlling their active and reactive power independently as long as their operational limits are not exceeded. When induction generators are used the reactive power is dependent on the active power and cannot be controlled unless some kind of controllable reactive power compensation device is used. At simplest the consumption of reactive power can be increased by disconnecting the power factor correction capacitors usually fitted at the generator terminals. If a power electronic compensator (STATCOM, SVC) is connected to the generator terminals the reactive power can be controlled continuously. [Jen00]

The traditional voltage control method of a synchronous generator is based on droop characteristics. The droop is a slope between the voltage and the reactive power produced by the generator (blue slope in Figure 3.1). The droop method in distribution network is not as effective as in transmission network due to low X/R ratio of distribution network. However the droop characteristic allows the parallel operation of generation units using decentralized control method without interference and a fast response in case of local voltage change. The same control method is applicable also in DG units equipped with power electronic converter and in STATCOM.

Another version of decentralised voltage control is the voltage constrained reactive power control method (red curve in Figure 3.1). The idea is to maintain constant power factor (e.g. unity power factor) as long as possible in order to avoid unnecessary reactive power flow but maintain network voltage level within specified limits by utilizing local reactive power support. The controller is based on cascade control of AVR, power factor regulator and voltage constrained method. The response of this controller is slow in order to allow the OLTC respond first.

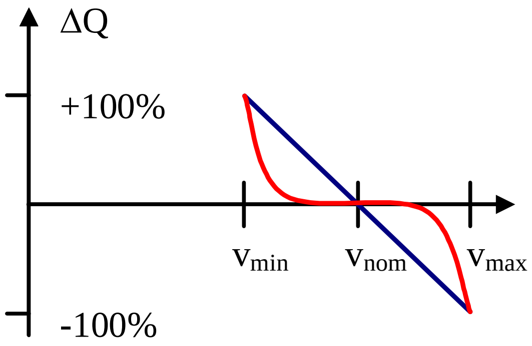


Figure 3.1. The droop characteristic (blue slope) and voltage constrained reactive power control method (red curve) of DG unit voltage controller.

The DNO's should, however, bear in mind that relatively large reactive power flows might be needed to mitigate the local voltage rise caused by real power generation since distribution networks tend to have low X/R ratios. Increased reactive power flows, in turn, require higher thermal capacity, cause bigger network losses, increase the burden on VAr sources and might interfere with the power factor sensitive tap changer schemes. [Sco 02] The DG unit reactive power control is, nevertheless, a potential alternative to network reinforcements, especially if the voltage rise problems are occasional. [Rep 05]

### 3.1.5 Load control

The ability to control customer loads provides another promising alternative for maintaining the voltage and frequency within permissible limits. Load control is based on switching controllable loads on (or off) to fill demand minima's (maximum's) during periods when the DG power generation is high (low). Voltage fluctuations originating from, for instance, wind generation can also be tracked and tackled by fast dynamic load switching. This, however, requires better control and communication systems but will be considerably more energy efficient compared to slower switching strategies. [Sco 02] The AMI, which in many countries are now being installed in increasing numbers, provide a very promising alternative as a communication medium for load control [Jär 07]. Loads that are capable of storing energy, such as thermal, cooling, pumping, etc. loads, are the most suitable ones for load control. This stems from the fact that turning such loads on or off basically causes no inconvenience to the customers since the energy can be stored for later use. [Sco 02]

The need for load control is infrequent because of the occasional nature of e.g. voltage rise problems. This leads to the fact that the payback time for the assets needed for load control devices will be relatively long. In order to improve the economical attractiveness of load control, the other possibilities provided by load control should also be harnessed. The other functionalities include, for example, peak shaping, the possibility of taking advantage of the low electricity cost periods, avoiding line over currents and alleviating LV network under voltage problems. All in all, load control is a potential alternative for enabling larger amounts of DG to be interconnected, although the contracts may become of somewhat complicated as there are three parties, namely the generator, supplier and distributor, involved. [Sco 02]

Direct load control based on local frequency measurement may also act as a frequency reserve. Space heating and similar type of loads may be controlled in accordance with dynamic demand control principle in which the temperature settings of space heater thermostats are frequency dependent. The reaction of dynamic demand control to frequency problem causes a period of zero load demand which length is dependent on the heat insulation of the building, the outdoor temperature and the length of frequency problem. If the indoor temperature will reach a preset limit for minimum temperature, the heating will turn on again and it will continue a normal operation within the preset minimum temperature.

The simulation results indicate that the operation of dynamic demand control loads is most effective in rapid and severe disturbances. The dynamic demand control method switches off load the amount determined by the severity of the disturbance and guarantees a certain predetermined minimum room temperature. Dynamic demand control requires frequency dependence from the thermostat, a feature which the space heaters do not have today. Nevertheless, adding the feature to new equipment can be done with low costs. As the number of loads needed is large, special attention should be paid to the coordination of operation. The management of dynamic demand control setting values and the monitoring of reserve functioning could be communicated via AMI. Furthermore the amount of controllable load is dependent on uncontrollable factors like outdoor temperature in a case of space heating, which causes a need to have several types of controllable loads in a portfolio in order to guarantee same level of service around a year. Perhaps the most problematic issues are however to find out a proper financial incentive and to dispel suspicions among the ownes of the resources. [Rau 08]

### 3.1.6 Production curtailment

Voltage rise can be decreased also by reducing the active power output of DG. If the voltage limit is exceeded only rarely the DG owner might find it beneficial to curtail some of its generation at times of high voltage if allowed to connect a larger generator to the network. The production curtailment terms could be agreed with the DG unit owner either in the interconnection contract or in an ancillary service contract. This kind of control would be particularly suitable for DG whose output depends on some external factor such as the wind speed. [Lie02]

The simplest method to implement production curtailment is to disconnect a required number of generating units when the voltage exceeds its limit. If the active power of DG can be controlled for instance by blade angle control of wind generators, disconnection is not required as the active power control of DG can be continuous.

