

313

CONNECTION CRITERIA AT THE DISTRIBUTION NETWORK FOR DISTRIBUTED GENERATION

**Task Force
C6.04.01**

February 2007



CONNECTION CRITERIA AT THE DISTRIBUTION NETWORK FOR DISTRIBUTED GENERATION

Task Force C6.04.01

Members:

Nikos Hatziargyriou – Greece (Convenor)
Chad Abbey - Canada
Abdullah Alabbas - Saudi Arabia
Stefano Barsali - Italy
Regine Belhomme - France
Roland Bruendlinger - Austria
Stale Daae - Norway
Nijaz Dizdarevic - Croatia
Johan Driesen – Belgium
Toshihisa Funabashi - Japan
Geza Joos - Canada
Jan Koningstein – The Netherlands
Joao Abel Pecas Lopes - Portugal
Stavros Papathanassiou - Greece
Glen Paskaruk - Canada
Raul Rodriguez – Spain
Han Slootweg – The Netherlands
Kai Strunz - USA
Julio Usaola - Spain
Michael Viotto – Germany
Inmaculada Zamora - Spain

Copyright © 2007

“Ownership of a CIGRE publication, whether in paper form or on electronic support only infers right of use for personal purposes. Are prohibited, except if explicitly agreed by CIGRE, total or partial reproduction of the publication for use other than personal and transfer to a third party; hence circulation on any intranet or other company network is forbidden”.

Disclaimer notice

“CIGRE gives no warranty or assurance about the contents of this publication, nor does it accept any responsibility, as to the accuracy or exhaustiveness of the information. All implied warranties and conditions are excluded to the maximum extent permitted by law”.

Table of Contents

<u>EXECUTIVE SUMMARY</u>	5
<u>CHAPTER 1. INTRODUCTION</u>	8
1.1 SCOPE	8
1.2 IDENTIFICATION OF ISSUES	8
1.2.1 General Context	8
1.2.2 Steady state and short-circuit constraints	9
1.2.3 Power quality issues	9
1.2.4 Reactive power and voltage control	11
1.2.5 Contribution to ancillary services	12
1.2.6 STABILITY AND CAPABILITY OF DG TO WITHSTAND DISTURBANCES	13
1.2.7 PROTECTION ASPECTS	14
1.2.8 ISLANDING AND ISLANDED OPERATION	14
1.2.9 SYSTEM SAFETY	15
1.2.10 INFORMATION EXCHANGES AND REMOTE CONTROL	15
<u>CHAPTER 2. CURRENT CONNECTION CRITERIA AND PROTECTION PRACTICES IN VARIOUS COUNTRIES FOR DGS</u>	17
2.1 EXECUTIVE SUMMARY	17
2.2 COMPARATIVE ASSESSMENT	18
2.3 KEY CONSIDERATIONS	27
2.3.1 Deep vs. Shallow Charges	27
2.3.2 Deterministic vs. Probabilistic Analysis	27
2.3.3 Participation in Ancillary Services	27
2.3.4 Stability and Capability of DG to withstand Disturbances	28
2.3.5 DC in LV Networks	28
2.3.6 Islanding and Isolated Operation	29
2.4 ALLOCATION OF DISTRIBUTED GENERATION GRID CONNECTION COST	29
2.4.1 Introduction	29
2.4.2 Possible Allocation Mechanisms	30
2.4.3 Criteria for Evaluation of Allocation Mechanisms	32
2.4.4 Evaluation of Allocation Mechanisms	32
2.4.5 Conclusion	34
2.5 ISLANDING PRACTICES IN CANADA	34
2.5.1 BC Hydro Case Study	34
2.6 DISTRIBUTED GENERATION AGGREGATION IN CANADA	35
2.6.1 Sherbrooke Hydro	35
2.6.2 Toromont	36
<u>CHAPTER 3. INTERNATIONAL STANDARDS</u>	37
3.1 GENERAL LIST OF STANDARDS	37
3.1.1 Interconnection	37
3.1.2 Hybrid Systems	37
3.1.3 Photovoltaic	38
3.1.4 Wind Turbine	41
3.1.5 Fuel Cells	42
3.1.6 Small hydro	42
3.1.7 Converters	43
3.1.8 Batteries	43
3.1.9 UPS	44
3.1.10 Cogeneration	44
3.1.11 Power Quality	45
3.1.12 Metering	47
3.1.13 Communications	48
<u>CHAPTER 4. SIMPLIFIED METHODS FOR DG CONNECTION ASSESSMENT</u>	49
4.1 SIMPLIFIED ASSESMENT OF REACTIVE CONTROL CAPABILITY OF WIND FARMS IN SPAIN	49
4.2 SIMPLIFIED METHODS FOR ESTABLISHING THE WIND POWER PENETRATION LIMIT IN THE GREEK ISLANDS	51

4.2.1	<i>The economic viability of the investment</i>	53
4.3	MODEL FOR EXPEDITED PROCEDURE OF DG CONNECTION IN THE UNITED STATES	53
4.3.1	<i>Introduction</i>	53
4.3.2	<i>Definitions</i>	54
	CHAPTER 5. IDENTIFICATION OF METHODS TO MEET NEW REQUIREMENTS	57
5.1	PROBABILISTIC VOLTAGE ANALYSIS	57
5.1.1	<i>Probabilistic Load Flow Formulation</i>	57
5.1.2	<i>Typical Results</i>	58
5.1.3	<i>Discussion</i>	59
5.2	ISLANDED OPERATION - MICROGRIDS	59
5.2.1	<i>Islanding Operation</i>	61
5.2.2	<i>LV Islanding Operation</i>	61
5.2.3	<i>Single Master Operation</i>	62
5.2.4	<i>Multi Master Operation</i>	62
5.2.5	<i>Study case results</i>	63
5.2.6	<i>Single Master Operation</i>	64
5.2.7	<i>Multi Master Operation</i>	65
5.2.8	<i>Conclusions</i>	66
5.3	HV AND MV DISTRIBUTION GRID ISLANDING OPERATION	66
5.3.1	<i>Results</i>	68
5.3.2	<i>Conclusions</i>	71
	CHAPTER 6. RECOMMENDATIONS AND CONCLUSIONS	73
6.1	STATUS OF DG IMPLEMENTATION	73
6.2	RECOMMENDATIONS FOR FUTURE STANDARDISATION ACTIVITIES	73
6.2.1	<i>Determination of DG installed Capacity</i>	73
6.2.2	<i>DG Participation in Voltage Control</i>	74
6.2.3	<i>Unintentional Islanding</i>	74
6.2.4	<i>Active Distribution Network Management - Microgrids</i>	74
6.2.5	<i>DG behaviour during Network Disturbances</i>	75
6.2.6	<i>DC injection into the LV network by DG Inverters</i>	75
6.3	EVOLVING GRIDS AND DG	75
6.3.1	<i>DGs and communication</i>	75
6.3.2	<i>Aggregation of grid connected DG</i>	76
6.3.3	<i>Remote applications</i>	76
6.3.4	<i>Microgrids</i>	76
6.4	RECOMMENDATIONS FOR POLICY AND FURTHER R&D	77
6.4.1	<i>Standardized Impact Assessment and Integration Techniques</i>	77
6.4.2	<i>Regulatory issues and interconnection agreements</i>	77
6.4.3	<i>Economic justification</i>	77
6.4.4	<i>Regional characteristics</i>	78
6.5	CONCLUSIONS	78
	APPENDIX A: GRID CONNECTION CRITERIA IN VARIOUS COUNTRIES	79
	REFERENCES	190

Executive Summary

The brochure identifies the main issues that should be considered with the advent of DG on distribution networks. These are:

- steady-state and short-circuit current constraints
- power quality
- voltage profile, reactive power and voltage control
- contribution to ancillary services
- stability and capability of DG to withstand disturbances
- protection aspects
- islanding and islanded operation
- system safety, etc.

It then reviews the current connection criteria applied in 12 countries for DGs, namely France, Spain, Italy, Canada, Greece, Croatia, Portugal, the Netherlands, Germany, Austria, Norway and USA and summarizes them in a comparative Table w.r.t. maximum DG penetration limits at the various voltage levels, operating power factor, power quality constraints, protection practices and other requirements, like low voltage ride through capability, synchronous generator synchronization, accessibility to disconnection switch, etc. Detailed information is provided in 12 Annexes, one for each participating country.

The key considerations identified are:

- The allocation of “deep vs. shallow charges” for possible reinforcements required to facilitate the connection of DGs. Several countries apply “deep connection” charges having a major impact on the ability of new DG installations. Possible allocation mechanisms are detailed and evaluated.
- The use of Deterministic or Probabilistic Analysis for the calculation of voltage effects produced by DG connection. Clearly using worst case senaria (typically min load-max DG), applicable only for few hours per year, limit unnecessarily DG penetration, while considering stochastic voltage limits leads to more objective decision making.
- Lack of market mechanisms and pricing policies for the participation of DG in ancillary services in most countries, e.g. voltage regulation through active or reactive power control is not developed at the distribution level.
- Current DG protection related standards and codes state only minimum requirements in form of levels and maximum times where the unit has to trip. However minimum requirements for the behaviour during disturbed conditions, where a tripping would be undesirable, are generally missing. This results in a lack of awareness among manufacturers, system operators and planners regarding the behaviour of DG units during network disturbances
- DC components injected into AC low voltage network are an important safety and protection issue, particularly for DG using inverters. However research has shown that networks can accept a level of DC without negative implications for performance, lifetime or safety, which is significantly higher than the limits defined in some of the current standards. Therefore, this issue should not limit the further deployment and application of directly coupled, transformerless inverters.
- There is still widespread discrepancy regarding the probability of occurrence and persistence of distributed resource islands. The possible occurrence of unintentional islands in distribution networks with distributed resources (loads and generation) has been one of the major issues in connection with the ongoing growth of DG. However, DG can fully show its benefits regarding enhancement of reliability and quality of supply, if it is allowed to stay connected and supply parts of the network during disturbances in the upstream network. Islanding practices in Canada are further described.

The brochure provides next an extensive list of international and US standards that may affect DGs grouped in interconnection standards, hybrid systems, photovoltaics, wind turbines, fuel cells, small

hydros, converters, batteries, UPSs, cogeneration, power quality, metering and communications. It then describes simplified methods for DG connection assessment applied in Spain for reactive control capability assessment of wind farms, penetration limits in Greek islands and in US.

The next chapter describes methods and techniques that can be used to face some of the identified considerations. Probabilistic load flow analysis for example constitutes a mature technique that can be used for objective assessment of the voltage rise effect under steady state conditions. The coordinated management and control of DGs in the form of Microgrids allowing flexible operation and seamless transition to islanded operation can exploit their full benefits regarding quality of service and costs. This form of MV-LV organization is currently the subject of several R&D efforts in US, EU, Japan and Canada. Intentional islanding at HV and MV is also investigated.

Finally the brochure provides a number of recommendations for future standardization activities. These include:

Determination of DG Installed capacity

A clear procedure for the definition of the requirements to calculate the possible DG capacity to be installed at one point of the network. The adoption of simple rules might not be appropriate, while more detailed calculations can often show that more generation can be connected with no difficulties. A probabilistic approach is shown to provide an objective assessment of the possible constraint violations, while a deterministic approach based on worst case situations leads to conservative results.

Active Distribution Networks

The overall performance of a distribution system with a significant penetration of DG may be optimized, if DGs are considered by the DNOs as one more control parameter in scheduling their network operation. For example, in some cases, the voltage rise can be limited by reversing the flow of reactive power (Q). In these cases, the DNO should clearly define under which conditions this should be allowed.

Unintentional Islanding

With increasing penetration levels of DG intended to support reactive power, voltage or frequency control, the potential risks associated with unintentional creation of an island may not be neglected. Hence additional protection methods to the standard voltage and frequency monitoring are required in order to detect a loss of mains at the generator and ensure the safety of customers and maintenance personnel.

Controlled Islanding - Microgrids

One of the potential key benefits of DG, being connected at the MV and LV networks, is increase in service quality, reliability and security. A radical shift from traditional central control philosophy to a more distributed control paradigm is provided by Microgrids. These systems can be operated in a non-autonomous way, if interconnected to the grid, or in an autonomous way, if disconnected from the main grid. The operation of Microgrids requires significant efforts in research, development and deployment of new technologies and required information and communication infrastructure, but is likely to deliver significant benefits over the traditional control policy in the long term.

DG behaviour during Network Disturbances

Most current DG related standards do not require a defined response of DG during typical network disturbances, such as voltage sags. This has led to a general lack of awareness towards these phenomena in context of DG and an unacceptably low level of equipment immunity. Moreover, the safe and secure operation of networks based on a high penetration of DG requires a defined response of the generation units during critical conditions and network disturbances. Of specific significance in this context are issues such as LVRT (low voltage ride through) capability or voltage support during disturbances.

DC injection into the LV network by DG Inverters

Currently the maximum levels of DC current which may be injected by distributed inverters according to various national and international codes vary in a wide range from levels as low as 20 mA up to 1 A or 0,5% up to 5%. Applying a fixed level is explicitly recommended to avoid imposing unnecessary requirements on micro-scale DG.

The brochure concludes with further recommendations for policy and R&D.

CHAPTER 1. Introduction

1.1 Scope

The Task Force has elaborated recommendations for technical rules to be integrated in the national distribution grid codes and for the development of international standards, in order to keep a safe operation of power systems with reasonable and economically acceptable requirements for dispersed generation of various types. Emphasis has been placed on criteria that put unnecessary restrictions on DG penetration. The contents include:

1. A review of the current connection criteria and protection practices applied in various countries for DGs, with special emphasis on the case of wind generators/wind farm integration.
2. A review of existing international standards.
3. A description of simplified methods applied to DG connection in various countries
4. Connection analysis techniques and identification of inadequacies and new requirements.
5. Formulation of recommendations

This brochure has greatly benefited from the work done within Workpackage 2 (Power Quality and Safety) of the European project DISPOWER (Contract No. ENK5-CT-2001-00522) supported in part by the European Commission under the 5th Framework Programme. Detailed information and project results can be found at the project website <http://www.dispower.org>

1.2 Identification of Issues

1.2.1 General Context

Since the beginning of the 1990's, a substantial growth of distributed generation (DG) was experienced on power systems in many countries. This growth may be explained by several factors : changes in the institutional context (e.g. deregulation), progress in generation technologies, cost reduction in materials, economic incentives (e.g. special purchase tariffs for electric energy produced by Renewable Energy Sources (RES), Combined Heat and Power (CHP) systems or plants making use of waste), ...

The connection of DG to the grid has given rise to new and sometimes challenging problems especially on distribution networks. Indeed, these latter were not initially designed to host DG. In particular they were usually operated with energy flowing in only one direction, namely from the substation to the customers, which is no more true with the advent of DG.

This has often led system operators, electric utilities, governments or regulatory boards to define technical specifications for the grid connection and the operation of DG units.

Moreover, in the last decade, wind energy has remarkably expanded due to concerns on environmental issues (reduction of CO₂ emissions, promotion of environmentally sustainable resources, ...) and international, European or national policies (Kyoto protocol, European Directive for the promotion of Renewable Energy Sources, government incentive measures at country level, ...).

Besides the constraints generally imposed by DG, the connection of wind farms to the grid (distribution and/or transmission networks) raises specific problems related to this particular type of generation process (wind energy conversion), and to the technologies used [1]. This has led either to

the definition of specific technical specifications for the connection of wind power plants or to the adaptation of the existing rules or in some cases to exemptions.

Different issues are at stake with the advent of DG on distribution networks :

- steady-state and short-circuit current constraints
- power quality
- voltage profile, reactive power and voltage control
- contribution to ancillary services
- stability and capability of DG to withstand disturbances
- protection aspects
- islanding and islanded operation
- system safety

Depending on the country, these issues may be more or less important or may be dealt with in rather different ways, since distribution networks throughout the world may be quite different. These differences may include: voltage levels, configuration and architecture, characteristics, operation and protections practices, regulations, types of loads, among others. Other factors such as political or socio-economic factors may also play an important role in this field.

1.2.2 Steady state and short-circuit constraints

Steady state thermal constraints and possible network congestion. The power delivered by a DG unit may lead to an increase in the current flowing on the distribution grid to which it is connected, depending on where it is connected and the size of the installation. The current or the power in the different pieces of equipment should not exceed the maximum admissible values or the rated power depending on the type of equipment.

In some cases of large DG units or for high penetration of DG on the distribution grid, the transmission grid may also be affected and therefore the impact on the transmission grid should also be studied.

Short-circuit currents. In faulted situations, the DG plant contributes to the fault currents on the network. This contribution may be more or less significant depending on the technology used and in particular on the “coupling system” used (e.g. machine directly connected to the grid or coupled through power electronics converters [2]). It will add to the short-circuit power of the already existing sources. Fault current may also decrease due to DG, if inverted-coupled units are in operation instead of conventional power plant with synchronous generators.

The maximum short-circuit currents on the grid should not exceed the maximum admissible values (e.g. short-circuit thermal constraints on the lines or breaking capacity of the circuit breakers).

1.2.3 Power quality issues

Depending on the primary energy source and on the technology used for the conversion process, the connection of DG units to the grid may raise a certain number of problems which, if not properly addressed, may reduce the quality of supply on the network. The degradation of the power quality may affect the installations of the network users and prevent the network operator from meeting its obligations.

Recommendations or requirements to limit the effects of the above phenomena and hence to guarantee the quality of supply have then to be drawn. Presently, they are generally included in the grid connection criteria for DG in the forms of limits or by referring to existing standards (for instance the IEC-EN 61000-3 series).

The following main problems may be encountered [3] and are described in more detail below : voltage fluctuations, flicker, harmonic and interharmonic emissions, unbalance, disturbance in the signaling system.

The impact of these phenomena depends largely on the short-circuit power available at the connection point of the DG unit and therefore on weak grids this may be one of the limiting factors which determines the number and size of DG units that can be connected. The impact also depends on the technology used, especially for the coupling with the grid : for instance, coupling systems making use of an electronic interface may help to limit or even to avoid voltage fluctuations or flicker but they may carry a risk in terms of harmonic pollution.

Flicker and Voltage Fluctuations

The connection of certain types of DG units to the distribution grid may lead to the occurrence of flicker and voltage fluctuations which may be due to different reasons. This is particularly true for renewable energy sources which are often characterized by rather high generation variability and a stochastic nature, e.g. wind turbines.

Slow voltage fluctuations generally resulting from the fluctuations of the power delivered by the DG plant. For instance, in the case of wind turbines the power varies with wind speed (which is not constant in time).

Fast voltage fluctuations or voltage step changes may be experienced at coupling and decoupling of the DG units (or their transformers), at starting up, or for some DG technologies when changing between generators (e.g. wind turbines).

Flicker may also be caused by switching operations, or power fluctuations resulting from the variability of the primary energy source, or by the conversion process itself (e.g. the tower shadow effect in the case of wind turbines).

Harmonic and Interharmonic Emissions

Harmonics emissions may also be an issue in particular with the use of power electronics converters as an interface between the DG units and the grid. Although power electronics interfaces can be seen as an opportunity to improve grid-connection characteristics (especially for renewable energy sources), it may also be a threat in term of harmonic pollution.

Harmonic currents emitted by a power electronics converter depend to a great extent on its features. With the use of forced switched inverters, better control is generally achieved regarding the waveform of the various electrical quantities at the inverter terminals. As a result, this type of inverter does not inject harmonic currents on the first harmonic orders. The remaining frequencies are of the order of a few kHz (operating frequency of the converter).

Interharmonics and harmonics of higher orders (> 2000 kHz) may thus be produced by power electronics converters. However, due to the lack of experience in this field, it is presently difficult to assess to what extent this is really an issue. With an increased use of power electronic converters on distribution grid, more detailed studies are necessary in order to determine what kind of measures have to be taken. Nevertheless, limits are sometimes already specified in grid connection criteria for DG.

Unbalance

Depending on the type of DG units and the voltage level to which they are connected, their connection to the grid may increase the unbalance rate and therefore may affect the quality of supply.

Disturbance of the signaling system

A signaling system may sometimes be implemented on the distribution network. Ripple signals may be transmitted on the grid, for instance to give information on applicable prices or changes in price (from day to night, peak prices), or to control the switching on or off of certain loads, e.g. street lighting.

The connection of DG plants modifies the network impedances especially when considering large generating plants. This phenomenon may cause a modification in the harmonic resonance conditions near the connection point and the ripple signal may thus be affected.

1.2.4 Reactive power and voltage control

The connection of a DG unit changes the voltage profile on the grid due to the change in the active and reactive power flows in the network impedances. Generally, the voltage increases at the connection point and on the feeder. This is illustrated in Fig. 1 which gives the voltage profile along a French 20 kV distribution feeder before and after the connection of a wind farm (WF) [2]. This increase is a function of the “weakness” (short-circuit power) of the network and of the values of the active and reactive power flows (e.g. see [4]).

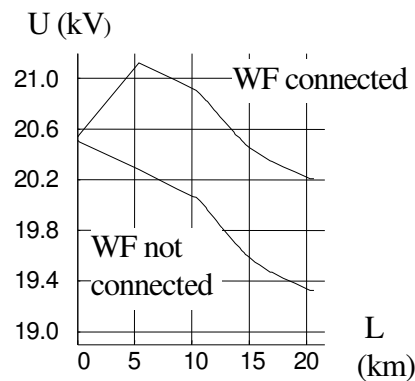


Fig. 1.1 Voltage profile along a 20 kV distribution feeder

In normal (steady state) conditions, for safe and efficient power supply and operation of the network, the voltage has to be maintained between upper and lower admissible values everywhere on the distribution grid regardless of the operating point of the DG unit. Therefore, limit values are generally specified in the grid connection criteria or references are made to existing national or international standards.

It should be noted that a voltage increase (or decrease) on a given voltage level may affect the voltage profile on lower voltage levels. For instance, the voltage rise due to the connection of a DG plant to a medium voltage (MV) feeder may also affect the low voltage (LV) feeders supplied by this MV feeder [5]. Hence, the voltage constraints should also be checked at lower voltage levels.

The control of the voltage or the reactive power is therefore an important issue for the Distribution Network Operator (DNO), which leads to requirements concerning the contribution of DG plants to the voltage or reactive power regulation on the distribution network. These requirements may take different forms and may vary from very basic ones to more sophisticated contributions, for instance :

- constant reactive power at the connection point by means of capacitor banks,
- constant power factor or constant $\tan \phi$ (ratio between reactive and active powers),
- reactive power control or actual voltage control within the reactive power capabilities of the DG units, ...

The larger the capacity of the DG unit, the greater its impact will be on the grid and therefore the greater the potential to contribute to the voltage control. Consequently, large DG plants are generally requested to provide more “complex” contributions than smaller ones.

However, exemptions sometimes apply depending on the DG technology and primary energy sources (for instance, for induction generators).

1.2.5 Contribution to ancillary services

Ancillary services are essential for the safe, secure and reliable operation of the power system as a whole. They are managed by the system operators and they presently include both mandatory services and services subject to competition. Definition of ancillary services may be rather different from country to country, however, they may generally be classified in the following main categories expressed in terms of contribution to specific system requirements [6]:

- voltage control
- frequency control
- stability control
- system restart

Ancillary services were and are still mostly provided by centralized power plants connected to the transmission network and therefore the definition and characteristics of ancillary services were devised in this context. With the advent of DG on distribution (and transmission) networks, these definitions might need to be adapted, extended or revisited :

- What are or what should be the ancillary services for distribution grids ?
- How should these be related to the transmission grid ?
- Who could/should provide them and how ?
- New needs may appear (e.g. increased reserve requirements for RES development, especially wind energy) but also requires new “solutions” (DG, load control).

As far as DG is concerned, depending on the technology involved and on the primary energy source, the capability to contribute to ancillary services will be quite variable [7]. A typical example is given by induction generators directly connected to the grid. Improvement can certainly be obtained with the use of synchronous generators and/or power electronics interface. Another example is given by the stochastic nature of wind energy which can prevent wind farms from contributing to active power reserves.

Voltage control

As discussed in Section 1.2.4, voltage control has to be performed locally in order to maintain the voltage within the admissible voltage range. Since DG has an impact on the voltage profile, it also has a role to play.

Depending on the country, voltage control on a power system may be implemented at several levels with different time scales. To keep it simple, voltage control may be described as a two-level control system [6] implying

- a primary voltage regulation which is a fast, local and generally automatic control,
- a secondary voltage regulation which is a remote, “centralized” (for instance at an area level) and somewhat coordinated (for instance between areas) control .

Presently, the participation of DG to secondary voltage regulation concern only large plants.

Frequency control

Frequency control is a system-wide issue. It implies several kinds of active power reserves characterized by different volume, activation speeds and duration of delivery. The implementation greatly varies from country to country. But again, it may be very roughly described as a two level system with [6]:

- a primary frequency regulation which is a local, fast and automatic control,
- a second-level or “load” frequency control which is a centralized remote control system used to remotely control the output of the generating units.

Except in island power systems, DG units connected to distribution grids are generally not requested to contribute to frequency control. In some cases, requirements concerning DG unit disconnection or power curtailment may be specified.

However with the growth of DG on distribution networks and with the deregulation of the Electricity Sector, this may become an issue in the future.

Stability control

Stability control is not considered as an ancillary service any country. However, it is more and more an issue for grid connection of DG.

The power system should remain stable after the occurrence of any contingency and the oscillations which follow should be suitably damped. Two main aspects have to be considered :

- static (or “small signal”) stability which deals with “small magnitude” disturbances around an equilibrium point,
- dynamic stability (transient or angle stability, voltage collapse, ...) related to “large magnitude” disturbances such as short-circuits, loss of generation, ...

In terms of stability control, DG can participate in two ways:

- support of power system stability, for instance in terms of contribution to voltage and frequency control (see above) in the case of disturbances on the network,
- capability to withstand disturbances (see Section 1.2.6 below) and to operate for limited time duration under degraded voltage and frequency conditions.

System restart

Depending on their size, location and black start capabilities, DG units may be requested to contribute to network restoration after a partial or complete shutdown. Presently, only large DG plants are involved.

However, due to their location (closer to the customers than centralized power plants), DG units may provide a useful black start service, provided that they have the suitable equipment and capacity.

1.2.6 Stability and capability of DG to withstand disturbances

Stability of DG units and their capability to withstand disturbances become a more and more important issue. Following the occurrence of disturbances on the network (short-circuits, important line outages, voltage dips, loss of generation plants, or important load variations), the loss of DG plants results in a loss of generation and of support to the network. Depending on the amount of lost DG generation, the situation on the grid may worsen and in some case lead to very severe stability problems.

In this respect, the impact of DG depends on several factors such as :

- the size of the DG plant (the impact is larger for large DG plants), or the penetration level of DG on the grid (large number of small units representing a significant total generation may have the same impact as large DG plants),
- the voltage level at the connection point and the network configuration,
- the characteristics of the connection and the DG technology used.

In distribution grid connection criteria, requirements are already often specified concerning the capability of DG to operate under specific voltage and frequency ranges that can occur in degraded conditions. But as a consequence of the important developments in wind energy, system operators now require “Fault Ride Through” or “Low Voltage Ride Through” capabilities in order to ensure that the DG units will not disconnect in the case of voltage dips.

1.2.7 Protection aspects

As already mentioned, the connection of DG units may change the value and direction of the power flows in the network lines or cables, the values of the short-circuit currents, and the equivalent impedances of the network. These changes may affect the proper operation of the protection system.

In particular, the sensitivity and selectivity of the protection system as a whole may be affected. For instance, some faults may be undetected by the protection normally dedicated to their detection or their clearing may require the tripping of much larger parts of the network than necessary. Besides, the presence of DG units must not lead to unwanted tripping of parts of the network (such as neighboring feeders not affected by the fault) and it should not prevent the proper operation of the automatic or manual reclosing scheme that may be implemented. Examples of potential problems in the case of generating plants connected to MV networks can be found in [5] (non-detection of faults by feeder over-current protection, unwanted tripping of a healthy feeder, or disturbance of fault locators).

Generally, detailed case by case studies have to be done to determine whether the protection system will still operate properly after the connection of DG. If this is not the case, suitable measures have to be taken because on the one hand the safety of people and equipment is at stake and on the other hand the quality of supply may be degraded.

In particular, decoupling criteria are often defined in order to prevent DG to supply power in abnormal conditions : voltage and frequency outside admissible ranges, fault on the feeder. They generally consist of voltage and frequency criteria and may imply time delays. The use of a dedicated “decoupling” protection may also be required.

Another aspect concerns the protection of the DG installation itself which should be ensured and generally implies the use of dedicated “internal” protections. These protections should also be coordinated with distribution grid protections.

Finally, neutral grounding should be implemented in accordance with the grid protection scheme.

1.2.8 Islanding and islanded operation

With the evolution of power systems and the advent of DG, many questions have been raised concerning islanding and possible islanded operation of DG on parts of a grid.

Unwanted islanding. Generally, unwanted islanding is not desirable because this may cause large voltage and frequency variations on the islanded grid and the supply of power to the customers under abnormal conditions until either the system collapses (or the DG units are disconnected) or the balance between generation and consumption is obtained. Therefore, the above mentioned decoupling criteria often involve “anti-islanding” criteria.

Since detection of islanding alone is not easy, these anti-islanding criteria rely on variations of electrical quantities which may be due to other phenomena and then lead to the disconnection of DG when there is no actual islanding. On the contrary, with such criteria there is also a possibility that an islanded situation will not be detected. In that case, there may be a risk for the safety of people and equipment. Hence islanding is an important issue.

Presently, consumption and generation on distribution grid are not balanced in “most cases” and the islanded system is not viable. But there is still a probability of having generation and load conditions such that islanded operation may be maintained for a certain amount of time. How high is this probability ? How long can an islanded situation last? What is the safety risk ? A lot of questions need to be answered.

Deliberate islanding. In particular cases, black start and islanded operation may be required for instance for units participating in network restoration as discussed in Section 1.2.5.

In other cases, it is still an open question :

- On the one hand, islanded operation may sometimes be useful and even desirable. For instance, in the case of blackouts or long duration cuts of supply for distribution feeders (due to important problems on the transmission grid), islanded operation of distribution feeders would allow supply of power to the customers until the system is restored. As another example, in certain areas where the transmission network is often subject to disturbances (e.g. strokes of lightning) and voltage dips, islanded operation may be interesting to provide higher quality of supply. Anyway, new concepts of distribution grids are presently developed incorporating the principle of deliberate islanding : for instance Microgrids concept discussed in Section 5.2.
- On the other hand, islanded operation of distribution grids is a very complex problem and the possibility of deliberate islanding must be very carefully planned [8] in order to first ensure a safe and reliable operation of the islanded network and second to guarantee a sufficient level of quality of supply to the customers. The DG units must be equipped with suitable voltage and frequency regulation capabilities. Modifications to the grid itself are generally required (for instance concerning the protection scheme) and depending on the case, they may sometimes be quite expensive.

Finally, regulatory issues will need to be addressed and possibly new contract structures might need to be developed : for instance, the DNO has contractual obligations in terms of quality of supply to its customers. In the case of islanded operation of a part of distribution network, should the DNO still be obliged to meet these requirements ? Who is legally responsible in the case of failures and possible injuries ?

1.2.9 System safety

The safety issue is of primary importance. It has already been partially addressed in previous sections such as when dealing with protection and islanding issues.

Requirements to guarantee the safety are specified and they often refer to national or international standards. The safety of the whole power system shall be ensured, that is to say : safety of the DG installation itself, of the equipment in the grid, of the customers' installations, and of people living, working, or coming in to contact of any kind with these installations and equipment.

Concerning grid connection itself, requirements are generally specified not only for the connection equipment or possibly the interconnection configuration, but also for the conditions in which the coupling will be permitted.

1.2.10 Information exchanges and remote control

In order to properly manage and operate the distribution network, the DNO needs information on the operation of the DG plants and sometimes on the network status at the connection point. Exchanges of information are therefore required.

They can concern very basic information for small DG units. For larger units, the producer may be asked to send its forecasted production. In some cases, a communication link may be installed between the generating plants and the DNO to exchange operating information (e.g. active and reactive powers of the DG plant) and possibly information on the grid voltage or other pieces of information.

Finally for large DG plants, remote control possibilities may be implemented such as for DG units contributing to secondary voltage regulation (and maybe in the future “load” frequency control).

With the growth of DG on distribution network, exchanges of information and possible remote control of DG units will become a very important issue.

CHAPTER 2. Current connection criteria and protection practices in various countries for DGs

2.1 Executive summary

This chapter considers the relevant connection requirements from various countries for distributed generation. The considerations include the interconnection requirements, protection practices, capacity assessment techniques, and the cost of the interconnection. While these issues are important in order to guarantee safe and reliable operation of the power system, they may also hinder its growth and present themselves as barriers to the integration of DG. Whereas regulatory aspects can differ greatly between countries, in general interconnection requirements are similar, usually the result of collaborative efforts in the development of internationally accepted standards.

Interconnection standards are most often cited in the majority of the countries concerning the voltage, frequency, and power quality requirements that need to be respected by the DG plant. These criteria are based upon the need to guarantee certain modes of operation and are generally independent of precise voltage levels, system configurations, and DG technology. In some cases, certain requirements specific to a country are defined, however, in general they do not deviate greatly from those contained in the standards.

Protection practices and interconnection assessment address whether the DG would require a change in the present system infrastructure or protection strategies. If the answer is yes then the system configuration or operation strategy needs to be modified. Reconfiguration of protection settings is possible, but then implies that either the DG is always connected, or that the status of the generator is known and can be used to dictate the status of the protection element. Also, conventional techniques such as fuse saving becomes more complicated and requires a greater amount of control over the DG unit.

Probabilistic studies, while a powerful technique for capacity assessment, have yet to be widely adopted, particularly by utilities that generally favour the more conventional, deterministic approach. While the risk may be less on the part of the utility, it does not favour DG and in many cases, DG interconnection when not granted, may or may not be warranted. On the other hand, the power of these techniques greatly depends on the accuracy of the probability functions, which in turn often depends upon the availability of reliable, historical data. In many cases the necessary data is not available and therefore, makes the argument for probabilistic methods problematic.

There is always a cost associated with the integration of DG as there is with the introduction of any generation source. The utilities in different countries choose to either absorb this cost, charge the producers or share the cost. Various countries implement different strategies and this affect the level of DG integration. Whereas cost is a major source of conversation, the benefits of DG are not as often discussed and rarely, if ever, are they quantified. Whereas some countries do have incentive programs for alternate energy sources and in some isolated cases are compensated for ancillary services, in general, the cost-benefit relationship and methods for their determination have yet to be understood and implemented.

The various issues are elaborated upon in the following sections and a comparison of the connection requirements and individual philosophies are given. Details regarding each of the countries are contained in the 12 Annexes at the end of the brochure, while the main points are highlighted in the sections that follow.

2.2 Comparative Assessment

		AUSTRIA	BELGIUM	CANADA	CROATIA	FRANCE
System Type	Interconnected	x	x	x	Interconnected	x
	Isolated	-		x	Not isolated	x (Islands & overseas departments)
Voltage Levels	LV	230/400 V	230/400 V	240/600 V	400 V	230/400 V
	MV	10/20/30/60 kV	6 to 36 kV	12,5 to 69 kV	10, 20, 30, 35 kV	1 kV to 50 kV (mainly 20 kV, some grids at 15kV and 33kV)
	HV	110/220/380 kV	70 to 380 kV	69 to 735 kV	110, 220, 400 kV	63, 90, 150, 225, 400 kV
Network Topologies	LV	Radial, 3Ph+N	Radial, 3Ph+N (some older grids have 3x230V)	Radial, 1 or 3 ph	Radial	Radial, 3 Ph + N
	MV	Radial, 3Ph; Meshed 3Ph	weakly meshed, 3Ph	Radial, Weakly meshed, 3ph	Radial	Radial, 3 Ph
	HV	Meshed 3Ph	Network, 3Ph	Radial and Meshed, 3ph	Meshed	Meshed, 3 Ph
Neutral Earthing Scheme	LV	TN-C	TN-C in industrial systems, TN-S in others (is promoted), occasional IT	Directly	TN	TT
	MV	resonant earthed (most resistance 10-30 Ω (only a few))	TT in distribution grids, Inductive - $3 I_0 \leq 2000A$ (or 1000A)	Directly	At 35 kV resistance to limit current to 300 A; At 10 and 20 kV resistance to limit current to 150-300 A	Resistance, reactance or Petersen coil on MV side of the HV/MV substations to limit fault current
	HV	110 kV: resonant earthed >110 kV: Directly	Direct - sometimes insulated to limit I_{lg}	Directly	Directly	Grounding reactor at transmission substations
Design Fault Level	LV	25 MVA	$S_{sc}=16$ MVA		24 kA	24 kA
	MV	~250 MVA	16, 20, 25 kA	8 - 20kA	12,5 kA	2kA to 22 kA depending on grid equipment type
	HV	110 kV: 1-5 GVA	40 kA	30 - 50 kA	18,4/26,2/31,5/40 kA	31.5 kA, 40 kA, 63 kA
Max DG Power Limits	LV, 1Ph	4,6 kVA	< trans. of MV/LV	15 kW	5 kW	18 kVA
	LV, 3Ph	not defined	< trans. of MV/LV	50 kW	100 kW; total up to 500 kW	250 kVA
	MV	not defined	< trans. of HV/MV in n-1 stage, 15 MVA	25 MVA	from 500 kW to 5 (10) MW	12 MW

Operating Power Factor	Min Ind.	not defined	No specific limits	0,9	0,85	Depends on the DG installed power; 3 possibilities determined by DNO: constant reactive power, reactive power control or voltage control
	Min Cap.	not defined		0,9	1	
Power Quality Constraints	Slow voltage changes	LV: $\pm 3\%$ of V_n MV: $\Delta U = 2\%$ of V_n	< $\pm 3\%$ between on-off switching; EN 50160	CSA C235 - LV: -9% +4% of V_n	LV: +6%/-10% (till 2010), $\pm 10\%$ (after 2010) of V_n MV (10 kV, 20 kV, 30 kV, 35 kV): $\pm 10\%$ of V_n	LV: ΔU between +6% and -10% MV: $\pm 5\%$
	Fast voltage changes	LV: = 3%. MV = 2% when repeat rate $r < 0,1 \text{ min}^{-1}$ and in some cases ($r < 0,01 \text{ min}^{-1}$) LV: = 6%. MV = 3%	PST < 1; EN 50160	not defined	For $r = 1$ then $\Delta V_{dyn}/V_n$ (%) = 4; For $1 < r \leq 10$ then $\Delta V_{dyn}/V_n$ (%) = 3; For $10 < r \leq 100$ then $\Delta V_{dyn}/V_n$ (%) = 2; For $100 < r \leq 1000$ then $\Delta V_{dyn}/V_n$ (%) = 1,25;	$\Delta U < 5\%$
	Flicker	Plt=0,46 p.u.	IEC/EN 6100-3-3 for DG ≤ 16 A in LV; IEC/TR2 61000-3-5 for DG > 16 A in LV; IEC/TR3 61000-3-7 for DG connected to MV & HV	Varies, typically based on either IEEE 519 or IEC 61000 series standards	IEC 61000, DIN/VDE; Pst=0.7 (0.35 for WPP) and PIt=0.5 (0.25 for WPP)	LV : limited such that DNO can meet its commitments in terms of power quality MV : depends on short-circuit power, and on other conditions. Base levels : Pst < 0.35, PIt < 0.25
	Harmonics & Interharmonics	individual calculated when inverters are used	IEC/EN 6100-3-2 for DG ≤ 16 A in LV; IEC/TR3 61000-3-4 for DG > 16 A in LV; IEC/TR3 61000-3-6 for DG connected to MV & HV	Varies, typically based on either IEEE 519 Table 10.3, TDD = 5%	IEC 61000, DIN/VDE Uh < 0.2% for the 3rd and 5th; Uh < 0.1% above the 5th; THDmax for connection at 0.4 kV equals 2.5%, at 10 and 20 kV equals 2.0%, at 30 and 35 kV equals 1.5%	LV: harmonics emissions should be limited. MV: maximum limit values specified in ministerial order of March 17, 2003.
	Mains signalling	DG must not negatively impact mains signalling	$f = 175/180/217/315/1347$ Hz; $\Delta V = 2\%$		/	$f = 175$ Hz. DG must not affect mains signalling.
Protection	DC injection	Recommendation for PV < 0,2s	DC current < 1% of rated current, if higher 1% trip after 0,2s	IEEE 1547: < 0.5% of rated current	/	
	LV antiislanding	PV: ENS or non-islanding inverter Generally: $U > U_{<}, f > f_{<}$	V: $V > 1.06 p_u$ instantly, $V < 0.5 \pm 0.85$, delay 1.5s, f: 49.5, 50.5, instantly; DG must be disconnected with one-phase fault V: $0.25 \pm 0.5 p_u > V$ or $V > 1.1 p_u$ instantly, $V < 0.5 \pm 0.85$, delay 1.5s; f: 49.5, 50.5, instantly; Uo relay	Must meet CSA C22.2 anti-islanding test for inverter based DG	Protection at LV connection: $I > I_0$, $U > U_{<}, f > f_{<}$, direct/indirect touch, back-flow power, unsymmetry	Decoupling protection with $U > U_{<}, f > f_{<}$ relays
	MV interconnection protection	$U > U_{<}, f > f_{<}$ in some cases ΔU and ΔP protection is necessary		U/O voltage, U/O freq. Reverse Power, Negative sequence current, zero sequence voltage; in some cases transfer trip signal to utility protection is required	Protection at MV connection: $I > I_0$, $U > U_{<}, f > f_{<}$, back-flow power, unsymmetry, differential	Decoupling protection with $U > U_{<}, f > f_{<}, V_0 >$ instantaneous or delayed relays, intertripping in some cases (NB. V_0 is zero sequence voltage)

Other Requirements	Low Voltage Ride Through	not required	none	one, except for wind in some province	None	On interconnected network, DG must not disconnect before the decoupling protection. On islands, DG must stay connected for voltages of 0.3 Un for 600 ms and 0.7 Un for 2.5 s (with Un nominal voltage)
	SG Synchronization	$\Delta U < \pm 10\%$, $\Delta f < \pm 1$ Hz, $\Delta \phi < \pm 10^\circ$	ΔV , Δf , $\Delta \phi$ must be such that they do not cause any sudden variation >6% in voltage	IEEE 1547: must not cause a dV greater than +/-5%	$\Delta U < \pm 10\%$, $\Delta f < \pm 0.5$ Hz, $\Delta \phi < \pm 10^\circ$	$\Delta U < \pm 10\%$, $\Delta f < \pm 0.1$ Hz, $\Delta \phi < \pm 10^\circ$. Maximum loading speed : 4 MW/min
	MV/LV TF group	Dyn	often Yd + earthing transformer direct to earth no spec. requirements	delta/gndY, or gndY/gndY	Dyn (and sometimes zig-zag at LV side)	
	Accessible Disconnect	Yes (LV and MV), Not required when ENS/non-islanding inverters are being used		Yes	Yes	

Person providing the information	Name	Roland Bründlinger	Johan Driesen	Glenn Paskaruk	Nijaz Dizdarevic	Regine Belhomme
	Affiliation	arsenal research	K.U.Leuven - ESAT/ELECTA	Manitoba Hydro	Energy Institute Hrvoje Pozar	EDF R&D
	Address	Faradaygasse 3 1030 Vienna	Kasteelpark Arenberg 10, B-3001 Leuven, Belgium	1200 Waverley St., Winnipeg, MB, Canada	Savska 163, HR- 10000 Zagreb, Croatia	1 Avenue du Général de Gaulle, 92141 Clamart CEDEX, France
	Phone	+43 50550 6351	+32 16 321020	+1 (204) 474-4659	+385 1 6326159	+ 33 1 47 65 38 60
	Fax	+43 50550 6390	+32 16 321985	+1 (204) 474-3583	+385 1 6040 599	+33 1 47 65 32 18
	e-mail	roland.bruendlinger@arsenal.at	johan.driesen@esat.kuleuven.be	grpaskaruk@hydro.mb.ca	ndizdar@eihp.hr	regine.belhomme@edf.fr

		GREECE	ITALY	JAPAN	NETHERLANDS
System Type	Interconnected	x	x	x	X
	Isolated	x	only on small islands	x	only on one or two small islands
Voltage Levels	LV	230/400 V	230/400 V	100/200 V	230/400 V
	MV	15 or 20 kV	15 or 20 kV+ others	6.6/22/33 kV	3/10/20/25/30 kV
	HV	150, 400 kV	60, 132, 150, 230, 400kV	66/77/154kV	50/110/150/220/380 kV
Network Topologies	LV	Radial, 3Ph+N	Radial, 3Ph+N	Radial, 3ph	Radial, sometimes meshed, 3 Ph
	MV	Radial, 3Ph+N	Radial or radially operated, 3Ph	Radial, 3ph	Both radial and meshed, 3 ph
	HV	Meshed, 3Ph	Meshed, 3Ph	Meshed, 3ph	Meshed 3 Ph
Neutral Earthing Scheme	LV	TN-C	TT (TN or IT only in specific cases)		TT or TN
	MV	Resistance, 9 or 12 Ω	Isolated, Resistance, Petersen coil	Resistance, 10k Ω	Directly, Isolated and Impedance
	HV	Directly	Directly	Directly	Directly or with Petersen coil
Design Fault Level	LV	24 kA	16 kA		NA
	MV	7.2 or 10 kA	12.5 kA	12.5kA for 6.6kV	NA
	HV	30 or 40 kA	30 kA - 50kA on 400kV	40kA for 154kV, 31.5kA for 66/77kV	NA
Max DG Power Limits	LV, 1Ph	5 kVA	5kVA	50kW	1*40A=10 kVA
	LV, 3Ph	100 kVA	50 kW	2MW	3*250 A=173 kVA
	MV	20 MVA	8 MW	10MW	Not strictly defined. In practice from 173 kVA up to several tens of MW, depending on the local MV voltage and HV voltage and the geographical distance to the HV network

Operating Power Factor	Min Ind.	0,95	-	LV: 0.85, MV,HV: 0.95	LV: 0.9, MV and HV: 1.0
	Min Cap.	0,85	-	1	LV: 0.9, MV and HV: 0.85
Power Quality Constraints	Slow voltage changes	LV: $\pm 3\%$ of V_n MV: Annual V_{mean} : 95..105% of V_n ΔV around V_{mean} : $\pm 3\%$ of V_n	IEC 50160, IEC 61000 series	101 \pm 6V, 202 \pm 20V	LV and MV: during one week 95% of time between $\pm 10\%$, always between +10% and -15%; HV: during one week 99.9% of time between $\pm 10\%$
	Fast voltage changes	LV: $\sim 5\%$, MV: 3-4% Depending on frequency	IEC 50160, IEC 61000 series	LV: 10%, MV:2%	LV, MV and HV: max. 10%
	Flicker	Per IEC 61000 (3-3,3-5,3-7,3-11)	IEC 50160, IEC 61000 series	$\Delta V_{10}=0.45V$	LV, MV and HV: during one week 95% of time PLT<1 , always PLT<5;
	Harmonics & Interharmonics	Per IEC 61000 (3-2,3-4,3-6) $U_h < 0.2\%$, h non-integer or $h > 40$	IEC 50160, IEC 61000 series	LV,MV: 5% HV: 3% with guideline for each order harmonics	LV and MV: IEC 50160 for individual harmonics; during one week THD<8% (up to 35 kV), <6% (up to 110 kV) or <5% (above 110 kV) for 95% of the time; during one week THD<12% (up to 35 kV), <7% (up to 110 kV) or <6% (above 110 kV) for 99,5% of the time.
	Mains signalling	$f_{ms}=175$ Hz, $U_{ms}=2\%$ Specific restrictions apply	-		Ripple control at various frequencies between 200 Hz and 1600 Hz, DG must not negatively impact ripple control, otherwise measures are required
	DC injection	Under consideration: <1%	IEC 50160, IEC 61000 series		No specific requirement
Protection	LV antiislanding	PVs: Per VDE 0126 (ENS) Generally: $U>,U<,f>,f<$	Generally: $U>,U<,f>,f<$	Alternator: UFR+UPR+RPR, Inverter with reverse power: OFR+UFR+Active LOM+Passive LOM, Inverter without reverse power: UFR+RPR+UVR+UPR	LV: Undervoltage, Overvoltage, Frequency deviation, Connection delay after tripping
	MV interconnection protection	$U>,U<,f>,f<,U_0>,I>,I_0>$ Intertrip in special cases Settings depend on system type	$U>,U<,f>,f<,U_0>,I>$	SG: DSR+OVGR, IG, Inverter: UVR+OVGR, With reverse power: OFR+UFR+Active LOM, Without reverse power: UFR+RPR	MV and HV: no general rules, but dedicated decisions partly depending on the protection schemes of the grid company and also on the technology and characteristics of the DG itself

Other Requirements	Low Voltage Ride Through	None for interconnected system Under consideration for islands	-		LV and MV: none; HV (windparks): no disconnection for voltages >70% during 300 ms, for voltages <70% disconnection allowed within 300 ms
	SG Synchronization	$\Delta U < \pm 10\%$, $\Delta f < \pm 0.5$ Hz, $\Delta \phi < \pm 10^\circ$	-	$\Delta U < \pm 1-4\%$, $\Delta f < \pm 0.05-0.30$ Hz, $\Delta \phi < \pm 11^\circ$	Considered responsibility of generator operator, no specific requirements by grid company
	MV/LV TF group	Dyn	Dyn		,
	Accessible Disconnect	Yes (LV and MV)	-		LV: no; MV and HV: yes

Person providing the information	Name	Stavros Papathanassiou	Stefano Barsali	Toshihisa Funabashi	
	Affiliation	NTUA, Electric Power Division	University of Pisa, Department of Electrical Systems and Automation	Meidensha Corporation	
	Address	9, Iroon Polytechniou st. 15780 Zografou, Athens	via Diotisalvi, 2 I-56122 Pisa, Italy	36-2 Nihonbashi-Hakozakicho, Chuo-ku, Tokyo 103-8515 Japan	
	Phone	+30 210 7723658	+39 050 2217320	+81 3 5641 7509	
	Fax	+30 210 7723593	+39 050 2217333	+81 3 5641 9310	
	e-mail	st@power.ece.ntua.gr	barsali@dsea.unipi.it	funabashi-t@mb.meidensha.co.jp	

		PORTUGAL	SAUDI ARABIA	SPAIN	USA
System Type	Interconnected	x	o	x	Yes
	Isolated	x	o	x (extra peninsular systems)	Yes
Voltage Levels	LV	230/400 V	127/231&231/400V	230/400 V	(60 HZ) 120/240 V, 208Y/120V, 480Y/277V - Residential and small Commercial
	MV	10, 15, 30 Kv	11/13.8/33/34.5/69KV	20,45 kV	kV Classes 5, 15, 21, 25, 35kV There are many system voltages applied within each class (i.e., 12.47, 13.09, 13.2 etc.)
	HV	63, 150, 220, 400 kV	132/380KV	66/132/220/400 kV	(60HZ) 55, 69, 115, 132, 169, 230, 345, 500, 765kV (DC) 400 to 1000kV
Network Topologies	LV	Radial, 3Ph+N	Radial, 3ph,4W	Radial, 3ph+N	Radial, Radial (open looped), or Networked (meshed)
	MV	Radial, 3Ph+N	Radial,Ring 3ph, 3W	3Ph radial up to 45 kV-meshed above	Radial, Radial (open looped), or Networked (meshed)
	HV	Meshed, 3Ph	Radial,Ring 3ph, 3W	Meshed, 3Ph	Radial, Radial (open looped), or Networked (meshed)
Neutral Earthing Scheme	LV	The neutral of the generator is connected to the neutral of the LV network	<10? ,Solidly grounded	TN	Solid Grounded (directly at single point)
	MV	Resistance or reactance used to limit earth current to 1KA (cables) or 300 A	<10? ,Solidly grounded	Isolated	Solid Grounded at Source (multigrounded along feeder), Grounded at Source (resistance or reactance),
	HV	Directly	Whole system < 5?	Directly	Solid Grounded (directly at single point), grounding shield wires (multigrounded)
Design Fault Level	LV	NA	20KA	20 kA	Typically 200 Amp Service is rated <10kA, however larger sizes are available
	MV	NA	25KA	25 kA	Feeder equipment is typically rated <10kA, however, for higher fault duty, current limiting devices are used
	HV	NA	Not Applicable	31,5 kA; 40 kA on 220 kV	20 to 40 kA
Max DG Power Limits	LV, 1Ph	5 kVA		less than 50% of transformer power	<25kVA (Size ranking very small<25, small <100, large < 1000, and very large >1000kVA)
	LV, 3Ph	150 kVA		100 kVA and less than 50% of transformer power	< 1000kVA
	MV	For synchronous generators, the capacity cannot exceed 0,08*Scmin. If the generators are asynchronous the nominal power is limited for the installation to 0,08*Scmin, with a limitation for largest generator to to have capacity less than 2 MW without excing 0,05*Scmin.		5000 kVA and less than 50% of transforming capacity. For larger powers there must be an agreement with the company. Wind generation should not surpass 5% of Sc.	<3MVA applied directly to multi-use feeder, <10MVA assigned a dedicated feeder, >10MVA with specific MV to HV transformation

Operating Power Factor	Min Ind.	0,8	0,85	async gen: pf>0,86; sync. gen.pf>0,8	0,95
	Min Cap.	0,8	Unity p.f	1	0,8
Power Quality Constraints	Slow voltage changes		LV: ?5% of V _m , MV: ±5% of V _m	IEC 50160, IEC 61000 series	LV: <±3% of V _n MV: Annual V _{mean} : 95..105% of V _n ΔV around V _{mean} : <±3% of V _n
	Fast voltage changes	Hydro ant thermal units < 5%, wind generators < 2%	Not Applicable	IEC 50160, IEC 61000 series	LV: ~5%, MV: 3-4% Depending on frequency
	Flicker	Standard EN 50160	Not Applicable	IEC 50160, IEC 61000 series	IEEE Std 519
	Harmonics & Interharmonics	Standard EN 50160; The compability level for interharmonics is 0.2% U _n , per IEC 1000-2-2:1900; THD < 8%	Not Applicable	IEC 50160, IEC 61000 series	IEEE Std 519
	Mains signalling	Remote control signal, high frequencies	Not Applicable	IEC 50160, IEC 61000 series	Unknown (varies among utilities)
	DC injection			IEC 50160, IEC 61000 series	Unknown (varies among utilities)
Protection	LV antiislanding	Under study	Not Applicable	3 inst. undervoltage relays at 0.85U _{rated} ; 1 inst. overvoltage at 1.1U _{rated} ; Underfreq. relay at 49 Hz; Overfreq. at 51 Hz.	Volt and frequency deviation, overcurrent, harmonic volt change, rate of change of power, reactive and capacitive insertion Protection Equipment Specifications IEEE C37.90, C39.90.1, C37.2
	MV interconnection protection	U _{max} and U _{min} , f _{max} and f _{min} , I _{max} and U _o	Not Applicable	3 inst. undervoltage relays at 0.85U _{rated} ; 1 inst. overvoltage at 1.1U _{rated} ; Underfreq. relay at 49 Hz; Overfreq. at 51 Hz. Overcurrent relay. Synchronizing relay.	U>, U<, f>, f<, U0>, I>, I0>, time overcurrent with voltage constraints, voltage balance, newutral time overcurrent, Synchronizing, differential gnd, reverse/low power and islanding protection, and reclose blocking schemes Intertrip in special cases Settings depend on system type

Other Requirements	Low Voltage Ride Through	To be applied for new wind generation		Necessary.	
	SG Synchronization	Sn< 500 kVA: 0.9 - 1.1 pu (V); frequency deviation: $\pm 0,3$ Hz; phase angle: $\pm 20^\circ$. Sn> 500 kVA: 0.92 - 1.08 pu (V); frequency deviation: $\pm 0,2$ Hz; phase angle: $\pm 10^\circ$.		Sync.gen: $\Delta U = \pm 10\%$. Df = ± 2 Hz; Dphase = ± 20 deg. Async.gen: s<10% when P \leq 1000kVA; s<5% when P>1000kVA. Wind generation connection cannot produce voltage drops larger than 2% of rated value, and may be only less than three connections per minute.	depends on margin of protection setting tolerance
	MV/LV TF group	Dyn	Dyn 11	Dyn	$\Delta U < \pm 10\%$, $\Delta f < \pm 0.5$ Hz, $\Delta \phi < \pm 10^\circ$
	Accessible Disconnect	Yes	yes(LV&MV)	Yes	Unknown (varies among utilities)
					Yes (LV and MV)

Person providing the information	Name	J. A. Pegas Lopes		Julio Usaola	Robert Fletcher
	Affiliation	INESC Porto		Universidad Carlos III	Snohomish Public Utility District
	Address	Campus da FEUP, Rua Dr. Roberto Frias, Porto		Av. Universidad 30. 28911 Leganes(Madrid)	P.O. Box 1107, Everett, WA 98201 USA
	Phone				1-425-783-4305
	Fax				1-425-783-4470
	e-mail	jpl@fe.up.pt			rhfletcher@snopud.com

2.3 Key Considerations

2.3.1 Deep vs. Shallow Charges

Connection charges have a major impact on the ability of new DG installations. “Deep charges” include all costs of reinforcements required to facilitate the new connection. Potential new DG owners can be barred from entry into the market, as the costs associated with such reinforcements can be so high, as to render the project non-viable. This approach is based on considerations of connection priority, i.e. it is argued that “there would be no need to reinforce the system if the new user had not appeared”. The other approach is to apply so-called “shallow connection charges”, which only include the assets required exclusively by the new DG, and does not include cost of system reinforcement. Clearly, the practice chosen has a considerable impact on the cost base of new entries and resolution of this is critical for penetration of DG. Several countries apply “deep connection” charges, as also discussed in the following Section. However, in accordance with conventional economic theory, it can be argued that any system reinforcement should be considered as a system related investment and its cost recovered through the use of system charges rather than through connection charges. This can be achieved by adjusting the use of system charges with respect to the respective contribution of all generators in the following price review period. Under such scenario, large generators connected to the transmission system would be likely to be required to compensate the majority of these costs. A further discussion on connection charges follows in Section 2.4.

2.3.2 Deterministic vs. Probabilistic Analysis

The voltage level to which a DG is connected determines critically the overall connection costs, i.e. the higher the voltage level, the larger the connection costs. On the other hand, the higher the voltage, the lower the impact DG has on the performance of the local network. These two conflicting objectives need to be balanced appropriately requiring an in depth technical and economic analysis of the connection design. The effects on voltage depend on the DG size, the local network characteristics and the load. Given this diversity of considerations, it is not possible to derive generalised rules regarding the voltage level at which DG should be connected. In many cases, particularly critical is the voltage rise effect that can be produced when a DG is connected to a weak network. In all countries, the classical tools used to assess the impact of DG on the network voltages are load flow programs. Using traditional load flow analysis however, it is not possible to achieve a realistic impression of where and when overvoltages or undervoltages occur during a whole study period, because these analyses are based on some selected combinations of consumer loads and DG production, typically min load-max DG. As these conditions may only apply for a few hours per year it is clearly desirable to consider stochastic voltage limits, as proposed under European standard EN 50160. The application of probabilistic load flow [9], [10] and Monte-Carlo simulation techniques provide probabilities of voltage limit violations and thus leads to objective decision-making. This is further discussed in Chapter 5.

2.3.3 Participation in Ancillary Services

Adequate reactive or/and active power control can be used as a means for controlling voltage rise effects. However, in most countries, the commercial framework for the voltage regulation policy through active or reactive power control is not developed at the distribution level. For example, VAR management as a means of reducing the voltage fluctuations in distribution networks is not supported by appropriate pricing mechanisms. Absorbing reactive power by DG can be very beneficial to controlling voltage rise effect in weak overhead networks. Clearly, this would normally lead to an increase in network losses, however the inability of the present reactive power pricing concept to support provision of voltage regulation may unnecessarily force DG to connect to a higher voltage level, imposing significant connection costs. DG does not have the opportunity to balance the connection costs against cost of losses and make an appropriate choice. Furthermore, the DG may find

it profitable to shed some of its output for a limited period if allowed to connect to a lower voltage level. However, this option has not yet been offered to generators. It is clear that market mechanisms and pricing policies are required that will allow DG to participate not only in the energy market but also in a market for provision of ancillary services.

2.3.4 Stability and Capability of DG to withstand Disturbances

Historically, the emphasis of protection system design for DG was to reliably detect possible critical situations in the network, such as e.g. islanding events. Inadvertent and unnecessary tripping resulting from this “disconnect at the first sign of trouble” approach was only seen in terms of lost generation revenue – not from a system’s perspective. The fact that a minor disturbance on the network can cause the disconnection of a significant amount of distributed generation could have a major impact on networks operation in a future high penetration DG scenario. In particular, islanding protection schemes implemented at the generator site are of critical importance in this context. Inappropriate – usually too tight – protection settings could potentially have severe impact on system stability due to the risk of system-wide loss of generation.

In the context of system security, the behaviour of protection equipment and generation units under disturbed network conditions is of further crucial importance in future DG based networks.

In DISPOWER Tasks 2.3 to 2.5 the laboratory investigations of state-of-the-art equipment were carried out. These showed, there are significant deficits regarding the response to typical steady state or transient phenomena, such as voltage sags, interruptions and superposed harmonic or interharmonic voltages. The largest portion of the tested devices, exhibited an extremely high sensitivity towards these events. These characteristics, resulting in frequent spurious tripping of the protection, not only negatively influence the overall performance of the DG units. Also they can worsen the effects of the disturbance and so negatively impact network operation. As the main reason for the observed behaviour the investigations identified in most cases an inappropriate design of the protection circuitry. However it is basically not the lack of efforts put on the development of the equipment, which are to be blamed for the unsatisfactory performance. It is rather the lack or absence of adequate requirements and standards, which is responsible for this development.

Current DG protection related standards and codes were primarily developed from the network safety point of view. Accordingly, the diverse documents state only minimum requirements in form of levels and maximum times where the unit has to trip. However minimum requirements for the behaviour during disturbed conditions, where a tripping would be undesirable, are generally missing. Consequently, this results in a lack of awareness among manufacturers, system operators and planners regarding the behaviour of DG units during network disturbances.

2.3.5 DC in LV Networks

DC components injected into AC low voltage network are another important and relevant safety and protection issue, particularly for DG using inverters. Generally it is crucial to separate symmetrical DC, flowing in phase and neutral conductors from unsymmetrical leakage current, flowing from phase to ground. The latter has fundamentally different implications, mainly related to electric shock and corrosion issues whereas the first is relevant for the components inserted in the network such as distribution transformers.

To assess the effects of DC, various components such as distribution transformers or RCDs were investigated with the help of simulation and lab tests within DISPOWER Workpackage 2. The results allow the conclusion that distribution transformers represent the most critical network element in this context. However the evaluations also show that networks can accept a level of DC without negative implications for performance, lifetime or safety, which is significantly higher than the limits defined in

some of the current standards. Therefore, this issue should not limit the further deployment and application of directly coupled, transformerless inverters.

2.3.6 Islanding and Islanded Operation

The possible occurrence of unintentional islands in distribution networks with distributed resources (loads and generation) has been one of the major issues in connection with the ongoing growth of DG. However, there is still widespread discrepancy not only concerning interconnection practices and protection systems required in the various national grid codes or standards, but also regarding the probability of occurrence and persistence of distributed resource islands. It also has been recognized that today existing standards often do not deliver consistent policy among network operators or consensus with their customers, developers and operators of distributed generation.

Though it is not inherently a problem, the unintentional creation of an island has a number of implications for the safe operation of the islanded section of the network, such as *exceeding of the acceptable limits* for voltage, frequency and other power quality parameters, *uncleared earth or phase faults* due to too low short-circuit capacity or unearthed operation, or *out-of-phase re-closing*. In LV networks, there is also an important concern related to the *hazard of electric shock* due to touching of live conductors assumed to be dead.

With the exception of Canada (see Section 2.5), operation in islanded mode is not allowed under any circumstances. On the other hand, DG can fully show its benefits regarding enhancement of reliability and quality of supply, if it is allowed to stay connected and supply parts of the network during disturbances in the upstream network. Moreover, DGs can help parts of the system to blackstart, thus relieving the stress during restoration after major system collapses. The potential benefits obtained when such an operation is allowed are further discussed in Chapter 5.

2.4 Allocation of Distributed Generation Grid Connection Cost

2.4.1 Introduction

In order for a distributed generator (DG) to inject the power it generates into the electricity grid, the generator must of course be connected to this grid. This implies that someone has to pay the cost (of equipment, engineering, construction, etc.) of the grid connection of the DG. The question who is going to bear this cost has been fiercely debated both in the scientific community as well as in practice. Reason for this debate is that there seems to be no clear answer to the question of how to allocate distributed generation grid connection cost between the parties involved in such a way that the allocation is considered as *reasonable* or *just* by all stakeholders. Reasons for this are:

- Many parties are involved. The grid company and the distributed generator operator are concerned directly, but also governments and regulators and their goals and philosophies play an important role.
- Due to the historical development of the grid, the cost to connect a similar DG may differ significantly between different locations and the question of how to divide the consequences of the historical development of the grid between the involved parties is a complicated one.

In this contribution, various approaches are discussed towards the allocation of DG connection cost between the DG operator on the one hand and the grid company on the other hand. First, the allocation mechanisms are introduced. Then, a set of possible criteria for the evaluation of DG connection cost allocation mechanisms are commented upon. Finally, these criteria are applied to the discussed allocation mechanisms. This contribution is based on a recent discussion between the Dutch grid companies and the Dutch Office for Energy Regulation (DTe), that is summarized in references [16] and [17].

2.4.2 Possible Allocation Mechanisms

At least four mechanisms for the allocation of DG grid connection cost can be identified, namely:

- A *shallow* connection tariff: the connection tariff charged by the grid company to the DG operator only covers the cost of a connection between the location of the DG and the nearest point of the grid with an *appropriate voltage level*, independent of whether the grid at this location has indeed sufficient capacity to transport the DG's output power or not.
- A *deep* connection tariff: the tariff charged by the grid company to the DG operator covers all expenses that the grid company incurs due to the connection of the DG.
- A *mixed* connection tariff: the tariff charged by the grid company to the DG operator covers the cost of the connection between the location of the DG and the nearest point of the grid with an appropriate voltage level, as well as a certain fraction of any further (or 'deep') investments that may be needed
- A *true* connection tariff: the tariff charged by the grid company to the DG operator covers the cost of a connection between the location of the DG and the nearest point of the grid with an appropriate voltage level where the grid has sufficient capacity to transport the DG's output power.

The *appropriate voltage level* is determined by the rating of the DG.

The different allocation mechanisms are now illustrated using Figure 2.1. In this figure, a typical MV (medium voltage) grid is depicted. It consists of an HV/MV transformer, two MV (n-1) safe transport corridors and a number of MV distribution rings. To one of the MV buses, a DG is connected already. It is assumed that the power of this DG is such, that in situations where the MV distribution rings have a low load, the DG power to be transported from bus 3 to bus 2 is such that the two cables between buses 2 and 3 are loaded at 50%, which means that the (n-1) criterion is just fulfilled. Further, it is assumed that the location of the additional DG to be connected is geographically closest to one of the MV distribution rings connected to bus 3, then to bus 3 itself, then to bus 4 and finally to bus 2.

Now, a DG operator wants to connect a second distributed generator to this grid. The rating of the generator is such that it is too large to be looped into a distribution ring. This means that technically, there are three possibilities, namely:

- Connect the DG to bus 2
- Connect the DG to bus 3 and add an additional cable between buses 2 and 3 in order to guarantee (n-1) safety.
- Connect the DG to bus 4
- As will be discussed now, both the connection point as well as the cost allocation between the grid company and the DG operator depend on the applied method to calculate the connection tariff to be paid by the latter.

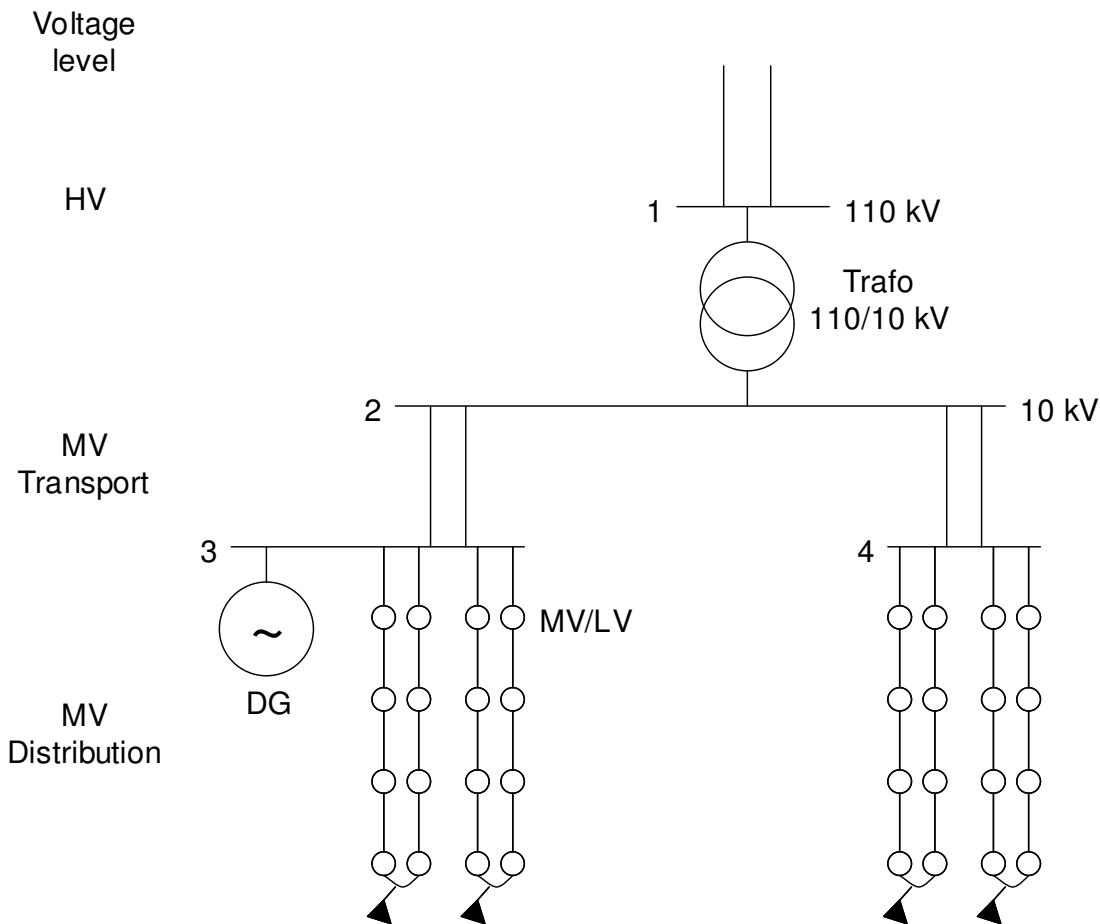


Fig. 2.1 Example grid to illustrate the application of the various DG connection tariffs

When the *shallow* connection tariff is applied, the DG operator only pays for the distance between the location of the DG and the nearest MV distribution ring, although the DG's rating does not allow looping into the MV ring because of the limited capacity of the latter. Therefore, the grid operator must bear the cost difference between the fixed fee paid by the DG operator that is based on the distance of the DG's location to the nearest MV distribution ring on the one hand and the physical connection on the other hand. The grid company can freely choose one of the three above mentioned technical options for the construction of the actual connection. Depending on the distances between the buses and the cost of cables of different capacity, as well as on generation and load forecasts, either connection to bus 4 or connection to bus 3 and reinforcement of the connection between buses 2 and 3 may be the most advantageous.

When the *deep* connection tariff is applied, the grid company can choose to connect the DG either to bus 4 or to bus 3 with reinforcing the connection between buses 2 and 3. The DG operator then pays the full cost of connecting the DG to bus 4 or to bus 3 as well as the reinforcement of the connection between buses 2 and 3. When the tariff is negotiable, the DG operator will have a say in where the DG is connected. If not, the grid company can freely choose where to connect the DG and is allowed to charge all cost to the DG operator.

When the *mixed* connection tariff is applied, the grid company will connect the DG to bus 3 and reinforce the connection between buses 2 and 3. The DG operator has to pay the cost of the connection of the DG to bus 3 as well as a certain part of the cost of the required reinforcement. Depending on the fraction of the deep investment that must be paid by the DG operator as well as on the distances between the buses and the cost of cables of different capacity, it may be cheaper for the DG operator

to connect to bus 4 instead of to bus 2. Whether this is indeed possible or not, depends on the negotiability of the tariff.

Finally, when the *true* connection tariff is applied, the grid company must connect the DG to bus 4, because this is the nearest point where the grid has sufficient capacity. When the tariff is negotiable, the DG operator may prefer to pay both the connection to bus 3 as well as the reinforcement of the connection between buses 2 and 3, when the total cost of this is lower. There is, however, no *obligation* for the DG operator to contribute to the deep investment.

2.4.3 Criteria for Evaluation of Allocation Mechanisms

For choosing one of the mechanisms for the allocation of the connection cost described above, one of course needs criteria to evaluate the various possibilities. In the discussion between grid companies and the Dutch Office for Energy Regulation, the following criteria for the evaluation of the various mechanisms for the allocation of DG grid connection cost were identified:

- *Compatibility with applicable legislation*: if a mechanism is not feasible within the boundaries imposed by higher level legislation (e.g. an Electricity law), it can of course not be implemented without changing the law. Practically, this means that it would take much time to implement it, so that a mechanism that is not compatible with legislation can de facto not be implemented.
- *Promotion of DG operator efficiency*: a mechanism should promote the efficiency of the DG operator, which means that the DG operator should have an incentive to connect the DG in such a way that total cost (both of the DG operator and the grid company) is minimized.
- *Promotion of grid company efficiency*: analogously, a mechanism should promote the efficiency of the grid company, which means that also the grid company should have an incentive to connect the DG in such a way that total cost (both of the DG operator and the grid company) is minimized.
- *Cost of allocation mechanism*: the mechanism must be prevented from becoming too complex and thus expensive. In other words, if a mechanism guarantees minimization of total connection cost, but execution of the mechanism is very expensive, total cost (both of the DG connection and of the execution of the mechanism itself) could be higher than when a simpler mechanism is applied, even when the point of connection in that case might be less than optimal. In terminology of economics, this type of cost can be compared to *transaction cost*.
- *Cost reflectivity*: the true cost associated with the connection of a DG should somehow be reflected in the connection fee paid by its operator. This does not necessarily mean that the DG operator has to pay all the cost. It implies, however, that it should at least be true that the more the total cost of the connection, the higher the fee paid by the DG operator. Stated differently, it should not be possible that the allocation mechanism works out in such a way that a DG operator whose DG is relatively cheap to connect to the grid can pay the same or even more than another DG operator whose DG is much more expensive to connect to the grid.

2.4.4 Evaluation of Allocation Mechanisms

The possible mechanisms will now be evaluated using the identified criteria. As for the first criterion, *compatibility with the applicable legislation*, it is clear that the score of the different mechanisms on this criterion will be very much dependent on the legislative framework. It is hence not possible to draw general conclusions in this respect and the score of the mechanisms mainly depends on (supra)national laws.

With respect to the second criterion, *promotion of DG operator efficiency*, it can be stated that the larger the part of the connection cost the DG operator has to pay, the more efficient it will operate in order to reduce its cost. Hence, the deep connection tariff will promote the efficiency of the DG operator mostly, whereas the shallow connection tariff does hardly promote the efficiency of the DG

operator. The balance between the mixed and the true connection tariff depends on the part of the cost to be paid by the DG operator in case of the mixed connection tariff: when the fraction of the connection cost to be paid by the DG operator is small, a true connection tariff will better promote the DG operator efficiency than a mixed connection tariff, whereas when a large fraction of the cost should be paid by the DG operator, it will be the other way around.

Concerning the third criterion, *promotion of grid company efficiency*, the score of the mechanisms is exactly the opposite as in case of the second criterion. A shallow connection tariff will promote the efficiency of the grid company mostly, as the grid company can only charge a fixed tariff, so that it benefits when it can keep the cost lower than the connection fee, whereas when the cost becomes higher, the grid company itself should pay it. On the other hand, a deep connection tariff will not promote grid company efficiency, as it can pass through all the cost to the DG operator. For the true and the mixed connection tariff, the balance again depends on the division of the cost between grid company and DG operator in case of the mixed connection tariff: the higher the fraction of the cost to be paid by the grid company in case of the mixed connection tariff, the more the efficiency of the grid company will be promoted, whereas when the fraction of the connection cost to be paid by the grid company is very low, a true connection tariff may better promote grid company efficiency than a mixed connection tariff.

With respect to the fourth criterion, *the cost of the allocation mechanism*, it can be remarked that the main factor that affects the cost of the execution of an allocation mechanism is the amount of discussion between the DG operator and the grid company that will take place and the effort that a DG operator spends on finding the right location for its installation. In case of the shallow connection tariff, the DG operator will not engage in any discussion with the grid company and will neither spend much effort on finding the most suitable location from the perspective of connecting to the grid, because it only pays a fixed connection tariff and hence has no incentive for this. In the case of the other allocation mechanisms, the DG operator will have to invest in engaging in a discussion with the grid company on the connection cost, as well as in finding a location that is suitable for the DG, so that the other three criteria perform more or less equally on this criterion.

Finally, the fifth criterion, *cost reflectivity*, is of importance. As a matter of fact, it is the DG operator that causes the cost. Hence, from the perspective of cost reflectivity, the deep connection tariff scores the best. The shallow connection tariff scores worst, because in this case, there is no direct relation between the real cost that the DG operator causes and the tariff it pays. The other two allocation mechanisms score the same, because in both cases, a certain part of the connection cost is paid by the DG operator, who causes the cost.

The evaluation of the allocation mechanisms is summarized in table 1.

Table 2.1 Summary of evaluation of connection cost allocation mechanisms

Allocation mechanism	Shallow	Deep	Mixed	True
Criterion				
Compatibility with legislation	*	*	*	*
DG operator efficiency	-	+	o	o
Grid company efficiency	+	-	o	o
Mechanism cost	+	o	o	o
Cost reflectivity	-	+	o	o

*: no general conclusion possible, +: positive, o: neutral, -: negative

2.4.5 Conclusion

As can be concluded from Table 2.1, there is no allocation mechanism that outperforms the other in every respect. Therefore, any allocation mechanism will be a compromise and the final choice depends on the weight that is assigned to the individual criteria.

The Dutch situation can serve as an example in this respect. The discussion between the Dutch grid companies and the Dutch regulator was raised because the mechanism used at that time for the allocation of connection cost between the grid companies and the DG operator, which was the shallow connection tariff, led to unacceptable cost for the grid companies. The regulator accepted this point of view and it was decided that actions had to be undertaken quickly.

Due to the required quick implementation of a change of allocation mechanism, the first criterion, compatibility with existing legislation, became the most important criterion for the choice, because changing a law takes a considerable amount of time. Taking into account Dutch law, it was decided to change to a true connection tariff. As this example shows, the final choice for a connection mechanism depends on the situation, which to a large extent determines the weight assigned to each of the criteria.

2.5 Islanding Practices in Canada

In Canada, the majority of utilities have set interconnection guidelines, which regarding islanding of DG typically follows that of IEEE 1547, which requires that the units disconnect for island events. Under no conditions are the DG unit allowed to maintain the island and the equipment must be certified for anti-islanding capability prior to commissioning. However, in the western part of the country, BC Hydro has used planned islanding as a means of improving local reliability of rural distribution systems. It represents an interesting case study that demonstrates interesting possibilities for DG participation in the operation of networks and benefits for the community it serves.

2.5.1 BC Hydro Case Study

The BC Hydro Boston Bar 69/25 kV substation is supplied from 60 km of radial 69 kV transmission line from the south in the town of Hope. The majority of the line is built off the highway and passes through steep canyon, which is subject to rock, mud, and snow slides and where access is difficult. On average, the line experiences 12-20 hour outages a couple of times per year. The substation has one 14 MVA transformer which serves three 25 kV feeders. An independent power producer (IPP) operates an 8.6 MVA run-of-river hydro-electric plant which is connected to one of the feeders about 8.3 km south of Boston Bar on the west side of the Fraser River. The generating station is equipped with islanding capability and islands the interconnected 25 kV feeder typically twice per year for about 15 hours per occasion.

The Boston Bar IPP differs from most distributed generators (DG) in that it may remain connected following loss of the grid, thus sustaining the 25 kV feeder island. Therefore, additional equipment exists which is not in place for most DG interconnections. Depending on the creek water level, the IPP may be able to pick up all or only a portion of the feeder load. As well, there are various procedures that must be adhered to when starting up the generators, synchronizing to the grid, and disconnection of the IPP.

The IPP paid the incremental capital cost associated with islanding capability, which includes the following:

- i) Automatic voltage regulators (AVR)/exciters have positive field forcing for current boost during feeder faults in order to assist overcurrent protection,
- ii) Black start capability via 55 kW diesel,
- iii) Engineered mass for turbines & generators. This is the inertia constant H in MW-sec/MVA,
- iv) BC Hydro approval of exciters, AVR & turbine speed control governors,

- v) Grid & off-grid settings for 25 kV line power quality and overcurrent protection,
- vi) Synchronizing capability at BC Hydro substation 25 kV feeder breaker 25CB52, so BC Hydro can synchronize to the running IPP when BC Hydro recovers from a substation or transmission line outage,
- vii) Real-time IPP data telemetry via telephone lease copper wire from the IPP to Boston Bar substation then via BC Hydro SCADA to the BC Hydro Area Control Centre,
- viii) Commissioning tests for island operation.

The IPP is paid a bonus when it is able to sustain the island as compensation for its incremental capital cost for islanding capability. The incremental capital cost was about \$500,000 CDN on a capital cost base of \$12 million CDN.

The islanding scenario is as follows. In the event of a permanent fault in the BC Hydro Boston Bar substation or its 69 kV transmission supply, protection tripping is extended to the substation 25 kV feeder. Opening of this substation feeder circuit breaker is telemetered to the IPP and the IPP automatically changes to the line protection settings for island mode. The IPP will hold the feeder island unless quality protection relays (under/over voltage or under/over frequency) pick up and clear the IPP from the 25 kV feeder. If the IPP disconnects from the 25 kV feeder, it will re-start then energize the dead feeder following a telephone call request from the BC Hydro Area Control Centre. Further, BC Hydro may sectionalize the feeder if water level is low. In rare cases the IPP may also island each of the three distribution system feeders if the IPP has sufficient water available.

2.6 Distributed Generation Aggregation in Canada

For small distributed generator units the regulatory barriers and costs associated with market participation are often insurmountable, the result being that power is either only consumed locally or that the power exported onto the grid is not attributed an accurate value. Although demand in most cases exceeds production, the value of the overall production may exceed that of the energy consumed, should the produced power be delivered primarily during peak hours. The ability to participate in the market allows the DG owners to get a fair price for the produced electricity and thereby improve profits and the successfulness of the project.

Aggregation of generators is one way to help DGs participate in the energy market by limiting the associated costs and regulatory barriers. Costs are shared amongst generators and implementation issues are handled by either the utility or a third party. In addition, the overall availability of the aggregated generator is higher than that offered by individual units. In Canada, aggregation has been successfully implemented in at least two cases, providing benefits to both the distribution companies and the independent power producer. While these projects have set precedence, there is a need to extend the principles to environmentally friendly technologies and to microgrid applications.

2.6.1 Sherbrooke Hydro

Sherbrooke Hydro is a small distribution company that serves the city of Sherbrooke in Southern Québec. They purchase power from the provincial transmission company Hydro Québec, at a rate that is determined by the annual kWh and the annual peak load. They have implemented an aggregation methodology whereby they use local back-up generators to help limit the peak load, which typically occurs during the coldest winter months due to the large amounts of heating loads. In addition, management of non-essential loads helps them to reduce the peak load and consequently the price of electricity. The additional profits are transferred in part to the DG owners and the load owners to compensate for their participation in this project. This innovative idea has provided incentives for DG owners as well as a foundation for widespread DG and load management structure for peak load management.

2.6.2 Toromont

In the province of Ontario, the summer peak load in Toronto is of greatest concern and in the past mobile diesel generators have been brought in to provide peaking capability during the hottest days. An alternative had been proposed by Toromont in cooperation with a local aggregator to aggregate back-up generator units. They have proposed to aggregate 30 MW generators to help meet summer peak load in Toronto and avoid the costs associated with bringing in peaking generators. This also defines the necessary framework for extension to other DG technologies.

CHAPTER 3. International Standards

3.1 General list of standards

This chapter was contributed by the DISPOWER Task 2.1 (Standards) working group. It comprises the list of the main international and USA standards that may affect DG. Please note the following terms according to the stage of the standard:

- Published
- Work in progress: an amendment or a new part of the standard that is in the development stage.
- Under revision: a new edition of the standard is in development stage.