## 3.2 Area control

### 3.2.1 Coordinated voltage control

Coordinated voltage control (CVC) methods use information about the state of the whole distribution network when determining their control actions. Coordinated voltage control has been a subject of extensive research in the past decade and several CVC methods of different complexity and data transfer needs have been proposed in publications. The number of real implementations is, however, still very low.

Commercial product GenAVC implements coordinated control of substation voltage based on network maximum and minimum voltages. It includes a state estimator and a CVC algorithm and has been successfully in operation in three different network locations.

The operational principle of GenAVC is based on the fact that the voltage profile in a radial distribution feeder with no DG usually resembles that depicted in Figure 3.2. In maximum loading conditions, the substation voltage cannot be lowered as this would lead to minimum voltage falling below feeder voltage lower limit. However, in minimum loading conditions the feeder's voltage drop is smaller and the substation voltage could be lowered. On the other hand, voltage rise caused by DG is largest in minimum loading conditions. [Lak95, Lie02]

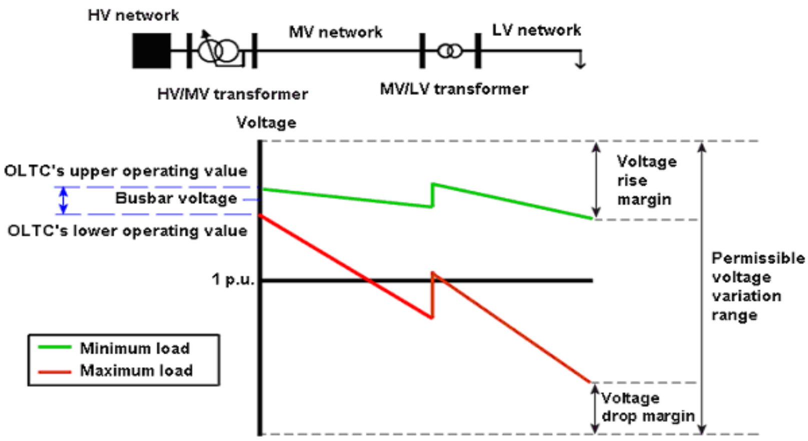


Figure 3.2. Voltage profile of a radial distribution feeder in maximum and minimum loading conditions.

The control principle of GenAVC is the following: The substation voltage is decreased, when maximum voltage is too high, and increased, when minimum voltage is too low. If both maximum and minimum voltages are outside the feeder voltage limits it is not possible to normalize the voltages by controlling the substation voltage and, therefore, nothing is done. The substation voltage is controlled through changing the set point of the AVC relay which controls the on-line tap changer (OLTC) of the HV/MV transformer. [Hir04, Lei03]

The operation of the OLTC alters the voltages on all the feeders fed by the HV/MV transformer where the OLTC is mounted. Therefore, the voltage drop margin is determined by the minimum voltage of all the feeders and, of course, the minimum permissible voltage level. Usually the minimum voltage on a lightly loaded network can be found from a feeder where no DG units are interconnected. If a voltage rise problem at some DG unit connection point caused by high production should occur, the AVR relay can order the OLTC to utilize the voltage drop margin, and hence reduce the network voltage. This way the DG production may be allowed to be higher than without coordinated voltage control. As the need for adjusting the HV/MV voltage set-value is mainly caused by the DG units, the production of the biggest DG unit needs to be measured online. [Rep 05] The measurements needed along the network can be carried out by remote terminal units (RTU's) or AMIs which are partially intelligent systems that have measurement, communication and control capabilities. The communication system required strongly depends on the complexity of the voltage control method being used. If a coordinated control method is used together with local voltage control schemes then communication mediums between the RTU's, DMS and AVR are needed. [Str 02]

### 3.2.2 Power flow management

This chapter briefly presents the idea of power flow management. The ideas presented in the following are to be utilized in meshed networks or substations with two or more main transformers. Figure 3.3 illustrates a typical British network, where power flow management could be applied.

Managing the distribution network power flows can be used as a means to increase the amount of DG that can be connected to the network. The power flow management concept is based on segregating the network into zones and controlling the power flows between the zones so that the network transfer capacity will not be exceeded. This, of course, necessitates power flow measurements between the zones. The concept divides generation into three categories, namely firm generation (FG), non-firm generation (NFG) and regulated non-firm generation (RNFG), which all are controlled in their own way. [Cur 07]

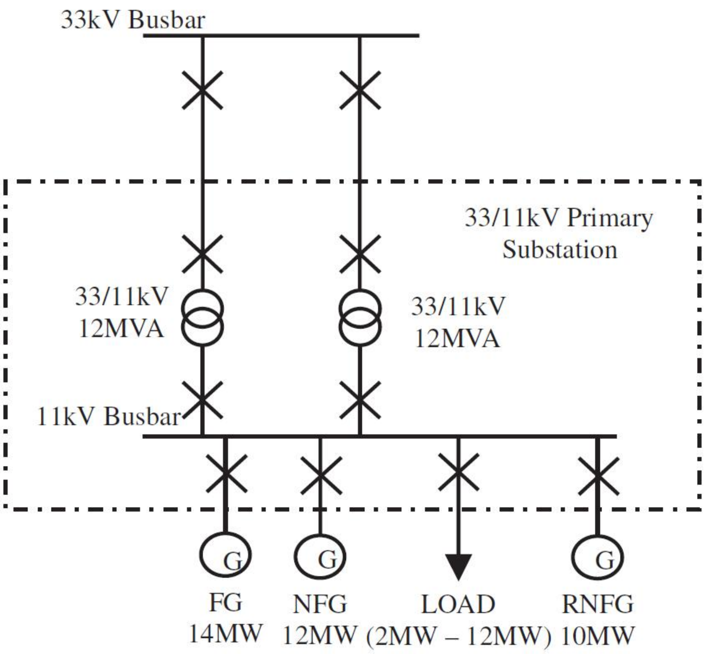


Figure 3.3. Example network. [Cur 07]