3.1.1 Interconnection

Standard no.	Stage	Technical Committee	Standard
IEEE 1547	Publisher	SCC21	Standard for interconnecting Distributed resources with electric power systems
IEEE P1547.1	Published	SCC21	Draft Standard for Conformance Test Procedures for Equipment Interconnecting Distributed Resources with Electric Power Systems
IEEE P1547.2	Draft	SCC21	Application Guide for IEEE Std.1547 Standard for Interconnecting Distributed Resources with Electric Power Systems
IEEE P1547.3	Draft	SCC21	Guide for monitoring, information exchange and control of distributed resources interconnected with electric power systems.
IEEE P1547.4	Draft	SCC21	Guide for design, operation, and integration of Distributed Resource Island Systems with Electric Power Systems

3.1.2 Hybrid Systems

Standard no.	Stage	Technical Committee	Standard
IEEE P1561	Draft	SCC21	Guide for Optimizing the Performance and Life of Lead Acid Batteries in remote Hybrid Energy Systems

3.1.3 Photovoltaic

Standard no.	Stage	Technical Committee	Standard
IEC 60364-7-712	Published	TC82	Electrical installations of buildings - Part 7-712: Requirements for special installations or locations - Solar photovoltaic (PV) power supply systems
IEC-EN 60891	Published	TC82, CLC/TC82	Procedures for temperature and irradiance corrections to measured I-V characteristics of crystalline silicon photovoltaic devices
IEC-EN 60904-1	Published Under revision	TC82, CLC/TC82	Photovoltaic devices. Part 1: Measurement of photovoltaic current-voltage characteristics
IEC-EN 60904-2	Published	TC82, CLC/TC82	Photovoltaic devices. Part 2: Requirements for reference solar cells
IEC-EN 60904-3	Published Under revision	TC82, CLC/TC82	Photovoltaic devices. Part 3: Measurement principles for terrestrial photovoltaic (PV) solar devices with reference spectral irradiance data
IEC- 60904-4	Draft ANW	TC82	Photovoltaic devices. Part 4: Procedures for establishing the traceability of the calibration of photovoltaic reference devices
IEC-EN 60904-5	Published	TC82, CLC/TC82	Photovoltaic devices. Part 5: Determination of the equivalent cell temperature (ECT) of photovoltaic (PV) devices by the open-circuit voltage method.
IEC-EN 60904-6	Published	TC82, CLC/TC82	Photovoltaic devices. Part 6: Requirements for reference solar modules
IEC-EN 60904-7	Published	TC82, CLC/TC82	Photovoltaic devices. Part 7: Computation of spectral mismatch error introduced in the testing of a photovoltaic device
IEC-EN 60904-8	Published	TC82, CLC/TC82	Photovoltaic devices. Part 8: Measurement of spectral response of a photovoltaic (PV) device
IEC-prEN 60904-9	Published	TC82, CLC/TC82	Photovoltaic devices. Part 9: Solar simulator performance requirements
IEC-EN 60904-10	Published	TC82, CLC/TC82	Photovoltaic devices. Part 10: Methods of linearity measurement
IEC-EN 61173	Published	TC82, CLC/TC82	Overvoltage protection for photovoltaic (PV) power generating systems. Guide
IEC-EN 61194	Published	TC82, CLC/TC82	Characteristic parameters of stand-alone photovoltaic (PV) systems
IEC-EN 61215	Published Under revision	TC82, CLC/TC82	Crystalline silicon terrestrial photovoltaic (PV) modules – Design qualification and type approval
IEC-EN 61277	Published	TC82, CLC/TC82	Terrestrial Photovoltaic (PV) power generating systems – General Guide

IEC-EN 61345	Published	TC82, CLC/TC82	UV test for photovoltaic (PV) modules
IEC-EN 61427	Published Under revision	TC82, CLC/TC21 X	Secondary cells and batteries for solar photovoltaic energy systems – General requirements and method of test
IEC-EN 61646	Published	TC82, CLC/TC82	Thin film terrestrial photovoltaic (PV) modules – Design qualification and type approval
IEC-EN 61683	Published	TC82, CLC/TC82	Photovoltaic systems – Procedure for measuring efficiency
IEC-EN 61701	Published	TC82, CLC/TC82	Salt mist corrosion testing of photovoltaic (PV) modules
IEC-EN 61702	Published	TC82, CLC/TC82	Rating of direct coupled photovoltaic (PV) pumping systems
IEC-EN 61721	Published	TC82, CLC/TC82	Susceptibility of a photovoltaic (PV) module to accidental impact damage (resistance to impact test)
IEC-EN 61724	Published Under revision	TC82, CLC/TC82	Photovoltaic system performance monitoring. Guidelines for measurement, data exchange and analysis
IEC-EN 61727	Published Under revision Exp. 12/2004	TC82, CLC/TC82	Photovoltaic (PV) systems. Characteristics of the utility interface.
IEC-prEN 61730-1	Draft Exp. 9/2004	TC82, CLC/TC82	Photovoltaic module safety qualification – Part 1: Requirements for construction
IEC-prEN 61730-2	Draft Exp. 9/2004	TC82, CLC/TC82	Photovoltaic module safety qualification – Part 2: Requirements for testing
IEC-EN 61829	Published	TC82, CLC/TC82	Crystalline silicon photovoltaic (PV) array. On site measurement of I-V characteristics
IEC 61836	Published Under revision	TC82	Solar photovoltaic energy systems – terms and symbols
IEC 61853	Draft ANW	TC82	Performance testing and energy rating of terrestrial photovoltaic (PV) modules
IEC-prEN 62093	Draft ADIS	TC82, CLC/TC82	Balance-of-systems components for photovoltaic systems – Design qualification and type approval
IEC 62108	Draft PWI	TC82	Concentrator photovoltaic (PV) receivers and modules – Design qualification and type approval
IEC 62109	Draft	TC82	Electrical safety of static inverters and charge controllers for use in

	?		photovoltaic (PV) power systems
IEC 62116	Draft PWI	TC82	Testing procedure – Islanding prevention measures for power conditioners used in grid connected photovoltaic (PV) power generation systems
IEC-prEN 62124	Draft Exp. 8/2004	TC82, CLC/TC82	Photovoltaic (PV) stand alone systems – Design Verification
IEC 62145	Draft PWI	TC82	Crystalline silicon PV modules – Blank detail specification
IEC 62234	Draft PWI	TC82	Safety guidelines for grid connected photovoltaic (PV) systems mounted on buildings
IEC 62253	Draft PWI	TC82	Direct coupled photovoltaic pumping systems – Design qualification and type approval
EN 50380	Published	CLC/TC82	Datasheet and nameplate information for photovoltaic modules
IEEE 928	Published	SCC21	IEEE Recommended Criteria for terrestrial photovoltaic power systems
IEEE 929	Published	SCC21	IEEE Recommended Practice for Utility Interface of Residential and Intermediate Photovoltaic (PV) Systems
IEEE 937	Published	SCC21	IEEE Recommended Practice for Installation and Maintenance of Lead-Acid Batteries for Photovoltaic (PV) Systems
IEEE 1013	Published	SCC21	IEEE Recommended Practice for Sizing Lead-Acid Batteries for Photovoltaic (PV) Systems
IEEE 1145	Published	SCC21	IEEE Recommended Practice for Installation and Maintenance of Nickel-Cadmium Batteries for Photovoltaic (PV) Systems
IEEE 1361	Published	SCC21	Guide for the selection, test and evaluation of lead acid batteries for stand-alone photovoltaic (PV) systems
IEEE P1479	Draft	SCC21	Recommended practice for the evaluation of photovoltaic (PV) module energy production
IEEE 1513	Published	SCC21	IEEE Recommended Practice for Qualification of Concentrator Photovoltaic (PV) Receiver Sections and Modules
IEEE 1526	Published	SCC21	IEEE Recommended Practice for Testing the Performance of Stand Alone Photovoltaic Systems
IEEE P1562	Draft	SCC21	Guide for array and battery sizing in Stand - Alone Photovoltaic (PV) Systems
IEEE P 1611	Draft	SCC21	Recommended Practice for Characterizing Solar Tracker Controllers Used for Solar Electric Systems

UL 1703	Published Under revision		Flat-Plate Photovoltaic Modules and Panels
---------	-----------------------------	--	--

3.1.4 Wind Turbine

Standard no.	Stage	Technical Committee	Standard
IEC 60050-415	Published	TC1	International electrotechnical vocabulary – Part 415: Wind turbine generator systems
IEC WT 01	Published	TC88	IEC System for conformity testing and certification of wind turbines – Rules and Procedures
IEC-EN 61400-1	Published Under revision	TC88, CLC/TC88	Wind turbine generator systems. Part 1: Safety requirements
IEC-EN 61400-2	Published Under revision	TC88, CLC/TC88	Wind turbine generator systems. Part 2: Safety of small wind turbines
IEC 61400-3	Draft ANW	TC88	Wind turbine generator systems. Part 3: Design requirements for offshore wind turbines
IEC 61400-4	Draft ANW	TC88	Wind turbine generator systems. Part 4: Design requirements for gearboxes for wind turbines
IEC-EN 61400-11	Published Under revision	TC88, CLC/TC88	Wind turbine generator systems. Part 11: Acoustic noise measurement techniques
IEC-EN 61400-12	Published	TC88, CLC/TC88	Wind turbine generator systems. Part 12: Wind turbine power performance testing
IEC 61400-13	Published	TC88	Wind turbine generator systems. Part 13: Measurement of mechanical loads
IEC 61400-14	Draft CDTS	TC88	Wind turbine generator systems. Part 14: Declaration of sound power level and tonality values
IEC-EN 61400-21	Published	TC88, CLC/TC88	Wind turbine generator systems. Part 21: Measurement and assessment of power quality characteristics of grid connected wind turbines
IEC 61400-22	Draft AMW	TC88, CLC/TC88	Maintenance cycle report to IEC WT 01 Ed.1: IEC System for conformity testing and certification of wind turbines - Rules and procedures
IEC 61400-23	Published	TC88	Wind turbine generator systems. Part 23: Full-scale structural testing of rotor blades
IEC 61400-24	Published	TC88	Wind turbine generator systems. Part 24: Lightning protection
IEC 61400-25	Draft	TC88	Wind turbine generator systems. Part 25: Communication standard for

	CDM		remote control and monitoring of wind power plants
IEC-prEN 61400-121	Draft CCDV	TC88	Wind turbine generator systems. Part 121: Power performance measurements of grid connected wind turbines
prEN50308	Draft Exp. 2004	CLC/TC88	Wind turbines - protective measures – requirements for design, operation and maintenance
prEN50376	Draft Code: 4060	CLC/TC88	Declaration of sound power level and tonality values of wind turbines

3.1.5 Fuel Cells

Standard no.	Stage	Technical Committee	Standard
IEC-EN 61982	Published Work in progress	TC21,CLC/T C21X	Secondary batteries for the propulsion of electric road vehicles – Part 3: Performance and life testing (traffic compatible, urban use vehicles)
IEC-prEN 62282	Draft ?	TC105, CLC/SR105	Fuel cell technologies
UL 2262	Draft		Portable proton exchange membrane (PEM) type fuel cell power plants with or without uninterruptable power supply (UPS) features and portable proton exchange membrane (PEM) type fuel cell modules for factory installation in original equipment manufacturer (OEM) type equipment for indoor use

3.1.6 Small hydro

Standard no.	Stage	Technical Committee	Standard
IEC-EN 61116	Published	TC4, CLC/SR4	Electromechanical equipment guide for small hydroelectric installations
IEC 62006	Draft PWI	TC4	Hydraulic machines - Acceptance tests of small hydro turbines
IEEE 1020	Published		IEEE Guide for Control of Small Hydroelectric Power Plants

3.1.7 Converters

Standard no.	Stage	Technical Committee	Standard
IEC-EN 60146-1-1	Published	TC22, CLC/TC22X	Semiconductor converters – General requirements and line commutated converters - Part 1-1: specifications of basic requirements
IEC 60146-1-2	Published	TC22	Semiconductor converters – General requirements and line commutated converters - Part 1-2: Application guide
IEC-EN 60146-1-3	Published	TC22, CLC/TC22X	Semiconductor converters – General requirements and line commutated converters - Part 1-3: Transformers and reactors
IEC-EN 60146-2	Published	TC22, CLC/TC22X	Semiconductor converters – General requirements and line commutated converters - Part 2: Self – commutated semiconductor converters including direct d.c. converters
IEC 60146-6	Published	TC22	Semiconductor converters – General requirements and line commutated converters - Part 6: Application guide for the protection of semiconductor converters against overcurrent by fuses
IEC 62103	Published	TC22	Electronic equipment for use in power installations
UL 1741	Published		Inverters, Converters, and Controllers for Use in Independent Power Systems

3.1.8 Batteries

Standard no.	Stage	Technical Committee	Standard
IEC 60050-482	Published	TC1	International Electrotechnical Vocabulary – Part 482: Primary and secondary cells and batteries
IEC-EN 60086	Published Under revision	TC35, CLC/SR35	Primary cells and batteries
IEC-EN 60095	Published Under revision	TC21,CLC/T C21X	Lead acid starter batteries
IEC-EN 60254	Published Under revision	TC21,CLC/T C21X	Lead acid traction batteries
IEC-EN 60622	Published	SC21A,CLC/TC21X	Secondary cells and batteries containing alkaline or other non-acid electrolytes – Sealed nickel-cadmium prismatic rechargeable single cells
IEC-EN 60623	Published	SC21A,CLC/TC21X	Secondary cells and batteries containing alkaline or other non-acid electrolytes – Vented nickel-cadmium prismatic rechargeable single cells
IEC-EN 60896	Published	TC21,CLC/T	Stationary lead acid batteries – General requirements and test methods

	Part 12: PWI	C21X	
IEC-EN 61056	Published	TC21,CLC/T C21X	General purpose lead-acid batteries (valve-regulated types)
IEC/TR2 61430	Published	TC21	Secondary cells and batteries – Test methods for checking the performance of devices designed for reducing explosion hazards – Lead-acid starter batteries
IEC/TR3 61431	Published	TC21	Guide for the use of monitor systems for lead-acid traction batteries
IEC-EN 61434	Published	SC21A,CLC/ TC21X	Secondary cells and batteries containing alkaline or other non-acid electrolytes – Guide to designation of current in alkaline secondary cell and battery standards
IEC-EN 61660-1	Published	TC73, CLC/SR73	Short-circuit currents in d.c. auxiliary installations in power plants and substations – Part 1: Calculation of short-circuit currents
IEC 62060	Published	TC21	Secondary cells and batteries – Monitoring of lead acid stationary batteries – User guide
EN 50272	Published Work in progress	CLC/TC21X	Safety requirements for secondary batteries and battery installations
IEEE 485	Published		IEEE Recommended Practice for Sizing Lead-Acid Batteries for Stationary Applications
IEEE 1106	Published		IEEE Recommended Practice for Installation, Maintenance, Testing and Replacement of vented nickel-cadmium batteries for stationary applications
IEEE 1115	Published		IEEE Recommended Practice for Sizing Nickel-Cadmium Batteries for Stationary Applications

3.1.9 UPS

Standard no.	Stage	Technical Committee	Standard
IEEE 446	Published		IEEE Recommended Practice for Emergency and Standby Power Systems for Industrial and Commercial Applications
IEEE 1184	Published		IEEE Guide for the Selection and Sizing of Batteries for Uninterruptible Power Systems

3.1.10 Cogeneration

Standard no.	Stage	Technical	Standard
--------------	-------	-----------	----------

		Committee	
IEEE 502	Published		IEEE Guide for Protection, Interlocking, and Control of Fossil-Fueled Unit-Connected Steam Stations
UL 2200	Published		STANDARD FOR SAFETY Stationary Engine Generator Assemblies

3.1.11 Power Quality

Standard no.	Stage	Technical Committee	Standard
EN 50160	Published	CLC/TC8X	Voltage characteristics of electricity supplied by distribution systems
IEC 61000-1-4	Draft 2CD	SC77A	EMC – Part 1-4: Rationale for limiting power-frequency conducted harmonic and internharmonic current emissions from equipment, in the frequency range up to 9 kHz
IEC-EN 61000-2-2	Published	SC77A,CLC/TC210	EMC – Part 2-2: Environment. Section 2: compatibility levels for low frequency conducted disturbances and signalling in public low-voltage power supply systems
IEC-EN 61000-2-4	Published	SC77A,CLC/TC210	EMC – Part 2-4: Environment. Section 4: Compatibility levels in industrial plants for low-frequency conducted disturbances
IEC/TR3 61000-2-6	Published	SC77A,CLC/TC210	EMC – Part 2-6: Environment. Section 6: Assessment of the emission levels in the power supply of industrial plants as regards low-frequency conducted disturbances
IEC/TR 61000-2-8	Published	SC77A,CLC/TC210	EMC – Part 2-8: Environment – Voltage dips and short interruptions on public electric power supply systems with statistical measurement results
IEC-EN 61000-2-12	Published	SC77A,CLC/TC210	EMC – Part 2-12: Environment. Section 12: Compatibility levels for low-frequency conducted disturbances and signalling in public medium-voltage power supply systems
IEC/TR 61000-3-1	Draft PWI	SC77A	EMC – Part 3-1: Limits - Overview of emission standards and guides - Technical Report
IEC-EN 61000-3-2	Published Work in progress	SC77A,CLC/TC210	EMC – Part 3-2: Limits – Limits for harmonic current emissions (equipment input current up to and including 16 A per phase
IEC-EN 61000-3-3	Published Work in progress	SC77A,CLC/TC210	EMC – Part 3-3: Limits – Limitation of voltage changes, voltage fluctuations and flicker in public low-voltage supply systems, for equipment with rated current ≤ 16 A per phase and not subject to conditional connection
IEC/TS 61000-3-4	Published	SC77A	EMC – Part 3-4: Limits – Limitation of emission of harmonic currents in low-voltage power supply systems for equipment with rated current greater than 16 A
IEC/TR2	Published	SC77A	EMC – Part 3-5: Limits – Limitation of voltage fluctuations and flicker in low-voltage power supply systems for equipment with rated current greater

61000-3-5			than 16 A
IEC/TR3 61000-3-6	Published	SC77A	EMC – Part 3-6: Limits – Assessment of emission limits for distorting loads in MV and HV power systems – Basic EMC publication
IEC/TR3 61000-3-7	Published	SC77A	EMC – Part 3-7: Limits – Assessment of emission limits for fluctuating loads in MV and HV power systems – Basic EMC publication
IEC 61000-3-9	Draft PWI	SC77A	EMC – Part 3-9: Limits for interharmonic current emissions (equipment with input power ≤ 16 A per phase and prone to produce interharmonics by design)
IEC61000-3-10	Draft PWI	SC77A	EMC – Part 3-10: Emission limits in the frequency range 2 ... 9 kHz
IEC-EN 61000-3-11	Published	SC77A,CLC/ TC210	EMC – Part 3-11: Limits – Limitation of voltage changes, voltage fluctuations and flicker in public low-voltage supply systems – Equipment with rated current ≤ 75 A per phase and subject to conditional connection
IEC-prEN 61000-3-12	Draft ADIS	SC77A,CLC/ TC210	EMC – Part 3-12: Limits for harmonic currents produced by equipment connected to public low-voltage systems with input current < 75 A per phase and subject to restricted connection
IEC-EN 61000-4-4	Published	SC77B,CLC/ TC210	EMC – Part 4-4: Testing and measurement techniques – Electrical fast transient/burst immunity test
IEC-EN 61000-4-5	Published	SC77B,CLC/ TC210	EMC – Part 4-5: Testing and measurement techniques – Surge immunity test
IEC-EN 61000-4-7	Published	SC77A,CLC/ TC210	EMC – Part 4-7: Testing and measurement techniques – General guide on harmonics and interharmonics measurements and instrumentation, for power supply and equipment connected thereto
IEC-EN 61000-4-11	Published	SC77A,CLC/ TC210	EMC – Part 4-11: Testing and measurement techniques – Voltage dips, short interruptions and voltage variations immunity tests
IEC-EN 61000-4-13	Published	SC77A,CLC/ TC210	EMC – Part 4-13: Testing and measurement techniques – Harmonics and interharmonics including mains signalling at a.c. power port, low frequency immunity tests
IEC-EN 61000-4-14	Published	SC77A,CLC/ TC210	EMC – Part 4-14: Testing and measurement techniques – Voltage fluctuation immunity test
IEC-EN 61000-4-15	Published	SC77A,CLC/ TC210	EMC – Part 4-15: Testing and measurement techniques – Flickmeter – Functional design specifications
IEC-EN 61000-4-16	Published	SC77A,CLC/ TC210	EMC – Part 4-16: Testing and measurement techniques – Test for immunity to conducted, common mode disturbances in the frequency range 0 Hz to 150 kHz
IEC-EN 61000-4-17	Published	SC77A,CLC/ TC210	EMC – Part 4-17: Testing and measurement techniques - Ripple on d.c. input power port immunity test
IEC-EN 61000-4-27	Published	SC77A,CLC/ TC210	EMC – Part 4-27: Testing and measurement techniques – Unbalance, immunity test
IEC-EN	Published	SC77A,CLC/	EMC – Part 4-28: Testing and measurement techniques – Variation of

61000-4-28		TC210	power frequency, immunity test
IEC-EN 61000-4-29	Published	SC77A,CLC/TC210	EMC – Part 4-29: Testing and measurement techniques - Voltage dips, short interruptions and voltage variations on d.c. input power port immunity tests
IEC-EN 61000-4-30	Published Work in progress	SC77A,CLC/TC210	EMC – Part 4-30: Testing and measurement techniques – Power quality measurement methods
IEC 61000-4-34	Draft CD	SC77A	EMC – Part 4-34: Testing and measuring techniques – Voltage dips, short interruptions and voltage variations immunity tests for equipment with input current more than 16 A per phase. Basic EMC publication
IEEE 519	Published	SCC22	IEEE Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems
IEEE 1159	Published		IEEE Recommended Practices for monitoring electric power quality
IEEE 1250	Published		IEEE Guide for service to equipment sensitive to momentary voltage disturbances
IEEE 1346	Published		IEEE Recommended Practices for evaluating electric power system compatibility with electronic process equipment
IEEE P1409	Draft	Custom power task	IEEE Guide for the application of power electronics for power quality improvement on distribution systems rated 1 kV through 38 kV
IEEE P1453	Draft		IEEE Recommended Practice for measurement and limits of voltage flicker on AC power systems
IEEE P1495	Draft		Standard for harmonic limits for single-phase equipment
IEEE P1564	Draft		IEEE Recommended Practice for the establishment of voltage sag indices

3.1.12 Metering

Standard no.	Stage	Technical Committee	Standard
IEC-EN 60870-5-102	Published	TC57, CLC/SR57	Telecontrol equipment and systems – Part 5: transmission protocols – section 102: companion standards for the transmission of integrated totals in electric power systems
IEC-EN 62056	Published Work in progress	TC13, CLC/TC13	Electricity metering – Data exchange for meter reading, tariff and local control
IEC-EN 61334-4	Published	TC57, CLC/SR57	Distribution automation using distribution line carrier systems – Part 4: Data communication protocols

3.1.13 Communications

Standard no.	Stage	Technical Committee	Standard
IEC-EN 61850	Published Work in progress	TC57, CLC/SR57	Communications networks and systems in substations
IEC 62350	Draft ANW	TC57	Communications Systems for Distributed Energy Resources (DER)

CHAPTER 4. Simplified Methods for DG connection assessment

4.1 Simplified assessment of reactive control capability of wind farms in Spain

Reactive control capability is an important issue for the connection of wind farms. Former regulations simply required unity power factor. This measure could be adequate in cases of small penetration, but when great amounts of distributed generation are to be connected, this generation should participate somehow in voltage control, both in the distribution and in the transmission level. Current standards tend to require that they participate in this control, with incentives that vary with changing grid conditions.

On the other hand, the owners of the new facilities to be connected are not specialists in power systems, and to make a detailed assessment of the reactive regulation capability of its installation may be a burden in the initial stages of the project. However, this information is interesting for distributing companies in order to plan their grids.

For this reason, a new recommendation [27] has been issued in Spain that tries to solve this problem. It is intended to help distributors and distributed generation owners, and establishes the information to be exchanged between generators and distributors concerning this point, as well as a simplified method for this assessment.

The method consists basically in making a reactive power balance at three voltage levels: 0.95 p.u., 1.00 p.u. and 1.05 p.u. Transformers' taps effects are not considered in order to give a 'worst case' estimation. In this reactive balance all the components within the wind farm (apart from the transformer tapping) are taken into account, namely, the reactive consumption (or generation) of wind generators, the existing compensation within the farm and the reactive power generation and consumption of lines and transformers. The result of this method is an estimation of the amount of reactive power that could be produced or consumed by a wind farm for a given active power production, between 0 and 100% of rated power.

Although this is not an exact calculation, the results are close enough to be considered a very good estimation in practical cases. An example is provided in the standard, whose results, compared with exact calculation, are shown here.

The electrical connections of a typical wind farm are given in Fig. 4.1. Two possibilities have been studied for the wind turbines: turbines with the possibility of controlling the power factor (primarily variable speed turbines), and turbines without this possibility. In the later case, capacitors are used to improve the power factor. Data for lines and transformers are standard. Wind turbines rated power is 720 kW. It is assumed that all the turbines provide the same power.

In both cases, the differences between the simplified calculation and the exact ones, obtained through a load flow program are given in Fig. 4.1 and Fig. 4.2. Fig. 4.1 shows the reactive power that a wind farm gives for the whole power range with different settings of power factor for each machine (0.95 inductive, 1.0 and 0.95 capacitive). Both the load flow results and the results from the simplified method are represented. It can be easily seen that the differences are negligible.

In Fig. 4.2 the same results are shown for the fixed speed machines. In this case, the results are shown for no reactive compensation of the machines (capacitors disconnected), full compensation (all capacitors connected) and half compensation (no load capacitors connected). Results are shown also for the load flow method and the simplified method. Only the case with greatest discrepancies (that

take place when the grid voltage is 1.05 p.u.) has been shown. Although in this case the differences are greater, the results are a good approximation at the planning stage.

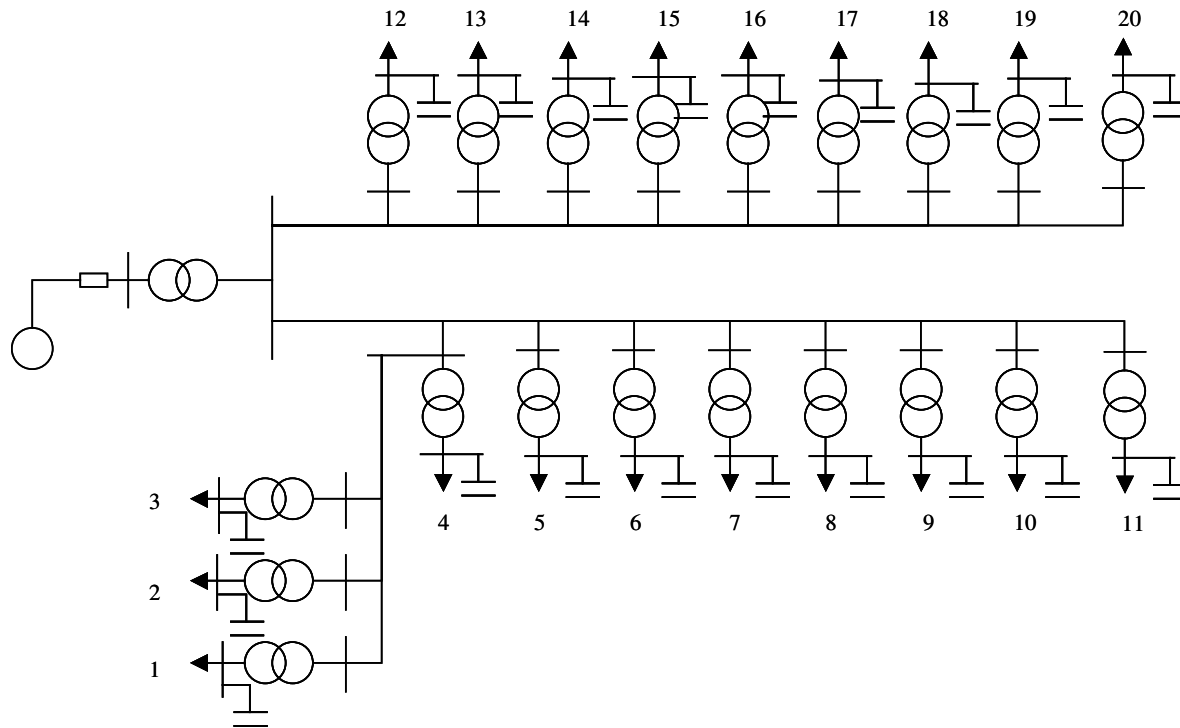


Fig. 4.1 Example of wind farm

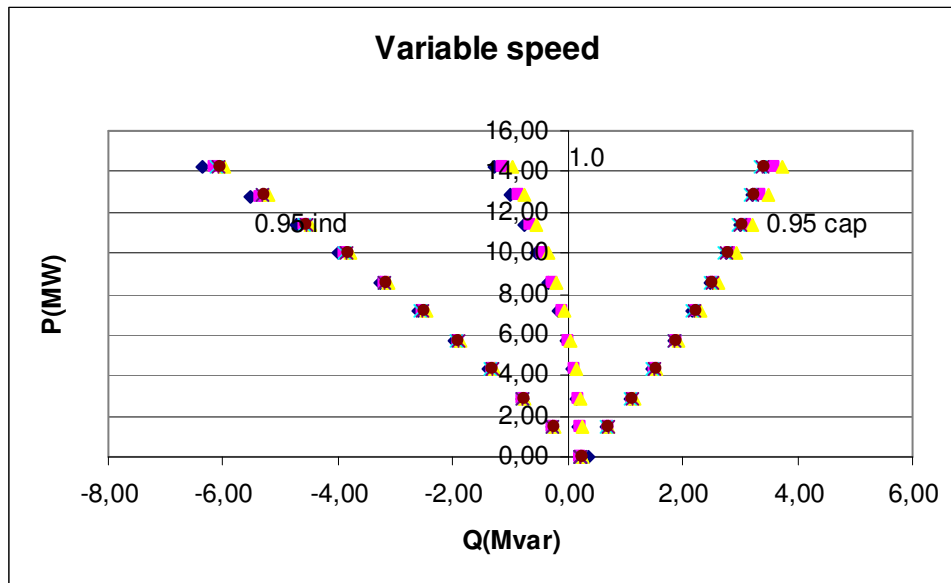


Fig. 4.1 Comparison between simplified and exact method for variable speed wind turbines.

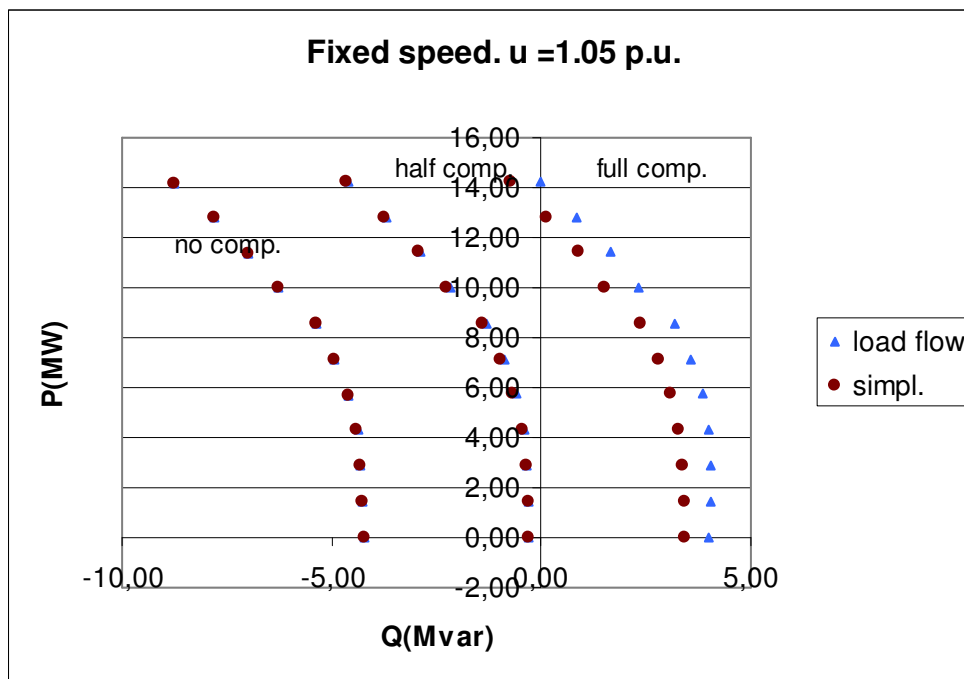


Fig. 4.2. Comparison between simplified and exact method for fixed speed wind turbines. Grid voltage of 1.05 p.u.

4.2 Simplified Methods for Establishing the Wind Power Penetration Limit in the Greek Islands

At the *planning* stage in the development of an island power system, an important problem is the determination of the maximum wind power that can be installed in the island during the next years, so that, these investments can be economically viable, without jeopardizing the current quality of service.

This must be done considering many years ahead, taking into account the expected load growth and the expansion of the power system. In addition, it is advisable, in the planning of the power system of the island to be effectuated “in total”, that is including conventional and renewable power sources.

Especially in Greece, according to the licensing procedure applied by RAE in the frame of deregulated electricity market, the predetermination of the permissible power that could be installed is necessary for the declaration of the interest of the private investors. Additionally, an estimation of the rejected (not produced) wind energy by the planned new wind parks has to be given to the investors, in order to take into account this parameter, before they declare their interest.

However, it is clear that at the planning stage, detailed simulations are meaningless, given that main parameters of the problem are not known accurately and must be estimated or assumed. Under these conditions, considerable simplification of the above-described operational models is possible, if typical frequency or cumulative load and wind speed curves, instead of time series, are used. A considerable advantage is that these curves are more representative for long-term studies, especially for the wind itself. Wind cumulative curves can be obtained using Weibull family curves, that match more in the available time series for several years. In many cases these are the only wind data available.

In more detail the method based on the following:

(a) A discrete frequency distribution of the “*capability of wind power absorption*” is obtained as follows:

- The cumulative load curves, one for each year, are formed. Each year is divided into N “operational states”. If h_i are the hours and P_{Li} the mean power corresponding to the operational state i , the probability of its occurrence will be $f(PLi)=h_i/8760$.
- For each operational state, the minimum required controlled units are considered in operation, so that the demand P_{Li} can be covered 100%. The “*capability of wind power absorption*” is calculated as previously by formulas similar to (1) and (2). The calculations are repeated for all the states $i = 1$ to N , so that the cumulative and the frequency distribution of the “*capability of wind power absorption*” curves can be obtained, as in the case of the operation stage. However, it is noted that in the planning stage the selection of the proper dynamic coefficient C_D is more difficult than in the operational stage because most of the parameters are unknown or impossible to be quantified. It is clear that this “capability” presents the maximum wind power and energy that could be absorbed from the system if unlimited controllable wind power was available.

(b) A discrete frequency distribution of the wind power that “*can be generated*”, is obtained as follows:

- Based on the Weibull distribution curve suited to the wind conditions in the island (it can be obtained by measurements), the probability of occurrence $g(V_j)$ of the wind speed V_j during the state j , is obtained considering M states $j = 1$ to M for the wind speed.
- Based on these M states, the corresponding wind power for each one can be calculated, considering an aggregate wind park of which each wind turbine receive the uniform wind velocity V_j at the state j and produces the power corresponding to a specific power curve. This approximation is on the safe side for system stability, because in the real world, the wind parks operating in a region rarely produce their nominal power at the same time (in average hour values), even if they are neighboring.
- In more advanced approximations, the diversification of the installed or new wind generators can be considered by different scenarios. For each one of these scenarios, the existing wind parks and the assumed new ones are taken into account, and for each state j and wind speed V_j , the produced wind power is calculated taking into account the corresponding power curves of the wind generators.
- The calculations are repeated for all states $j = 1$ to M , so that the discrete frequency distribution of the wind power P_{Wj} can be obtained.

(c) The discrete frequency distribution of the “*absorbed wind power*” is obtained by the convolution of the distributions (a) and (b), considering the occurrence of $N \times M$ states. The probability of occurrence can be calculated by the simple formula:

$$PR(P_{Li}, V_j) = f(P_{Li})g(V_j) \quad (4.1)$$

The calculation of the $PR(P_{Li}, V_j)$ by the simple relation (4.1) is justified because the distribution of load and the wind power, can be considered approximately uncorrelated.

So, for each operational state (i,j) the load demand, the capability of absorption and the really absorbed wind power are known, so that the total produced and the rejected (non produced) wind energy, as well as the energy produced by the conventional units, for the whole year can be calculated. Other interesting quantities, e.g. the obtained reduction of the oil consumption, can be easily calculated.

By the application of the above method for many years and different wind penetration scenarios, a clear picture of the wind penetration capacity that can be incorporated in the power system of the island, can be drawn. Extensive analyses concerning the different assumptions and values of the parameters considered, related with the particularities of the island or the installed equipment can be easily made.

4.2.1 The economic viability of the investment

The economic viability of the investment of a wind park clearly depends on its produced energy during a year. This is mainly related to the wind potential at the wind park site and the capability of the power system to absorb the produced energy by the wind park. In the case of islands, the Distribution Network Operator-DNO imposes the obligation to each wind park to spill (not produce) a part of the energy that it could produce, in cases where the system cannot absorb it. This obligation is realized by the regularly defining is over a specific time interval (e.g. for each hour), of the power that can be absorbed from the power system (set point).

A coefficient, defined by the relation (4.2), named “Capacity Factor-CF”, is usually used to indicate the viability of a wind park.

$$CF = \frac{E_w}{8760 \cdot P_w} \quad (4.2)$$

Where:

E_w : Total energy produced by the wind park in a year

P_w : Nominal power of wind park

According to the estimations of RAE, based on the applied economic conditions in Greece, a wind park investment in an island is considered as economically viable if the wind park can achieve a CF over than 27,5%. This value corresponds to a wind park operating in the mainland (that means without restrictions of energy absorption) and situated at a site with a mean annual wind velocity of 7,2 m/sec. It is remarkable that in many Greek islands, the value of CF, without rejected (not produced) energy, usually lies in a range of 30%-40% and in the extreme cases can be as high as 45%.

4.3 Model for Expedited Procedure of DG Connection in the United States

4.3.1 Introduction

To improve the interconnection procedure for small distributed generation resources, the National Association of Regulatory Utility Commissioners (NARUC) created the document, *Model Interconnection Procedures and Agreement for Small Distributed Generation Resources*. This document is a reference and guideline for states to improve upon the extensive interconnection processes. The documentation can be found at:

www.nrri.ohio-state.edu/programs/electric/distributedgeneration

The flowchart in Fig. 4.3 provided below describes the interconnection procedure. The super-expedited process allows the customer and provider to create an agreement on the interconnection without conducting tedious procedures such as a scoping meeting, a feasibility study, system impact study, or a facilities study. If possible, these procedures can be avoided. If a customer meets the criteria in the screening questions, the interconnection procedure can be expedited.

4.3.2 Definitions

Interconnection Customer: The entity that seeks to connect their small resource facility to the Interconnection Provider's existing electric system.

Interconnection Provider: The entity that allows the Interconnection Customer to connect to the existing electric system provided that they abide by the interconnection process.

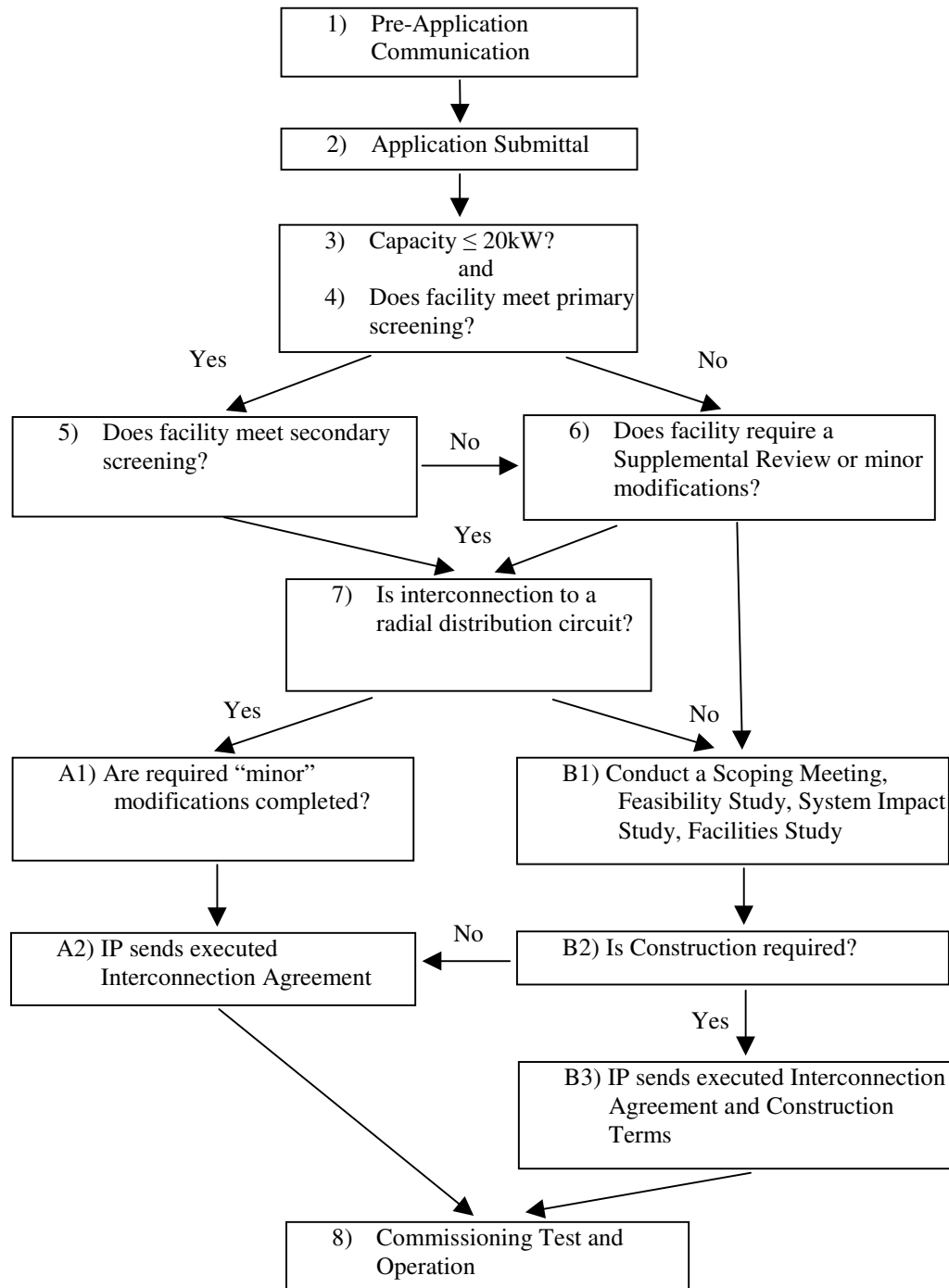


Fig. 4.3. Model Interconnection Procedures for Small Distributed Generation Resources Interconnection Process

1. Pre-Application Communication: The Interconnection Customer must begin the review process by requesting an application from the Interconnection Provider. The Interconnection Customer should present a proposed project and specific site.

2. Application Submittal: The application must include the following information:

- Interconnection Provider and contact information
- Interconnection Customer and contact information
- Purpose of the small-resource facility
- Generator specifications (components, models, capacity, etc.)
- Transformer specifications
- Circuit breaker specifications
- Protective relays specifications
- Any schematic drawings

3. Small generator capacity: Is the small generator capacity less than or equal to 20 kW?

4. Primary screening criteria: The primary screening criteria are a checklist of requirements that must be approved for the process to continue. One example of the requirements is that the interconnection to a radial distribution circuit will not exceed 5 % of the total circuit annual peak load as most recently measured at the substation. The list of other requirements can be found in the report, *Model Interconnection Procedures and Agreement for Small Distributed Generation Resources*.

5. Secondary screening criteria:

After approving the primary screening criteria, the Interconnection Customer must then meet the secondary screening criteria. The second screening criteria are a checklist of requirements that must be approved for the process to continue. One example of the requirements is for an interconnection to a radial distribution circuit, the capacity in aggregate with other generation on the circuit will not exceed 15 % of total circuit peak load as most recently measured at the substation. It will also not exceed 15 % of a distribution circuit line section annual peak load. The list of other requirements can be found in the report, *Model Interconnection Procedures and Agreement for Small Distributed Generation Resources*.

6. Supplemental review or minor modifications: An Interconnection Customer can agree to have a supplemental review completed at the cost of the customer. The Interconnection Provider will determine if the equipment used by the customer can be interconnected safely and reliably under super-expedited process. If this can be done with only minor modifications to the interconnection equipment, then the super-expedited process may proceed to Step 7.

7. Interconnection to a radial distribution circuit: If the Interconnection Customer wants to connect to a radial distribution circuit, then this will meet interconnection standards for the Interconnection Provider. However, if the customer does not connect to a radial circuit, it will be more difficult to limit the effects of interconnection to the Provider's system.

A1. Minor modifications completed: Were the minor modifications discussed in Step 6 completed? If so, Interconnection requirements are completed and the agreement must be made between the customer and provider.

A2. Interconnection agreement: If Interconnection Customer meets all primary and secondary screening requirements and steps mentioned above, then the Interconnection Provider will provide the Interconnection Customer with an Interconnection agreement.

B1. Scoping meeting, feasibility study, system impact study, and facilities study:

The purpose of the scoping meeting shall be to discuss the Interconnection Customer's interconnection request, and review existing studies relevant to the Interconnection Customer's interconnection request. The Interconnection Provider and Interconnection Customer will agree if the provider will need to perform a feasibility study or to proceed to a system impact study, facilities study, or straight to the interconnection agreement.

The feasibility study will include the following analyses:

- Initial identification of any circuit breaker short circuit capability limits exceeded as a result of the interconnection.
- Initial identification of any thermal overload or voltage limit violations resulting from the interconnection.
- Initial review of grounding requirements and system protection.
- Description and non-binding estimated cost of facilities required to interconnect the facility to an electric distribution power system or directly to a high voltage transmission system. This description should address the identified short circuit as well as power flow issues.

The impact study will detail the impacts that would result from connecting the proposed facility without project or system modifications. This study will also investigate potential impacts including those identified in the scoping meeting. The study will evaluate the impact of the new facility on the reliability of the interconnected transmission and distribution system.

The facilities study includes the facility design that must meet design requirements set by the Interconnection Provider. The Interconnection Customer or Interconnection Provider may arrange for the design and construction of the facility, either at the cost of the Interconnection Customer.

B2. Construction requirements: Does the Interconnection Customer need construction to meet interconnection standards? If so, proceed to interconnection agreement with a construction terms agreement. If not, conduct the interconnection agreement only.

B3. Interconnection agreement with construction terms: If Interconnection Customer meets all primary and secondary screening requirements and steps mentioned above (including requirements for construction), then the Interconnection Provider will provide the Interconnection Customer with construction terms and an agreement in addition to a interconnection agreement.

8. Commissioning test and operation: The Interconnection Provider will be given 5 business days notice written notice of the commissioning tests of the Interconnection Customer's installed equipment. The customer must abide by all applicable codes and standards.

CHAPTER 5. Identification of methods to meet new requirements

5.1 Probabilistic Voltage Analysis

An in-depth investigation of the DG effects on voltage profiles is possible only if the variations of the loads and productions are taken into account. This can be achieved applying probabilistic techniques like the probabilistic load flow (PLF) or the Monte Carlo Simulation. PLF requires modeling of loads and power productions as probability density functions and provides the complete spectrum of all probable values of the bus voltages and power flows in the study period with their respective probabilities taking into account generation and load uncertainties and correlations and topological variations. In this way, operational limit violations are obtained for the whole study period with the probability of each violation. Thus, PLF allows decisions to be based on objective data, i.e. probabilities of occurrence. It should be noted that the European Norm EN-50160 also specifies voltage limit violations in percentage within one week periods.

5.1.1 Probabilistic Load Flow Formulation

The load flow problem can be expressed mathematically by two sets of non-linear equations:

$$\begin{aligned} Y &= g(X, U) \\ Z &= h(X, U) \end{aligned} \quad (5.1)$$

Y is the input, Z the output, X the state and U the control vector. The input vector Y comprises nodal power injections, the state vector X voltage magnitudes and angles, the output vector Z power flows, generation reactive injections, etc. and the control vector U the control means of the system like transformer taps, reactive compensation, voltages and active production at PV buses, etc.

In the probabilistic load flow (PLF) formulation uncertainty in the input variables is due to load forecasting, generator outages etc. Probabilistic modelling of conventional production takes into account generator unavailabilities, while consumer demands normally follow normal and discrete distributions obtained from the analysis of load time series. The pdfs of the active production and the reactive power absorbed by the Wind Parks is obtained from the pdf of the wind speed, applying the Fundamental Theorem [15].

PLF provides the complete spectrum of all probable values of state and output variables, like bus voltages and power flows, each value with its respective probability taking into account generating unit unavailabilities, load uncertainties, dispatching criteria effects and topological variations. Most of the techniques developed for PLF are based on the linearization of (5.1) around an expected operating point defined by X_o , U_o .

$$X = X_o + J^{-1}Y \quad (5.2)$$

,where $J = \frac{\partial g(X, U)}{\partial X}$ is the Jacobian of the system.

After linearization, the output vector elements are expressed as linear functions of the nodal active and reactive power injections, defined by probability density functions, as:

$$Z = Z_o + A^T Y \quad (5.3)$$

The weighting coefficients of these linear functions are defined [5,6] as sensitivity coefficients obtained from the sensitivity matrix

$$A^T = \left(\frac{\partial h(X,U)}{\partial X} \right)^T \left(\frac{\partial g(X,U)}{\partial X} \right)^{-1} \quad (5.4)$$

Convolution techniques and the Fast Fourier Transform are used to deduce the unknown probability functions of the state and output variables.

Equipment and generator availabilities are modelled by considering unit Forced Outage rates and connection availabilities. The results of individual PLFs are then properly combined. Moreover, at generation level, in order to represent dispatching policies [13], the production units are modelled as capacity blocks placed in non-adjacent positions in a load priority list. The availability of each capacity block is represented as a two-state capacity model. The power balance equation is simulated as the probabilistic summation of the active generations, the active loads (negative) and losses. At a first approximation, the system active losses are assumed constant and equal to a percentage of the expected total active load. The probability density function of the total system demand is obtained next from the convolution of the specified busbar load densities, assumed statistically independent or linearly dependent. The pdf is then divided in a prespecified number of intervals defining different regions of system loading and corresponding linearization points. For each of these intervals the generating units' blocks are sequentially dispatched according to the priority list until the demand is satisfied, i.e. the probability that the unserved load falls beyond the required reliability level. For each linearisation point the power balance equation can be re-evaluated in order to take into account more accurately the losses.

5.1.2 Typical Results

In the following Figure an example of a probabilistic load flow analysis is provided showing the probability density functions of the voltage at the connection bus of a Wind Park for various levels of installed capacity. Assuming that the overvoltage limit would be set to 1.05 pu, it can be clearly seen that deterministic criteria would limit the maximum wind power penetration to 10%, while a probabilistic approach shows that 20% or even 30% of installed capacity would provide voltage limit violations with a very low cumulative probability.

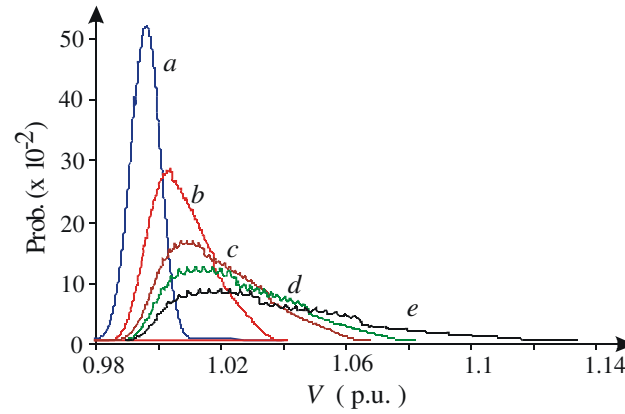


Fig. 0.1. Probability density function of voltage at connection bus for a) 0%, b) 10%, c) 20%, d) 30% and e) 40% wind power penetration.

This analysis would also allow DG to be curtailed in certain circumstances to limit voltage rise. Further, many DGs have the ability to operate at various power factors and may even be able to act as sources/sinks of reactive power when not generating. For some overhead distribution circuits (i.e. those with high reactance) the DGs could then contribute to circuit voltage control provided suitable control and commercial systems were in place.

5.1.3 Discussion

Future “active” networks likely to be characterised by interconnected operation and significant DG integration, will require both new advanced control systems and the accompanying commercial arrangements. The overall benefits of this integration include:

1. effective operation and use of distribution circuits to accommodate DG;
2. enhancement of the value of dispersed sources and hence of their competitiveness.

This could be achieved by a co-ordinated (but most likely distributed) control of the system through new Distribution Management System (DMS) applications that need to be developed to allow this integrated operation to be implemented.

5.2 Islanded Operation - Microgrids

Microgrids comprise distribution systems with distributed energy sources (micro-turbines, fuel cells, PV, etc.) together with storage devices (flywheels, energy capacitors and batteries) and controllable loads (Fig. 5.2). Such systems are operated interconnected to the distribution grid, or in islanded mode, or if disconnected from the main grid, as physical islands. The operation of micro-sources in the network introduces considerable complexity in the LV grid, especially under islanded operation, but at the same time, it can provide distinct benefits to the overall system performance, especially regarding reliability and quality of service, if managed and coordinated efficiently.

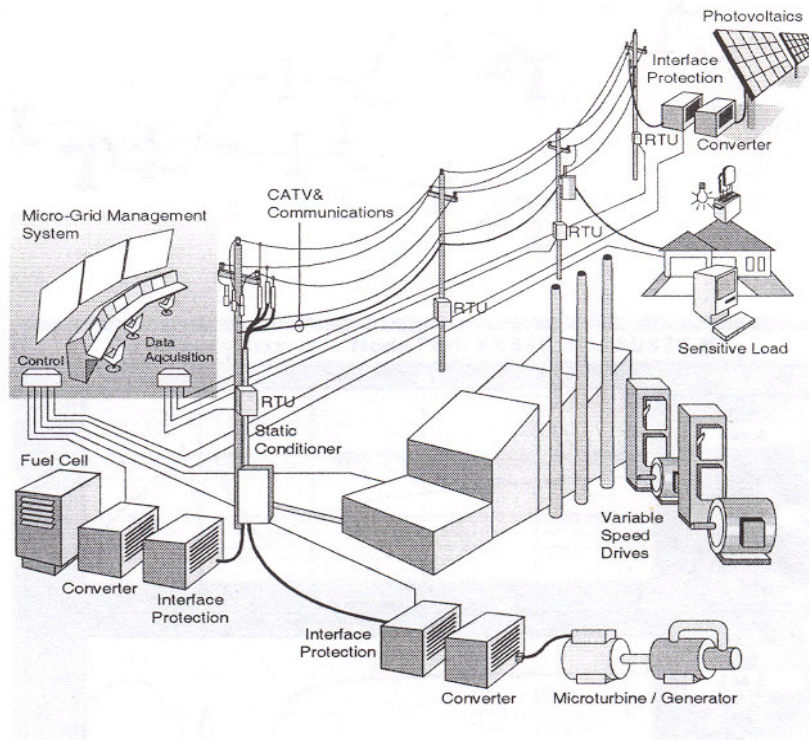


Fig. 5.2. Potential Microgrid architecture with DG systems and load types

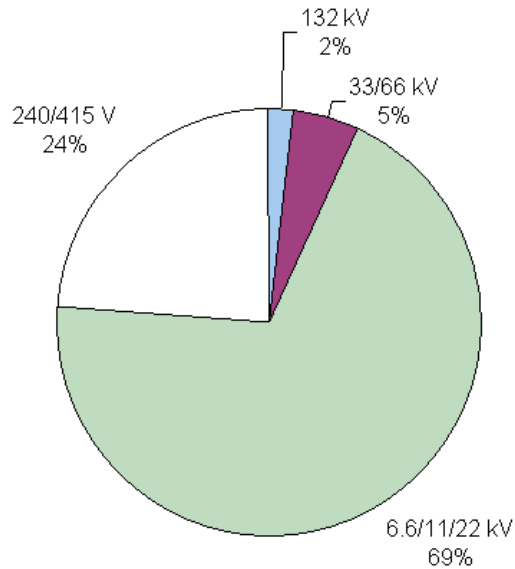


Fig. 5.3. CMLs

It is expected that Microgrids will under most conditions operate connected to the main power grid. In interconnected mode of operation, decisions on local generation are based on maximization of the Microgrids value, according to the availability of the primary energy source and the energy prices. When failures occur in the MV or HV system, the microgrid is automatically transferred to islanded operation, supplied by itself, as in physical islands. Seamless transition between the interconnected to the islanding mode is crucial for uninterrupted continuity of supply. With an intelligent distributed approach, local Micro-source Controllers (MCs) and Load Controllers will act, in a very fast way, as independent agents and making efficient use of the local resources, it will be possible to maintain system operation in islanded conditions. Figure 5.3 shows a typical percentage of Customer Minutes Lost (CMLs) due to faults in various voltage levels of the UK transmission and distribution system. It

is clear that only less than a quarter of this time is due to faults on the LV part of the network, therefore a remarkable increase in reliability should be expected, if Microgrids can successfully operate islanded. At this mode, economical operation is less relevant, what is important is the Microgrid survival, even if its demand is only partially satisfied. The output control of the microsources changes from a dispatched power mode to frequency mode. This is equivalent to primary frequency control of interconnected power systems. The possibility of secondary frequency control via the Microgrid Central Controller (MGCC) is of course also possible, although it is questionable if it is worthwhile.

If a system disturbance provokes a general blackout at the HV or MV networks, such that the Microgrid is not able to separate and continue in islanding mode, and if the MV system is unable to restore operation in a specified time, the MCs can provide local Black Start capabilities exploiting autonomous agent concepts. Moreover, the MGCC can support re-connection during Black Start, helping in this way the upstream DMS system that is managing the MV distribution network. During reconnection the issue of out-of phase reclosing needs to be carefully considered. The development of local controllers in close co-ordination with the MGCC functions need to be developed and evaluated from the dynamic operation point of view.

A number of technical and regulatory issues need to be solved before allowing such type of islanded operation. For example, in inverter – dominated Microgrids, single-phase fault currents are typically very small posing problems to timely detection and protection. Responsibility for the safety of islanding is an important regulatory issue, etc.

5.2.1 Islanding Operation

Islanding operation of distribution grids fed by dispersed generation (DG) sources is nowadays becoming a credible hypothesis, since the control capabilities of DG units allows such an operation, contributing to improve availability of service in distribution grids.

In this section two different strategies for islanding operation are described:

- An inverter dominated control approach used in LV grids;
- A conventional synchronous control approach adopted for MV and HV distribution grids.

The inverter control based approach is performed exploiting power electronic interfaces that interconnect microsources to LV grids [40]. These microsources are not suitable for direct connection to the electrical network due to the characteristics of the energy produced (DC power in fuel-cells and PV generators or high frequency AC power in microturbines). This islanding strategy is being developed under a Microgrid concept within the EU Project MicroGrids - Contract No. ENK-CT-2002-00610 [41].

In MV and HV distribution grids, although some generators are asynchronous units or use power electronic interfaces (like in wind energy conversion systems), the presence of synchronous generators allows the adoption of conventional voltage and frequency control strategies whose feasibility needs, however, to be checked through dynamic simulation.

5.2.2 LV Islanding Operation

Low Voltage islanding is being developed within the concept of a Microgrid (MG) [40,41] where it is assumed to exist a simultaneous interaction among microsources and loads (that can be partially curtailed). In this microgrid power electronic interfaces are responsible for controlling frequency and voltage. These power electronic interfaces can operate either in a PQ or in a Voltage Source Inverter (VSI) control mode. These strategies correspond to [42]:

- PQ inverter control - the inverter is used to supply a given active and reactive power pre-defined level.

- Voltage Source Inverter control logic - the inverter is controlled to “feed” the load with pre-defined values for voltage and frequency.

A disconnection of MG from the main power supply (the upstream MV network) would lead to the loss of the MG unless a VSI control mode is used to balance generation and consumption. Two main islanding operational control strategies are possible for a MG:

- Single Master Operation: A VSI or a synchronous machine directly connected to the grid (with a diesel engine as the prime mover, for example) can be used as voltage reference when the main power supply is lost; all the other inverters can then be operated in PQ mode;
- Multi Master Operation: More than one inverter is operated as a VSI, corresponding to a scenario with dispersed storage devices; other PQ inverters may also coexist.

The VSI has the ability to emulate the behaviour of a conventional synchronous generator changing frequency in the network according to the balance of load. It reacts to power system disturbances (for example, load-following situations or wind fluctuations) based only on information available locally at the inverter’s terminals (voltage and current measurements). In order to promote adequate secondary control with the aim of restoring frequency to the nominal value after a disturbance, two main strategies can be followed: local secondary control, by using a local PI controller at each microsource, or centralized secondary control mastered by a central controller installed at the MV/LV substation, both defining target values for active power outputs of the primary energy sources [43, 44].

5.2.3 Single Master Operation

In this case, a VSI (acting as “master”) is connected to the network; the other MS are connected to the grid through an inverter with a PQ control scheme (“slaves”). Droop settings of the VSI can be modified by a central controller according to the operating conditions and in order to avoid large frequency excursions.

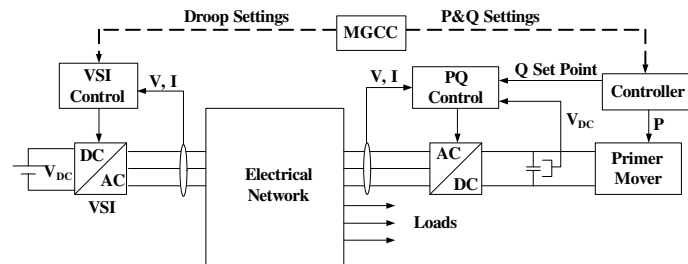


Fig. 5.4. Control scheme for single master operation

Assuring a zero frequency deviation during any islanded operating conditions should be considered the key objective for any control strategy. This is especially important since storage devices have limited capacity and it is necessary to avoid them from keep injecting (or absorbing) active power whenever the frequency deviation differs from zero.

5.2.4 Multi Master Operation

In a multi master approach, several inverters are operating as VSI with pre-defined frequency/active power and voltage/reactive power characteristics. Eventually, other PQ-controlled inverters may also coexist.

In this case correction of frequency deviations can be performed by changing the idle frequency value as used in proportional/integral frequency governors of synchronous generators. The change in the idle frequency can also be performed centrally by a central controller in a sort of centralized secondary

control, using a local communications infrastructure. In this control strategy the aim of obtaining zero frequency deviation is also a driving concern, as in the single master approach.

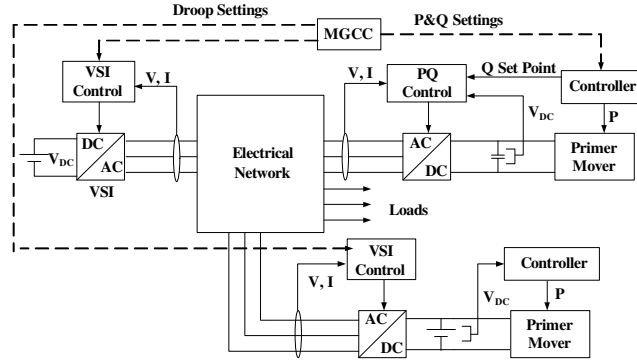


Fig. 5.5. Control scheme for multi master operation

5.2.5 Study case results

A simulation platform under the MatLab® Simulink® environment was developed in order to evaluate the dynamic behaviour of several microsources operating together in a LV network under pre-specified conditions including interconnected and autonomous operation of the MG. A LV test system, defined by NTUA [5], was used to test the approaches developed. Fig. 5.6 shows a single-line diagram with the different types of microsources operated in this MG.

Fig. 5.7 illustrates the LV simulation platform developed for the dynamic simulation studies [44]. It includes models and controls for microturbines (single-shaft and split-shaft), fuel-cells, small asynchronous wind generators, PV panels and storage devices (flywheels and batteries) as well as controllable loads (available for load-shedding). These models were developed within the Microgrids project and can be found in [45, 46].

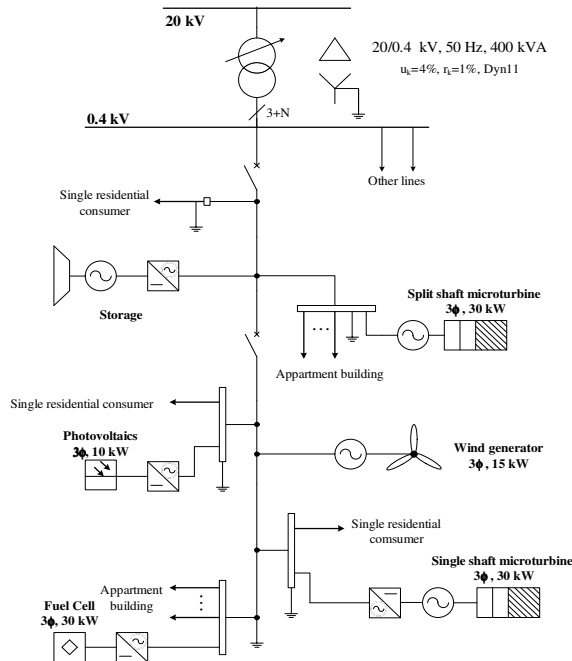


Fig. 5.6. LV network test system

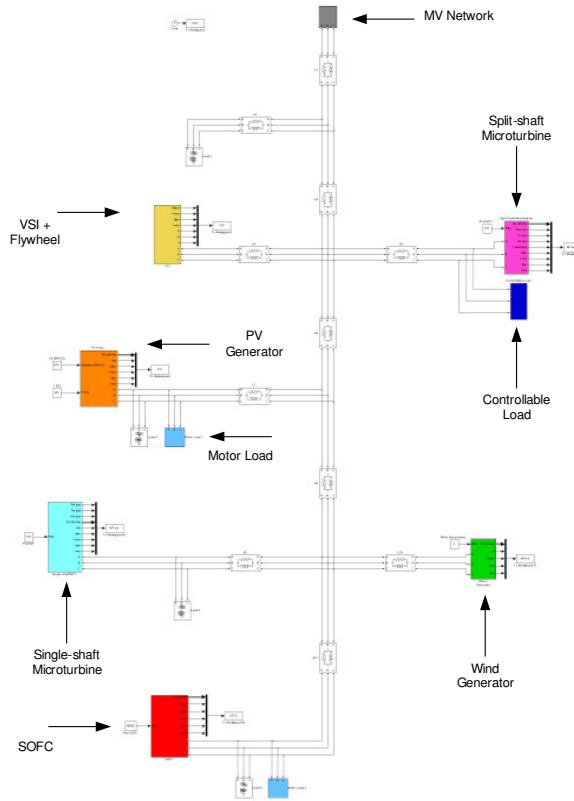


Fig. 5.7. LV network for the *Matlab® Simulink®* simulation platform

Disconnection from the upstream MV network and load-following in islanded operation was simulated in order to understand the dynamic behaviour of the MG and to evaluate the effectiveness of the developed control approaches. Islanding of the MG was investigated for two different situations: the scheduled islanding and the forced islanding (in case of a fault in the MV grid). Scenarios using the single master operation strategy with a VSI and multi master operation were tested.

5.2.6 Single Master Operation

A short-circuit was simulated to occur at $t = 10$ seconds, eliminated after 100 milliseconds followed by the islanding of the MG.

The initial total load of the MG was around 70 kW and the microsource generation, prior to the islanding, was around 45 kW. In face of the large initial frequency deviation an amount of load was automatically shedded in order to aid in frequency restoration. This load was reconnected later in small load steps allowing also for the evaluation of the MG behaviour in load-following conditions.

It is possible to observe from the frequency behaviour that MG stability is not lost following a short-circuit on the MV grid side.

In order to preserve MG stability it was necessary to shed the motor loads since the rotation speed would drop too much and cause the whole system to collapse. Asynchronous generators (single-shaft microturbine and wind generators) were not disconnected in order not to loose generation. After fault elimination, there is a transient period for restoring normal operation of these generators, which has a strong impact on inverter current and voltage, as it can be observed in next figures after $t=10.1$ seconds.

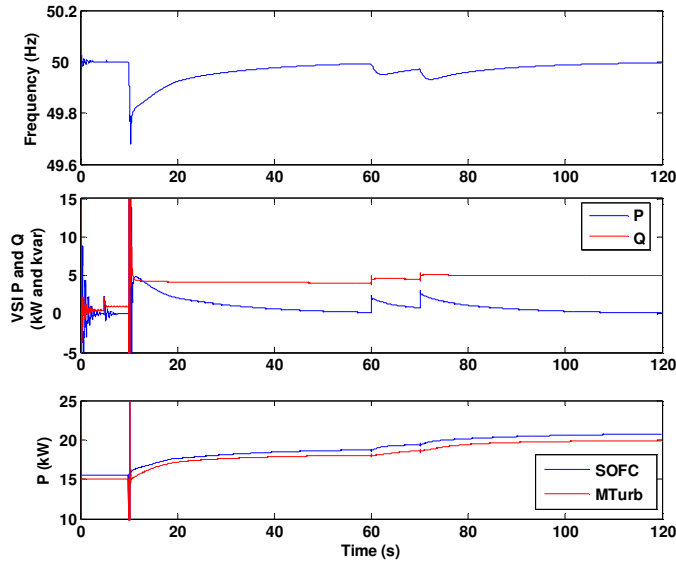


Fig. 5.8. MG Frequency, VSI active and reactive power and SOFC and single-shaft microturbine active power

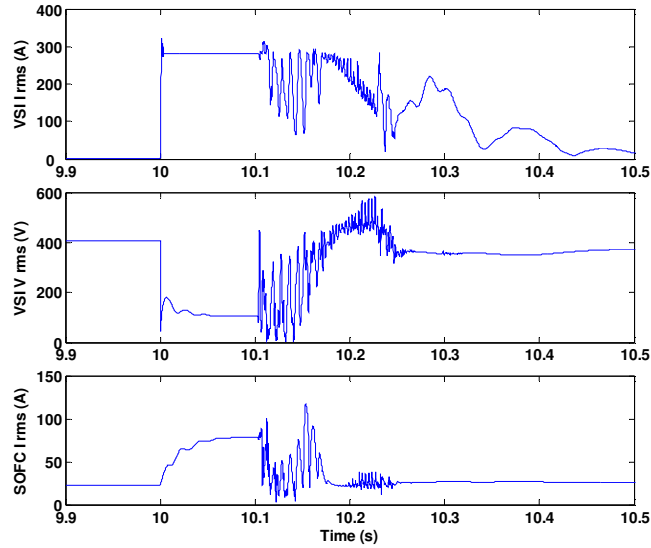


Fig. 5.9 VSI current and voltage and SOFC current (rms values)

5.2.7 Multi Master Operation

In order to analyze the dynamic behaviour of a MG under a multi master approach, the dynamics of the primary energy sources (single-shaft microturbine and fuel-cell) were neglected due to the high storage capacity assumed to be installed at their DC link. The considered scenario is similar to the previous one. After the islanding, active power is shared amongst several inverters according to droop settings. At $t = 20$ seconds a local secondary control (based on an integral frequency control deviation approach) is applied to correct the steady state frequency deviation after islanding. It is also possible to observe that voltage variations are very small. In this case voltage control through droops is sufficient to maintain voltage levels within acceptable limits.

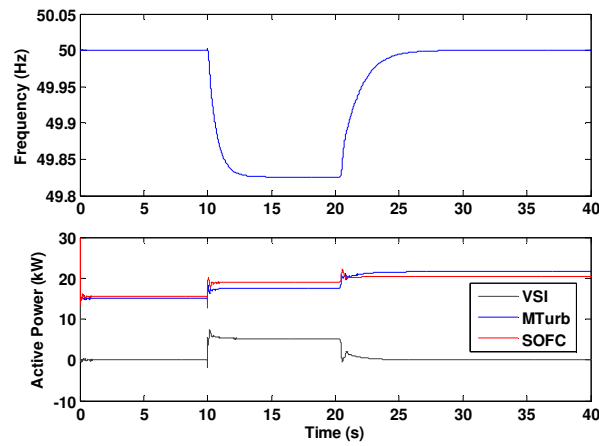


Fig. 5.10. MG frequency and active power in microsource

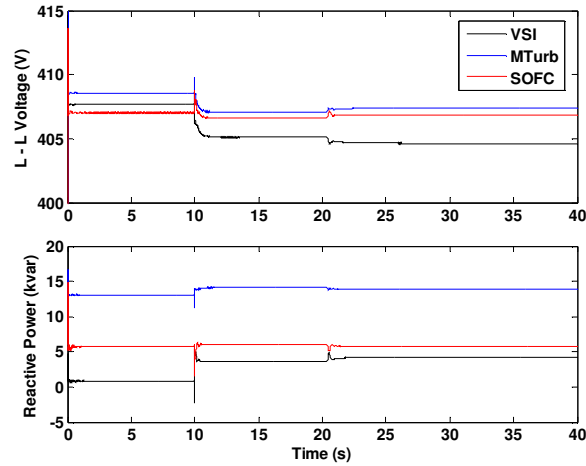


Fig. 5.11. Microsources voltages (rms values) and reactive powers

5.2.8 Conclusions

From these studies one can conclude that LV grids can be operated in islanding mode with microsources feeding local loads, provided that new control concepts are exploited. Load shedding capabilities and storage devices play a key role for the success of such islanding and load following strategies.

5.3 HV and MV Distribution Grid Islanding Operation

HV and MV distribution grids network with large penetration of dispersed generation (hydro, wind and thermal) are eligible for islanding operation under certain conditions.

In order to evaluate the possibility of operating such a network type in an islanding mode, two different approaches were studied. Conceptually, an islanding operation can result of a manual switching action or a protection device action that provokes the disconnection of the distribution grid from the main network. The first corresponds to an intentional island, as a consequence of maintenance or repairing action in the transmission network/interconnection. The second islanding situation is a consequence of a fault on the transmission line, followed by opening of the distance protections relays, which by tripping the line out will conduct to its formation in a spontaneous way.

In order to evaluate the feasibility of such operating strategy several simulation studies have been conducted in a real dimension HV / MV (60 kV / 30 kV) distribution grid existing in Portugal. Such analysis was based on the evaluation of the system's dynamic behavior following a sequence of simulated disturbances. Such a detailed analysis requires a complete modeling of all components and protection systems, as well as their operational logic, and was integrated in the dynamic simulation software. All the details previously referred to required a significant calculation effort, having analyzed 14 operation scenarios in situations of intentional and spontaneous islanding, with different regulations of the protection systems, leading to more than a hundred studies. For the dynamic behavior analysis considered, in most cases, a longer time scale than most stability studies was required, where in the latter case only the transient period is considered. This measure allows not only visualization of the system's capability to return to the initial state conditions, but also to verify its behavior in response to more complex and wider set of disturbances.

Feasible operation in islanding mode supposes that some of the dispersed generation, namely the one with the highest rated power and with control capability of the primary resource, is provided with a speed governor system. Adding to this, it was assumed that all the producers with synchronous machines have automatic voltage regulation, that is to say, are able to regulate their interconnection bus voltage towards an established reference, by injecting or consuming reactive power. As far as producers using asynchronous machines are concerned, there is no capability either in terms of voltage or frequency regulation, although existing capacitor banks allow some voltage control capacity.

For the scenarios definition, several criterions were considered such as year season, rainfall and wind power availability in situations of off peak and peak hours. The total installed generation capacity in the island is about 150 MVA for a maximum load of 103MW and 47 Mvar in the most loaded scenario, showing that it is possible, with appropriate primary resources availability, to fulfill the demand in the permanent regime using only distributed generation.

All the components were modeled for dynamic simulation, using models typically adopted in this type of studies. The loads, corresponding to consumptions per substation, were represented as constant admittance given the inexistence of enough detailed information to allow further complex models. The interconnection with the transmission network was also considered, being modeled as an equivalent machine, with close characteristics to the real network. That is to say, a very large inertia synchronous machine complemented with both speed and voltage regulation. The assumed values for the control loops of each regulator reflect the behavior of the European Network.

As far as distributed generation is considered, the models of the generators and their control systems were included in detail, reflecting the wide range of different existing technologies. From thermal and hydro units with synchronous generators, to wind units with both asynchronous and synchronous generators, all the models were treated in this study. For conventional synchronous machines a 6th order model, for asynchronous a 3rd order one and for variable speed synchronous generators a simplified aggregated model.

The high sensitivity of isolated networks to primary resources intermittence and load following implies that some of the synchronous units in operation must have speed and voltage regulation capability to grant a successful isolated network. In this case, five machines have this possibility, four of them being hydro units and the other a thermal one. These machines complement each other, as hydro units tend to respond in a slower way than thermal ones (due to water starting time phenomena), but assuring a more robust and less sensitive response to fast frequency deviations.

A very important part of these types of studies concerns the protection devices. Besides all the typical devices commonly used in networks, in this particular case the interconnection devices between the disperse generation and the network assume a preponderant role. In fact, their settings are vital to ensure the survival of an islanding, as the stability of such a network is clearly lower than when interconnected. The considered protection devices for each interconnection are the following:

- Over frequency relays

- Under frequency relays
- Under voltage relays
- Over voltage relays

In Portugal, the regulation of these devices is based on instantaneous operation, with the values included in the following table.

setting	Min voltage	Max voltage	Min Freq	Max freq
time	0.05 s	0.05 s	0.05 s	0.05 s
value	0.85 p.u.	1.15 p.u.	49.8 Hz	50.2 Hz

One can easily conclude that with these values, islanding operating mode is in fact unfeasible, even if referred to a programmed isolation. A small frequency deviation will trip one or two smaller machines, leading to under frequency relays installed in substations to activate, and a cascade effect leading to system blackout. So a new set of protection settings was proposed, as shown in next table, allowing a successful transfer in some cases while assuring a proper performance in terms of quality of service.

regulation	Min Voltage	Max Voltage	Min Freq	Máx freq
temporization	1.05 s	0.4 s	1 s	0.8 s
value	0.85 p.u.	1.18 p.u.	49.0 Hz	51.5 Hz

After separating the network and stabilizing the subsequent frequency oscillations, it is acceptable that a difference persists between the average frequency of the isolated network and the nominal frequency.

5.3.1 Results

After simulating several scenarios, one can conclude that it is possible to use distributed generation to improve system availability without compromising a safe operation.

The scenarios where the islanding was intentional, showed that if proper isolating conditions are created (by reducing the power flow in the interconnection line just before separating the networks) and hydro production has some reserve (only impossible in normal summer season), the success of islanding is a reality, given that the dispersed generation is able to fulfill all the loads in the network. As an example, one can observe the time evolution of frequency, voltage and load in the following figures

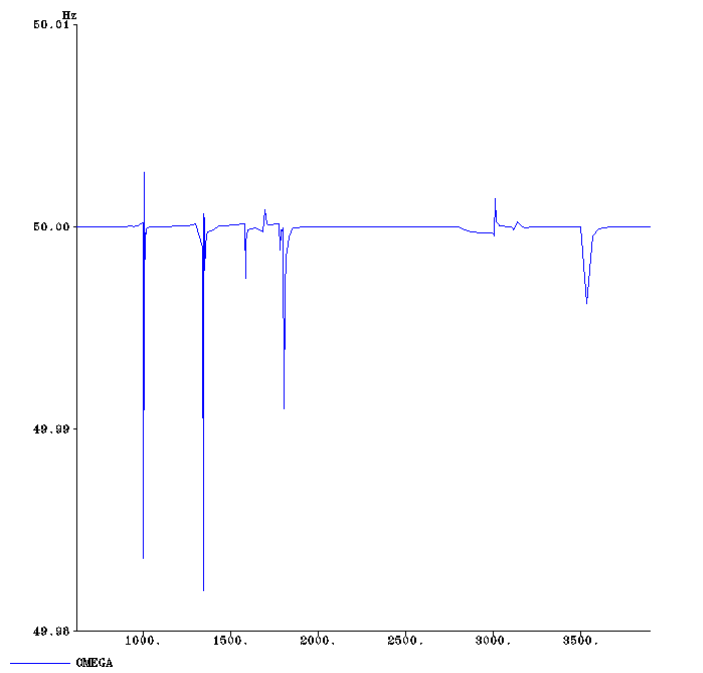


Fig. 5.12. Frequency of isolated network

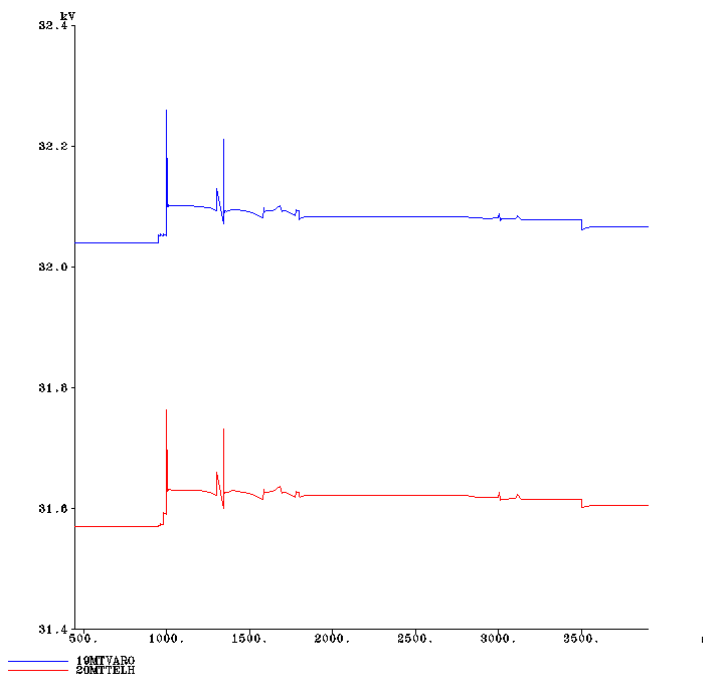


Fig. 5.13. Voltage in two substations

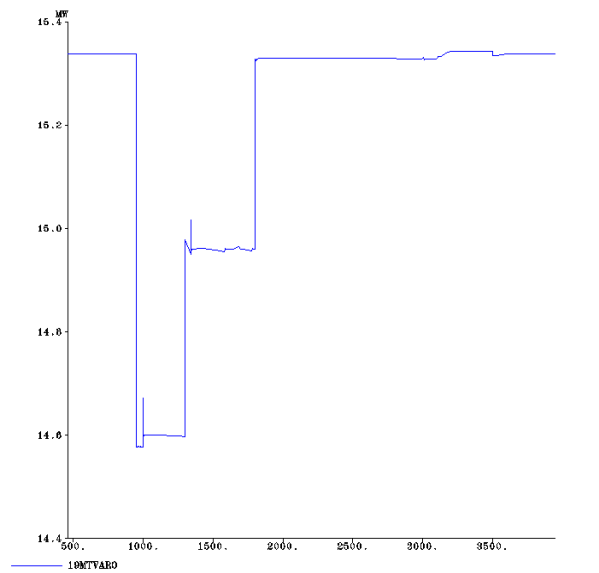


Fig. 5.14. Load in substation

Observing the frequency evolution, it can be noted that the oscillations due to load shedding and its reintroduction after the islanding do not compromise the quality of service. Voltage levels are also acceptable under these circumstances, showing that this operational mode is feasible.

The isolation due to a fault on the transmission line is, indubitably, more aggressive to the network stability and the success cases are by that fewer than when in an intentional isolation. The same system variables can be observed in the following figures

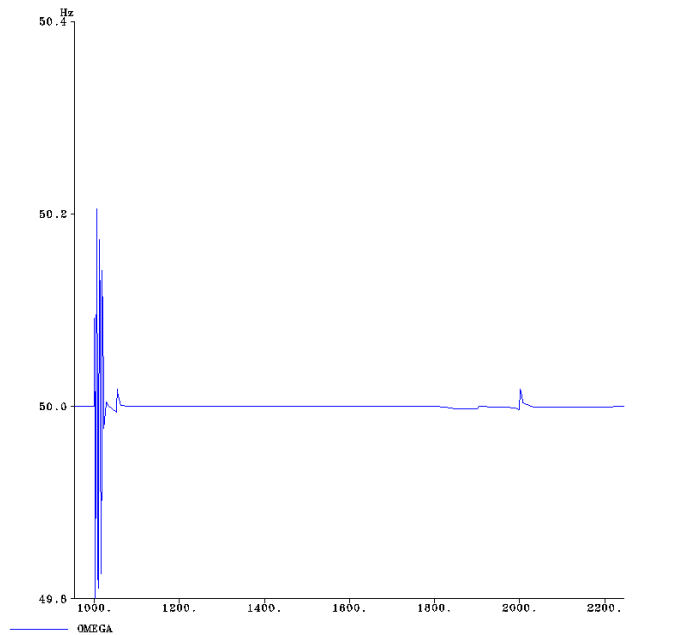


Fig. 5.15. Frequency in isolated Network

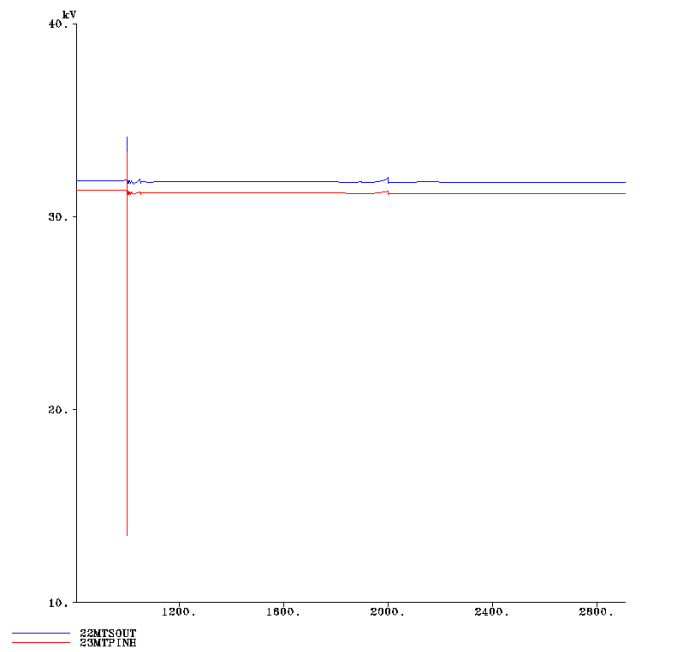


Fig. 5.16. Voltage in 30kV buses

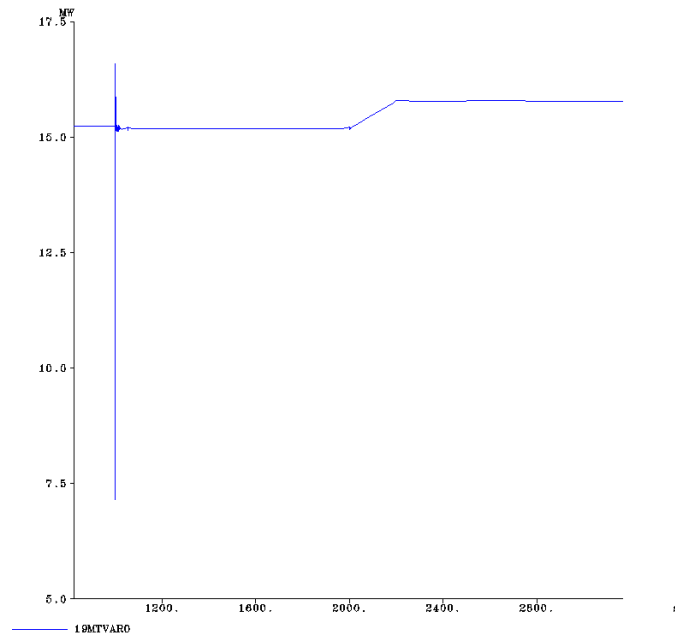


Fig. 5.17. Load in substations

This scenario is quite favorable for islanding, showing that not only the network is capable of being isolated after a fault without under frequency relay operation, but can also support a sustained increase in load without losing synchronism.

5.3.2 Conclusions

After analyzing all the simulated scenarios, the major conclusions to retain are that the success of islanding in a HV distribution network relies on the following aspects:

- The presence of speed and voltage regulation is mandatory for such an exploitation;
- The settings of the protection devices must allow frequency and voltage deviations within a

- wider range than is usually required, most notably regarding the time delays;
- The load flows between the network to be isolated and the interconnected one must not be very significant (in the studied cases 8% off consumption/production was the largest value to allow success)
 - Under frequency relays must be set to shed load only when frequency drops below 49 Hz, otherwise a cascade effect and consequent blackout may occur.
 - Recent technologies must be more accurately modeled so that their higher flexibility can in fact be used in islanding operation, reinforcing the idea that this sort of capacity can and should be used to improve network reliability.

CHAPTER 6. Recommendations and Conclusions

6.1 Status of DG Implementation

While there have been major developments in distributed generation over the past couple of decades, the industry is not yet mature. Pushed forward by policy changes which favour renewables, new technologies are only now been adopted, with many new planned wind projects worldwide, many of the new turbines, like many DG, employing power electronics as a means of interfacing with the grid.

Utilities, governments, and regulatory bodies have addressed this growth by developing interconnection requirements aimed specifically at these types of generation. Through international organizations, such as the IEC and IEEE, standards are now in place, that dictate conditions which interconnecting DG must abide by, covering normal operation and contingencies. However, the majority of these standards have been developed from the point of view of ensuring DG does not negatively impact the grid rather than integrating DG and making it a functional unit of the modern power system.

To complement the work on the standard's side, and in certain cases to support the development of standards, impact studies have been performed, typically in addressing potential negative impacts as well as for defining the reconfiguration of operational strategies, such as protection settings. While many of these works are publicly available, they do not always consider generic cases and a wide range of practices are employed. Generalized procedures have yet to be developed and adopted and as a result the real impact of DG is not clear in many cases.

The integration of DG has produced a great deal of knowledge and the majority of important issues have been well defined. However, to date, the general philosophy when considering DG has been one of annoyance as opposed to an opportunity, due in part to the complexity that it brings to the power system, but also due to the lack of willingness on the part of the DG producer to play an active role in the operation of the bula power system. The following section discusses various areas of interest where DG can potentially offer beneficial consequences. This subsequently followed by an outlook towards the role of DG in future power systems and recommendations for further integration of DG.

6.2 Recommendations for Future Standardisation Activities

Parts of the recommendations are based on results of the research work carried out within the Tasks 2.2 to 2.5 of DISPOWER, which aimed at developing new solutions for improved Power Quality and Safety in DG networks.