FG represents the DG units that are always allowed to operate at their full output power. This means that the FG units are allowed to produce their full output even in the case of a fault in the line with the highest transfer rating, while at the same time the consumption is at its minimum. Therefore, it is clear that the permissible DG penetration level will be fairly low if the level is not allowed to exceed FG, and there will, obviously always be spare transfer capacity in the network during normal operation. [Cur 07] This sort of design principle causes no risk for the network operator but it will greatly limit the amount of permissible DG production [Col 03].

The level of allowable DG can be raised by reinforcing the network which, however, is very costly. The level can also be raised by using the network more efficiently, i.e., using the spare capacity that would be unused if only FG was allowed. The NFG units are allowed to operate as they wish during normal operation, but during abnormal contingencies, the NFG units are trimmed or tripped depending on the required power reduction. [Col 03] The mathematical definition of NFG can be described as the transfer capacity of the circuits plus minimum load minus FG. [Cur 07]

Some of the FG and NFG units may be intermittent and thus do not operate at their rated output all the time. Similarly, the load is at its minimum rather occasionally. This leads to the fact that most of the time there would be room for more production in the network in addition to the FG and NFG units. The remaining extra space could be used by RNFG, which is subject to constraining or tripping whenever the network conditions require it. The constraining and tripping are done according to the defined operating margins which take account the variability of the load and generation. The operating margins have two boundaries. On the first limit, namely the trim margin, trimming orders are sent to the RNFG units. The trimming commands are based on the highest rate of change in the power transfer from the zone and the operating delay of the trimming order. If this is not enough, RNFG units within the zone are ordered to be tripped. The theoretical capacity of RNFG is defined as the maximum transfer capacity of the circuits plus the maximum load minus the sum of FG and NFG. In reality, however, the limiting factor of RNFG comes from economical considerations rather than from the theoretical limit. [Cur 07]

## 3.3 Fault management

### 3.3.1 Automatic network restoration

Active networks may also include network restoration procedures like automatic fault isolation and network restoration implemented in substation and feeder automation or in SCADA/DMS. Distribution network feeders are typically radially operated but partially looped which makes automatic network restoration possible utilizing e.g. remote-controlled disconnectors. Accurate fault location is the basis of distribution network restoration process. The fault isolation and network restoration are based on this information and hence the accuracy of these functions is totally based on initial data. The accuracy of fault location will however decrease due to influence of DG on fault currents if not properly taken into account.

The purpose of automatic network restoration is to safely restore the power supply to as many customers as possible by proper switching operation after a permanent fault. The process can be divided into two parts. The first phase aims to find out an optimal restoration configuration while the second part consists of the actual switching operation required for the desired configuration. The idea in the first phase is to minimize the number of unserved customers and the outage time while paying attention to the possible constraints. The restoration process constraints encompass the limited transfer capacity, limited available power sources and the required power balance between supply and demand. [Chi 05]

The fault location algorithm may be located either in IED or in DMS. The algorithms may be based on short circuit current and faulty phase measurements, reactance from the IED to the fault, and fault passage indicators. The information processed by IED is sent to DMS in order to analyse possible fault locations in the network. Otherwise the IED should have a complete model of protection zone in order to analyse fault locations. An estimate for the fault location is achieved by comparing the recorded fault currents with the fault currents computed by DMS. This requires that numerical relays, which are capable of recording and sending the fault currents to DMS, are used.

The second phase, namely the switching procedure, can be considerably accelerated by using remote controlled switches for isolating the faulted part of the network. The permanently faulted line section may be roughly isolated and the downstream network restored by backup connections. The field crew is further needed to operate manual switches in order to isolate the smallest possible line section and restore power to as many customers as fast as possible and to repair the faulted line section. The procedure can be completely autonomously operated, for instance, by predefining switching sequences in the SCADA that will be executed after the tripping of a certain circuit breaker. The predefined switching unfortunately has the disadvantage that the circumstances in the feeder concerned must be kept constant. More advanced automatic restoration techniques such as the FI-model (a fully automatic computer model) have, therefore, been developed. Some engineers, nevertheless, are of the opinion that the software should only have an advisory role, whereas the actual switching operation should be in the hands of the operator [Leh 01].

Temporary faults, such as earth faults caused by lighting strikes on the overhead lines, are generally cleared by automatic reclosing. Typically, in case if the first reclosing should fail, one or two more reclosings are made before the circuit breaker is ordered into permanent open position for the repair time.

Automatic reclosing, however, becomes a bit more complicated in the presence of DG because the DG units will have to be tripped off the grid first. If this was not the case, the DG unit might keep on supplying and thus sustaining the arc. The reconnection of the DG units into the re-energized network also has to be carried out with care in order to avoid dangerous stresses to the DG unit. This kind of coordination between the feeder protection and the protection of the DG units is quite challenging, especially in case if fast reclosing, operating in 0.2s, is applied. Typically the DG units are allowed to reconnect to “stabilized” network after a delay in order to give sufficient time for MV network restoration. [Ple 03]

### 3.3.2 Island operation

Islanding refers to a situation where a zone including DG in a distribution network is isolated from the main system as a result of a fault elsewhere in the network. This way the electricity supply to the customers in the zone may not need to be interrupted at all, which would otherwise be the case if there were no DG units supplying in the zone. This, however, requires that the DG units in the zone are capable of meeting the demand and maintaining the zone voltages and the zone frequency within the permissible limits. The co-ordination between the feeder protection system and DG units is, also, of great importance. [Pre 03]

The sequence leading to islanding usually begins by the operation of protection system after a fault. In such a case, the simplest way to change from grid connected mode to island mode is done by first disconnecting all the DG units in the power island area. The disconnection of the DG units is carried out by the LOM protection which all DG installations need to be equipped with. Then, after separating the power island area by an appropriate switching operation, a desired amount of DG units in the power island area can be reconnected and black started (a certain amount of the generation in the power island needs to be capable of black starting) to feed the loads in the power island. The LOM protection schemes of the DG units in the power island may also have to be readjusted to allow the islanding. The transition to island mode can, however, also be made to happen directly without an interruption. This requires a more sophisticated LOM protection arrangement that can determine when the transition to power island is desired and when it is not. Figure 3.4 illustrates this problem. This practically means that it is necessary to use a communication based LOM protection scheme of some kind. The IED controlling the circuit breaker separating the power island from the main grid would have to be equipped with synchronism check function in order to make it possible to reconnect the power island network back to the main grid without an interruption after the fault clearance. This IED would also have to be able to send control commands to the control systems of the DG units in the power island in order to carry out the possibly needed resynchronization.

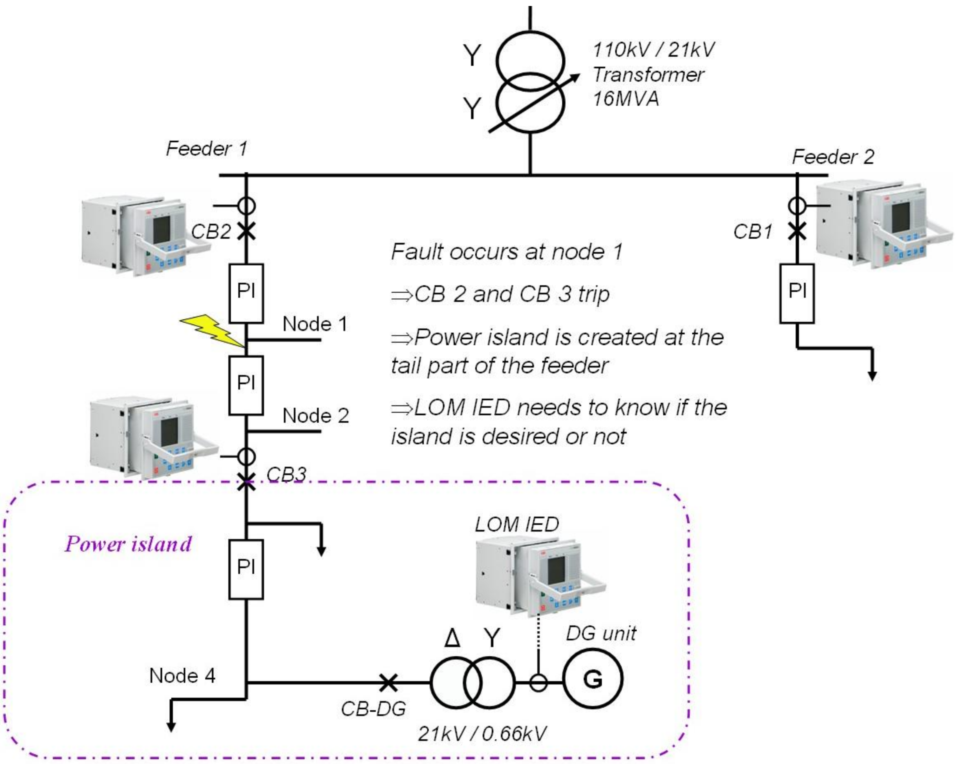


Figure 3.4. A challenge related to loss of mains protection

A planned transition to islanding due to network maintenance reasons is considerably simpler from the protection and automation point of view than a sudden unplanned transition due to a fault. This is because the network configuration as well as the demand in the planned island is known. This means that the functioning of protection systems in the power island can be checked beforehand and possibly needed readjustments can be made. Also the generation in the power island area can be controlled to match closely with the local loads, which is beneficial in the sense that the voltages and frequency in the power island do not drift much from their nominal values during the transition. It is also possible to makes changes to the size of the power island by changing the network configuration so that the generation in the island is large enough to cater the local loads.

The fault currents may be remarkably smaller in island operation compared to the fault currents in normal operation due to the reduced short-circuit capacity connected. This leads to prolonged fault clearance times and difficulties in coordinating the protection settings in the islanded zone because of the reduced difference between load- and fault currents. One way to solve this problem is to switch to different relay settings during island operation. The settings could then be changed back when connecting back to the main system. [Ple 03]

### 3.3.3 Network Reconfiguration

Distribution networks are usually built in a meshed way but operated in a radial mode due to the simplified protection design. The radial way of operation is realized by opening switches connecting adjacent feeders and thereby isolating the connected parallel feeders. Usually, there are multiple switches along the feeders so that the connection state can be changed, for example, for maintenance purposes. [Col 03] Network reconfiguration can, however, also be used for many other purposes as well. By a proper sequence of switching operations, it possible to maximize or minimize various kinds of objective functions. Such objective functions could, for example, deal with losses, economic and/or reliability indicators, load balancing, voltage control- or possible multipurpose formulations. The optimization of the objective functions will also have to take into account such possible restrictions as min/max node voltages, thermal limits, maximum three phase or earth fault currents, market rules, contracts and etc. Additionally, the optimal configuration could be variable in time. It is, therefore, clear that finding optimums for the kind of objective functions is very challenging. Various methods for solving have, nevertheless, been proposed in literature. [Mut 08]