6.2.1 Determination of DG installed Capacity

With the exception of micro-generation connected at the LV networks, a clear procedure should be defined in the requirements to calculate the possible DG capacity to be installed at one point of the network. In this case, the adoption of simple rules might not be appropriate, since these rules tend to be rather restrictive and more detailed calculations can often show that more generation can be connected with no difficulties. The required technical analysis should consider aspects like the network topology, the power quality requirements and the loads. A probabilistic approach is shown to provide an objective assessment of the possible constraint violations, while a deterministic approach based on worst case situations (mimimum load-maximum DG output) might unnecessarily limit DG

penetration levels. A relevant question concerns the allocation of costs for any required network reinforcements.

6.2.2 DG Participation in Voltage Control

DG is not allowed to perform voltage control. It is obvious however that the overall performance of a distribution system with a significant penetration of DG may be optimized, if DGs are considered by the DNOs as one more control parameter in scheduling their network operation. For example, in some cases, the voltage rise can be limited by reversing the flow of reactive power (Q) either by using an induction generator or by under-exciting a synchronous machine and operating at leading power factor. This can be effective on higher voltage overhead circuits which tend to have a higher ratio of X/R . In these cases, the DNO should clearly define under which conditions this should be allowed.

6.2.3 Unintentional Islanding

Design of islanding protection schemes should be driven by a risk-based approach, based on system configuration, plant operation and generator response. For large installations the risk of multiple tripping of generation units needs to be considered with reference to similar risks associated with sudden load loss.

The probability for the unintentional creation of an island shall not be regarded as virtually negligible. Especially with increasing penetration levels of DG intended to support reactive power, voltage or frequency control, the potential risks associated with this event may not be neglected any more. Hence additional protection methods to the standard voltage and frequency monitoring are required in order to detect a loss of mains at the generator and ensure the safety of customers and maintenance personnel.

For larger units, protection shall be designed on basis of a rigorous assessment of discrimination and risk. Since islanded operation does not necessarily carry high short term risk, delayed protection allows a better discrimination of the system and thus increases system security. This philosophy needs to be reflected in interconnection standards and grid codes.

For small-scale units standardised, integrated protection systems help to keep the system costs at a reasonable level. These protections should be type tested based on realistic situations in the network, such as matched load conditions. Additionally, in order to prevent inadvertent, spurious tripping and avoid negative impacts of protection devices on the quality of supply, clear requirements and limits for immunity as well as emission levels need to be included into the qualification procedures and interconnection standards.

6.2.4 Active Distribution Network Management - Microgrids

One of the potential key benefits of DG, being connected at the MV and LV networks, is increase in service quality, reliability and security. However, these benefits cannot be fully realized, if DGs are not integrated in the overall system operation and allowed to support the network in disturbed conditions and allow parts of the network operate islanded. Although transmission system operators have historically been responsible for system security, large integration of DG will require distribution system operators to develop active network management in order to participate in the provision of system security. This will present a radical shift from traditional central control philosophy to a new more distributed control paradigm. Such a control paradigm is provided by Microgrids. These systems can be operated in a non-autonomous way, if interconnected to the grid, or in an autonomous way, if

disconnected from the main grid. The operation of DG in these networks introduces considerable complexity in the operation of a LV grid, especially under islanded operation, but at the same time, it can provide distinct benefits to the overall system performance, if managed and coordinated efficiently. The operation of Microgrids requires significant efforts in research, development and deployment of new technologies and required information and communication infrastructure, but is likely to deliver significant benefits over the traditional control policy in the long term. Regulatory changes and well defined standards need to be developed to make their operation possible.

6.2.5 DG behaviour during Network Disturbances

Most current DG related standards do not require a defined response of DG during typical network disturbances, such as voltage sags. This has led to a general lack of awareness towards these phenomena in context of DG and an unacceptably low level of equipment immunity.

The safe and secure operation of networks based on a high penetration of DG requires a defined response of the generation units during critical conditions and network disturbances. To achieve this, it is essential to include clear and appropriate requirements concerning immunity as well as testing procedures in future DG standards. These should be accompanied by minimum requirements regarding the behaviour during network disturbances taking into account generation technology issues and the capacity of the installation. Of specific significance in this context are issues such as LVRT (low voltage ride through) capability or voltage support during disturbances.

6.2.6 DC injection into the LV network by DG Inverters

Currently the maximum levels of DC current which may be injected by distributed inverters according to various European national and international codes vary in a wide range from levels as low as 20 mA up to 1 A or 0,5% up to 5%. Based on the results it can be proposed to consider an acceptable (planning) level of DC in the range of the excitation current of the distribution transformer, which will not adversely affect transformer operation. For a realistic, high DG penetration scenario, this leads to a DC injection limit requirement of 0,5% of the generator rated current.

In addition a higher, fixed level limit of 0,1 A is proposed for micro-scale DG, due to the superposition effects of the DC injected by a large number of generation units. Applying a fix level is explicitly recommended to avoid imposing unnecessary requirements on micro-scale DG.

6.3 Evolving grids and DG

The modern power system has greatly benefited from microprocessor based devices as well as recent developments in communication. DG as an emerging technology also offers the potential to improve its reliability, increase diversity, and provide greater flexibility to help match the increasing and ever changing energy needs of the world's population. Small capacity generators essentially operate in three types of modes: grid connected, remote grids, and capability to operate grid connected or in islanded mode. The third mode can greatly benefit from experience gained operating the former two. In all cases, the flexibility and ease with which DG can be integrated will depend in large part on the monitoring and communication capabilities present in the network of interest.

6.3.1 DGs and communication

The power of communication in a power system is that one has greater access to information, enabling improved control, observability and inevitably planning of the system. It is apparent that DG will

depend on improved communication infrastructure and therefore would benefit from increased investment in communication. As many distribution companies are currently implementing distribution system automation programs, they are equally investing in DG although this is not the primary driving force. Not only will this permit monitoring of operation but it will also be used to aid in planning. This may eventually help to reduce the skepticism surrounding probabilistic methods.

Finally, communication between DGs and between DG and the distribution system operator will increase the likelihood of high penetration of DG. At the moment it is not clear how this infrastructure will be installed and by which party and more importantly who will be responsible for these costs. However, as demonstrated in the case of large wind parks, communication is vital to properly coordinate its operation with that of the power system. Widespread integration of DG will not occur until the necessary communication infrastructure is in place.

6.3.2 Aggregation of grid connected DG

The majority of DGs are presently grid connected and are based upon a wide range of technologies, with each type possessing a variety of advantages and disadvantages. As is well known, a producer holding a larger share of the total generation will typically be in a favoured position, and likewise one that can combine a number of technologies can possibly benefit from the diversity, exercising the advantages while limiting the drawbacks.

In the case where a number of DG are aggregated, that is they bid, respond, and pay costs as a single entity, they can potentially realize many of the gains associated with a large, dispatchable generator. Strategies for aggregating generators need to be developed for those at the distribution level. While this is typically an issue of improving the economics, it is important to realize that cost is perhaps DG's greatest barrier.

At larger levels, wind parks output combine the outputs of the individual generators, however, the wind park may be charged balancing services which obviously influence the profits and therefore viability of the plant. Should these services be offered from other sources or by storage devices, the overall economics could be improved. Time will dictate whether this need exists as the cost of electricity rises and studies determining the cost of this service are revisited and agreed upon.

6.3.3 Remote applications

In many countries the use of DG for remote applications is quite important although typically represent only a very small percentage of the total load served. However, much knowledge can be gained from operation of these systems. Methods for load following in small distribution networks can be demonstrated and proved in these systems. Furthermore the ability of wind and other intermittent technologies to serve these communities can help to push for acceptance of these types of DG in grid tied systems. Renewable technologies usually are placed at an advantage in remote applications due to their invariability in cost. Contrarily, the economics associated with diesel and other fossil fuel technologies is tied to the price of gasoline and the transportation and maintenance cost, which are typically much higher in these cases, due to their location with respect to urban centres.

6.3.4 Microgrids

Microgrids, while a new concept, it can greatly benefit from the research that has been done with grid connected DG together with the operation of remote power systems. While the combination of these two fields does not directly provide the information required for Microgrid operation, it sheds light on the operation of DG in these two types of systems. That aside, the economics are entirely different due to the fact that a Microgrid is under normal operation grid tied. As a result the economic argument for configuring a system for Microgrid is much more difficult, particularly given the relatively high degree of reliability that is presently offered by modern power systems.

Microgrid research needs have now reached the point of demonstration of practical operating systems. Often this is the stage where the feasibility of the concept and many of the details regarding operation of the system become apparent. Both in Europe and in North American, various groups now focus on implementation of real systems in order to verify many of the concepts that to date have been mostly dealt with in simulated or controlled environments.

The extension from research projects to utility adoption will only follow should the necessary justification be in place, which will primarily be argued from the point of view of reliability. The bulk of other arguments surrounding Microgrids are applicable to DG in distribution systems and are not necessarily specific to Microgrids per se. Although various utility case studies have been cited, it has yet to be established whether widespread utility adoption of the concept can be anticipated. This will depend on the extent to which DG is integrated, the cost of equipping a system with MicroGrid capability and the need for higher levels of reliability.

6.4 Recommendations for Policy and further R&D

Presently, a great deal of knowledge has been gained regarding DG technologies and their implementation. However, with the exception of wind parks, the actual implementation and operation of these systems is still minimal. In order to increase the acceptance and level of DG, further steps are required.

6.4.1 Standardized Impact Assessment and Integration Techniques

Most utilities worldwide have dealt with DG in one form or another, however, generalized practices have in most cases not yet been developed nor implemented. Connection requests are typically treated more on a case-by-case basis using the methods used by the local utility. In order to permit greater integration, experience in dealing with DG needs to be shared and contained in useful documents describing its effect and the conditions under which integration is realistic and when it is not. This work is now under way to a certain extent through the development of application guides (IEEE 1547 series) however the usefulness of these guides and their applicability will depend greatly on the participation in their development.

6.4.2 Regulatory issues and interconnection agreements

While many of the technical issues can be addressed through the development of guides and interconnection standards, regulations are typically a greater barrier to DG integration. Due to the fact that the utility owns the infrastructure and are responsible for its operation, the responsibility for serving the client rests almost entirely with this entity. As a result, the motivation for integration privately owned generators is not great considering that these systems generally add a degree of complexity and decrease the ability to which the system can be controlled.

Government policy changes can help to impose acceptance of certain amounts of renewable generation, however, equally important will be sharing of the responsibility for serving the load. Likely, DG may diverge into two general classes: those that are exempt from responsibility and simply disconnect in the event of disturbance and those that share in the responsibility and aid in supporting the system and in providing ancillary services. In some respects wind parks have already begun to move in this direction, however, the distinction should become clearer in order to streamline the process for integrating different types of DG sources.

6.4.3 Economic justification

Greater responsibility for certain DG as well as supply of various services should be compensated for economically. This will improve the economic viability of DG but also will encourage participation in

operation of the system. While this is more or less apparent what is not as clear is what the actual amount should be. In certain cases a DG may negatively impact the system whereas in different circumstances DG will greatly contribute to improvements in the overall operation of the system. Whereas methods for determining the technical impacts have already been developed and somewhat agreed upon, methods for quantifying the benefits and costs associated with DG are not well defined.

As the economics associated with DG presents itself as likely the most important barrier, it is imperative that methods for assessing the costs and benefits of DG be defined. In this way new generators are charged or compensated based upon well-defined techniques and as well the most economical locations for DG interconnection can be determined. Without properly defined methodologies much uncertainty remains regarding the actual costs that are charged to DG owners and benefits will never be appropriately acknowledged. While for technical characteristics the motivation to develop methodologies for utilities exists, for economic considerations there is little interest in acknowledging or compensating for benefits. This will require an initiative on the part of independent power owners together with government bodies in order to ensure that these issues are properly addressed.

6.4.4 Regional characteristics

Distributed generation has experienced a greater degree of growth in certain countries where the technologies implemented may not necessarily have been those best suited to the area in question. As the industry matures, site selection of the DG and selection of the technology itself should reflect what makes most sense in terms of cost, benefits, and needs of the local community. While optimal placement of DG may be too limiting in the site selection a move towards favoring certain regions over other through price signals should be considered. DG can benefit the system, however it should be ensured that this is the case and not that DG is integrated simply for the sake of integrating DG. Furthermore, the technologies that are chosen should be taken into consideration when selecting the site as well. Wind and small hydro are technologies that could certainly help to serve rural systems, however whether they will play a role in urban settings should be re-evaluated. Part of making renewables more competitive with conventional technologies is choosing where they are most beneficial and through the necessary pricing schemes are consequently the most competitive as well.

6.5 Conclusions

Distributed generation is an emerging technology that has the potential to offer improvements in power system efficiency, reliability and diversity, and to help contribute to making renewables a greater percentage of the generation mix. While a great amount of knowledge has been gained through past experience, the practical implementation of DG has proved to be more challenging than perhaps originally anticipated. Numerous barriers have presented themselves in opposition to large-scale DG integration, namely utility opposition, lack of the necessary regulatory framework, and of course the cost. As policy changes help to drive regulatory changes, DG research and development helps towards a greater understanding of this alternative and the cost of electricity increases, DG will inevitably experience further growth in the coming decades. The extent of this growth will depend in large part on the willingness of utilities along with the participation of independent power producers in developing a strategy for future DG integration.

Appendix A: Grid Connection Criteria in Various Countries

A.1 Grid Connection Criteria and Protection Practices for DG in France

A.1.1 Introduction

Like in many other countries, distribution networks in France were not initially designed for DG. They were mainly planned and operated to supply power to customers with the energy flowing in only one direction on the feeders (from the substation to the customers). The connection of DG units changes the situation and it has given rise to new problems and constraints.

In France, these new constraints led the government to set up working groups composed of the different players involved in the French power systems in order to discuss and define the technical requirements for the grid connection of DG units to the transmission and distribution networks. These technical requirements were then specified in Government decrees and Ministerial orders.

A.1.2 Grid connection regulations in France

Between 1995 and 1999, several ministerial orders were published concerning the technical specifications for the connection of DG units :

- larger than 1 MW [47][49] and smaller than 1 MW [48] to the distribution grid,
- smaller or equal to 120 MW to the transmission grid [50],
- to medium voltage (MV) and low voltage (LV) distribution grids which are not part of a large interconnected network and in particular the French islands [51].

These orders were very detailed and described the main technical issues related to grid connection along with the network requirements.

In February 2000, was published the French law on the modernization and development of the electricity public service [52] which resulted from the transposition of European Directive 96/92/CE concerning common rules for the internal market in electricity [53].

Following the publication of this French law, the above 5 ministerial orders were replaced in 2003 by new government decrees concerning the technical specifications for the connection of “installations” to the distribution [54] and transmission [55] networks. The term “installations” concerns all types of installations, i.e. consumers’ facilities, generating plants (and in particular DG units) or whatsoever. Special sections are devoted to generating units. Ministerial orders were then issued with more specific connection rules for generation plants [56], [57], [58].

The new decrees and ministerial orders are applicable for the generating plants connected for the first time to the network or for the generating plants that have been subject to significant modifications requiring a new connection agreement between the producer and the system operator : for instance for generating units that replace existing ones or when the installed power is increased by at least 10 %.

The new texts are much less detailed than the preceding ones and will be complemented in technical reference guides prepared by the transmission and distribution network operators (DNO and TSO grid

codes), as well as in contractual documents established between the producer and the network operator (e.g. the connection and operation agreements).

The network requirements for the connection to the distribution grid are described in the sequel. They concern all types of generation plants i.e. whatever the energy source and the generation process used. However, whenever applicable, the specific measures taken for certain types of DG units (e.g. induction generators, wind farms, very small units, etc.) will be pointed out.

A.1.3 Distribution grid connection criteria in continental France

A.1.3.1 Voltage level at the connection point

In France, the voltage level for the grid connection of a generating plant depends on its size. Table A1.1 gives the requirements concerning the voltage level at the connection point as a function of the size of the generating plant.

TABLE A1.1
VOLTAGE LEVEL AT THE CONNECTION POINT

Network	Voltage limits	Effective levels	Power limit
LV	$U \leq 1 \text{ kV}$ (single phase connection)	230V	$P \leq 18 \text{ kVA}$
	$U \leq 1 \text{ kV}$ (three-phase connection)	400 V	$P \leq 250 \text{ kVA}$
MV	$1 \text{ kV} < U \leq 50 \text{ kV}$	15kV, 20 kV	$P \leq 12 \text{ MW}$
HV	$50 \text{ kV} < U \leq 130 \text{ kV}$	63 kV, 90 kV	$P \leq 50 \text{ MW}$
	$130 \text{ kV} < U \leq 350 \text{ kV}$	150 kV, 225 kV	$P \leq 250 \text{ MW}$
	$350 \text{ kV} < U \leq 500 \text{ kV}$	400 kV	$P > 250 \text{ MW}$

with U the three-phase voltage, P the maximum power of the generating plant, LV low voltage, MV medium voltage, HV high voltage.

The distribution networks concern mainly the LV and MV levels. The HV levels concern the transmission networks. On the LV grids, two types of grid connection are possible: single phase connection for generating plants smaller than or equal to 18 kVA and three-phase connection for larger plants (with a limit of 250 kVA).

A.1.3.2 Steady-state thermal constraints

The maximum values of the current flowing in the distribution grid to which the DG plant is connected shall be checked to ensure that the maximum admissible current values are not exceeded.

N.B. In cases of large DG units or for high penetration of DG on the distribution grid, the impact on the transmission network should also be assessed in order to check that the maximum currents constraints (as defined to guarantee the safe operation of the transmission network) are not violated.

A.1.3.3 Short-circuit powers and currents

The maximum short-circuit currents when the DG unit is connected shall be computed to verify that they do not exceed the maximum admissible values for the different pieces of grid equipment (e.g. lines, cables, circuit breakers, ...). This verification is done according to the methods described in the IEC 60-909 standard with short-circuit times larger than or equal to 250 ms.

A.1.3.4 Voltage profile on the distribution grid

Before a DG unit could be connected to the grid, the Distribution Network Operator (DNO) checks and verifies that the voltage values can be maintained between the lower and upper admissible limit values everywhere on the distribution grid whatever the operating conditions may be with or without the DG unit connected. The voltage constraints are also checked at lower voltage levels.

A.1.3.5 Voltage control and reactive compensation

The following constraints are imposed in the regulatory texts concerning the control of the voltage and of the reactive power :

- Generating plants connected to the LV grid must not consume reactive power.
- For generating plants connected to the MV grid and with an installed power $P \leq 1$ MW, each generating unit shall be able to produce (at the machine terminals) a reactive power up to 40% of their apparent nominal power S_n .
- For generating plants with an installed power P such that $1 \text{ MW} < P \leq 10 \text{ MW}$, each generating unit shall be able to produce (at the machine terminals) a reactive power at least equal to 50% of S_n and to consume a reactive power of 10% of S_n [57]. Within their reactive power generation and consumption capabilities, they shall be able to adjust the voltage control at the DNO's request.
- Generating plants with a installed power larger than 10 MW shall be equipped with a voltage control system. Each generating unit must be able to produce (at the machine terminals) at least 60% of S_n and to consume at least 20% of S_n .

As regards induction generators, their reactive power needs, as well as the possibly required additional reactive power generation, are provided by capacitor banks connected to either the producer's installation or to the HV/MV substation. The reactive power produced by the capacitor banks at the DNO's request shall not exceed 0.4 S_n .

The value of the reactive power produced and the control mode (voltage or reactive power control) are determined by the DNO in accordance with network operation requirements.

These requirements are summarized in Table A1.2 below.

TABLE A1.2
REACTIVE POWER AND VOLTAGE CONTROL REQUIREMENTS

	Reactive power (Q) capacity minimum requirements	Control type determined by DNO
LV	$Q \geq 0$	Constant Q
$P \leq 1 \text{ MW}$	$0 \leq Q \leq 0.4 S_n$	Constant Q
$1 \text{ MW} < P \leq 10 \text{ MW}$	$- 0.1 S_n \leq Q \leq 0.5 S_n$	Q control Adjust V level on request
$10 \text{ MW} < P$	$- 0.2 S_n \leq Q \leq 0.6 S_n$	V or Q control DG equipped with V regulator
Induction generators	$0 \leq Q \leq 0.4 S_n$	Capacitor banks

A.1.3.6 Power quality requirements

In terms of power quality, the impacts of the grid connection of DG plants shall be limited in such a way that the DNO is still able to respect its commitments and obligations. More specifically, the following requirements are given in the ministerial order [56].

Flicker and voltage fluctuations. The following requirements in terms of flicker and voltage fluctuations are specified in the ministerial order :

- the flicker produced by a generating plant shall be limited in such a way that the DNO can respect the requirement $Plt \leq 1$ (Probability Long Term). The base levels on the MV grid are 0.35 for Pst (Probability Short Term) and 0.25 for Plt.
- the slow voltage fluctuations shall be limited so that the voltage does not exceed the voltage limit values specified by the DNO. These values are not given in the new ministerial order. N.B. in the “old” ministerial order, the voltage range for slow voltage fluctuations was $[-10\%, +6\%]$ of the nominal voltage on the LV grids and $[-5\%, +5\%]$ of the contractual voltage on the MV grids.

Harmonics emissions. Harmonics currents injected on the grid shall be limited according to the following requirements :

- On LV grids, the harmonics emissions shall be limited so that the DNO is still able to maintain the quality of the power supplied to other network users within the required limits.
- On MV grids, for generating plants with a power larger than 100 kVA, the harmonic currents injected on the grid shall be limited to the following values :

$$I_{n \text{ lim}} = k_n \frac{P_{ref}}{\sqrt{3} \cdot U_c}$$

where $I_{n \text{ lim}}$ is the limit current value for harmonics number n , P_{ref} is the maximum apparent power of the generating plant, U_c is the contractual voltage, and k_n is a coefficient depending on the harmonics number and given in Table A1.3.

TABLE A1.3
VALUES OF THE HARMONICS LIMITING COEFFICIENTS

Odd harmonics	k_n (%)	Even harmonics	k_n (%)
3	4	2	2
5 and 7	5	4	4
9	2	>4	0.5
11 and 13	3		
>13	2		

Unbalance. On LV grids, except for generating units with a single-phase connection, the contribution of generating plants to the unbalance rate shall be limited in such a way that the DNO is still able to ensure that the average rate for the negative sequence is lower than 2 % of the direct sequence.

On MV grids, measures shall be taken so that the contribution to the voltage unbalance rate shall be $\leq 1\%$ at the connection point of installations with single-phase equivalent load larger than 500 kVA.

Remark - Connection to the MV distribution grid. Regarding the connection to the MV distribution grid, the limits mentioned in the above three subsections are defined for a minimum network short-circuit power of 40 MVA at the connection point. If the network short-circuit power is lower than

40 MVA, the above limits should be multiplied by the ratio between 40 MVA and the actual short-circuit power.

A.1.4 Transmission of the ripple control signals

A ripple control system is implemented on the distribution network to transmit information on the applicable price or the change in prices (from day to night, peak prices, ...).

The influence of DG plants on the transmission of the ripple control signal has to be assessed and if it is affected, appropriate measures have to be taken in order to maintain the signal level to an acceptable value for the network users. This assessment is performed by the DNO and if necessary the DNO and the producer choose together how to solve the problem. If a filter has to be installed, the producer has to implement and maintain it.

A.1.4.1 Coupling requirements

The generating units shall not be connected to the grid if this latter is not energized except for certain generating plants which contribute to the network restoration after a black out (see below).

The coupling of synchronous machines shall occur at synchronism with a maximum gap of $\pm 10\%$ for the voltage, ± 0.1 Hz for the frequency and $\pm 10^\circ$ for the phase angles.

On the MV grids, the increase or decrease in the injected power on the grid shall not exceed 4 MW/minute. The fast voltage fluctuations at the connection point resulting from the coupling and start-up of the installation shall not exceed 5% during more than 0.5 seconds.

A.1.4.2 Neutral grounding requirements

On LV grids, as a general rule, the LV network neutral must not be grounded at the generating plant location while the plant is connected to the network. If the neutral must be grounded under isolated network conditions, an automatic control link will be required between the neutral grounding and plant coupling systems. However, depending on the network, it may sometimes be possible to ground the LV network neutral at the generating plant location after approval by the DNO.

On MV grids, the neutral must not be grounded at the generating plant location while the plant is connected to the network. Any underground cables leading to the generating plant must have their shields connected together and connected to the plant ground. If the plant is located in the vicinity of the HV/MV substation, it is preferable to connect the plant ground to the substation ground. The interconnection conductors should be sized on the basis of the maximum fault currents they are liable to handle.

A.1.4.3 Protection system

Detailed studies are carried out by the DNO to assess the impact of the connection of the DG plant. The impact on the sensitivity and selectivity of the protection system is assessed (whatever the voltage level), and it is checked that the connection of DG units does not lead to unwanted tripping of parts of the network nor conflict with the automatic or manual reclosing scheme that may be implemented.

Since the behavior of DG units may be rather different depending on the type of generators (synchronous or induction) and on their coupling systems to the grid (direct coupling or power electronics interface), the studies take into account the specific technology used for each considered case, along with an appropriate modeling.

To guarantee the safety of people and equipment as well as to prevent the generating plants to supply power under abnormal conditions, generating plants connected to distribution networks shall be equipped with decoupling protection systems in order to :

- ensure that the protection and automatic control systems fitted by the DNO on the network are able to operate properly,
- prevent operation of isolated networks under no-fault conditions, thus preventing the DG units to supply power to other users under abnormal voltage and frequency values and avoiding false couplings when these networks are reconnected to the main distribution network,
- instantly disconnect the DG plants in the event of a fault occurring during the special operating conditions which apply when live work is being carried out on the MV overhead network.

These decoupling protection systems must be coordinated with the DNO's protection scheme.

The decoupling protection shall be able to detect the following situations :

- islanded operation without fault,
- phase-to-ground faults,
- phase-to-phase faults for MV networks and faults between conductors (phase and/or neutral) for LV networks,
- risk of false couplings,
- faults on the HV network. This results from the fact that when the sum of the maximum active powers of all the generating plants connected to a HV/MV substation becomes significant (for instance larger than 12 MW), the DNO shall take appropriate measures to ensure the safety of people and equipment in case of faults occurring on the HV side.

The DNO specifies to the producer the performances which are expected from the decoupling protection. The DNO also provides the producers with the necessary information for the implementation and tuning of the whole protection system of the DG. This latter must be coordinated with the DNO's protection scheme.

Presently, different types of decoupling protections are defined for use with DG plants. They are mainly based on over- and under- voltage, over- and under-frequency criteria and in some cases on "intertripping", i.e. on the use of an automatic control link with the protections implemented at the substation level (such as the feeder protection or other protections which may lead to the islanded operation of DG units on parts of the distribution grid). Moreover, depending on the protection type, some relays may be instantaneous or delayed.

These decoupling protections were described in detail in the "old" ministerial orders [47, 48, 49]. In the new legislative context, only rather general information is given in the decree and ministerial order [54, 56]. They will probably be described in more detail in the technical reference guides that are being prepared by the DNO.

A.1.4.4 Dynamic behavior and stability

In the new decree [54], some requirements in terms of stability and dynamic behavior are specified for DG connected to distribution grids. Depending on their type, power and voltage level at the connection point, the generating plants shall be able to contribute to "support" the distribution network for limited time duration during degraded conditions, and more specifically :

- they shall be able to operate under the voltage and frequency ranges occurring in such degraded conditions,
- to a certain extent, they shall withstand and remain connected to the network for the voltage dips and frequency variations which spread on the network in case of disturbances,
- they shall remain stable for faults which are correctly cleared by the network protection system,
- their own protection system (machine protection, protection of power electronics interfaces,

etc.) shall not trip for conditions which are less severe than those implemented in their decoupling protections.

A.1.4.5 Network restoration

The DNO may ask the producer to adapt the protection system of the DG plant in order to contribute to the network restoration. This participation will be specified in the contractual documents established between the producer and the network operator (namely the connection and operation agreements).

A.1.4.6 Metering

Active and reactive energies exchanged with the network shall be counted at the “delivery” point (which may be different from the connection point). They can be measured at a different point (the “metering” point) defined in agreement between the DNO and the producer. In such a case, the measurements shall be transposed to obtain the values at the delivery point.

A.1.4.7 Operation rules and exchange of information

The procedure and measures taken to verify the conformity of the DG installation to the requirements specified in the regulation and in the contractual documents are described in the connection and operation agreements established between the producer and the DNO. In case the installation does not meet the requirements, the DNO may refuse the connection to the grid or may disconnect the DG plants from the grid.

Concerning information exchanges, when the nominal apparent power of a DG plant is significant with respect to the operation of the network, the producer has to provide the foreseen operation program to the DNO.

In some cases, a communication link will be installed between the generating plants and the DNO to exchange operating information (e.g. active and reactive powers of the DG plant) and possibly information on the network status such as the voltage.

In principle, it is considered that the DG plant is significant with respect to the network operation when :

- Its nominal apparent power is larger than 25% of the rating of the HV/MV transformer when the DG plant is connected to a dedicated feeder (feeder with no other users connected),
- Its maximum nominal active power is larger than 25% of the maximum load on the feeder, when the DG unit is not connected to a dedicated feeder.

The contents of the production program, the time period, as well as how much ahead of time it should be sent, are defined in an agreement between the producer and the DNO,.

A.1.5 Specific requirements for DG connected to isolated or island power systems

Due to the particular structure and characteristics of island power systems, the integration of DG leads to important and sometimes specific problems and constraints which have to be carefully and properly dealt with. This is particularly true for RE sources (such as wind energy) because of their high variability and rather unpredictable nature. Specific requirements have thus been defined [54],[56].

These requirements concern in particular :

- the possible reduction of the DG plant power depending on the network characteristics,
- the capability to withstand voltage dips and frequency variations,
- the DG plant stability for faults correctly cleared by the protection scheme,

- a possible limitation of the penetration level of DG plants which may be subjected to a sudden and large scale loss of primary energy.

They also concern the possible contribution of DG units to ancillary services such as primary and secondary control of network voltage and frequency, islanded operation and network restoration. The type of ancillary services requested from DG plants shall be specified in the connection agreement between the DNO and the producer.

A.1.5.1 Network security

Generating plants with an apparent power S_n larger than 1% of the minimal network “spinning” generation have to participate to the network security.

N.B. The network “spinning” generation at a given time can be defined as the sum of the nominal powers of the generating plants connected to the network at that time.

In this respect, except for induction generators, the requirements mentioned in the following two sections have to be fulfilled respectively in steady-state and disturbed conditions of the distribution network.

A.1.5.2 Requirements in steady-state conditions

Power delivered. At 50 Hz (nominal frequency), when the stator voltage (or for machines with power electronics the voltage at the inverter terminals) is between 95% and 105% of the nominal voltage, the generating unit must be able :

- to produce an active power P_n of 0.8 S_n ,
- to produce a reactive power Q_{n1} up to 0.6 S_n , and
- to absorb a reactive power Q_{n2} up to 0.1 S_n .

Continuous operation. In the frequency range between 48 and 52 Hz and in the voltage range between 95% and 105% of the nominal value, the generating unit must be able to control the generated active power and the generated (respectively consumed) reactive power within the following limits : +/- 5% around P_n and +/- 5% around Q_{n1} (respectively Q_{n2}), with P_n , Q_{n1} and Q_{n2} defined above.

Short duration temporary operation. The generating unit must be able to operate during a short time in frequency and voltage ranges larger than those described above. In such conditions, the generating plant performances may be lower than those required in continuous operation. The corresponding performances shall be described by the producer. At least, the generating unit must be able to operate for 3 minutes between 46 and 48 Hz.

A.1.5.3 Requirements in disturbed conditions

Fast frequency fluctuations. The generating units shall be able to withstand fast frequency variations in the following ranges and stay connected to the network :

- in the range 44Hz to 46 Hz during at least 30 seconds,
- in the range 52Hz to 54 Hz during at least 5 seconds.

Fast voltage decrease. The generating plants must stay connected and withstand voltage dips affecting one, two or three network phases such that the remaining voltage at the connection point is 0.3 U_n (with U_n the grid nominal voltage) for 0.6 seconds and 0.7 U_n for 2.5 seconds.

Stability. The producer must check by software simulation studies the stability of the generating plant before connecting it to the grid and he must send the results of these studies to the system operator.

In order for the producer to carry out these studies, the system operator provides the producer with the grid characteristics which are needed, as well as the generic schemes of the studies, the criteria and the required stability margins.

For island grids operating at a nominal frequency different from 50 Hz, the frequency values given above will be appropriately adapted.

A.1.5.4 Possible power limitations or disconnections

For security purposes, the DNO may need to limit the power injection or ask the disconnection of generating units connected to the grid which do not contribute to the primary reserve or may be subjected to a sudden and large scale loss of primary energy. In such a case, along with the results of the connection study (see Section 2.1.5 below), the DNO will give to the producer an estimate of the disconnections that could have taken place during a past (recent) period if the plant had been connected.

A.1.5.5 Decoupling Protection

The decoupling protection must be adapted, in particular to take into account the larger frequency ranges (see above).

A.1.5.6 Contribution to Ancillary Services

Generating plants with an apparent power larger than 1% of the minimum network “spinning generation” (see Section “Network Security” above) have to contribute to the frequency primary reserve and therefore maintain an active power reserve, except if the generation technology does not allow such a contribution. The maximum value of this reserve is +/- 15 % of the nominal power of the plant. The frequency control implies a droop coefficient with a value between 4 % and 6 %.

Generating plants which are considered as significant with respect to the network operation shall be equipped with a voltage regulator operating within the specified limits for the production and consumption of reactive power. They shall also be equipped with a regulator that adjusts the provided power within a few seconds on the basis of the difference between the frequency and its set point value. A slow regulation can be used to bring the power back to its set point value (in more than 10 minutes).

A generating plant is considered as significant with respect to the network operation if :

- when it is connected to a dedicated MV feeder (a feeder with no other users), its nominal apparent power is larger than 8% of the power rating of the HV/MV substation transformer to which the feeder is connected (or of whatever other equipment to which the MV feeder is connected),
- when it is connected to a feeder with other users, its power is larger than 20 % of the maximum load of the feeder,

When needed by the network operation, a DG plant may also be considered as significant if its nominal apparent power is larger than 1% of the minimum network spinning generation.

A.1.5.7 Exchange of Information between Producer and System Operator

Due to the necessity for DG plants to provide ancillary services specific communication procedures are used in island grids, relying on permanent links with a good availability. The list of information and data that shall be exchanged is defined by a dialogue between the producer and the system operator.

Like in distribution grids connected to the distribution network in continental France, the producer shall provide information on the operation program for generating plants which are significant for the network operation.

A.1.6 Procedure set up to deal with the grid connection requests

A.1.6.1 Waiting Lists for the Connection Requests

Due to the incentive measures taken by the French government to promote the development of wind energy in France (namely a purchase obligation at an attractive fixed tariff for wind farms smaller than 12 MW [59]), the system operators in France have received hundreds of requests for connecting wind farms to the grid, especially to the distribution network, due to the 12 MW size limit. For instance, in December 2004, there were more than 400 requests in the waiting lists (see below) for connection of wind farms to the distribution grid, corresponding to a total amount of more than 3100 MW installed power [60].

In order to deal with the large number of connection requests submitted to them, the French system operators have defined a procedure relying on waiting lists [60]. This procedure concerns all types of power plants for which a connection request is made, and in particular wind farms. Since the grid capacity limitations involve both the transmission and the distribution networks, the procedure implies a coordination between the transmission system operator (TSO) and the distribution network operator (DNO) for the management of the waiting lists.

The sharing of the grid capacity between the producers is based on the « first come, first served » principle.

A.1.6.2 Major Steps of the Procedure

The procedure for the submission of connection requests involves several steps. Some steps imply with fixed deadlines and if the producer does not meet these deadlines, the request is removed from the waiting list. The detailed description may be found in [60]. Only the basic steps are briefly presented below.

- For installations with a power lower than 2.5 MW, the producer may ask the DNO for a feasibility study. The DNO then carries out a limited study on possible grid capacity constraints. This study is optional.
- When all the technical data for the project are available and the producer is just about to ask for the administrative authorizations, the producer may ask the DNO to carry out a detailed study and then sends the DNO the required technical data. Again this study is optional but it will give the technical conditions of the grid connection taking into account all the projects which are at that time in the waiting list. The study will also give the estimate of the connection costs that the producer will have to pay. In case grid reinforcements are needed, the DNO provides information on the time period necessary to perform the work and on the possible power curtailments that will be required from the DG plant during this period.
- When the producer has obtained all the required administrative authorizations (for instance the building permission from the local authorities), he may then ask the DNO for a technical and financial proposal (TFP). If a detailed study has already been done, the results of this study are updated, if not a detailed study is done.
- If the producer accepts the TFP, the DNO performs complementary field studies and prepares the connection agreement. If the producer does not accept the TFP, the project is removed from the waiting list.
- If the producer accepts the connection agreement, the connection work begins. If the producer refuses the connection agreement, the project is removed from the waiting list.

A.1.6.3 Shallow versus deep cost approaches

Before November 1st, 2002, the deep cost approach was used in France and the producers had to pay all the costs related to the grid connection : the connection costs as such, and the costs for all the reinforcements that could be necessary, even if this concerned reinforcements on the HV side for DG connected to MV feeders.

In the present legislative context (i.e. since November 1st, 2002) the deep cost approach is no more used but the producer may still have to pay a part of the reinforcement needed.

More specifically, for DG plants connected to the MV grid, the producers pay the costs implied :

- by the connection (in itself) of their generating plant to the grid and
- by the network reinforcements needed between their connection point up to (and including) the substation to the higher voltage level, i.e. the HV/MV substation for a connection to the MV network.

The producers don't pay any more for the costs related to reinforcements on the HV side.

Moreover, to a certain extent, the producer may be reimbursed for a part of his/her spending if the network reinforcements are used afterwards for the connection of another producer.

A.1.7 Development of DG on the French distribution grid

At the end of 2003, the total DG installed power on the French distribution grid (without the French Island) was about 4326 MW [60] divided into :

- 1995 MW of CHP
- 673 MW dispatchable DG units (diesel gensets, etc.)
- 194 MW of wind energy
- 1093 MW of hydro power plants
- 297 MW of generating plants making use of waste
- 233 MW of other kinds of DG.

N.B. In February 2005, the total installed wind power was 398 MW.

Wind energy, cogeneration and photovoltaics are the DG types for which the numbers of connection requests are the highest : respectively 423 (for a total installed power capacity of 3175 MW), 61 (for a total installed power capacity of 299 MW) and 994 (for a total installed power of 9.7 MW).

A.1.8 Barriers against DG development

There are different kinds of barriers in France against the development of DG. These barriers are best illustrated in the case of wind energy and are therefore briefly described below in this context.

A.1.8.1 Heavy administrative procedure and public acceptance

The first barrier against wind power development in France is of administrative nature : it may be very difficult to obtain the required administrative authorizations. This situation may be explained by different factors :

- A lot of different administrative authorizations have to be obtained. So the procedure is complex and very heavy.
- Even if, at the national level, objectives for the development of wind power have been given, the situation and the political priorities at the local level are not always so clear.
- The local public opposition is often very strong (for sometimes very different reasons), which may lead to the rejection of projects by the local authorities.

A.1.8.2 Grid capacity limitations

Concerning the transmission grid in France. In 2003, RTE (transmission system operator in France) has announced a grid capacity for wind farms of 6 to 7 GW, taking into account the possible wind farm locations. So a wind power development of more than 6 to 7 GW will require transmission grid reinforcements or grid development. However, the development of a new transmission line can take between 7 to 10 years and often meet a strong public opposition. So an important wind power development in France will require a great implication of the government in order to speed up transmission grid development and reinforcement.

Nevertheless, at the distribution level, grid capacity constraints may sometimes appear depending on the feeder configuration and on the location. These constraints may imply in some cases :

- important interconnection work the cost which might jeopardize the economic viability of the project, and/or
- important grid reinforcements undertaken (and paid) by the DNO which may require power curtailment and important delay in the operation of the DG unit at full power.

A.1.8.3 Cost of DG and guaranteed purchase price

The cost of most DG technologies is still rather high especially for renewable energy sources (RES), and compared with the electricity price in France, they are not competitive yet.

Incentive measures have thus been taken at the government level to promote the development of RES and cogeneration on the distribution networks. These incentives measures consist mainly in a purchase obligation at fixed purchased feed-in tariffs which may be quite attractive for certain types of DG (see Section 2.1.5). These prices therefore rely on the national political priorities.

A.1.9 Conclusion

The grid connection technical requirements in France are specified in government decrees and ministerial orders and therefore are closely related to the legislative context. They will be complemented in technical reference guides (or grid codes) that are prepared by the system operators. These requirements generally aim at preserving the network security and safe operation, as well as preventing the deterioration in the quality of supply.

Many different technical aspects are taken into account in the regulatory texts : grid capacity requirements, steady-state voltage profile and reactive compensation, power quality issues, protection system issues, dynamic behavior and stability, exchange of information between the producer and the system operator,... And the particularities of island grids are also taken into account through the definition of specific technical requirements.

Generally the considered technical aspects highly depend on the processes and technologies that may be used at the different levels in the DG plant (e.g. energy conversion process, control strategies, type of generator, “coupling system” between the DG units and the network, ...). They also depend on the network configuration and operating conditions. This explains that studies have to be carried out for each specific case with an appropriate modeling and sufficiently accurate data for the different components involved (DG plant, network and coupling system between them).

A.2 Grid Connection Criteria and Protection Practices for DG in Spain

A.2.1 Introduction

Distributed generation is included in Spain under the so called *Special Regime*, as opposed to the *Ordinary Regime* that includes the greater power plants. According to Spanish current regulation, then, Special Regime includes the facilities of power less than 50 MW, coming from highly efficient cogeneration, renewables and electricity coming from residuals. Facilities included in the Special Regime have special conditions both technical and economical for grid connections. All of them are subsidized, and, in particular, renewables are subsidized in order to achieve in 2010 a goal of a 12% of the whole amount of energy in the country. The Ministry of Economy has set goals for the different kinds of Distributed Generation for the next years. These objectives, together with the present figures of Distributed generation are given in Table A2.1.

	2002	Forecast for 2011
Total demand (GWh)	211158	284000
Ordinary regime (%)	81	71
International exchanges (%)	2	
Special regime	17	29
Cogeneration	8	7.5
Wind	4	10
Minihydro	2	2.5
Others	3	9

Table A2.1. Source of energy produced in Spain

Special mention deserves the rapid growth of the installed power of Distributed Generation, especially wind energy facilities. This growth is shown in Figure A2.1.

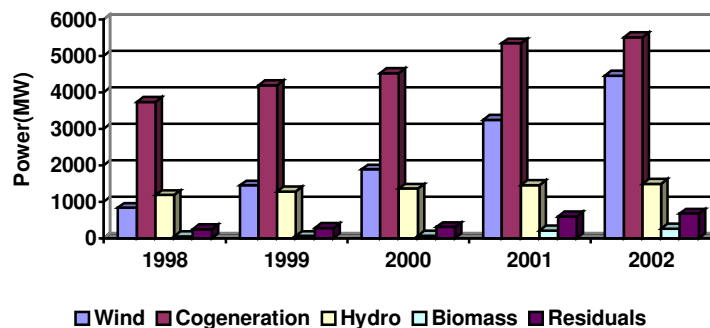


Figure A2.1. Distributed generation installed in Spain

The important amount of power and energy of Distributed Generation in Spain, specially the high rate of increase of wind energy is a challenge for Regulatory Authorities and must be dealt with special care in order to take benefit of the advantages of this kind of generation and the manageability and security of the grid at reasonable costs.

It must be remarked that due to the size of the generation facilities in Distributed Generation, a significant part of them, especially wind farms, are connected to the transmission grids (220 kV and above), and therefore, this connection concern the Transmission Grid Operator, Red Eléctrica de España, who has expressed its position in an specific document published in 2005 [65].

That is why the legislative documents about the connection criteria and protection about the distributed generation, can be divided in two main groups:

- The generation units that will be connected to the distribution network, property of the electrical utility but with the connection regulated by law.
- The generation units that will be connected to the transmission grids, concerning the Transmission Grid Operator, REE.

All these regulatory documents are summarized as shown in Table A2.2.