The increasing amount of DG in the distribution networks has raised the problem of increasing fault levels. This is due to the fault level contribution of synchronous and asynchronous generators used in the DG units. Network reconfiguration can be utilized as a means for mitigating the fault level problems either by reducing the parallel feeds in radial networks or by changing the fault current paths. The fault current path can be changed by opening and closing the switches so that a DG unit is moved electrically farther away from the substation (e.g. moved to another feeder) and thereby, also the fault current infeed to the substation is reduced. The DG unit(s) located on a feeder where fault level is a problem can also be changed to another feeder where fault level is not an issue. Parallel feeder paths in radial network can be reduced by network splitting configurations, which generally are divided into either operating the bus section circuit breaker open or operating a transformer circuit breaker in open standby. Network splitting also has, however, several disadvantages such as increased losses, harmonic voltage levels, flicker, voltage dips and generally decreased power quality because of the increased source impedance. [Col 03] Network reconfiguration affects the state of the network, which has to be taken into account when designing the distribution network state estimation [Str 02] and protection.

# 4 Network planning

Traditional network planning guidelines and restrictions are not changed due to integration of DG into distribution network. The physical reality in the form of Ohms law still exists. However the distribution network operation may change due to possibilities which DG units may provide for the network and these should be considered in network planning. The participation of DG unit to support the electricity network may be arranged by ancillary service contract or DG connection requirement.

## 4.1 Network dimensioning

### 4.1.1 Firm connection of DG

Normally network customers have a firm network capacity available which is guaranteed at all conditions by network itself. When a single large and intermittently behaving customer like a wind farm is connected to weak distribution network, there may appear extreme loading conditions (combination of demand and wind production) which restrict the size of wind farm remarkably in the existing distribution network.

Distribution network design is traditionally based on the so called worst case planning principle. In radial distribution networks, where no DG is present, the limiting worst case factors are derived from the voltage drop at the end of the feeder, which occurs during maximum load at the feeder, and the thermal limits of the conductor used. [Lak 95] When DG is present in the network, the worst case will occur in a combination of minimum DG production together with maximum load. In lightly loaded networks, the presence of DG, will however, introduce also another limiting worst case factor. This is the combination of maximum DG production together with minimum load, which might cause the maximum allowable voltage to be exceeded at the DG interconnection point of the feeder line. [Jen 00]

The worst case design principle has been considered satisfactory in networks where only few relatively large DG units are interconnected. The validity of this principle is, however, no longer clear when a large amount of DG units based on various kinds of energy sources are interconnected to the distribution network. This is because it is quite unlikely that all units would be operating at their maximum output at the same time. The worst case principle is, therefore, a fairly conservative design principle for networks with a high DG penetration level. [Rep 05]

### 4.1.2 Non-firm connection of DG

If the cost of network reinforcement to achieve the firm network capacity for the wind farm is large compared to the probability of extreme conditions, it may be favourable opportunity for both the network and the production company to utilize ancillary services for network management during these extreme situations. The benefit of e.g. occasional production curtailment comes from the fact that the non-firm network capacity, i.e. the amount of DG to be connected and operated under normal network conditions, is most of the time much higher than the firm capacity. Of course the drawback of production curtailment is the loss of otherwise produced energy in case of extreme loading conditions. The ancillary services like the reactive power support of DG unit may also be utilized to alleviate network reinforcements in weak distribution networks.

Ancillary services are not commonly applied in distribution network operation today although there are no restrictions for their application. The application of local reactive power or voltage control service would be straightforward in distribution network. The power flow management service could be based on similar approach than the counter-trade principle to release transmission network bottlenecks inside a price area in Nordel. The island operation would require many services like black start, frequency control, primary and secondary reserves and voltage control. Ancillary services like local voltage and frequency control could also be realised through direct load control [Pan 01].

The purpose of the non-firm interconnection of DG is to allow a higher DG penetration by increasing the distribution network transfer capability in normal conditions. The firm interconnection is always available and calculation of interconnection capability is based on the worst case planning principle. The increased transfer capability of non-firm interconnection, in turn, is achieved by using the network more precisely. This is done by utilizing the DG units e.g. voltage control or production curtailment when the network constraints occur occasionally. Ancillary service contracts between the DG unit owners and the local DNO are, of course, required to provide the controllability of the DG units for the DNO.

### 4.1.3 Stochastic planning of DG interconnection

Figure 4.1 represents an example of stochastic nature of wind turbine and its effect on network voltage at weak distribution network [Rep 05]. On both figures there are represented three scenarios: 1) No production, 2) Constant 3 MW production and 3) Production from 3 MW wind turbine (blue curves). Load profile (one week from January, starting from Wednesday) is the same for all production scenarios. Within no production scenario the voltage profile is an opposite load profile, voltage increases during the night-time when load decreases and voltage decreases when load increases during a daytime. Voltage level is normal and there seems to have available network capacity for load increment. Constant 3 MW production will create voltage conditions which always exceeds the highest allowed voltage level which is 21 kV in this case. Wind production and corresponding voltage varies between previous scenarios.

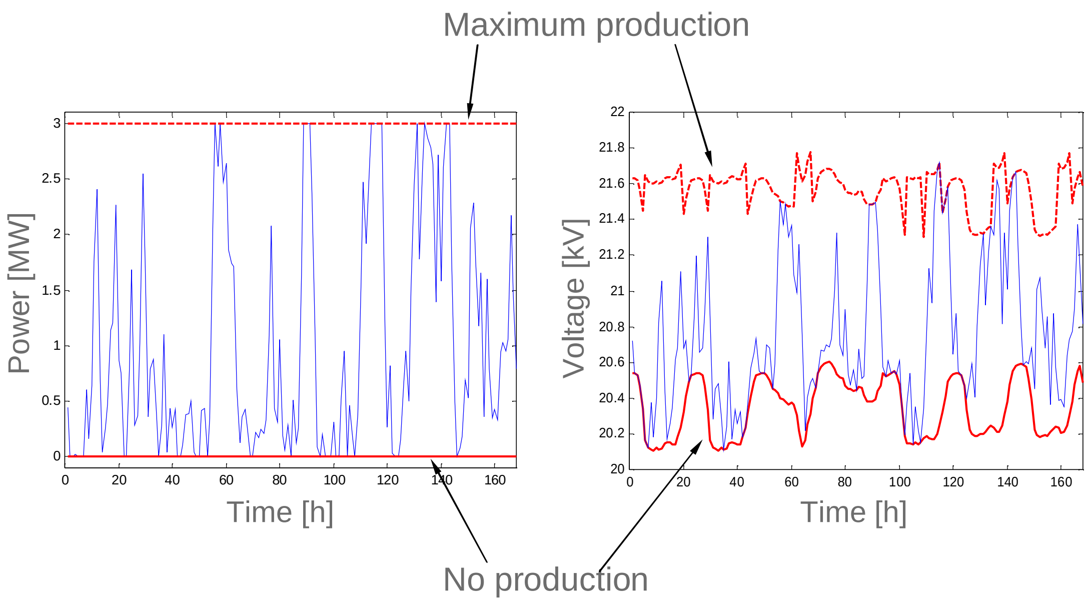


Figure 4.1. Example of hourly time series of power production and connection point voltage.

The statistical network planning method proposed in [Rep05] takes into account the stochastic nature of load demand, power production and correlation between these. The planning of MV network and DG unit interconnection is not based on a single worst case but series of possible network conditions. When the output power of DG unit is dependent on weather conditions of a site and the probability of maximum output power of DG unit is low enough during a minimum loading condition of network, there is an opportunity to enhance network operation by controllability of DG unit. The idea is based on facts that the minimum loading of network occurs at summer nights (at least in Finland) and the mean value of wind turbine output is less at summertime than at wintertime. The “minimum loading – maximum production” planning condition is very conservative in that sense and some advantage may be achieved when the active network management is applied. The worst case planning principle is also very conservative when there is different kind of production units at the distribution network. For example it is very unlikely that wind turbine and district heating CHP plant would operate at maximum power at summer time.

The proposed method is based on stochastic load flow computation. The hourly load flows are calculated for a study period i.e. for 8760 hours. The stochastic part of calculations is based on statistical load curves (mean value and standard deviation) and estimations of production curves which are time series for each customer type. The Association of Finnish Electricity Utilities has published load curve models for 46 different customer groups. In near future more accurate load curves may be designed for each distribution network by utilizing hourly load demand data from automatic meter reading system. Due to a lack of actual measurements and heavy dependence between power production and the location of wind turbine, the wind power production curve is based on long-term statistics of wind speed. Similarly district heating CHP production curve is based on long-term statistics of outdoor temperature.

The application of both the load and the production curves at load flow calculation makes it possible to simulate the hourly functioning of the distribution system including DG. The planning of the distribution network is not restricted to certain fictive planning conditions, but a series of hourly conditions is considered. The load flow simulations are used to analyse what kind of network conditions might exist. The methodology has one strong assumption: load demand and power production are statistically independent. If a correlation between power production and load demand exists, that will have a great impact on network conditions. The assumption is quite true for wind power but not for district heating CHP. The production curves are not accurate in the same way as load curves are. The load flow simulation with production curves is more or less a good guess about what might actually happen. The results of certain hour especially would not be accurate due to uncertainty of future wind and temperature.

The load flow simulations with production curves enable interconnection studies to see what kind of network conditions might exist and to see the differences between active network management strategies or network enforcements. When a number of different production curves are used in load flow simulations and the simulation results are examined together, the method will converge towards probabilistic load flow simulation e.g. Monte Carlo simulation. The calculation of economic effects, like costs of network losses and transmission charges which are dependent on the point in time, also becomes possible. The hourly load-flow information is needed to calculate time dependent costs and income, which are further needed, for example, in the planning of distribution tariffs for DG.

## 4.2 Reliability

### 4.2.1 Backup power and island operation

Similarly as DG may be utilized in distribution network dimensioning, DG may also be utilized in distribution network reliability enhancement. Utilizing intended islanding can significantly increase the reliability of the power supply in areas that are capable of operating as an island. The most classical way to reduce the harmful effects of supply outage is the utilization of backup generators at customer side. Similar idea works also on larger perspective. When a permanent fault occurs at radial distribution network, customers behind a fault will have an outage as long as outage repairing time when backup connection to adjacent feeder does not exist. DG unit located behind the outage may be restarted if it has black start capability, capability to control frequency and voltage and it is capable of supplying all loads. Island operation will reduce the outage duration in that case.

If appropriate automation system exists and DG unit is running, island may also created without interruption in a similar way than UPS systems are working. In that case it is also possible to reduce outage frequency. However island operation including various production types and owners requires special care. In order to harness such reliability benefits, one must pay special attention to the recloser and remotely controlled disconnector placement. This stems from the fact that the island zones must have adequate generation capacity. Also the nature of the DG units will have to be taken into account. The controllability and control systems of DG units have great influence on the stability of an island. An islanded zone containing only DG units based on intermittent primary energy, such as wind, obviously cannot operate properly. [Pre 03] The island operation requires typically additional control resources like production and load control in order to keep balance between load demand and power production, and maintain appropriate frequency and voltage in the network. The costs of introducing such equipment of course has to be weighted against the benefits expected with island operation.

Island operation is also an alternative for distribution network backup connections. Sometimes these connections may be very expensive due to long distance to area or difficult location (island) of target area. DG and mobile backup generation units operated in island mode may be cheaper alternative compared to e.g. long backup cable connection or to long backup connection going through forest (high fault frequency). [Ant09] The mobile backup generators can be relocated quickly and start or support island operation. This is important because DG units are not located everywhere in the distribution network.