Connection to the Distribution Network	Connection to the Transmission Grid
OM September, 12 th 1985	P.O. 12.1, 12.2 & 12.3 (REE)
RD 436/2004	
RD 1663/2000	

Table A2.2. Regulatory documents

A.2.2 Technical Conditions for Connection of DG to Distribution Network

Following, different standards applied in the connection of Dispersed Generation to the distribution network are presented. Throughout these standards, the most relevant characteristics of the connection criteria are highlighted.

RD 436/2004. “Methodology for updating and systematizing the legal and economical activity of the special regime energy production”.

This document only gives some general criteria for network connection, remarking the importance of the OM 1985/09/12, which is nowadays still applicable. These general criteria are the following ones:

- The owners, whose generators are not parallel connected to the network, must connect their installations using a switching system either to the utility power system or to their own generators, to avoid the possibility of connect the generators to the network.
- If they are parallel connected to the network, their connection point must be only one, being possible the use of asynchronous or synchronous generators. The installations above 5 MW with synchronous generators must be capable of automatic disconnecting when the voltage or frequency fluctuations are greater than the regulated ones.
- The power factor of the energy generated and provided to the electrical power system should be as closer to one as it is possible.
- The maximum power allowed in the interconnection should be less or equal to the 50% of the installation thermal capacity (power lines) or transformation capacity (substations) where the producer is connected.

Besides, in this document, wind farms are economically benefited depending on their electrical disturbance withstand.

OM September, 5th 1985. “Administrative and technical specifications for grid connection and required performance of hydraulic power plants up to 5000 kVA, and electrical self-generation”.

This is a collection of technical and administrative details that gives the conditions of connections of small power plants. Although this is a rather old document made when distributed generation was not so extended, it is expected to be replaced in the very near future, adapting its contents to the created new situation. This Ministerial Order includes details about required protection systems and some other requirements, such as minimal Short Circuit Power requirements for Wind Farms. It gives the current conditions for connection of Distributed Generation.

Furthermore, some of the requirements shown below have been also used in the new Low Voltage Regulations (2002), more specifically in its ITC-BT-40 (technical instruction) [64].

Maximum allowed installed power of connected generation plants

Here two different situations are differentiated:

- Generation plants connected to LV grid
- Generation plants connected to HV grid

The multiple possible situations considered by this document are summarized in Table A2.3.

	GENERATOR	Maximum allowed power	Comments	Constraint
LOW VOLTAGE CONNECTION	3 Phase Asynchronous Generators	100 kVA (380/220 V)	N/A	≤ 50% Connection Line Capacity
		60 kVA (220/127 V)	They have to be prepared to be used with 380/220 V in the future	
	3 Phase Synchronous Generators	100 kVA	They have to be connected using a switched rectifier-inverter	
	DC Generators with Low-Voltage Inverters	100 kVA	They have to use three phase switched inverters	
HIGH VOLTAGE CONNECTION	Asynchronous generators	5000 kVA	For greater maximum power installed, the utility must decide	≤ 50% Transmission Line Capacity
	Synchronous generators	10 MVA	For greater maximum power installed, an agreement is desirable. Otherwise, Spanish Administration must decide	
	Wind generators (sync. & async.)	1/20 of shortcircuit power in the connection point	N/A	N/A

Table A2.3. Maximum allowed installed power

Specific interconnection conditions for power plants with asynchronous generators

- The power factor of the energy provided should be no less than 0.86 and whenever it is necessary, capacitor batteries can be used.
- When asynchronous generators are connected, these limits in voltage drop must be respected:
 - Voltage drop up to 5% of rated voltage
 - In wind generators, the connection frequency will be no more than three per minute, and the voltage drop will be less than 2%.
- In order to limit these voltage drops and the currents generated when the connection is done, it is possible to use some specific devices, such as:
 - Limiting reactances between the generator and the grid
 - No load self-excitation using condensers
- The synchronization constraints will limit the connection instant under the following synchronous speed requirements:
 - $S \leq 1000$ kVA: 90-100%
 - $S > 1000$ kVA: 95-100%
- The motor starting of thermal power plants is allowed, if voltage variations are less than 5%

up to 1 second.

Specific interconnection conditions for power plants with synchronous generators

- The required power factor will be between 1 and 0.8 (lag or lead)
- It is necessary to have a manual or automatic synchronizing device, and also a synchronism interlocking relay. It can be omitted if the connection can be done asynchronously or using a rectifier-inverter.
- The limits used between the electrical magnitudes of generators and network, must be less or equal than the values shown in Table A2.4.

	S > 1000 kVA	S ≤ 1000 kVA
Voltage difference	± 10%	± 8%
Frequency difference	± 0.2 Hz	± 0.1 Hz
Phase difference	± 20°	± 10°

Table A2.4. Limits between generators and network

- The generators up to 1000 kVA, can be asynchronously connected to the network if the maximum voltage drop is 5% (no more than 0.5 second) in the connection instant. In case of wing generators, the maximum frequency of connection is 3 per minute, with a voltage drop of 2%.
- In order to control the reactive power provided by the synchronous generator, it is absolutely necessary to have an excitation control device.

Required protection systems

The required protection systems are divided depending on the voltage level where the generation plant is connected. Ones connected to the utility LV system ($S \leq 1000$ kVA), and the others connected to the HV side (asynchronous with $S \leq 7500$ KVA and synchronous with $S \leq 10000$ kVA). Some of the protection devices are the same regardless of voltage level:

- 1 Automatic circuit breaker
- 3 instantaneous undervoltage relays (0.85 Vm)
- 1 instantaneous overvoltage relay (1.1 Vm)
- 1 underfrequency and overfrequency relay (49-51 Hz)

If the generation plant is connected to the high voltage network, the protection requirements are increased with:

- Zero sequence maximum voltage relay
- Transfer Trip

Although the previous ones are the “interconnection protections”, some other devices are required in order to protect the power plant.

RD 1663/2004. “Connection requirements for photovoltaic installations to the LV grid”.

The scope of this specification is the PV installations up to 100 kVA and connected to the Low Voltage Grid. In this document, the installed rated power is defined considering the sum of every inverter power. It gives details about the ways of measuring delivered energy, technical conditions of installations and the protection systems required.

According to this document, the operation of PV installations should not cause damages in the electrical network, nor create decreasing of security conditions (even for maintenance people).

Besides, if utility distribution power line is disconnected due to maintenance or protection, the PV should not maintain voltage in that line. Finally, the main points to be considered to connect the PV installation to distribution grid are:

- Distribution line rating
- Installed power in secondary distribution transformers
- The distribution per phase of the different generators connected with single phase inverters

Specific interconnection conditions

The specific interconnection conditions defined in this document, are the following ones:

- PV installations can be connected to LV grids up to 100 kVA. All the installations connected to will not exceed half of the capacity of the connection line. If it is directly connected to a secondary distribution transformer, they will not exceed half of the transformer power.
- If the rated power of the PV installation is above 5 kW, its must be three-phase connected. It can be done either using one or more single phase inverters (up to 5 kW) or directly through a three phase inverter.
- The voltage variation caused by the connection or disconnection must be no greater than 5%
- Power Factor must be as close as possible to 1.

Required protection system

The basic protection system used in PV installations must be:

- Manual magneto thermal circuit breaker with greater breaking capacity than the short-circuit power of the connection point.
- Automatic differential breaker
- Automatic circuit breaker, used to connect-disconnect the installation in case of voltage or frequency loss, with an interlocking relay
- Underfrequency and overfrequency protection (49 and 51 Hz), and undervoltage and overvoltage protection (0.85 and 1.1 rated voltage). These protections can be integrated in the inverter, so in this case the inverter must do the connection-disconnection procedures. Using this option and providing that some specific conditions are performed, it is possible to use only the manual and the automatic differential circuit breakers.
- The reconnection with the LV grid must be automatic, once the utility power has been recovered

EN 50160. “Voltage characteristics of electricity supplied by public distribution systems”.

From the point of view of power quality, Spanish electrical installations, in general, must cope with the European Standard EN 50160. Therefore, DG installations should not fail in verifying the limits imposed by this standard. In general, EN 50160 defines the main characteristics of the voltage at the customer’s supply terminals in public low voltage and medium voltage distribution system and gives the limits or values within which any customer can expect the voltage characteristics to remain under normal operating conditions. This standard does not apply under abnormal operating conditions like conditions arising as a result of a fault or a temporary supply arrangement, in case of non-compliant customer installations or equipment.

Nature of the standard is to give limits for measured indices during a long period like one week. The index itself is measured as average value over a period varying between 10 seconds and 10 minutes. Limits are given with two categories. First, maximum limits are given (all measured values shall be

under the given limit). Then, another limit is given so that small percentage of the measured values is allowed to be between given limit and the maximum limit.

As summary this standard is ignoring the short time events that are affected by relay operations. Instead, it is concentrated to long period power quality measurement and monitoring. So, the following values are allowed:

a) Frequency: nominal frequency must be 50 Hz. In normal operating conditions the fundamental frequency, measured in 10 s periods, must be situated in the following intervals:

- | | | |
|----------------------------|-----------------|--------------------------|
| - Interconnected networks: | 50 Hz \pm 1% | during 99,5% of the year |
| | 50 Hz + 4% - 6% | during 100% of the year |
| - Islanded networks: | 50 Hz \pm 2% | during 99,5% of the year |
| | 50 Hz \pm 15% | during 100% of the year |

b) Voltage amplitude: for MV networks is the declared voltage U_c . For LV networks the normalized nominal value is:

- 4 conductors: 230 V phase to neutral
- 3 conductors: 230 V phase to phase

c) Voltage variations: for a week period, 95% of rms values (averaged in 10 min intervals) in the interval $U_n \pm 10\%$. For every 10 min period, average rms values must be in the interval $U_n + 10\% - 15\%$ (only in LV networks)

d) Fast voltage variations: in normal operating conditions fast variations are usually under 5% of U_n for LV networks and 4% for MV networks. But, in certain conditions, can reach 10% of U_n in LV networks and 6% in MV networks. During a week period, flicker severity caused by voltage fluctuations should be $\leq 1 (P_{1t})$ during 95% of the time.

e) Voltage sags: these phenomena are fundamentally random and its frequency depends on the type of distribution network and the observation point. Indicative values in normal operating conditions for a year vary from several tens to a thousand. The great part of the sags have a duration of less than a second and a depth below 60%

f) Temporary phase to ground overvoltages: are usually due to faults in the network or in a client installation. Generally, the overvoltage can reach the phase to phase voltage value due to the displacement of the neutral. For LV networks, indicative values are normally less than 1,5 kV for faults in the HV side of a distribution transformer.

For MV networks, it depends on the grounding method. For solidly grounded or impedance grounded networks, the overvoltage must not exceed 1,7 U_c . For ungrounded or resonant grounded systems the overvoltage must not exceed 2 U_c .

g) Transient phase to phase overvoltages: For LV networks, generally, they have a peak value less than 6 kV but, sometimes it can be higher. Rise time can vary between less than a μ s to several ms. For MV networks, switching overvoltages generally have a lower amplitude than lightning overvoltages, but their rise time can be faster and their duration longer.

h) Voltage imbalances: for every week period, 95% of the inverse voltage component rms values averaged in 10 min. must be between 0% and 2% of the direct component value. in regions with single phase or two phase supply imbalances can reach 3%.

i) Harmonic voltages: for every week period, 95% of the rms values of each harmonic voltage averaged in 10 min. can not exceed the values shown in the Table A2.5. The Total Harmonic Distortion (THD) can not exceed 8%

Odd harmonics				Even harmonics	
Non-multiples of 3		Multiples of 3			
Order	Individual Distortion	Order	Individual Distortion	Order	Individual Distortion
5	6%	3	5%	2	2%
7	5%	9	1,5%	4	1%
11	3,5%	15	0,5%	6 ... 24	0,5%
13	3%	21	0,5%		
17	2%				
19	1,5%				
23	1,5%				
25	1,5%				
Values corresponding to harmonics of an order above 25, which generally are weak and very unforeseeable due to resonant effects, are not indicated in this table					

Table A2.5. RMS values of each harmonic voltage averaged in 10 min.

A.2.3 Technical Conditions for Connection of DG to the Transmission Network

As it has been said previously, wind generation in Spain has increased spectacularly last years. Consequently, its current influence in the Spanish Power System can not be ignored, specially its sensitivity with electrical disturbances and the difficult predictability of its generation. In 2005, some operating procedures have been published by the transmission grid operator (P.O. 12.1 and 12.2) [66], REE, relating to different requirements for installations connected to the transmission grid. According to this, the large wind farms connected to those grids must obey different required constraints. The main points required are summarized below:

- The installations connected to the transmission network must withstand the voltage and frequency values stated in other REE procedures. The limits of these values are:
 - Voltage
 - Under normal circumstances:
 - 400 kV grid: $390 \text{ kV} \leq U \leq 420 \text{ kV}$
 - 220 kV grid: $205 \text{ kV} \leq U \leq 245 \text{ kV}$
 - Eventually:
 - 400 kV grid: $375 \text{ kV} \leq U \leq 435 \text{ kV}$
 - 220 kV grid: $200 \text{ kV} \leq U$
 - Frequency: $49.85 \text{ Hz} \leq f \leq 50.15 \text{ Hz}$
- Generation installations will not be disconnected due to the voltage sags produced in faults correctly opened. The basic design and control requirements will lead to no disconnection in the grey zone of figure A2.2.

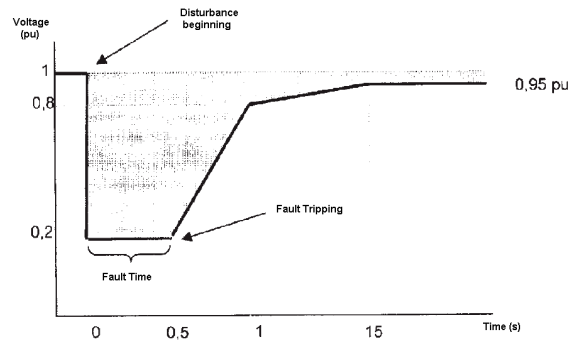


Figure A2.2. Voltage sag requirements [66]

- All the generation units must withstand a 5% of the rated current, negative sequence current component.
- The installations connected to the transmission system will be design to withstand 50 kA in 400 kV and 40 kA in 220 kV, at least.
- There are two ways for generating installations of connecting to the transmission line. The choice between them will depend on the transmission development criteria stated by the existing regulations.
 - Modifying or enlarging an existing or planned substation
 - Connecting to an existing line, creating a new substation
- The protection system used in the installation connected to the transmission grid must fulfil at least, the requirements mentioned in the document "Spanish electric system protection general criteria" by REE [68].

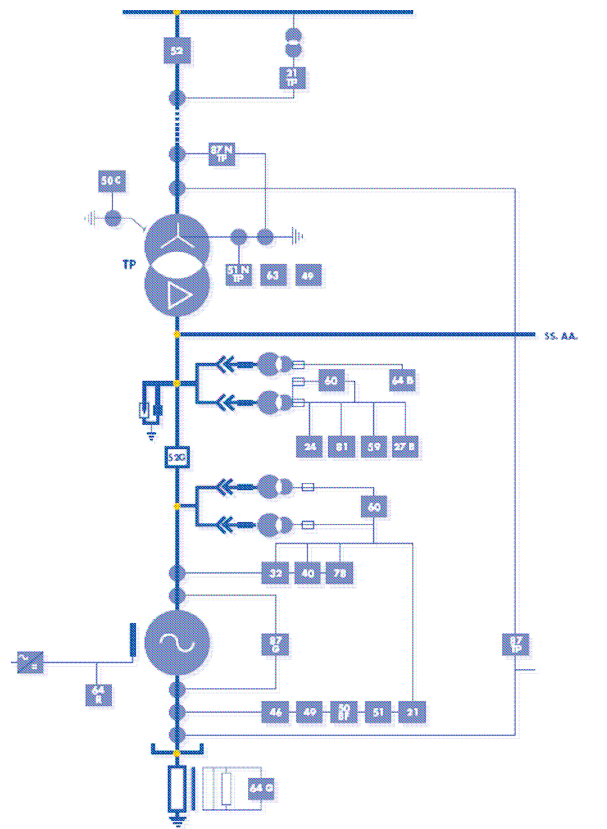


Figure A2.3. Typical example of a generation unit [68]

A.2.4 Economic Conditions for DG

This section is a short review of **Errore. L'origine riferimento non è stata trovata.** Distributed Generation is, as told above, included in the Special Regime. It includes installations smaller than 50 MW. All the energy produced by them must be bought and paid under special conditions.

Special regime is divided into different groups: Cogeneration, Renewable energy (solar, wind, geothermal, small and large hydro, biomass), Residuals, and Cogeneration with residuals. Each one of them have different economic conditions. Wind and solar energy have to fulfill additional special conditions.

Under the new regulation (27th March 2004) the distributed generators may choose between a fixed rate established yearly, and to sell the energy in the electricity market, following the same rules than the rest of generators.

Those who choose the fixed rate must forecast their production for a day 30 hours before that day begins (that is, with a time horizon up to 54 hours) that may be updated several times along the day. Deviations from this forecast higher than 5% (20% for wind energy and photovoltaics) would incur in penalties of 10% of the energy price of the deviations. The amount of this rate (tariff) depends on the technology and the age of the installation. Renewables are paid more, and older facilities receive less.

Those who choose the market will have, besides the income from the market, one incentive and a premium that depends on the technology. They are, in general, higher for the renewables. The generators follow the same rules than the rest of generation. Their bids must be presented by an authorised agent, that may join the bids of several producers, compensating the possible imbalances. Distributed generation cannot be disconnected because of a grid constraint if their bids are at zero.

Additional aspects include a bonus for following a schedule in power factor. The legal obligation is to keep the power factor between 0.86 (lagging) and 1 for the asynchronous generators, or between 0.8 and 1 for the synchronous generators. However, incentives have been set in order to encourage a better voltage schedule. These incentives (and penalties, with minus sign) are shown in Table A2.6.

Table A2.6

	Power factor	Bonus in %		
		Peak	Shoulder	Valley
Inductive	< 0.95	-4	-4	8
	$0.95 \leq pf < 0.96$	-3	0	6
	$0.96 \leq pf < 0.97$	-2	0	4
	$0.97 \leq pf < 0.98$	-1	0	2
	$0.98 \leq pf < 1$	0	2	0
	1	0	4	0
Capacitive	$0.98 \leq pf < 1$	0	2	0
	$0.97 \leq pf < 0.98$	2	0	-1
	$0.96 \leq pf < 0.97$	4	0	-2
	$0.95 \leq pf < 0.96$	6	0	-3
	< 0.95	8	-4	-4

The percentage shown in the table is over the average tariff of energy. The power factor is the average for 15 minutes. The peak, shoulder and valley hours are fixed for all the Spanish territory.

Another point is the bonus established for those wind energy plants that can withstand voltage dips. This must be certified by the turbine manufacturer.

A.3 Grid Connection Criteria and Protection Practices for DG in Italy

A.3.1 Introduction

The Italian yearly electricity demand is around 300TWh supplied by hydro power (50TWh), import from neighbouring countries (50TWh) and thermal generation plus some small percent of other renewables.

The total gross capacity of generators in Italy is around 80GW. 3500MW are supplied by plants below 10MW. The regulatory framework in Italy and the connection practice make this size the proper frontier between conventional generation and distributed generation.

The Italian transmission grid is structured in 4 voltage levels (380kV, 220kV, 150kV in the southern part and 132kV elsewhere). The distribution grid has a HV level (150kV, 132kV, 60kV), a MV level (usually 15kV or 20kV, but other voltages are adopted) and a LV level (400V).

The MV and the LV grids are radial or radially operated grids. MV is an isolated neutral system but is currently being converted in impedance (resistance or Petersen coil) grounded neutral system, while BT is a solidly earthed neutral system.

The transmission grid is operated by an Independent System Operator (GRTN: Gestore della Rete di Trasmissione Nazionale), while the distribution system is owned and operated by several distributors; one of them covering something like 90% of the distribution system.

Connection rules for generators above 10MVA define the participation of the plants to the frequency and voltage regulation. The main prescriptions are gathered in the Italian standard CEI 11-32: “Electrical energy production systems connected to III class network”. Energy is sold through bilateral contracts between producers and free customers or through a reserved market to supply the distributors the energy they need to feed the other customers.

Generators below 10MVA are subject to simplified rules. They do not have to participate in the system regulation.

Renewables, combined heat and power (CHP) and autoproducers who consume more than 70% of their yearly generation can inject all their exceeding power into the grid without being subject to balancing charges but receiving a fixed energy price based on the variable cost of the energy produced through thermal power plants. Renewable sources also receive additional payments.

The other producers must participate into the market either through bilateral contracts, or selling in a reserved market to supply tariff customers. Shortly an exchange market will start also in Italy.

A.3.2 Applicable standards

In Italy, a specific and complete regulatory framework for distributed generation connection has not been developed yet.

The technical feasibility and the analysis of the issues related to the connection of a DG plant (voltage rise, voltage fluctuation, power quality) is practically left to the designers and to the distributors, except for the prescriptions given in some national and international standards.

The Italian Electrotechnical Committee (CEI) has issued a national standard regarding the connection of generating units to the LV and MV distribution grids:

- Italian standard CEI 11-20: “Electrical energy production system and uninterruptible power systems connected to I and II class network”

For the safety issues of plants the following national standards apply:

- Italian standard CEI 11-1: “Power installations exceeding 1kV ac”
- Italian standard CEI 64-8: “Power installation below 1kV ac and 1.5kV dc”

For power quality issues and EMC the Italian Electrotechnical Committee has adopted the international standards:

- European standard EN 50160: “Voltage characteristics of electricity supplied by public distribution systems”
- International standard series IEC 61000: “Electromagnetic compatibility”

The main Italian distributor has then issued specifications that each plant must satisfy to be connected to the distribution grid. These specifications take into account the characteristics of the distributor own networks giving specifications for protections and their settings.

A.3.3 Connection practice

Distributed generation in Italy means small CHP plants and small renewable sources. Except a few isolated small wind turbines, the wind generators in Italy are gathered into wind farms, which supply power directly to the 150kV grid through a dedicated substation. In this case the GRTN jointly with the distributor is the responsible of the connection of the wind farm.

Distributed generation can therefore be regarded as a MV and LV issue. The leading principle of the connection practice regulation is that the Italian distribution grid is conceived, designed and developed as a radial or radial operated passive network.

The prescriptions aim therefore at making the grid behave passively even if some generators are connected at LV or MV levels.

A.3.3.1 Connection checks

The Italian standard CEI 11-20 gives some general principles for checking the feasibility of a specific connection. Such principles regard the loading factor of the grid components, the short circuit levels, the protection selectivity, voltage profiles and voltage quality after the installation of the new generator. It does not fix specific values for each issue and addresses to the other standards which usually apply to passive systems, such as IEC 50160 and IEC 61000. Some details are specified in the connection guidelines issued by the main Italian distributor.

The distributor must check that the characteristics of the plant, jointly with the connection point, ensure those principles to be satisfied.

In practice the maximum size of generators which can be connected to a MV grid is 8 MW for a dedicated connection and 3 MW in the other conditions. All generators above 50kW must be connected to MV level.

For LV grids the maximum size is 20kW, while the units between 20 and 50 kW can be connected either on MV or LV depending on the characteristic of the grid itself.

If the preliminary checks show that the connection to an existing point does not satisfy the requirements, the connection shall be accomplished through a direct line.

The producer is charged the investment needed for upgrading the grid.

Anyway the distributor owns and manages the connection equipments except if the line serves a single producer. In such a case the distributor may leave a portion of the interconnection under the property and responsibility of the producer. The delivery point is anyway the point of frontier between the producer and the distributor equipments and the measuring devices must be installed in such location.

A.3.3.2 Connection schemes

The Italian standard CEI 11-20 defines a connection scheme as reported in fig. A3.1, which must accomplish the following functions:

- plant start-up, operation and shut down in normal condition,
- generator shut down for a fault or misoperation in the generator set,
- coordinated action of the devices after a fault or misoperation in the island operating mode,
- coordinated action of the devices after a fault or misoperation in the parallel to grid operating mode,
- trip of the interface device following the trip of the grid device or for a fault on the grid.

When the generator is connected to a LV grid through a static device, the scheme must include the electrical separation between the dc and the ac side of the system. In practice a transformer must be installed except for single-phase plants where an electromechanical protection device must be installed, sensible to the dc component.

If the plant is connected through a direct line the main device can be omitted and its function replaced by the grid device installed on the grid itself.

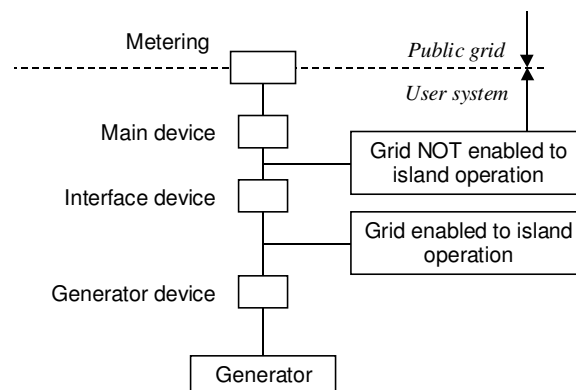


Figure A3.1 Connection scheme of DG to LV and MV grids as defined by CEI 11-20

A.3.3.3 Operating conditions

The operating conditions of a generator connected to a distribution grid must satisfy the following prescriptions:

- the island operation supplying preferential loads is permitted for whatever generation system,
- the operation in parallel to a LV grid is only permitted for asynchronous generators and electronically interfaced generators which operate with unitary power factor,
- the operation in parallel to a MV grid is always permitted.

The distributed generation plants shall never supply part of the distribution system separately from the rest of the system.

A.3.4 Protection practice

The protection system must act on the three devices shown in the scheme of fig. A3.1 in a coordinate way together with the grid device installed on the distributor side.

The following table resumes the coordination criteria that must be adopted to install and set the relays.

<i>Event</i>	<i>Device</i>			
	<i>Grid</i>	<i>Main</i>	<i>Interface</i>	<i>Generator</i>
<i>Fault or misoperation on the grid</i>	1 st level	NO	2 nd level	3 rd level
<i>Fault or misoperation on the user grid</i>	3 rd level	1 st level	2 nd level	3 rd level
<i>Fault on the generator</i>	NO	3 rd level	2 nd level	1 st level

The interface device must anyway ensure the separation from the grid for whatever fault or misoperation of the grid. The relays which act on each device depend on the voltage level of the grid and small differences exist between LV and MV connections due to the different neutral connection on the two systems.

A.3.4.1 Main device

The main device must trip for a fault on the user grid.

For a low voltage connection point the main device can be either a maximum current relay or a fuse.

For a medium voltage connection the main device must protect against ground faults on a isolated neutral system and must include a maximum current relay with at least two tripping threshold.

A.3.4.2 Interface device (anti-islanding protection)

The interface device is conceived to permit the generator to supply the preferential loads when the grid trips and to perform the anti-islanding protection; i.e. avoiding the unwilled creation of self supplied island on the distribution grid.

For a LV system the interface device must trip for the following relays:

- Instantaneous minimum and maximum frequency relay
- Delayed minimum voltage relay
- Instantaneous maximum voltage relay
- Anti islanding relay (e.g. frequency derivative relay)

For a MV systems these relays must be completed by a

- Delayed zero sequence maximum voltage relay

These protections must be installed even if the generator system is not able to supply a passive grid (asynchronous generators, current source inverters etc.)

A.3.4.3 Generator device

The choice of the generator device depends on the type of generator installed. It is aimed at stopping the energy conversion process for whatever fault on the generation plant.

A.3.4.4 Distributor prescriptions

The distributor guidelines define the relays which must be installed in conformity with the standard CEI 11-20. They also define the setting values for all the relays and define some standard protection panels that should be installed accordingly.

A.3.5 Barriers to wider DG interconnection

DG in Italy is seen as a potential benefit to the power system and to the overall energy balance. But at the moment it is regarded as an exception to the normal operation of the distribution grid and as a problem that might increase the complexity of the operation of the grid itself.

The main barrier to wider DG interconnection is the structure of the grid itself, which is a radial or radially operated system. A high level of DG would require the modification of the whole protection system.

The existing standards reflect these aspects and the actions that must be taken to satisfy the national and the distributor prescriptions often have a large impact on the cost effectiveness of a plant especially for the smallest units. For the micro generation connected to LV grids through an inverter, a major barrier is the required installation of a transformer.

Another key issue is the structure of the electricity and gas tariffs, which often do not properly boost the development of CHP plants.

Finally the permitting procedure requires several authorities to be contacted. A simplified procedure for small plants has not been developed yet except for few issues.

A.4 Grid Connection Criteria and Protection Practices for DG in Canada

A.4.1 Introduction

Canada consists of several electric utilities each of which deals with Distributed Resources independently. There is no Canadian standard related solely to DR. Each utility has their own technical requirements which are typically based on IEEE Standards. The policy applied by each utility, however, is either provincially governed, dictated by an Independent System Operator (ISO) or administered by the utility.

For the purpose of this report, the term ‘Distributed Resources’ (DR) shall be used. IEEE Standard 1547 defines DR as:

“Sources of electric power that are not directly connected to a bulk power transmission system. DR includes both generators and energy storage devices”

For Canadian utilities, ‘distribution’ is typically 35kV and below. From a technical perspective, DR interconnection is distinguished from generation interconnected at transmission voltage levels.

The information summarized here is based on a sampling of some of the larger Canadian utilities including;

- BC Hydro
- Aquila Networks Canada
- SaskPower
- Manitoba Hydro
- Hydro Quebec

The report shows that although technical requirements are fairly consistent, the policies and processes vary between the utilities.

A.4.2 Current Level of DR

Customer-owned DR facilities that parallel the Canadian distribution system generally fall into one of two broad categories;

- 1) load displacement
- 2) export to utility

and in some cases, they are both. Based on a sample of four Canadian utilities, Table A4.1 shows the current level of DR penetration in 4 Provinces:

Table A4.1

Installed DR (MW)				
Type:	British Columbia	Saskatchewan	Manitoba	Quebec
Hydraulic	137	-	-	234
Biomass	6	0.6	-	31
Biogas	13	-	-	30.5
Wind	0.004	21.8	-	-
Solar PV	0.02	0.0054	0.015	-
Fuel Cells	0.55	-	-	-
Submarine Batteries	3.6	-	-	-
Diesel UPS	-	-	6	-
Total (MW)	160	22	6	296

Manitoba Hydro classifies DR by interconnection types as shown in Table A4.2:

Table A4.2

Type	Description	Typical Example
Type 1	Interconnected with momentary closed transition switch. Parallels for 100ms or less (make-before-break) usually to avoid nuisance outages associated with monthly testing of standby generators.	Standby diesel generator
Type 2	Interconnected using sustained closed transition switching. Can parallel indefinitely, primarily used for load displacement. Power is not allowed to flow to the utility.	Standby diesel generator that is also used to displace load (also known as 'peak shaving')
Type 3	Primarily load displacement with the ability to export to the utility when local load is less than the generator output, ie., power is allowed to flow back to the utility by using bi-directional revenue metering.	Small windmill, solar panel or micro-DG
Type 4	Export for sale to Manitoba Hydro as an Independent Power Producer (IPP).	Wind farm, bio-energy generating facility, large solar array

A.4.3 Connection Criteria

All the Canadian utilities surveyed had some form of DR interconnection policy and technical standards or guidelines. (see References) The level of installed DR on a feeder is limited by the distribution itself. In most cases, the thermal limits of the feeder conductor is the limiting factor.

As a result, most utilities have limits on the maximum allowable size of an individual DR (or aggregate) connected to distribution feeders. For example, some of the limits are:

Table A4.3

Province	Maximum Size	Max DR Voltage	Technical Guideline Internet Link
British Columbia	13 MVA	35 kV	PDF
Alberta	None Specified	25 kV	PDF
Saskatchewan	1 MW, study for >1 MW	25 kV	PDF
Manitoba	10 MVA	25 kV	PDF
Ontario	None Specified		PDF
Quebec	25 MVA	34.5 kV	Web Site

With respect to power quality, all the utilities include some form of criteria within their interconnection requirements. Steady-state voltage, harmonics and flicker limits are applied to the DR facility to ensure compliance with existing power quality standards. In some cases they are stated explicitly or reference another standard, like IEEE 519, for example.

Table A4.4 summarizes and compares some of the power quality requirements:

Table A4.4

	Voltage Limits	Power Factor Control	Steady-State Frequency Range	Harmonic Limits
BC Hydro	CSA-C235	0.9 lag to 0.9 lead	60 ± 0.5 Hz	Based on IEEE 519
Alberta ¹	CSA-C235	0.9 lag to 0.9 lead	60 ± 0.5 Hz	Based on IEEE 519
SaskPower	CSA-C235	0.95 lag to 0.95 lead	60 ± 0.5 Hz	VTHD based on ANSI G50.10 ITHD based on IEEE 519
Manitoba Hydro	CSA-C235	0.9 lag to 0.9 lead	60 ± 0.5 Hz	Based on IEEE 519
Hydro Quebec	CSA-C235	For <5MW: 0.95 lag to 0.95 lead	60 ± 0.6 Hz	IEC 61000-3-6 IEC 61000-2-2

¹ Provincial Standard

A.4.4 Market Participation

There are usually two options for DR wishing to export electricity. They can either sell to the utility or into the export market the utility is a member of. Table A4.5 is a summary of the type of market participation currently offered by each utility:

Table A4.5

Utility	Allow DR Market Participation	Purchaser
BC Hydro	Yes	BC Hydro or other
Fortis Alberta	Yes	Alberta Power Pool
SaskPower	Yes	SaskPower (for <72kV)
Manitoba Hydro	Yes	Manitoba Hydro or other
Hydro Quebec	Yes	Hydro Quebec

A.4.5 Interconnection Costs

In general, the ownership boundary between the utility and the DR facility is at the point of interconnection, which varies depending on the location of the DR facility. In Manitoba, for example, the point of interconnection may be the primary of the supply transformer, if it is a customer-owned transformer, or the secondary, if the transformer is utility-owned.

Typically, the full interconnection costs including any incremental system upgrade costs that may be required, are paid for by the DR facility. The exception is BC Hydro, where Transmission and Distribution work identified as a ‘System Upgrade’ will be paid by BC Hydro, but capped at an upper \$ limit which depends on the annual energy delivered by the DR to BC Hydro. In Manitoba and Quebec, interconnection system upgrade costs are initially paid for by the DR owner and recovered through the export rate.

A.4.6 Protection Practices

Protection practices are typically specified in each utility’s interconnection guideline, specification or standard. There is no common ‘Canadian’ interconnection standard, with the exception of the ‘*Micropower Connect Interconnection Guideline for Inverter-based Micro-DG Connected to 600V and Less Distribution Systems*’. It is a guideline developed by a consortium of utility and industry representatives, and for the moment, application of this document by utilities is voluntary.

From the utility’s perspective, the protection requirements are usually related to the generating technology being used by the DR facility and the type of interconnection. In order to be more accommodating to the wide variety of DR requests, Manitoba Hydro is currently revising its current interconnection guideline such that the protection requirements will be based on 3 main factors:

- the type of generator (synchronous, induction, or inverter)
- the amount of existing system load (relative to the generator size)
- the type of interconnection (see Table A4.2)

Although the level of detail varies across utilities, typical protection schemes for rotating generators include four zones of protection:

1. Generator Source Protection

- protects the generator from internal faults

2. Synchronization Protection

- provides automatic connection to the utility, and disconnection when synchronization is lost

3. Utility Source Protection

- protects the DR facility from utility system faults

4. Anti-islanding Protection

- used when islanding of the distribution system is not allowed by the utility

Table 6 is an excerpt from Manitoba Hydro’s Interconnection Guideline that summarizes the minimum DR facility relay requirements. (note: this is currently under revision)

A.4.7 Islanding

Under normal circumstances, Canadian utilities do not allow unintentional islanding of the distribution system. This is due primarily for safety reasons and is consistent with IEEE Standard 1547. In special

cases, controlled islanding is allowed if it is technically and financially acceptable for the utility and DR facility to do so.

Anti-islanding protection is achieved in several ways. IEEE Standard 1547 provides 4 examples by which anti-islanding might be achieved:

- 1) The DR aggregate capacity is less than one-third of the minimum load of the local system
- 2) The DR is certified to pass an applicable non-islanding test
- 3) The DR installation contains reverse or minimum power flow protection, sensed between the Point of DR Connection and the PCC, which will disconnect or isolate the DR if power flow from the system to the DR facility reverses or falls below a set threshold
- 4) The DR contains other non-islanding means, such as a) forced frequency or voltage shifting, b) transfer trip, or c) governor and excitation controls that maintain constant power and constant power factor

Utilities typically include one or more of these requirements in their interconnection guidelines.

Device	A.1.1 Description	Protection Zone			
		AIP	USP	SP	GSP
TT	Transfer trip	O			
59G	Ground overvoltage	X			
32	Reverse power	X	X		X
27	Under voltage trip	X	X	X	X
59	Over voltage trip		X	X	X
46	Negative sequence overcurrent	O	X		
47	Negative sequence voltage	O	X		
67	Directional overcurrent	O	O		
51	Overcurrent		X		X
51G	Neutral overcurrent		O		
51V	Voltage controlled overcurrent		O		
59I	High speed overvoltage		O		
59T	Time overvoltage		X		
25	Synchronization check			X	
40	Loss of excitation				X
81O	Over frequency		X	X	X
81U	Under frequency		X	X	X
89	Interconnect disconnect device	X	X		

A.4.8 Barriers

All the utilities surveyed allow DR interconnection with the distribution system. As a result, the main barrier to DR installation in Canada is cost. The costs associated with a DR project can usually be attributed to one or more of the following groups;

- 1) Capital cost of DR
- 2) This includes the cost of the particular DR technology being used, as well as any protection required.
- 3) Cost of meeting utility's technical requirements
- 4) In order to meet utility anti-islanding requirements, additional protection is often required. As well, there may be costs associated with upgrading the distribution system in order to

- accommodate the DR.
- 5) Costs associated with open access interconnection tariffs (OAIT)
- 6) A utility's OAIT often results in additional costs including Engineering costs, liability insurance, study fees and maintenance agreements.

In Manitoba, the above combined with a relatively low cost of energy (approximately \$0.05 CDN /kwh) make it difficult for DR business cases to succeed.

A.4.9 Ancillary Services

With the exception of BC Hydro, there is not much participation in the ancillary services market. A 7 MW run-of-river DR facility, which exports into a BC Hydro 25 kV feeder, is allowed to island the 25 kV feeder load during a permanent outage in a radial 69 kV transmission line.

Manitoba Hydro is currently looking at utilizing dispatchable DR to act as spinning reserve, however, the concept is still in its infancy.

A.5 Grid Connection Criteria and Protection Practices for DG in Greece

A.5.1 Introduction

In the last two decades several DG installations have been connected to the Greek distribution networks, mainly at the Medium Voltage (15 or 20 kV) level, but also at Low Voltage (230/400 V) during the last few years. The majority of the installations are wind farms or individual wind turbines and small hydroelectric power stations. A couple of biogas fired generation plants exist, as well as several small photovoltaic installations at the LV level.

For the interconnection to the grid of DG station a technical evaluation is conducted to ensure that the installation is compatible and does not affect the proper operation of the grid. The criteria evaluated include the effect on power quality, the fault level contribution and the interconnection protection, [78]. The fundamentals of this methodology have been presented in [79]. In this report, first some fundamental considerations are presented, regarding the grid-interconnection schemes used in practice, which are factors affecting critically the feasibility of a DG investment. Then, the framework of technical criteria and requirements is presented, concentrating on its philosophy, without going into all practical application detail. The main focus is on power quality issues, namely slow and fast voltage variations, flicker and harmonic emissions. The interconnection criteria and guidelines presented in this report are based on the extensive set of IEC power quality standards (part of the IEC 61000 series of EMC publications), as well as on the practice of other European utilities. Interconnection protection requirements are also discussed briefly. The critical issue of the fault level contribution of DG is not dealt with here.

A.5.2 Interconnection Schemes

DG installations are connected to the distribution grid using arrangements not essentially different from those used for consumers, as it is schematically illustrated in Fig. 1. Most important is the differentiation between the actual connection point (CP) and the Point of Common Coupling (PCC). The latter is defined as the closest to the DG installation node, where other users are (or may be) connected and it may differ from the physical point of coupling, when the installation is interconnected via a dedicated line segment, as in Fig. A5.1.

The equipment used for the connection to the grid varies, depending on the size of the installation and the type of the network (overhead, underground). Nevertheless, the coupling substation comprises the required switching/protection equipment and metering devices, which at a minimum are the following:

- A circuit breaker (a fuse-load switch combination is acceptable for overcurrent protection of smaller installations, typically below 800 kVA).
- The interconnection protection system, acting on the interconnection breaker, to isolate the DG installation from the grid upon detection of abnormal network operating conditions¹.
- Metering arrangements for the power and energy produced and consumed by the installation.

The most common schemes for the interconnection to the MV and HV grid are illustrated in Fig. A5.2. For smaller installations (<100 kW), which may be connected to the LV network, cases 1, 2 and 5 of Fig. 2 are the basic alternatives (HV/MV substations being replaced by MV/LV ones). The numbering of the five schemes in Fig. 2 corresponds to increasing DG source capacity, fault-level at the PCC and cost and time of construction for the interconnection works.

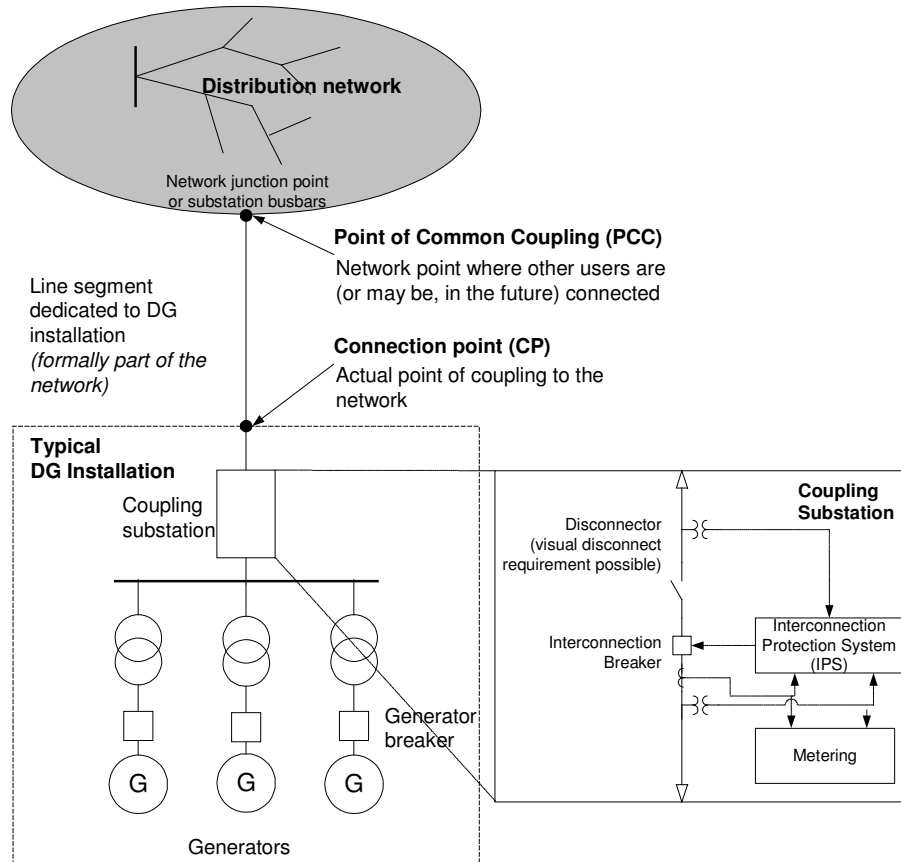


Figure A5.1. Connection Point (CP) and Point of Common Coupling (PCC).

¹ In certain cases (particularly in LV) protection functions may be implemented within the protection system of the generating units themselves.