The utilization of island operation requires careful preplanning. During an outage there is very short time to do decisions. The first thing to decide is where island operation is going to be utilized. Island operation should be profitable in long term compared to other more traditional network reliability enhancement methods. The evaluation of outage cost over long period is one way to compare reliability enhancement alternatives. This requires calculation of outage probabilities and expected value of the outage times in different parts of the network. The calculation of outage cost is possible when interruption cost for different customer groups are defined.

Intended island operation may also be executed by means of mobile stand-by generation units located in MV network. The focus of this approach is to enhance the reliability and outage cost impacts of intended island operation during long fault interruptions in distribution systems. Effects of this approach were examined by reliability-based software in a test network consisting of two rural feeders. In this study, traditional development actions on a network such as renovating an existing network in different constructions are explored to enable comparison between the effects of intended island operation. According to this study, intended island operation based on mobile stand-by units can increase the reliability of the distribution network and reduce outage costs of the network. These cost savings can be very substantial in relation to operation costs of an island. According to the calculations, the number of positive effects in costs and reliability grows when possibilities to use intentional islanding increase. Based on the study results, it can be possible to reduce outage costs in a more cost-effective way by means of intended island operation instead of renovating the network with more reliable constructions compared to overhead lines. This presents an interesting possibility of using intended island operation to ensure reliable power supply instead of rebuilding obsolete backup connections, but it is also important to notice the effects that the removal of backup connections can cause on a larger scale. The number and quality of the effects are strongly dependent on the start-up time of the island compared to expected outage time or failure repair time. Therefore island operation has to be well-planned to properly ensure its potential. [Ant 08]

### 4.2.2 Power flow management during a backup connection

The reconnection of DG unit into the feeder supplied by backup connection may improve the power quality at the feeder. The amount of customers connected behind a backup connection may be limited due to thermal or voltage drop limitations. A DG unit located behind the backup connection will reduce the current at the feeder when the production of DG unit is consumed locally behind the backup connection. This will reduce feeder voltage drop or will avoid thermal limitation of backup connection and thus larger area may be supplied via backup connection. On the other hand a large DG unit connected behind the backup connection may cause a serious voltage rise problem due to weak connection. The power flow management supported by DG unit improves distribution network reliability and has positive effect on network investments.

### 4.2.3 Replacement of network connection with permanent island operation

The replacement of network connection with permanent island operation is extremely radical method to improve system reliability and reduce investment costs. There is no sense to replace the well functioning part of the network with island operation. However the idea might be worth of consideration in the extremely remote locations of the network which are also lightly loaded and network is in a bad condition (i.e. reinvestments are needed). The similar logic is used by telephone companies when they are removing phone lines and replacing them with wireless solutions. DG technology developed for microgrids might be applied in this case. For example a small-scale wind turbine or photovoltaic cells could provide the major part of energy and the reliability of local microgrid would be ensured by batteries or diesel engine.

If the low-loaded branch is removed or de-energized and power supply to the low voltage network is arranged by means of DG, the customers of the low voltage network will not suffer outages that occur in the medium voltage network. In that case, reliability of power supply in the low voltage network depends on the characteristics of DG. And vice versa, reducing the length and number of branches in the medium voltage network diminishes the possibility of outages. So, reliability of the medium voltage network will increase. This affects a large group of customers.

## 5 References

[Ack 05] T. Ackermann (ed.), “Wind power in power systems”, John Wiley & Sons, 2005, 742 p.

[Ant 08] Antikainen, J., Repo, S., Järventausta, P. and Verho, P., ”Interruption costs management in distribution network by intentional islanding based on mobile stand-by generation units”, The 8th Nordic Electricity Distribution and Asset Management Conference, Bergen, Norway, 8-9 September, 2008.

[Ant09] J. Antikainen, S. Repo, P. Verho, P. Järventausta, “Possibilities to Improve Reliability of Distribution Network by Intended Island Operation”, International Journal of Innovations in Energy Systems and Power, Vol. 4, no. 1, April 2009.

[Bar 00] Barker, P.P. and De Mello, R.W., “Determining the impact of distributed generation on power systems: Part 1 - Radial distribution systems”. Proceedings of IEEE Power Engineering Society Summer Meeting, Seattle, USA, 16-20 July, 2000.

[Brü06] Brüdlinger, R. et. al., “State of the art solutions and new concepts for islanding protection”, DISPOWER Project, Deliverable 2.2., February 2006.

[Chi 05] Chin, H., -C., Su, Y., -S., “Application of the Ant-Based Network for Power System Restoration”, IEEE/PES Transmission and Distribution Conference & Exhibition, Asia and Pacific, Paper No. 40, 2005.

[Col 03] Collision, A., Dai, F., Beddoes, A., Crabree, J., “Solutions for the connection and operation of distributed generation”, UK July 2003, DTI New and Renewable Energy Programme, K/EL/00303/00/01/REP URN 03/, 71p.

[Cur 07] Currie, R., A., F., Ault, G., W., Foot, C., E., T., McDonald, J., R., “Active power-flow management utilizing operating margins for the increased connection of distributed generation”, IET Gener. Distrib., Vol. 1, No. 1, January 2007.

[Dti05] Kema Limited, “The Contribution to Distribution Network Fault Levels From the Connection of Distributed Generation”, UK 2005, DTI New and Renewable Energy Programme, DG/CG/00027/00/00 URN NUMBER 05/636, 59p. + 2 App.

[Dug 01] Dugan, R.,C., McDermott, T., E., ”Operation Conflicts for Distributed Generation on Distribution Systems”, IEE Rural Electric Power Conference 2001, pp. A3-1 – A3-6.

[Hir04] Hird, C. M., Leite, H., Jenkins, N. and Li, H., “Network voltage controller for distributed generation”. IEE Proceedings - Generation, Transmission and Distribution, vol. 151, 2004, pp. 150-156.

[Hol 07] Holttinen, H. et al., “Design and operation of power systems with large amounts of wind power”. State-of-the-art report, IEA Wind Task 25, VTT Working papers 82, Finland, 2007.

[IEE02] IEEE Power Engineering Society, "IEEE Guide for Automatic Reclosing of Line Circuit Breakers for AC Distribution and Transmission Lines", IEEE Std. C37.104TM-2002.

[Jen 00] Jenkins, N., Allan, R., Crossley, P., Kirchen, D. and Strbac, G., "Embedded generation". The Institution of Electrical Engineers, London, United Kingdom, 2000.

[Jär 07] Järventausta, P., et. Al., "Using Advanced AMR Systems in Low Voltage Distribution Network Management", Proceedings of the 19th International Conference on Electricity Distribution", Paper No. 0560, May 2007.

[Kir 99] Kirby, B., Hirst, E., "Load as a Resource in Providing Ancillary Services", Oak Ridge National Laboratory, 1999.

[Kul09] Kulmala, A., Mäki, K., Repo, S. & Järventausta, P., "Network interconnection studies of distributed generation". IFAC Symposium on Power Plants and Power Systems Control PP&PS, 5-8 July 2009, Tampere, Finland, 2009, 6 p.

[Kum04] Kumpulainen, L., Kauhaniemi, K., "Analysis of the impact of distributed generation on automatic reclosing", Power Systems Conference & Exposition, October 2004, New York.

[Kum05] Kumpulainen, L., Kauhaniemi, K., Verho, P., Vähämäki, O., "New Requirements on System Protection caused by Distributed Generation", 18th International Conference on Electricity Distribution, 2005, Turin.

[Lak95] Lakervi, E. and Holmes, E.J., "Electricity distribution network design". The Institution of Electrical Engineers, London, United Kingdom, 1995.

[Leh 01] Lehtonen, M., et. al., "Automatic Fault Management in Distribution Networks" Proceedings of the Sixteenth International Conference and Exhibition on Electricity Distribution (CIRED 2001), Paper No. 482, Netherlands, June 2001.

[Lei03] Leite, H., Li, H. Y., Jenkins, N. and Gale, P.F., "Real-time voltage regulation of distribution networks with distributed generation". Proceeding of the 17th International Conference on Electricity Distribution, Barcelona, Spain, 12-15 May, 2003.

[Lie 02] Liew, S.N., and Strbac, G., "Maximising penetration of wind generation in existing distribution network", IEE Proceedings in Generation, Transmission and Distribution, Vol. 149, 2002.

[Mor 06] Morren, J., de Haan, S., W., H., Ferreira, J., A. "Contribution of DG units to primary frequency control", European Transactions on Electrical Power, pp. 507 – 521, 2006.

[Mut 08] Mutanen, A., Repo, S., Järventausta, P., "AMR in Distribution Network State Estimation", The 8th Nordic Electricity Distribution and Asset Management Conference, NORDAC 2008, September 2008.

[Mäk 04] Mäki, K., Repo, S., Järventausta, P., “Effect of Wind Power based Distributed Generation on Protection of Distribution Network”, International Conference on Developments in Power System Protection, Amsterdam, The Netherlands, April 2004, pp. 327-330.

[Mäk 05] Mäki, K., Repo, S., Järventausta, P., “Blinding of Feeder Protection caused by Distributed Generation in Distribution Network”, Proceedings of the 5th WSEAS Int. Conf. on Power Systems and Electromagnetic Compatibility, Greece, August 2005.

[Mäk 06] Mäki, K., Repo, S., Järventausta, P. “Studying the Protection Impacts of Distributed Generation Using Network Planning Systems”. NORPIE2006.

[Mäk07] Mäki, K., “Novel Methods for Assessing the Impacts of Distributed Generation in Distribution Network Planning”, Doctoral dissertation, Tampere University of Technology, Finland, 2007.

[Nor 08] The Organisation for the Nordic Transmission System Operators, web page available: http://www.nordel.org/Content/Default.asp

[Pan 01] Pandiaraj, K. et al., “Distributed load control of autonomous renewable energy systems”, IEEE Transactions on Energy Conversion, Vol. 16, 14-19, 2001.

[Ple03] Pleym, A., et. al., “Connection of distributed generation – effect on the power system”, Norway, March 2003, Report of CODGUNet work package 5, 115p.

[Pre 03] Pregelj, A., Begovic, M., Rohatgi, A., Novosel, D. ”On Optimization of Reliability of Distributed Generation-Enhanced Feeders”, Proceedings of the 36th Hawaii International Conference on System Sciences (HICSS’ 03), IEEE Computer Society.

[Rai09] Raipala, O., “Real Time Simulation of Active Distribution Network”, Master of Science thesis, Tampere University of Technology, 111p. , 2009.

[Rau 08] Rautiainen, A., “Ancillary services for power system disturbance management provided by virtual power plant”, MSc thesis, Tampere University of Technology, 2008, (in Finnish).

[Rep 05] Repo, S., Laaksonen, H., Järventausta, P. “Statistical Short-Term Network Planning of Distribution System and Distributed Generation”, PSCC 2005.

[Sco 02] Scott, N., “Use of load control to regulate voltage on distribution networks with embedded generation”, IEEE Transaction on Power Systems, vol. 17, pp. 510- 515, May 2002.

[Sen04] Sähköenergialiitto ry & Energia-alan Keskusliitto ry, ”Keskeytystilasto 2003”, Helsinki 2004, 21p. (in Finnish).