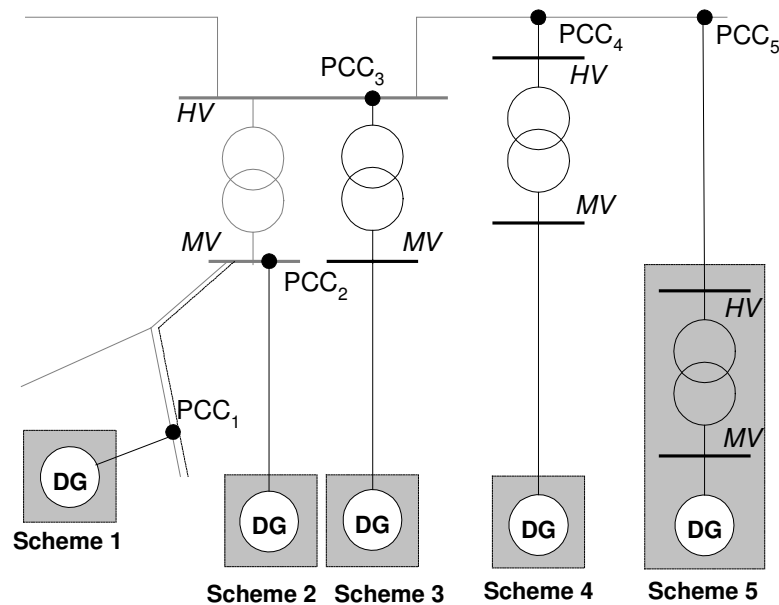


Figure A5.2. Alternative interconnection possibilities for a DG installation (MV and HV network) and associated PCCs. Grey line for existing parts of the network, black line for extensions.

In Scheme 1 the DG station is connected to an existing distribution feeder, via an extension of the line. It is possible that reinforcement (e.g. conductor upgrade) may be required for the existing feeder (dashed black line in Fig. 2). In Scheme 2, a dedicated line connects the DG station directly to the MV busbars of the HV/MV substation (where the PCC is located). When this is not possible or acceptable, an expansion of the existing substation is examined (Scheme 3), installing a new HV/MV transformer with independent MV busbars (bus-couplers open). If this is not possible (for space limitation reasons, distance from the DG station to the substation etc.), a new HV/MV substation has to be built, either under/near an existing HV line, whereupon the DG station is connected at the MV level (Scheme 4), or within the premises of the DG installation (Scheme 5). In the latter case, an extension of the HV line is needed (often a radial single-circuit line, to keep costs down) and the station becomes a user of the HV network, unlike all the other schemes, where the station is a MV network user. Large stations, of the order of tens of MW and above, are connected directly to the HV grid, as in Scheme 5.

Selecting the appropriate interconnection scheme is a complicated economic and technical decision, which takes into account:

- The existing network infrastructure
- The cost of grid reinforcement and extension works
- The cost of power and energy losses on the interconnecting network, over the considered investment period
- Implications of possible delays in the construction of major grid works (e.g. environmental permits for new HV lines)
- Technical criteria and requirements, related to power quality, fault level, protection etc.

As an example, a rule-of-thumb algorithm for selecting the interconnection scheme is outlined in flowchart form in Fig.3, based on data from a study performed by the Greek Regulator for wind farm and small hydroelectric stations, intended to be connected to the MV (20 kV) or HV (150 kV) grid. The evaluation is based on the agreed power of the installation and the existing grid conditions in the vicinity of the station. Decision criteria are derived on the basis of the net present value of the total cost of alternative solutions (initial investment plus cost of losses over the expected lifetime of the investment). Technical requirements included in the algorithm of Fig. 3 are presented in more detail in the following.

A.5.3 Overview of Technical Requirements

The requirements and evaluation methodologies applied in general comprise two stages:

- Estimation of the expected magnitude of disturbance due to a particular DG installation. Power quality phenomena taken into consideration are:
 - Slow (steady-state) voltage variations
 - Fast rms voltage variations and flicker, during normal operation and due to switchings
 - Harmonic emissions

Evaluation of the disturbances is performed at the Point of Common Coupling (PCC) to the grid².

- Application of suitable limits to ensure that the expected disturbance level does not adversely affect other users of the network. The IEC 61000 series of publications differentiate between the compatibility levels and the planning limits ([80]). In broad terms, the former express the acceptable disturbance level in the network, so that the operation of user equipment is not adversely affected. The latter are limits adopted at the planning stage and therefore stricter than the compatibility levels

Additional considerations and requirements include also:

- Network capacity. Ratings of all network components must be sufficient to handle the power of the DG station.
- Short circuit capacity. DG source contribution should not lead to exceeding the design fault levels of the network, which is 250 MVA for the MV grid. A minimum fault contribution may also be demanded, to facilitate operation of over-current protection schemes.
- Switching and protection equipment. All DG installations must be equipped with decoupling protection, to enforce disconnection upon detection of abnormal grid conditions.
- Effect on network signaling systems. User equipment should not interfere with the operation of public network signaling systems (e.g. attenuate or amplify signals of the acoustic frequency ripple control systems).

In this report, the attention is focused on power quality considerations. Protection requirements for the interconnection are also briefly discussed.

² Dedicated interconnection lines are formally a part of the grid. For this reason, disturbance limits are also enforced for the point of connection (PC) as well, albeit more lenient than for the PCC.

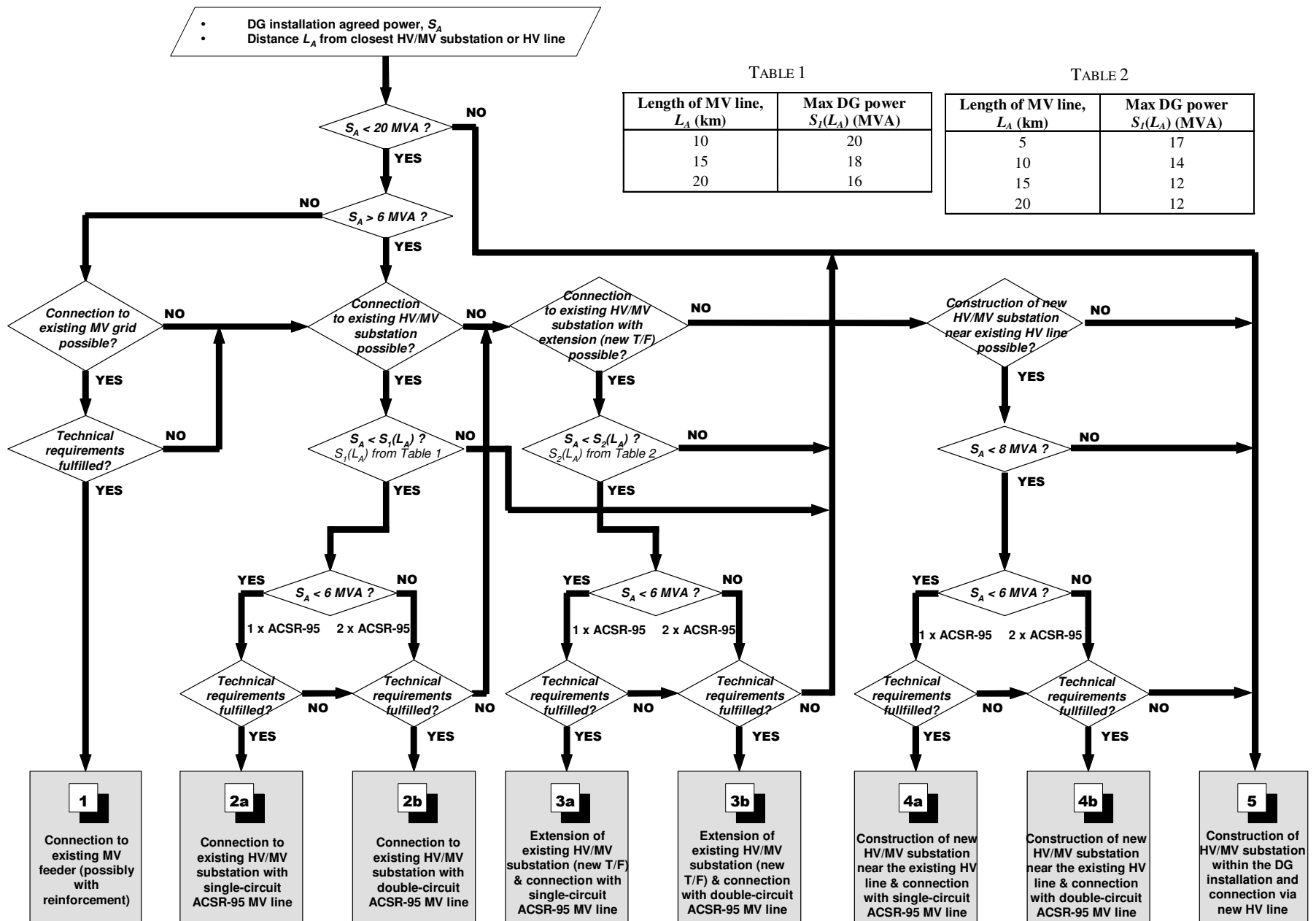


Fig. A.5. 3. Flowchart for selecting the interconnection scheme for DG installations rated above a few hundred kVA (Schemes 1-5, illustrated in Fig. 1).

A.5.4 Slow Voltage Variations

Traditionally, utilities have imposed limiting values to the acceptable steady state voltage deviations, both at the MV and LV levels, which should not be exceeded in normal operation of the system. During the last decade, the statistical nature of the voltage variations has been recognized and relevant norms have been issued, such as the European Norm EN 50160, [81], which imposes statistical limits, in the sense that a small probability of exceeding them is acceptable.

Although voltage variations are random variables in nature, checking the conformity against statistical limits at the planning stage calls for elaborate procedures, such as probabilistic load flow techniques (e.g. [82,83]). Such an approach is relatively difficult to apply, would require data usually unavailable in practice and completely defies the objective of simplicity and efficiency in the evaluation. For this reason, simpler and more straightforward procedures have been adopted for the connection of DG. The evaluation procedure presented in the following utilizes 10-min average values of the voltage and can be applied in two stages.

At a first stage, the maximum steady-state voltage change $\varepsilon(\%)$ at the PCC is evaluated and compared to the limit:

$$\varepsilon(\%) \cong \frac{100}{U^2} (R_k P_n + X_k Q_n) = 100 \frac{S_n}{S_k} \cos(\psi_k + \phi) \leq \varepsilon_{\max} \quad (1)$$

where $S_n = P_n + jQ_n$ is the DG rated power, S_k the network short circuit capacity, ψ_k the angle of the network impedance $Z_k = R_k + jX_k$ and ϕ the power factor angle of the DG output current. $R = S_k/S_n$ is often termed as the short circuit ratio.

The ε_{\max} limit is set to 3%. This limit is relatively strict because it is allocated to a single user of the network, whereas the grid voltage level is determined by the aggregate effect of all connected consumers and generators.

Eq. (1) is accurate enough for most practical purposes (its error being less than 0.5% for $R \geq 15$). Depending on the grid angle ψ_k and the power factor angle ϕ of the installation, short-circuit ratios down to 15 or even lower may be acceptable. The effect of the DG power factor on the voltage variations is evident in Fig. A5.4, drawn for $\psi_k \approx 55^\circ$ (corresponding to MV overhead lines with ACSR-95 conductors). Inductive power factors are often preferable, to counterbalance the voltage increase due to the active power flow on the resistive part of the network impedance (eq. (1)).

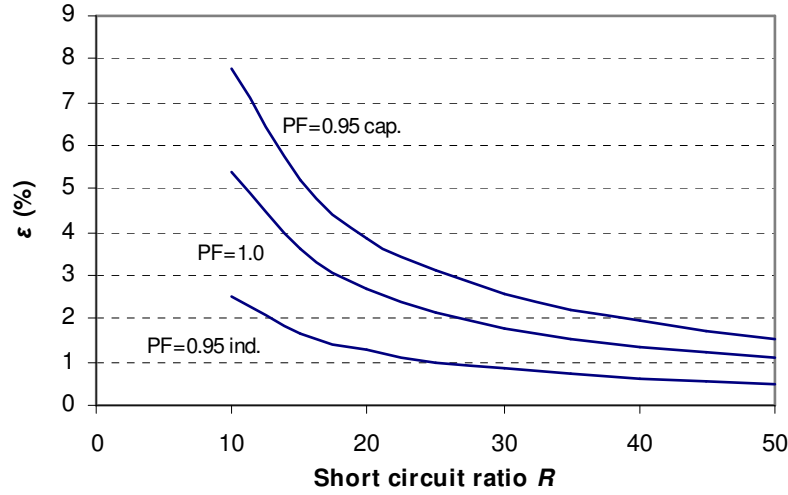


Figure A5.4. $\varepsilon(\%)$ vs. short circuit ratio R , for three DG power factors ($\psi_k \approx 55^\circ$).

This simplified evaluation procedure is not suitable for cases of high DG penetration, multiple installations on the same feeder, long feeders with significant loads and other special cases. Since voltage variations are the aggregate effect of generating facilities and network loads (existing and foreseen), load flow calculations are required, taking into account the actual network configuration and loads. Four basic load-generation combinations are examined:

- Min load-Min generation
- Min load-Max generation
- Max load-Min generation
- Max load- Max generation

In this way, the maximum and minimum voltages, U_{max} and U_{min} , are determined for each node. Typically, case B yields the maximum and case C the minimum voltages, which are then appropriately bounded. The following requirements are set for the steady state voltage of all nodes (see also Fig. A5.5, top diagram):

- The median voltage of each node should lie within $\pm 5\%$ of the nominal voltage, a requirement dictated by the off-load tap changer of the MV/LV distribution transformers (-5% to $+5\%$ regulation, in steps of 2.5%):

$$0.95 \cdot U_n \leq U_{med} = \frac{U_{min} + U_{max}}{2} \leq 1.05 \cdot U_n \quad (2)$$

- The variation of the voltage around its median value should not exceed $\pm 3\%$ of the nominal, so that the LV network voltage deviations remain within $\pm 8\%$ (planning limit), after the median deviation is corrected by the fixed taps:

$$2 \cdot \Delta U = U_{max} - U_{min} \leq 0.06 \cdot U_n \quad (3)$$

The requirements expressed by eqs. (2) and (3) determine the region of acceptable maximum and minimum node voltages illustrated in Fig. 5 (bottom diagram), against which the load flow results are compared.

In the four load-flow calculations proper account is taken of the voltage regulating means of the network (OLTCs of HV/MV transformers, line voltage regulators, switchable capacitors etc.),

which normally operate on time scales of 30 s-1 min and therefore affect the steady-state (10-min average) values. Further, when dealing with sources with adjustable output PF (synchronous generators, PWM converters), this is accounted for in the load flow calculations by selecting the most favorable PF value within the permissible range of variation for each source (0.95 ind. to 0.95 cap.).

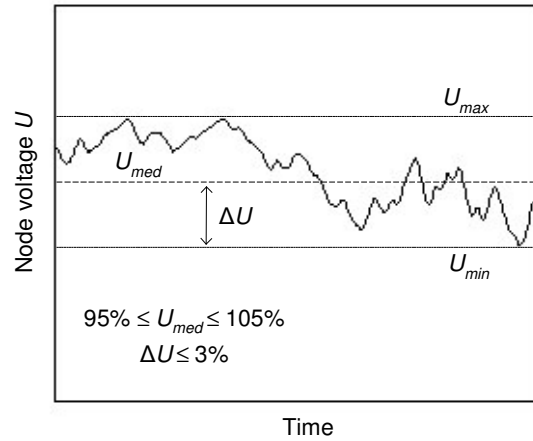


Figure A5.5. Top diagram: Definition of maximum/minimum and median node voltage in steady state. Bottom diagram: Acceptable region of maximum and minimum node voltages.

A.5.5 Rapid voltage changes - Flicker

Rapid voltage changes occur within the 10-min averaging interval used in the definition of slow voltage variations, typically on a time scale between half a period (10 ms at 50 Hz) and a few seconds. They are induced either by switching operations in the DG installation (usually start/stop operations of equipment) or by the variability of the output power during normal operation (e.g wind turbines).

In the case of rapid voltage changes, both their magnitude and the resulting flicker emissions should be limited. Measures of the flicker emissions are the short term, P_{st} , and long term, P_{lt} , flicker severity indices ([84-86]).

Regarding switching operations, the limits imposed depend on the voltage level (LV or MV) where the installation is connected, the size of the equipment and the frequency of the operations. Taking into account the requirements of the relevant IEC documents, [86-90], the limits of Table A5.1 are set for the relative (%) voltage change (Fig. A5.6):

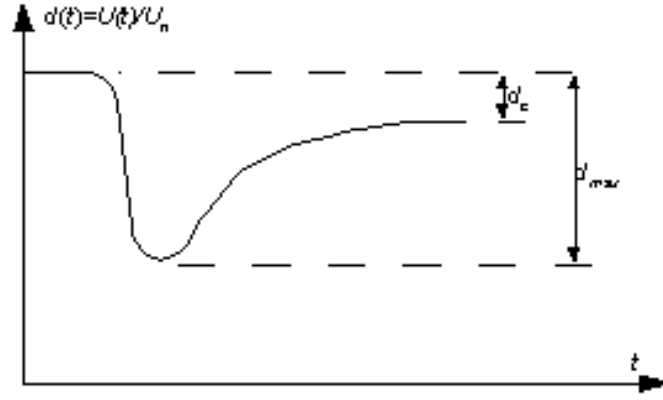


Fig. A5.6. Fast voltage change pattern and characteristics.

TABLE A5.1
MAGNITUDE LIMITS FOR RAPID VOLTAGE CHANGES

		Frequency of switching operations, r (h^{-1} : per hour, d^{-1} : per day)		
LV		$r > 1 \text{ h}^{-1}$	$2 \text{ d}^{-1} < r < 1 \text{ h}^{-1}$	$r < 2 \text{ d}^{-1}$
	Steady-state change, d_c	$\leq 3 \%$		
	Maximum change, d_{max}	$\leq 4 \%$	$\leq 5.5 \%$	$\leq 7 \%$
MV		$r > 10 \text{ h}^{-1}$	$1 \text{ h}^{-1} < r \leq 10 \text{ h}^{-1}$	$r \leq 1 \text{ h}^{-1}$
	Steady-state change, d_c	-		
	Maximum change, d_{max}	$\leq 2 \%$	$\leq 3 \%$	$\leq 4 \%$

An evaluation of the expected voltage change at the PCC during the cut-in of a DG unit is given by:

$$d_{\max} (\%) = 100 \cdot k \cdot \frac{S_n}{S_k} = \frac{100}{R} \cdot k \quad (4)$$

For simplified calculations, k can be set equal to the ratio of the equipment starting current to its rated current, ranging from less than 1 to higher than 8, depending on the type of equipment and the starting method used. Accurate evaluation of $d_{\max}(\%)$ is possible if k is set equal to the *voltage change factor* $k_v(\psi_k)$, which is defined for wind turbines in IEC 61400-21, [91], and is given in test certificates as a function of the grid angle ψ_k . Summation rules for simultaneous switchings of equipment need not be applied, due to the very low probability of coincident events.

For the case of wind turbines, flicker emissions resulting from switching operations can be calculated as ([91]):

$$P_{st} = \frac{18}{S_k} \left(\sum_{i=1}^N N_{10,i} \left(k_{f,i}(\psi_k) \cdot S_{n,i} \right)^{3.2} \right)^{1/3.2} \quad (5)$$

$$P_{lt} = \frac{8}{S_k} \left(\sum_{i=1}^N N_{120,i} (k_{f,i}(\psi_k) \cdot S_{n,i})^{3.2} \right)^{1/3.2} \quad (6)$$

where N is the number of generators operating in parallel, $S_{n,i}$ the rated capacity and $k_{f,i}(\psi_k)$ the flicker step factor of unit i (defined in [91]). $N_{10,i}$ and $N_{120,i}$ are the maximum number of switching operations that can take place in a 10-min and a 120-min interval for unit i . If the flicker factor is unavailable, the flicker has to be evaluated either by the shape characteristics and the frequency of the disturbance (IEC 61000-3-3, [87], provides useful guidance), or by simulation using a software implementation of the flickermeter algorithm of IEC 61000-4-15, [86]. In the absence of other information, an easily applicable rule for maintaining the flicker emission limits due to switching operations is the following:

$$r \leq \frac{m}{[d_{\max}(\%)]^3} \quad (7)$$

where r is the maximum number of switchings per minute within the DG installation and $m=5$ for LV installations and 3.5 for MV installations.

At the LV level, limits for P_{st} and P_{lt} are:

$$P_{st} \leq 1 \text{ and } P_{lt} \leq 0.65$$

At the MV level, the IEC 61000-3-7 ([90]) principles are applied. In broad terms, depending on the *compatibility levels* (i.e. the existing disturbance level in the grid, [80]) and the internal quality objectives of the utility, *planning levels* are set, which are the overall disturbance limits allowed at the planning stage (lower than the compatibility levels). Indicative values for the planning levels in MV systems, according to IEC 61000-3-7 ([90]), are:

$$P_{st} \leq 0.9 \text{ and } P_{lt} \leq 0.7$$

The allocation of the global limits to individual installations is made according to the principles presented in the next section for harmonics (equations similar to (11) and (13) are applied) and takes into account the following:

- Voltage flicker within a certain network is the combined result of emissions from users connected at this network and flicker transferred from the higher voltage level.
- Flicker emissions from individual installations are superimposed to determine the overall voltage flicker disturbance in the network.

The following rule is commonly applied for the summation of flicker (used for P_{lt} as well):

$$P_{st} = \sqrt[3]{\sum_i P_{st,i}^3} \quad (8)$$

During normal operation, voltage changes resulting from fluctuations of the DG output power may create flicker problems, a well-known fact for WTs. According to IEC 61400-21 ([91]), the expected flicker emissions of WTs can be assessed using the flicker coefficient, $c(\psi_k, v_a)$, dependent on the average annual wind speed, v_a , of the WT installation site and the grid short circuit impedance angle, ψ_k :

$$P_{st} = P_{lt} = c(\psi_k, v_a) \frac{S}{S_k} \quad (9)$$

For the total flicker emissions of a wind farm comprising N WTs, the following relation is used:

$$P_{st\Sigma} = P_{lt\Sigma} = \frac{1}{S_k} \sqrt{\sum_{i=1}^N (c(\psi_k, v_a) \cdot S_i)^2} \quad (10)$$

Limits for flicker emissions during normal operation and their allocation to individual users of the system are the same as for switching operations.

A.5.6 Harmonics

The increasing use of power electronics at the front end of many DG types (variable speed WTs, photovoltaics, microturbines etc.) poses harmonic control requirements for their connection to the grid. During the last decade several national and international standards and recommendations have been developed (e.g. [92-95]), permitting the elaboration of appropriate evaluation procedures. In this section, an approach based on the IEC set of standards is described, which comprises three basic steps: First, the definition of acceptable voltage distortion limits (planning levels), second, the allocation of global harmonic voltage limits to individual users (producers or consumers) and third, the determination of the corresponding current distortion limits for a specific installation.

TABLE 2
PLANNING LEVELS FOR LV, MV AND HV NETWORKS (IEC 61000-3-6)

Odd harmonics $\neq 3k$				Odd harmonics $= 3k$				Even harmonics			
Order h	Harmonic voltage (%)			Order h	Harmonic voltage (%)			Order h	Harmonic voltage (%)		
	LV	MV	HV		LV	MV	HV		LV	MV	HV
5	6	5	2	3	5	4	2	2	2	1.6	1.5
7	5	4	2	9	1.5	1.2	1	4	1	1	1
11	3.5	3	1.5	15	0.3	0.3	0.3	6	0.5	0.5	0.5
13	3	2.5	1.5	21	0.2	0.2	0.2	8	0.5	0.4	0.4
17	2	1.6	1	>21	0.2	0.2	0.2	10	0.5	0.4	0.4
19	1.5	1.2	1					12	0.2	0.2	0.2
23	1.5	1.2	0.7					>12	0.2	0.2	0.2
25	1.5	1.2	0.7								
>25	0.2+	0.2+	0.2+								
	$1.3 \cdot \left(\frac{25}{h}\right)$	$0.5 \cdot \left(\frac{25}{h}\right)$	$0.5 \cdot \left(\frac{25}{h}\right)$								
THD: 8 % at LV, 6.5 % at MV, 3% at HV											

For LV systems specific compatibility levels are given in IEC 61000-2-2, [96], and IEC 61000-3-6, [95], which also serve as planning levels, and are included in Table 2. At higher voltage levels (MV and HV), it is the responsibility of the utility to determine the compatibility levels in its network and then define appropriate planning levels. For reference purposes, Table 2 summarizes indicative planning levels suggested in IEC 61000-3-6, which can be applied in the absence of more specific data.

A.5.6.1 MV systems

The coordination of harmonic emission control at the different voltage levels (LV, MV and HV) of a power system requires that distortion transmitted from one level to another be taken into account. Hence, the distortion limit G_{hMV} , available to all installations connected to the MV system is ([95]):

$$G_{hMV} = \sqrt[a]{L_{hMV}^a - (T_{hHM} \cdot L_{hHV})^a} \quad (11)$$

where L_{hMV} and L_{hHV} are the MV and HV planning levels for harmonic order h (from Table 2) and T_{hHM} the harmonic transfer coefficient from HV to MV level (ranging from below 1.0 to more than 3). a is the exponent of the harmonic summation rule:

$$U_h = \sqrt[a]{\sum_i U_{hi}^a} \quad \text{or} \quad I_h = \sqrt[a]{\sum_i I_{hi}^a} \quad (12)$$

IEC 61000-3-6 suggests: $a=1$ for $h<5$, $a=1.4$ for $5 \leq h \leq 10$ and $a=2$ for $h>10$, since harmonics of higher orders tend to have random phase angles.

From G_{hMV} , the voltage distortion limit E_{Uhi} for an individual installation can then be determined, in proportion to its rated power, $S_{n,i}$:

$$E_{Uhi} = G_{hMV} \sqrt[a]{\frac{S_{n,i}}{S_t}} = G_{hMV} \sqrt[a]{s_i} \quad (13)$$

where S_t is the total «feeding capacity» of the network (e.g. equal to the rated MVA of the feeding transformer). The ratio s_i can also be interpreted as the ratio of the rated power of the connected equipment to the total capacity of the distorting equipment in the network, to avoid over-pessimistic results.

It is common practice in harmonic studies to regard the connected equipment as a harmonic current source (although this may not be correct in certain cases, e.g voltage controlled converters), whereas the limits discussed previously refer to the harmonic distortion of the system voltage. In order to relate these quantities, the system harmonic impedance Z_h at the PCC is needed. Then:

$$U_{hi} = Z_h \cdot I_{hi} \leq E_{Uhi} \Rightarrow I_{hi} \leq E_{Ihi} = \frac{E_{Uhi}}{Z_h} \quad (14)$$

where U_{hi} and I_{hi} are the h -order harmonic voltage and current due to installation i and E_{Uhi} , E_{Ihi} the respective limits allocated to this installation.

For MV systems no standardized reference impedance is available and the harmonic impedance Z_h has to be evaluated for each specific network. For systems without significant capacitance and DG installations without PFC correction capacitors or filters:

$$Z_h \approx h \cdot X_k \quad (15)$$

where X_k is the fundamental frequency inductive component of the short circuit impedance at the PCC, evaluated from:

$$X_k = \frac{U_n^2 \sin \psi_k}{S_k} \quad (16)$$

where ψ_k is the short circuit impedance angle at the fundamental frequency and U_n the rated system voltage.

When these assumptions are not valid, a simplified approach can be established ([95]) with reference to Fig. 7, where all network capacitance is aggregated at the MV busbars and any possible resonance in the HV system is ignored.

The capacitance in Fig. A5.7 accounts for the first order parallel resonance with the upstream system (but not for possible higher order resonances). If all resistances and system loads in Fig. 7 are ignored, the resonant frequency f_r and the respective harmonic order h_r (not necessarily an integer) are given by

$$f_r = f_1 \sqrt{\frac{S_{kS}}{Q_c}} \Rightarrow h_r = \frac{f_r}{f_1} = \sqrt{\frac{S_{kS}}{Q_c}} \quad (17)$$

where S_{kS} is the short circuit capacity at the MV busbars of the HV/MV substation and Q_c is the total capacitive reactive power of the MV network. A rough and conservative estimation of Z_h (usually providing results on the safe side) is then given by the “envelope impedance curve” of IEC 61000-3-6, shown in Fig. A5.8. The resonant amplification factor, k_r , of the system impedance at the PCC typically varies between 2 and 5 in public distribution networks, depending mainly on the damping effect of the system load.

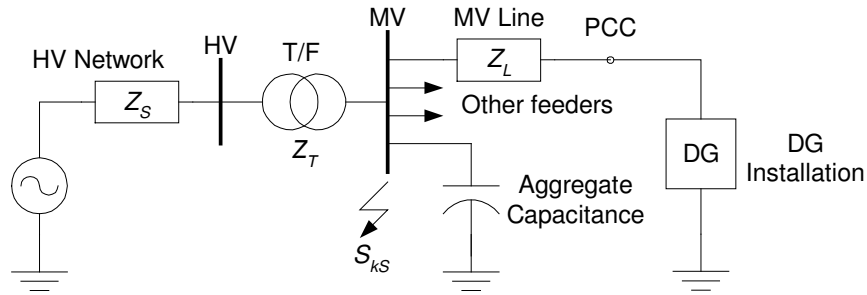


Figure A5.7. MV network equivalent for simplified harmonic analysis ([95]).

For installations with filters or significant PFC capacitance, in more complex networks or when resonant conditions exist in the HV network, the approach presented above is not suitable. Manual computation of Z_h is possible in certain cases but the application of harmonic load flow software is recommended.

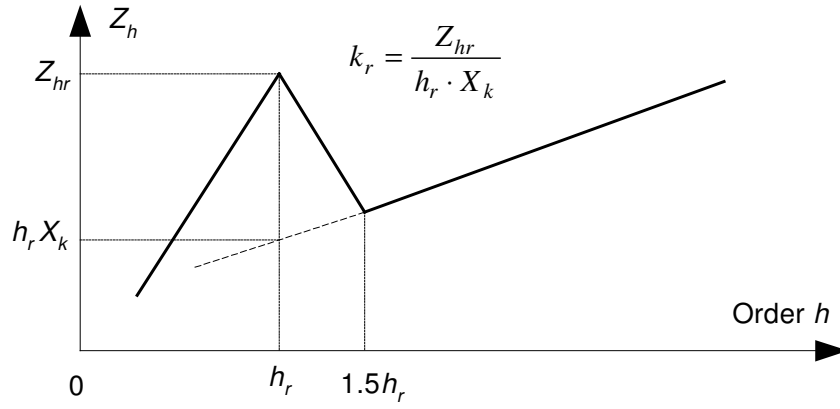


Figure A5.8. System harmonic impedance approximation, using the «envelope impedance curve» ([95]).

The procedure described above, although heavily simplified by research standards, may already be complicated enough for application in practical situations by utility or DG investor technical staff. To further facilitate the evaluation of low distortion equipment at the MV level, without resorting to the procedure described above, a “Stage 1” set of requirements may be formulated. Using eqs. (14)–(16) and the definition of the resonant amplification factor, k_r , from Fig. 8, it is derived:

$$U_{hi} \approx k_r \cdot h \cdot \frac{U_n^2}{S_k} \cdot \sin \psi_k \cdot I_{hi} \leq E_{Uhi} \quad (18)$$

For “Stage 1” evaluation, a conservative approach is adopted. The resistive part of Z_k is ignored ($\sin \psi_k = 1$) and the limit E_{Uhi} is deduced from the planning levels L_{hMV} (or G_{hMV}) in proportion to the ratio s_i ($a=1$ in eq. (13)). Then, from eq. (18):

$$\frac{I_{hi} / s_i}{S_k} \leq \frac{L_{hMV}}{k_r \cdot h \cdot U_n^2} = M_{hMV} \Rightarrow \frac{I_{hi}}{s_i} \leq M_{hMV} \cdot S_k \quad (19)$$

The limit M_{hMV} in eq. (19), expressed in A/MVA, is then directly evaluated using the nominal voltage of the network and assuming an appropriate value for k_r ($k_r=5$ would be a conservative approach). Such a simplified evaluation is adopted in [97]. If eq.(19) is not satisfied, a more detailed evaluation has to be conducted, as discussed previously.

A.5.6.2 LV systems

The principles outlined in the previous section for MV systems are also applicable to the LV level. However, for LV systems IEC 725, [98], establishes a reference system impedance, permitting thus the direct determination of harmonic current limits. Based on IEC 61000-3-2 ([93]), the limits shown in Table A5.3 can be applied for DG units with rated current ≤ 16 A/phase (Class A equipment).

For DG units with rated current between 16 and 75 A/phase, the limits of IEC 61000-3-4 ([94]) are applicable, when connected to a PCC where the short circuit ratio is higher than 33. The evaluation is performed in two stages, using the limits of Table A5.4 (Stage 1) and then those of Table 5.5 (Stage 2), if the equipment does not comply with the Stage 1 emission values.

For DG installations with rated current higher than 75 A per phase, the Stage 1 evaluation procedure used for MV installations (eq. (19)) can be applied, using as emission limit:

$$I_h \leq M_{hLV} \cdot \frac{S_k}{\sin \psi_k} \quad (20)$$

where M_{hLV} is the harmonic current limit per MVA of the system short circuit capacity and ψ_k the short circuit impedance angle at the PCC (not ignored, because of the dominantly resistive character of the LV network impedance). M_{hLV} values can be derived based on eq. (19).

TABLE A5.3
HARMONIC CURRENT LIMITS FOR LV EQUIPMENT
WITH RATED CURRENT ≤ 16 A

Odd harmonics		Even harmonics	
h	$I_{h,max}$ (A)	h	$I_{h,max}$ (A)
3	2.30	2	1.08
5	1.14	4	0.43
7	0.77	6	0.30
9	0.40	≥ 8	$0.23 \cdot (8/h)$
11	0.33		
13	0.21		
≥ 15	$0.15 \cdot (15/h)$		

TABLE A5.4
STAGE 1 HARMONIC CURRENT LIMITS FOR LV EQUIPMENT
WITH RATED CURRENT BETWEEN 16 AND 75 A

h	$I_{h,max}/I_{In}$ (%)	h	$I_{h,max}/I_{In}$ (%)
3	21.6	19	1.1
5	10.7	21	0.6
7	7.2	23	0.9
9	3.8	25	0.8
11	3.1	27	0.6
13	2	29	0.7
15	0.7	31	0.7
17	1.2	≥ 33	0.6
h even		$\leq 8/h$ or ≤ 0.6	

TABLE A5.5
STAGE 2 HARMONIC CURRENT LIMITS FOR LV EQUIPMENT
WITH RATED CURRENT BETWEEN 16 AND 75 A

Min R_k	Admissible harmonic current distortion factors (%)		Admissible individual harmonic currents I_h/I_{In} (%)			
	THD	PWHD	I_5	I_7	I_{11}	I_{13}
66	16	25	14	11	10	8
120	18	29	16	12	11	8
175	25	33	20	14	12	8
250	35	39	30	18	13	8
350	48	46	40	25	15	10
450	58	51	50	35	20	15
600	70	57	60	40	25	18

Even harmonics: $I_h/I_{1n} \leq 16/h$ (%)
Linear interpolation for intermediate values of R_k
I_1 : Fundamental component of equipment rated current
I_h : h^{th} order harmonic current component
$PWHD = \sqrt{\sum_{h=14}^{40} h \cdot (I_h/I_1)^2}$

A.5.6.3 Interharmonics and higher order harmonics

The evaluation procedures outlined above cater for harmonic orders $h \leq 40$ (IEEE Std. 519, [92], provides limits up to the 50th order), which is sufficient for line-commutated converters, as well as for voltage-source converters with a low switching frequency. However, the increasing utilization of PWM converters with fast switching elements, such as IGBTs, has extended the harmonic frequency spectrum well beyond 2 kHz, where limits and evaluation methodologies are still unavailable (IEC 61000-3-10 “Emission limits in the frequency range 2...9 kHz” is under preparation and still awaited). Due to the lack of relevant standards and experience in this range, a conservative approach is adopted, setting a strict limit on the voltage distortion due to higher order and interharmonic components:

$$U_h \leq 0.2 \%, h > 40 \text{ or } h \text{ non-integer}$$

An issue related to harmonics is also the possible interference of DG installations with mains signaling, such as ripple control systems. Such systems usually operate in the range 100 to 500 Hz (up to 2-3 kHz) by injecting a voltage signal of higher frequency on the power frequency voltage waveform, whose magnitude is around 2% of the nominal supply voltage. To ensure no interference, the injection of harmonics or interharmonics from the DG installations should be minimized at the ripple control frequency and its side-bands at frequencies differing by twice the fundamental frequency. In addition, the installations should not attenuate the ripple control signal (e.g. due to low impedance at its frequency).

A.5.7 Interconnection Protection Requirements

The DG-utility interface protection is primarily intended to ensure the safety of other users of the network and of utility personnel and it should be properly coordinated with other protections of the grid. The protective functions incorporated in the utility interface may differ considerably, depending on the size, voltage level, type of DG equipment and operation and protection scheme of the network.

Traditionally, the primary function of the interconnection protection (besides fault detection via overcurrent relays) has been the detection of islanding situations and the immediate disconnection of the generating equipment. Islanding has been extensively studied for PVs connected to the LV network and islanding detection and protection schemes have been proposed, tested and gradually implemented in commercial products (e.g. [99-101]). In case of DG installations utilizing synchronous generators, islanding is a serious concern, too. If induction generators are used, the possibility of self-excited operation still exists, although the probability of favorable active and reactive power equilibrium within the islanded part is fairly low. Nevertheless, it cannot be ruled out and such situations have been encountered in practice. An example is shown in Fig. A5.9, recorded on the Greek island of Chios, where about 5 MW of wind power are connected to a 20 kV line, which includes a 20 km section of submarine cable, [102]. The opening of the feeder circuit breaker resulted in a voltage swell in the isolated

part, sustained for about 15 sec (the WT over-voltage protection was set at high values, due to the high operating voltage because of the submarine cable).

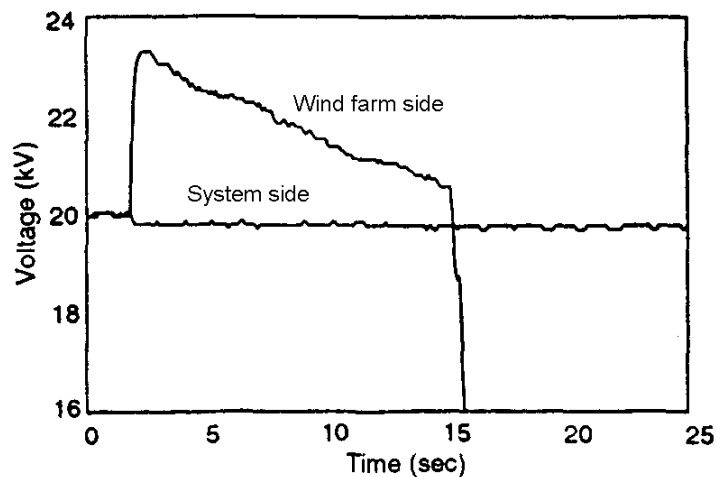


Figure A5.9. Recorded voltage during the isolated operation of a feeder with significant wind power, following the opening of the circuit breaker at its departure ([102]).

Typical minimum protective functions required for the interconnection protection system are over-/under-voltage and over-/under-frequency, as shown in Fig. A5.10. Zero-sequence (residual) voltage relays are also stipulated in most cases. In Table A5.6, two groups of indicative relay settings are provided and discussed in the following.

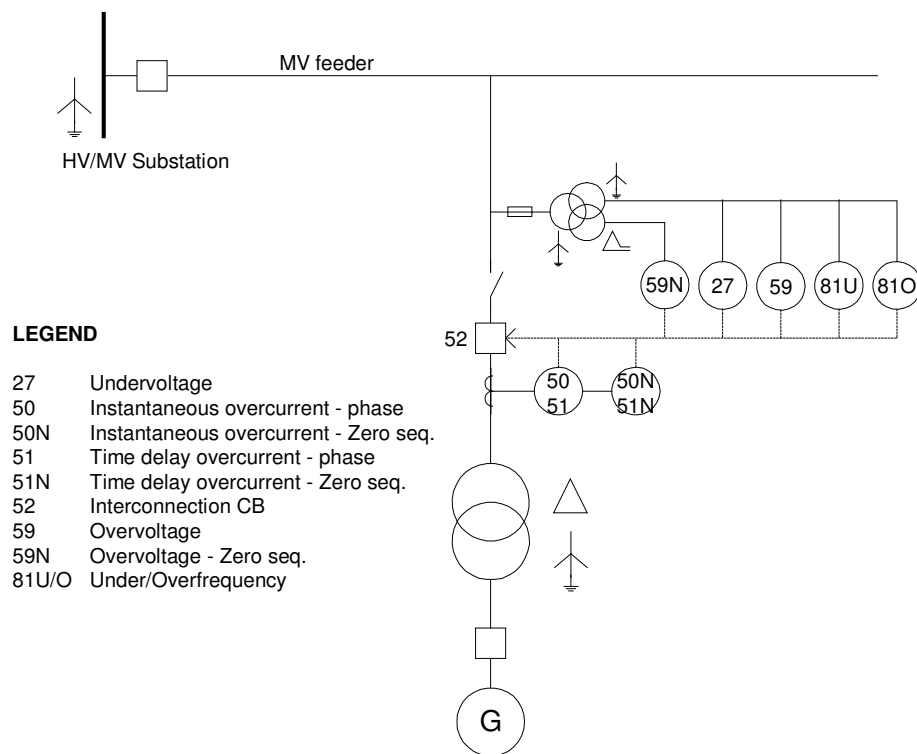


Figure A5.10. Basic functions of the interconnection protection system.

TABLE A5.6
SETTINGS FOR THE INTERCONNECTION PROTECTION RELAYS

Relay	Settings Type A		Settings Type B	
	Threshold	Delay	Threshold	Delay
27	$0.85 \cdot U_n$	0.3 s	$0.80 \cdot U_n$	1.2 s
59	$1.10 \cdot U_n$	0.3 s	$1.15 \cdot U_n$	1.2 s
81U	49.5 Hz	0.3 s	47.5 Hz	1.2 s
81O	50.5 Hz	0.3 s	51.5 Hz	1.2 s

U_n: Nominal voltage of the MV grid

To ensure the prompt detection of islanded operation, strict settings are needed in the voltage and frequency protection, both in deviation limits and activation times. Such settings are also suitable when DG sources -primarily without active front-end interfaces- are connected to lines with fast reclosing protection schemes. In such cases, if the DGs are not disconnected before reclosing, unacceptable stresses may occur, with possible damaging effects ([103]). In Table 6, these requirements are fulfilled by the Type A settings. Transfer-trip schemes can also be used between the line and the DG circuit breakers, which is nevertheless an expensive solution, typically used for large installations. The 0.3 s activation time is short enough to ensure disconnection before the first reclosing of the feeder breaker (approximately 0.5 s after initiation of the fault). At the same time, it is also long enough to avoid tripping by voltage dips due to faults on adjacent feeders, cleared in the first reclosing cycle (with instantaneous overcurrent relays dips last approximately 0.1 s).

Fast activation times, however, as for Type A settings, lead to increased “nuisance” trippings of the DG, which may pose a threat to the stability of systems with high levels of DG penetration (e.g. faults may trigger the undervoltage protection of all DG stations within an extended area). Until recently such situations appeared only as visions of the future. During the current decade, however, high wind power penetration levels have been achieved in several European grids (e.g. interconnected systems of Germany, Denmark, Spain), as well as in isolated grids on many Greek islands. In such cases, maintaining generation capacity in operation during critical disturbances takes precedence over other considerations, leading to the adoption of less sensitive protection settings. The Type B settings in Table 6, applicable for DG stations connected to the MV network of island grids, ensure adequate ride-through of voltage sags due to faults cleared by the time delay overcurrent relays of the feeder breakers. They are also much less sensitive to temporary voltage and frequency excursions, typical in small isolated power systems.

To maintain generation capacity in operation during critical disturbances, besides adopting less sensitive protection settings, imposes also requirements for the fault ride-through capability (i.e. immunity to voltage and frequency variations) of DG resources. A characteristic example is the requirement recently imposed by a German utility (E.ON.) to all large wind farms connected to its system, that their generators should ride through all voltage sags above the magnitude-duration characteristic of Fig. A5.11, [104]. In addition, wind farms should actively assist the grid in case of faults, by properly regulating their output active and reactive power. For such requirements to be met, the design of the DG units themselves has to be revised (fast action of pitch controllers, moderate over-speed allowance, possibly incorporation of storage at the DC-link, installation of SVCs at the generator terminals for conventional induction generators etc.).

In Greece, such requirements have been proposed by operators of isolated island systems, but they have not yet been adopted as a prerequisite for the connection of DG stations.

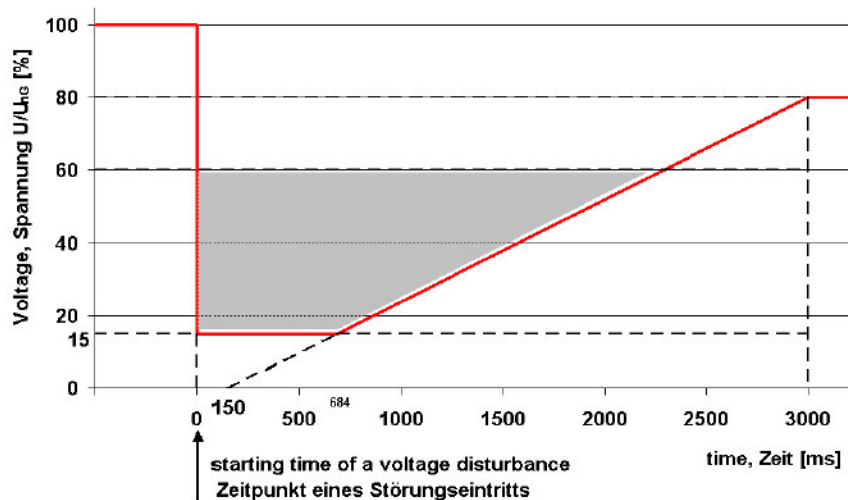


Figure A5.11. Voltage sag immunity requirements imposed to large wind farms by E.ON. Netz GmbH ([104]).

At present, this discussion is relevant for large DG installations connected to the HV level (in some countries also at MV level). In the case of LV installations, the functional requirements for the utility interface concentrate mostly on the islanding detection, which in general is the responsibility of the manufacturer to provide as an integrated part of the equipment. The protection functions of LV DG equipment will be heavily revised in the medium- or long-term, due to the increasing momentum of the “Microgrid” concept, i.e. the possibility for parts of LV networks with sufficient distributed generation to intentionally isolate and operate autonomously from the main grid (e.g. [105, 106]).

A.5.8 Conclusions

This report includes a presentation of important technical considerations for the interconnection of distributed generation resources, as applied currently in Greece. Technical requirements and assessment criteria are described for power quality related issues, including steady state and rapid voltage variations, flicker and harmonic emissions, which are suitable for practical application by utility engineers or DG producer technical staff. The criteria and procedures presented are largely based on the set of relevant IEC publications and on the current practice of European utilities.

The accumulation of knowledge and experience, along with the rapid advancements in DG technology, impose a need for continuous updating and revision of the applied restrictions, limits and methodologies. In the following years more radical updates are to be expected. For instance, active front-end converters, with load balancing, flicker cancellation and active filtering capabilities, may soon find their way into commercial DG equipment. The grid operating principle will also evolve, permitting the exploitation of DG resources for providing back-up power to parts of the grid during power failures, increasing thus the service reliability. Apart from the core technical issues, several other market and regulatory factors will affect

critically the degree of future DG penetration, such as tariffication policies, metering practices, pricing of power quality, possibly provision of ancillary services etc.

A.6 Grid Connection Criteria and Protection Practices for DG in Croatia

A.6.1 Introduction

Generally, distributed generation in Croatia is treated as a generation connected at nominal voltage levels that belong to the MV and LV distribution networks (35 kV and lower). Small power plants with total installed capacity >500 kW shall be connected to the MV distribution network, and the plants with total installed capacity <500 kW at the LV distribution network. Small power plant could be connected either directly at the radial feeder or to the low-voltage bus-bars of a distribution transformer. At the MV feeder it is possible to connect small power plant with total installed capacity up to 1000 kW. At the LV feeder it is possible to connect small power plant with total installed capacity up to 100 kW. It is possible to connect small power plants to the MV network when they have less installed capacity than stated limit (500 kW) but only if it could be justified as better technical and economical solution. Nominal voltage levels of 35 kV, 30 kV, 20 kV and 10 kV belong to the MV distribution network, while 0.4 kV level belong to the LV one. These voltage levels are found in 21 distribution areas that currently belong to single energy undertaking carrying out distribution of electrical energy (HEP – Distribution). Transmission networks have nominal voltage levels of 110 kV, 220 kV and 400 kV that belong to single energy undertaking carrying out transmission of electrical energy (HEP – Transmission). Independent system and market operator (CROISMO) is responsible for safe and secure operation of the power system which has a peak load of 2800 MW and energy consumption of 15000 GWh.

As a rule of thumb, small power plants (hydro, thermal and cogeneration) with installed capacity of less than 5 MW (firm limit) are connected to the MV distribution network. Power plants that are larger than 5 MW but still fall in the group of distributed generation are connected either to 35 kV or even at 110 kV nominal voltage levels. Connection criteria mutually differ. At first as an exemption from the rule, there is one set of criteria if distributed generation (such as hydro, cogeneration, industrial thermal or larger wind power plants) is to be connected at 110 kV nominal voltage level. Hydrogeneration that is connected at 110 kV is not treated here as distributed generation due to its system effects. Then, there are two sets of connection criteria if distributed generation is to be connected at nominal voltage levels of 35 kV or less depending on generating plant installed capacity limit of 5 MW. Connection criteria of wind power plants should be made soon depending on the connection nominal voltage level as well as on the plant installed capacity. It is expected that the installed capacity of wind power plant and condition of the network surrounding its site would define nominal voltage level of connection point.

Current level of installed distributed generation (year 2002) is divided in three parts. The first one gives information on total number of small and industrial hydroelectric power plants that are connected at 35 kV or less nominal voltage level (see Tables). The second part describes total number of cogeneration and industrial thermal power plants that are connected at 35 kV or less. The third part describes two power plants from previous group that are connected at 110 kV nominal voltage level.

Table A6.1. Small and industrial hydroelectric power plants connected at 35 kV or less

Hydroelectric Power Plant	Installed capacity (MW)	Energy produced (GWh)
HPP Miljacka	24 MW (at 35 kV)	121.6
HPP Golubic	6.54 MW (at 35 kV)	28.7
HPP Fuzine	4.8 MW (at 35 kV)	6.6
HPP Lepenica	1.326 MW (at 35 kV)	2.7
HPP Ozalj	5 MW (at 35 kV)	24.7
HPP PI Duga Resa	1.2 MW (at 35 kV)	4.5
HPP Zeleni Vir	1.7 MW (at 20 kV)	7.7
HPP Krcic	0.35 MW (at 10 kV)	1.4
HPP Zavrelje	2.1 MW (at 10 kV)	4.5
HPP Roski Slap	2.8 MW (at 10 kV)	9.2
HPP Jaruga	5.6 MW (at 6.3 kV)	24.9
HPP Finvest	1.26 MW	3.17
Other small HPPs (7 in total)	6 MW	no data available
TOTAL	62.676 MW	>239.67 GWh

Table A6.2 Cogeneration and industrial thermal power plants connected at 35 kV or less

Cogen/Thermal Power Plant	Installed capacity (MW)	Energy produced (GWh)
INA/Molve	11.1	40.7
INA/Etan	5.6	9.3
TS Osijek	11	18.6
TS Virovitica	8	5.9
S Zupanja	8.5	18.5
DINA Omisalj	23	3.7
PLIVA Savski Marof	6	40.0
INA/R Urinj	40.5	114.1
INA/R Sisak	30	77.8
INA/M Mlaka	3	14.2
Z Sisak	17.2	no data available
TP Rijeka	4.6	no data available
DIK Durdenovac	1.8	no data available
TOTAL	170.3 MW	>342.8 GWh

Table A6.3 Cogeneration and industrial thermal power plants connected at 110 kV

Cogen/Thermal Power Plant	Installed capacity (MW)	Energy produced (GWh)
K Belisce	34.2	86.1
P Kutina	35.2	112.1
TOTAL	69.4 MW	198.2 GWh

From Table A6.4 which contains summary of installed capacity and energy produced from various types of distributed generation in Croatia, it is seen that current level of DG falls at 300 MW of installed capacity and 800 GWh of energy produced. No wind power plants have been installed so far.

Table A6.4 Summary of distributed generation

Distributed Power Plants	Installed capacity (MW)	Energy produced (GWh)
HPPs	62.7	>239.67 GWh
Cogen/Thermal at 35 kV or less	170.3	>342.8 GWh
Cogen/Thermal at 110 kV	69.4	198.2 GWh
TOTAL	302.4 MW	>780.7 GWh

However, Croatia has substantial RES future potentials that could be treated as a part of distributed generation. Biomass and geothermal are more present in the continental part, while wind, hydro and solar resources dominate the coastal part of the country. Concerning only electric power production (RES-E), the most important contribution in the future can be expected from wind, hydro and biomass. According to preliminary wind resource modelling there are many areas having mean annual wind speed in excess of 6 m/s. More than 100 potential wind project sites are identified, with a total capacity of 1300 MW and estimated electricity generation of 3000 GWh. Up to now the potential is identified for about 180 MW of small hydro in 58 projects, 60 MW of geothermal and approx. 160 MW of biomass, mainly biomass fired CHP. Total potential of RES in Croatia, assessed on the basis of identified renewable energy projects is, thus, approximately 1700 MW.

Without considering the limits of intermittent generation that can be absorbed in the Croatian electricity system (peak load 2800 MW, minimum load 950 MW) and excluding environmental issues, natural RES potentials and spatial availability would provide probably even several times larger distributed renewable generating capacity in Croatia.

Thorough project oriented cost-benefit analyses for RES in Croatia, carried out for HBOR and World Bank/GEF suggest that, according to given assumptions, it would be economically viable to include around 900 GWh from RES in 2010, which would represent approx. 4.5% of a total Croatian electricity demand. Such a RES share and associated incremental costs of electricity generation are justified on the grounds of avoided externality costs of electricity production from non-renewable energy sources. 900 GWh target is proposed to be adopted by the Government as a part of recently drafted new RES regulation in Croatia.

If these future RES potentials are combined with current level of distributed generation, it results with future level of nearly 2000 MW of installed capacity and 1700 GWh of energy produced from distributed generation (year 2010).

A.6.2 Level of DG Connection

The decision on the level of installed DG connected at LV or MV distribution network is based first on the firm limit of generating plant installed capacity equal to 5 MW, and then on specific studies that cover technical, economical and security aspects of power system operation.

Among technical aspects it is necessary to pay attention to following:

- determination of maximum allowed power that generating plant could securely inject into the network at the site according to thermal and voltage criteria,
- prediction of slower power fluctuations with respect to changes due to various generating plant operating regimes,
- evaluation of angle/voltage stability of the power system either at distribution level or at general level depending on the level of penetration,
- computation of short-circuit capacity and estimation of power quality with respect to flicker emissions and relative voltage changes,
- discussion of possible interaction of the generating plant with already existing protection systems especially for connection at distribution level, and
- need for eventual voltage profile flattening in the network by various means of reactive power compensation.

Among economical aspects it is necessary to pay attention to following:

- power and energy losses in distribution network before and after connecting generating plant,
- capacity credit to transmission network after connecting generating plant at distribution network,
- incurred costs needed for network reinforcements due to connection of generating plant, and
- incurred costs to system operator which is responsible for safe and secure operation of the power system with respect to primary, secondary and tertiary regulation and ancillary services.

Among security aspects it is necessary to pay attention to following:

- regulation needs and ancillary services in the power system with large penetration of distributed generation that is not centrally supervised,
- load shedding schemes at radial distribution feeders with connected distributed generation.

A.6.3 Technical Documents Used

Various technical criteria are covered in the following document ‘Connection Criteria at the Distribution Network for Wind Power Plants in Croatia’ written by N. Dizdarevic. This document exclusively treats connection of wind power plants to distribution network, but general idea is applicable to connection of other generating sources to distribution network. Issues such as thermal loadings, voltage conditions (slow and fast), angle/voltage stability, short circuit capacity and power quality are discussed in detail. Connection criteria for small generating power plants are also shown in following documents of Hrvatska elektroprivreda (Croatian Electric Power Utility):

- Technical conditions for connection of small power plants to electric power system of Croatian Electric Power Utility, No. 4.25/97, N.073.01,
- Standard condition requirements for connection of new generators to distribution network (Grid code – distribution, in process of proclaiming),

- Standard condition requirements for connection of new generators to transmission network with respect to access, regulation and ancillary services (Grid code – transmission, in process of proclaiming).

A.6.4 DG Participation in Markets

In Croatia, electricity market is opened for eligible consumers (>40 GWh per year) since November 2003. Many necessary documents have been prepared and are currently in the process of proclaiming. Moreover, ancillary services market is not effective yet. There are lots of expectations related to fast restructuring of electricity sector in Croatia. Currently (February 2004), there is no functioning electricity market where DG could independently and solely participate. However, the Hrvatska elektroprivreda (Croatian Electric Power Utility, HEP) noted special status of privately owned small power plants connected to its system. This status is primarily related towards following:

- readiness of the HEP to buy all generated electrical energy from such generating sources,
- possibility for the owner of the plant to use a part of generated electrical energy for own needs at the site and to deliver the rest to the HEP, and
- guaranteed buying price of delivered electrical energy to the HEP.

Small power plants are defined as the ones which deliver generated electrical energy or its available surplus after balancing own needs at the site with maximum installed capacity of 5 MW. Rating power of individual generating unit can not be larger than 5 MW. To that category of small power plants belong small thermal power plants with cogeneration schemes aimed at high energy efficiency and small hydroelectric power plants.

A.6.5 Deep or shallow charges applied for reinforcing the network

Deep charges are applied for reinforcing the network, if needed for secure operation and supply of electrical energy generated in the power plant. In previously mentioned document ‘Connection Criteria at the Distribution Network for Wind Power Plants in Croatia’, various technical requirements set as connection criteria are explained in a form of an illustrating example. The example treats one real site in Croatia where surrounding distribution network has restricted further activities due to incurred costs needed to cover network reinforcements by applying deep charges.

A.6.6 Responsibility for interconnection costs and ownership of the DG interconnection

Investor of generating power plant is responsible for interconnection costs. The investor is obliged to finance construction of lines and devices to the point of the connection, eventually needed reconstruction works at the point of connection and eventual network reinforcements needed for secure operation and supply of electrical energy generated in the power plant.

The authorised body of the distribution area defines the point of the power plant connection to the distribution network and all other technical and economic conditions with respect to the General Conditions for Delivery of Electrical Energy (currently in process of proclaiming, February 2004).

The point of the connection shall be equipped with the device for metering of electrical energy that the power plant supplies to the network and with the circuit breaker for separation of the

power plant from the network. The authorised body of the distribution area may request installation of the equipment for tele-control of the metering device for the small power plants with installed capacity larger than 1000 kW. The authorised body of the distribution area defines equipment for tele-control, and the investor shall cover installation costs. Owner of the power plant may install supervisory measuring devices of the same type, but only at own expenses.

Generally, the point of the connection of small power plants (which contains the metering device and the circuit breaker for separation) as well as everything else that is located further into the network is owned by the energy undertaking which carries out distribution of electrical energy (HEP – Distribution). This energy undertaking is responsible for maintenance costs of the metering device. Ownership over the power plant depends on contractual agreements between investors.

A.6.7 Protection practices

Protection systems of the power plant shall be coordinated with protection systems existing in part of the distribution network to which it shall be connected. Types of protection systems to be applied depend on characteristics of the power plant and the network. Protection systems shall at least cover following:

- protection from inadequate and unwanted parallel operating conditions between the plant and the network,
- protection of the plant and network parts from disturbances and faults that happen in the plant, and
- protection of the plant from disturbances and faults that happen in the network.

In addition to previously mentioned, the investor may apply other protection systems. Overvoltage, phase-to-ground and touch voltage protection systems shall be coordinated with neutral point grounding in the distribution network. In parallel operation of the plant and the network, it is desirable to have un-grounded neutral point of the generators in the power plant. Selectivity of protection systems shall be preserved upon connecting the power plant to the network.

For small power plants with installed capacity less than 100 kW, the protection system shall comprise following:

- overcurrent protection of the generator stator windings,
- overcurrent protection from phase-to-ground fault,
- protection from overvoltage,
- protection from undervoltage,
- protection from overfrequency,
- protection from underfrequency, and
- protection from direct and indirect touch.

For small power plants with installed capacity larger than 100 kW, previous set of protection systems shall be supplemented with:

- protection from power back-flow, and
- protection from unsymmetrical conditions.

For small power plants with installed capacity up to 1000 kW, set of protection systems shall contain following:

- overcurrent protection of the generator stator windings,
- overcurrent protection from phase-to-ground fault,

- protection from overvoltage,
- protection from undervoltage,
- protection from overfrequency,
- protection from underfrequency,
- protection from power back-flow, and
- protection from unsymmetrical conditions.

For small power plants with installed capacity larger than 1000 kW, previous set of protection systems shall be supplemented with:

- differential protection.

In most cases of protection system operation due to faults in the network or inadequate parallel conditions, it is sufficient to separate the power plant from the network at the main circuit breaker or at the generator circuit breaker, providing possibility for islanded operation if designed for the plant. If protection system is operated due to faults in the power plant then it may be necessary not only to activate the breakers but to shut-down turbine prime-mover as well (differential protection, over/undervoltage protection, over/underfrequency protection).

In some more complex small power plants, in addition to previously mentioned, it is possible to apply following protection systems aimed at protection of the plant:

1. protection systems that only activate separation of the power plant from the network
 - protection from high windings temperature
2. protection systems that shut-down turbine prime-mover:
 - protection from loss of excitation,
 - protection from faults in excitation circuits,
 - protection from high temperature of the shaft parts,
 - protection from overspeed,
 - protection from underspeed,
 - protection of the prime-mover,
 - protection from faults in auxiliary systems, and
 - activation of security systems (fire).

In previously mentioned document 'Connection Criteria at the Distribution Network for Wind Power Plants in Croatia', various technical requirements set as connection criteria from protection viewpoint are discussed in a form of an illustrating example.

A.6.8 Islanding and Anti-islanding Protection

From technical and technological viewpoint, small power plants may be designed for

- disconnected operation (rare cases),
- parallel operation with distribution network, and
- parallel operation with distribution network and enabled islanded operation.

The islanded operation of the power plant (mainly industrial) may be enabled if it is designed to supply own local demand at the installation site within the plant. Generally, islanded operation of privately owned small power plants and part of the distribution network is not allowed. However, if some distributed power plants owned by the HEP are connected to the distribution network and supervised centrally it may be possible to find them in islanded operation during heavily disturbed transmission system operating conditions.

Anti-islanding protection is applied through activation of the circuit breaker aimed for separation of the plant from the network which is located at the point of the connection. This shall enable safe disconnection of the plant and avoidance of partial distribution network supply only from the power plant. Operation of this circuit breaker is under exclusive supervision of designated distribution system operator. Control over this circuit breaker is local, but the authorised body of the distribution area may request implementation of its tele-control if installed capacity of the power plant is larger than 1000 kW. Incurred costs of its installation and incorporation in whole tele-control system are investor's responsibility. The breaker is initiated to separate the power plant from the distribution network in their parallel operation when voltage magnitudes deviate more than $\pm 10\%$ of U_n and frequency is either $>51\text{Hz}$ or $<48\text{Hz}$.

Depending on characteristics of the power plant and its design for eventual islanded operation (supply of local load at the site within the plant), other switching devices should be provided in addition to the circuit breaker for separation of the plant such as the main circuit breaker of the plant and the generator circuit breaker for its synchronisation. The generator circuit breaker shall be used for synchronisation of the generator if the power plant is designed only for the parallel operation with the distribution network. The generator circuit breaker and the main circuit breaker of the plant shall be used for synchronisation if the power plant is designed for parallel and islanded operation. This means that when the small power plant is designed for parallel and islanded operation it is necessary to provide the main circuit breaker of the plant.

Automatic line reclosing at the radial feeder to which the power plant is connected imposes appearance of special type of islanded operation and shall be approached independently of general considerations regarding anti-islanding protection systems.

In previously mentioned document 'Connection Criteria at the Distribution Network for Wind Power Plants in Croatia', various technical requirements set as connection criteria from viewpoint of islanded operation are discussed in a form of an illustrating example.

A.6.9 Main barriers to wider DG interconnection

It is expected that in the fast track reforms of electricity sector in Croatia following political, administrative, technical, financial, organisational, awareness, and public involvement barriers will be successfully eliminated:

A.6.9.1 Political

Lack of mandatory strategic aim

Clear mandatory aim regarding RES is not yet defined in Croatia. Draft new regulation proposes target for RES-E, but the regulation is still not adopted.

Policy inconsistency

Support to RES in Croatia is still on a declarative level. Supreme laws recognise importance of renewables (Energy Law, Environment Protection Law) but concrete activities and implementation are missing. Vertical policy inconsistency could also be found at different levels of state organisation.

A.6.9.2 Administrative

Lack of legal framework

Although a package of new energy sector laws was adopted in summer 2001 containing some positive shifts, a decree-level regulation is still missing, which would put into effect purchase obligation, set tariffs for RES-E, enable non-discriminatory access of distributed generation to the electric grid, enable priority access of RES-E producers to forthcoming energy trading market etc. Infrastructure and connection costs also need to be addressed in the secondary legislation.

Complexity of authorisation procedures

Current project development practice is time consuming and ineffective. Some segments of planning procedure are not transparent or have not even been established. As such, these planning steps lead to non-consistent and uneven operational practice across the country. *Circulus vitiosus* – closed loops of the planning procedure sometimes happen. Authorisation rules often change and in most cases make additional requirements to project developers.

A.6.9.3 Technical

Lack of reliable data

Lack of meteorological data represents a limitation, which cannot be overcome in short time. Croatia has rather complex terrain, especially in the most promising regions for wind projects, which make available data insufficient for reliable wind potential assessment and/or initial site searching purposes. Large regions are still black holes on wind atlases, while other regions have a high level of uncertainty. According to ornithologists, Croatia is very rich in bird species, but knowledge about their behaviour is rather insufficient. Lack of bird monitoring could be a problem in the future. Ornithological science in Croatia doesn't have enough resources to respond in short time and carry out monitoring campaigns.

Grid limits

Technical limits of the electrical network transmission/distribution capacity could become a major problem in Croatia. High wind energy share in the local, especially islands' electric network could cause a quality problem, defined by standards for the electric energy supplied. Grid reinforcement represents additional cost, which can be a notable portion of the total investment. This could be important for many areas where considerable wind resource exists, but this resource could remain largely unused in the short- and medium-term period just because of high connection and reinforcement cost.

A.6.9.4 Financial

Price paid for RES-E is still not defined

Total payment per kWh from various RES-E producers is still subject to uncertainties. Differentiated price for electricity from various renewables is subject of new draft regulation, but still need to be put into practice.

Lack of incentive measures

No direct or indirect financial support exists presently for RES projects in Croatia. Besides, social and political driving forces for RES still have not been recognised by Croatian politicians. Rather, support to RES is explained as unnecessary spending, while benefits are overlooked.

Taxation policy

“Polluters pay” principle is just emerging in Croatia. Renewable energy sources do not benefit from ecologically driven or any other tax relief.

Financial resources and cost of capital

Source of money for the overcost of RES-E is conceptually worked out within new draft regulation, but the concept still need to be put into operational practice. Lack of seed money for project identification, lack of risk capital or its high cost make the RES-E projects insufficiently attractive to investors.

A.6.9.5 Organisational

Energy market monopolies

Electric energy market in Croatia is still operated by state-owned utility company (HEP) that has a monopoly on power-industry activities. The process of HEP restructuring and privatisation is under way, as well as deregulation and liberalisation of energy markets, which is expected to have important impact on future utilisation of RES in Croatia.

Institutional arrangements

Important role in energy sector organisation, especially regarding licensing of energy undertakings, project authorisation, organization of the electricity market and purchase of electricity from RES-E producers (eligible producers), is envisaged for two newly established independent institutions: Croatian Energy Regulatory Council (CERC) and Croatian Independent System and Market Operator (CROISMO). CERC is still in making, under-capacitated for planned activities, both in terms of manpower and financially, and CROISMO, who is to be the main purchaser of RES-E, still waits to be detached from the corporate structure of HEP.

Property issues

Land on which potentially many projects could be developed is owned by the state. State owned land cannot be rented, leased or bought without clear legal interest, which private investors prove by the process of project development and collection of various permits and consents. Thus, legally binding “site reservation” in advance (prior to measurement campaign) is not possible, which means that initial risk of site acquisition is rather high. Additionally, procedures to lease or rent state property need to be clarified or re-established.

A.6.9.6 Awareness rising

Lack of information

Some opposition to RES can be found among authorities and decision-makers because they often do not have right and accurate information about renewables, its impacts and benefits.

Education

Lack of professional organizations with knowledge and experience in the field of RES, lack of courses and lectures at universities, reluctant teaching stuff...

Public involvement

The public is generally inadequately included in the decision-making process.

A.7 Grid Connection Criteria and Protection Practices for DG in Portugal

A.7.1 Short description of current and future level of DG

In Portugal there is a considerable amount of DG, mainly connected at MV and HV distribution grids. From the legal point of view this DG is considered as a Special Regime Generation, remunerated through specific feed in tariffs and operating such that all energy produced can, usually, be delivered to the system without no restrictions. It corresponds presently already to a significant amount of energy and installed capacity, as described in Table A7.1.

Table A7.1 Special Regime Generation installed capacity and energy delivered to the grid in 2003 (Mainland)

Technology	Installed capacity (MW)	Energy produced (GWh)
Wind	300	472
Mini-hydro	308+324	1729
Biomass, including waste to energy	76	NA
Cogeneration	1186	2202
Others (PV, sea waves)	2	NA

For 2010 the Special Regime Generation is expected to increase considerably as depicted in the Table A7.2.

Table A7.2 Target values for Special Regime Generation for 2010 - installed capacity and energy expected to be delivered to the grid (Mainland)

Technology	Installed capacity (MW)	Energy produced (GWh)
Wind	3750	8500
Mini-hydro	400+324	1850
Biomass, including waste to energy	360	1200
Cogeneration	1700	NA
Others (PV, sea waves)	200	300

However for wind generation, most of the future installed capacity will be obtained through large wind parks, directly connected to the transmission system.

A.7.2 Rules to decide on the level of DG to be installed

The general rule followed to decide about the connection of DG units is based on the verification if the ratio between the installed capacity of the DG unit and the minimum short-circuit power at the grid connection point is less than 8%.

However additional studies are performed to evaluate the impact of the connection of DG units of the congestion levels of the HV distribution network and transmission grid for a worst case scenario. This means that the n-1 security criterion is checked for several load and production scenarios. The transmission system is divided in network areas and for each area the amount of Special Regime Generation (DG or large wind farms) that can be connected in this area is determined, such that it will not provoke any congestion in the grid for using the n-1 criterion.

A.7.3 Voltage changes and power quality

In Portugal there is an additional rule for the reactive power generation for special regime units: these plants are obliged to follow a generation rule such that they have to produce, during the off-valley hours, reactive power in the amount of 40% of the active power, and they should not inject reactive power in the grid during the valley hours.

With this rule it happens that sometimes during off-valley hours steady voltages may become high and even provoke the trigger of the maximum voltage relays of these generators. Because of that flexibility is allowed for these cases and these generators can reduce the reactive power production levels.

Power quality issues are not a matter of concern regarding DG connection to the grid.

A.7.4 Participation of DG in markets

DG units do not participate in the energy market neither they participate in ancillary services markets.

A.7.5 System reinforcement

No deep or shallow charges are applied for reinforcements of the network because of DG expansion.

The approach adopted passes through the identification of the areas where it is most probable that DG generation will appear. Plans for the expansion and reinforcement of the transmission grid are performed tackling simultaneously with the growth of DG generation. These plans are submitted to the approval of the Regulator and if accepted the corresponding costs that will result from this will be passed to the consumers through the transmission tariffs.

A.7.6 Responsibility for interconnection costs

Specific costs for building connection infrastructures are a responsibility of the DG developer. However the property of these infrastructures is passed afterwards to the distribution or transmission utilities.

A.7.7 Protection practices

Apart from the protections each generator should possess, DG plants are required to install a set of protections for interconnection with the local grid, such that they will be able to assure that the production plant will be disconnected from the network once a fault is detected in the grid. In Portugal, this set of protections includes three phases overcurrent relays, three phases under and over voltage relays, under and over frequency relays and a zero sequence voltage relays (used to detect in an efficient way impedant earth faults in the distribution network). Usually these relays

are set to instantaneous operation, due to the need of assuring enough safety levels to the maintenance staff in case of development of works on voltage.

In a scenario of large participation of DG, concentrated in one area, a simultaneous miss operation of the interconnection relays of these DG plants may provoke serious problems to system operation. In fact, if a short-circuit takes place in the transmission grid and its effects on voltage are propagated downstream to the distribution level, it may provoke the disconnection of a large amount of DG production.

A.7.8 Anti-islanding protection

There are no specific anti-islanding protections. However the maximum and minimum frequency relays will be able to detect islanding situations, since very difficultly load will be equal to generation and generation has, generally, no frequency regulation capabilities.

Allowing islanding operation is presently under study for networks with large DG penetration in some remote areas, to increase reliability in the local grid.

A.7.9 Barriers to wider DG interconnection

Since DG units are completely non-controllable and non-dispatchable utilities adopt a conservative approach regarding DG connection to their grids. If DG units could be more controllable and participative in the management of the system it will, for sure, be possible to increase their integration. This will require at the same a new attitude from the utility managers.

Management of at least larger DG unit capabilities should be used also to help manage the local distribution grids and the production / transmission system through the new additional functionalities of DMS or through the introduction of area production dispatch control centres, able to provide namely:

- Capability of aggregation of hourly DG production levels, to provide power forecasts;
- Ability to limit production injections in the transmission grid through local DG control;
- Ability to limit DG production ramping rates, if necessary;
- Management of reactive power support (presently already technically feasible);
- Management of active power reserves, namely secondary reserve going down, (which can be easily implemented in the present technology scenario).

A.8 Grid Connection Criteria and Protection Practices for DG in the Netherlands

A.8.1 Introduction

In the early 1980's there was a growth of distributed generation that made it necessary to formulate separate connection criteria for units up to 5 MW, connected to 10 kV- grids, followed in the 1990's by connection criteria for units connected to low voltage-grids and photovoltaic systems.

The new Electricity Law of 1998 introduced the National Regulator made it necessary to compose one National code with technical demands that consists of a Gridcode, a Systemcode and a Meteringcode. The separate connection criteria mentioned before were integrated in these codes.

So all technical rules for the grid connection criteria can be found in those codes.

A.8.2 Current and future level of DG

Since the end of the 1980's, a substantial growth of distributed generation (DG) and has been established. Combined Heat Power units reached a level of 7400 MW in 2004, partially connected to 110 kV-grids.

Current level of DG (including wind energy etc.) connected to 10 kV-grids and lower in 2004 is 3000 MW.

Expected level of DG in 2010 is 4000 MW.

These DG's are merely connected to 10 kV-grids.

Production units (including CHP) connected to 110 kV-grids and higher are not being regarded as DG.

A.8.3 Main barriers to wider DG interconnection

I cannot identify barriers to wider DG interconnection in the Netherlands.

A.8.4 General system characteristics

In the Netherlands the voltage characteristics of electricity supplied by the distribution systems and the reliability of the distribution-function of the system have been described in chapter 3 of the Gridcode. The remaining chapters embody the conditions relating to connection, planning and management.

The technical criteria for DG up to 5 MW are all embodied in the Gridcode.

For units greater than 5 MW there are some extra demands embodied in the Systemcode with regard tot primary control and requirements in disturbed conditions.

A.8.4.1 Common demands

The demands that are always (not only production units) applicable are:

- Electrical installations and their components are protected in a way, that the sensitivity and selectivity of the protection system as a whole are still ensured.
- The DNO will provide the owner of the installation connected on request, and as applicable, with information concerning:
 - a. the protection philosophy
 - b. the short circuit power
 - c. the earthing procedure
 - d. the isolation co-ordination
 - e. the supply network configuration.
- Electrical installations and the appliances connected to the supply network are not allowed to cause any impermissible obstruction to the network.
"Impermissible obstruction" has to be judged by comparing phenomena to the voltage characteristics in chapter 3 of the Gridcode.

A.8.4.2 Voltage level at the connection point

On the basis of the following Table in the Dutch Gridcode, the supply network manager will determine in which way the supply is to be provided to the connection. The supply network manager is permitted to establish deviating table-values for the connection capacity for his area. These deviating values are available for inspection at the supply network manager's premises, and they, and any changes to them, are notified to the Director of DTe in writing.

Those who wish to deviate from those rules are allowed to do so, if there are no technical problems caused by doing so.

Table A8.1

Connection capacity	Nominal connection capacity	Comments
<=5.5 kVA	0.23 kV single-fase	
>5.5 kVA up to and including 60 kVA	0.4 kV	
>60 kVA up to and including 0.3 MVA of secondary side LS transformer	0.4 kV	
>0.3 MVA up to and including 3.0 MVA	>1 kV and < 25 kV	
>3.0MVA up to and including 100 MVA	25 kV up to and including 50 kV	In areas where no voltage from 25 kV up to and including 50kV is available, connection is made to the next higher or lower voltage level. The supply network manager should adapt the values for the connection capacity accordingly.
>100 MVA	>50 kV	

A.8.4.3 Short- circuit power

In faulted situations DG plants will contribute to the fault currents in the network. If more production units are operating in parallel on a restricted part of the MV supply network, the supply network manager will examine, on the basis of calculations, whether, and if so, which measures are necessary to restrict the contribution of a three-phase current machine to the short-circuiting capacity on the supply network to which it is connected to a minimum.

A.8.5 Voltage control and reactive compensation

The following constraints are imposed in the control of the voltage and of the reactive power.

- On LV-grids there is no obligation to produce or consume reactive power, but the power factor of a DG connected with the LV-grid must be between 0.9 consuming and 0.9 producing.
- In MV grids with a voltage level below 50 kV all production units shall be equipped with a voltage control-system.

The value of the reactive power produced and the controle mode (voltage- or reactive power control) are determined by the DNO in accordance with network operation requirements.

- On MV grids with a voltage level below 50 kV all production units shall be able to

operate with a power factor between 1.0 and 0.85 (producing) measured at the generator terminals.

- In the MV grids with a voltage level below 50 kV all production units shall be able to supply the maximum available reactive power under the circumstances of reduced network voltage for the following period of time:

	Drop in voltage	Period of time
Supply network < 50 kV	$U_n \geq U \geq 0.95 U_n$	Unrestricted
	$0.95 U_n > U \geq 0.85 U_n$	15 minutes
	$0.85 U_n > U \geq 0.8 U_n$	10 seconds

A.8.6 Power quality requirements

In terms of power quality, the impacts of the grid connection of DG plants and loads on all remaining connections shall be limited in such a way that the DNO is still able to respect its commitments and obligations as described in chapter 3 “The quality of supply” in the Dutch Gridcode.

A.8.6.1 Flicker and voltage fluctuations

- The contribution to flicker by all (house)installation connected to the LV-grid is restricted by the demands of an maximum contribution to Pst (Probability short term) and Plt (Probability long term) as follows: $\Delta Pst \leq 1,0$ and $\Delta Plt \leq 0,8$ ($Z_{ref} = 283 \text{ m}\Omega$ conform IEC 61000-3-3)
- For installations connected to MV-grids there is only a more common article for all grids that may be used to restrict the contribution to flicker: Electrical installations and the appliances connected to the supply network are not allowed to cause any impermissible obstruction to the network. The DNO may instruct the person connected to take action to prevent the impermissible obstruction, or to forbid the person connected to use appliances and motors to be specified by the DNO for a number of hours to be specified by him.
- The slow voltage fluctuations shall be limited so that the voltage doesn't exceed the voltage limits as described in chapter 3 “The quality of supply” in the Dutch Gridcode.

A.8.6.2 Harmonic emissions

Harmonic currents injected on the grid shall be limited according to the following requirements:

- For small appliances up to 11 kVA harmonic emissions shall be limited so that the DNO is still able to maintain the quality of the power supplied to other network users within the required limits of chapter 3 “The quality of supply” in the Dutch Gridcode. The article the DNO has to use to achieve this goal is the common article above, that forbids to cause impermissible obstruction.
- For the larger appliances the owner of the installation connected, must prove that machinery, appliances, materials and components included in electrical installations, or connected to electrical installations, whose electromagnetic compatibility is not established by a statutory regulation, comply with the provisions relating to electromagnetic compatibility established by the supply network manager. For apparatus with a power greater than 11 kVA are applicable, the “Guidelines for permissible harmonic currents produced by apparatus with a capacity greater than 11

kVA” dated January 1996, published by EnergieNed.

A.8.6.3 Unbalance

On MV-grids the DNO has to ensure that the average rate for the negative sequence is lower than 2% of the direct sequence.

Here again, the DNO has to use the common article above, that forbids to cause impermissible obstruction.

A.8.7 Protection

In the future the protection settings for overvoltage, undervoltage, overfrequency and underfrequency for DG's connected to LV-grids will be most probably harmonised with EN50438 that is being drafted.

Loss of Mains protection is not required.

A.8.8 Participation in market

The DG is obliged to participate in the market. He has to find a buyer. He has also to pay for the ancillary services.

A.8.9 Shallow versus deep cost approach

Costs for reinforcing the network have to be paid by the DNO.

A.8.9.1 Interconnection

The DG has to pay for the interconnection. The interconnection is owned by the DNO

A.9 Grid Connection Criteria and Protection Practices for DG in Germany

Requirements in the Legislative Documents

A.9.1 PRINCIPAL REQUIREMENTS OF THE NETWORK

A.9.1.1 Maximum DG Power

DG systems might increase the load of the wires, transformers and other operating devices. Hence, a verification of fulfilling the permitted load limits of those operating devices after the connection of the DG systems is required, according to the corresponding rating rules. Contrary to ordinary customers the DG systems are calculated with steady load meaning that they are considered to deliver rated power all the time.

With most DG systems it is possible to use the agreed apparent power for calculating the thermal load of the operational equipment of the grid. This is also true for *wind energy* systems where the maximum apparent power for 10 minute intervals can be used for the calculations.

A.9.1.2 Short circuit capacity

The short-circuit current of the grid is increased by the short-circuit current of DG systems, in particular near the PCC. When the short-circuit current of the DG is not known, the following estimates of its RMS value can be used (in multiples of rated current):

- Systems with synchronous generators: 8
- Systems with asynchronous generators: 6
- Systems with converters: 1

For a detailed calculation, the impedances between generator and PCC must be taken into consideration.

If the DG system causes a rise of the short-circuit current in the grid above the rated value, appropriate systems which limit the short-circuit current from the DG system are to be agreed between operator of the DG system and the DNO and implemented.

A.9.2 ELECTRICAL INTERCONNECTION REQUIREMENTS

A.9.2.1 Installation

The PCC of DG installations in *low and medium voltage* grids has to be defined under consideration of the given grid conditions (impedance of the grid at the PCC), the capacity (rated power) and the operating method of the DG system, as well as the legitimate interest of the DNO. This is to assure that the DG system can be operated without disturbing the grid and the supply of other customers.

In *low voltage grids*, the compliance to **DIN VDE 0100-551** (Elektrische Anlagen von Gebäuden - Teil 5: Auswahl und Errichtung elektrischer Betriebsmittel; Kapitel 55: Andere Betriebsmittel; Hauptabschnitt 551: Niederspannungs-Stromversorgungsanlagen) is required. This is the modified international standard IEC 60364-5-51 "Electrical installations of buildings - Part 5-51: Selection and erection of electrical equipment - Common rules".

In *medium voltage grids*, it is required to comply with **"Bau und Betrieb von Übergabestationen zur Versorgung von Kunden aus dem Mittelspannungsnetz"**. These are general installation requirements which apply to loads, as well. See (German language) document "RichtlinieTrafoMittelspannung2003.pdf" which lists standards on the last pages. This is a rather long list of standards and requirements which can not be summarised to a short comprehensive text.

A.9.3 Protection issues

In *low and medium voltage*, protection against overvoltage and undervoltage and protection against over- und underfrequency are required.

The German Association of Power Supply Companies (VDEW) sets a strict regulation concerning the connection of DG to the public low voltage (LV) grid. In accordance with this guideline each DG connected to the public LV grid must have an accessible switch, which can be switched by maintenance personnel of the grid operator at any time of the day in case of a failure in the grid. Alternatively, an automatically triggered switch that disconnects the generator in case of a failure in the public grid will be accepted. This device is called “ENS” conforms to VDE0126 and is widely used in Germany for DG units designed for operation in LV grids. In inverter coupled DG (eg. PV), ENS is already implemented in the inverter by the manufacturer. Similar forms of “loss of mains” protection are required in other countries.

To detect a failure in the public grid the ENS device observes the RMS voltage and the frequency. If the continuously measured values are out of the ranges shown in the table below then the switch disconnects the DG unit automatically:

Function	Tolerable Range
Protection in case of voltage drop (phase to neutral)	0.80 U_n , 184 V
Protection in case of voltage rise (phase to neutral)	1.15 U_n , 264.5 V
Protection in case of frequency drop	49.8 Hz
Protection in case of frequency rise	50.2 Hz

In inverter coupled DG the frequency is not monitored. The time delay between detecting a failure and switching of the ENS is 200 ms.

A.9.3.1 Sizing rules

Reference to general standards, no difference from regulations for loads (see above).

A.9.3.2 Measurements

In *LV and MV*, metering systems must not count in both directions meaning that separate meters are installed for energy generation and consumption. Only calibrated meters are allowed. Measures to monitor the maximum allowed power delivered to the grid might be necessary. Compliance to “Technische Richtlinie Abrechnungszählung und Datenbereitstellung” as well as “Metering Code” is required.

In *medium voltage* systems, more advanced meters are used measuring not only energy consumption / generation over a time period of one year but the average power consumption / generation in 10 minute intervals. These meters are often connected to a public telephone line or a GSM modem for remote control.

A.9.3.3 Synchronisation

Manual synchronisation is allowed, in *low and medium voltage* systems, but automatic synchronisation is preferred. If only coarse synchronisation is available an inductor is required as an impulse current limiter.

A.9.3.4 Accessible disconnection switch

In *LV and MV* an accessible all pole circuit breaker with galvanic isolation is required.

For *low voltage* single-phase systems, an automatic disconnection unit based on three phase voltage monitoring can be used instead of the accessible switch. A further alternative for *PV*

systems below 30 kW is a fail safe disconnection device based on, among others, impedance monitoring. Please refer also to chapter 1.2.2.

In *medium voltage*, the customer has the choice if the disconnection switch can switch the complete electrical system of the customer or only the DG unit.

A.9.4 POWER QUALITY

The evaluation of the allowable DG system perturbation is referenced, in general, to the normal state of the grid. In case of circuit modification, due to works and/or faults for example, it can be temporarily required to reduce the capacity of the DG systems or to disconnect them from the grid.

A.9.4.1 Power factor

In *low voltage grids*, DG units up to 4,6 kVA per phase do not need compensation: a power factor from 0,9 leading to 0,8 lagging is tolerated for the complete electrical system of the customer

The “distribution grid code” requires a power factor from 1,0 to 0,9 lagging which is more strict than the above mentioned requirement for low voltage DG systems.

In *low and medium voltage grids*, generators with strongly fluctuating reactive power need an automatic compensation system. The capacitors must not be connected to the grid before the generator and have to be disconnected with it. Measures to avoid interference with a ripple control system are required.

A.9.4.2 Harmonics

In *low voltage grids*, the requirements of the EN61000-3-2 or EN61000-3-12 standards must be met. As an alternative the maximum values specified in the table below must not be exceeded.

For *medium voltage grids* the maximum values specified in the table below must not be exceeded:

$$I_{vzul} = i_{vzul} \cdot S_{kV}$$

I_{vzul} : maximum current at v_{th} harmonic

i_{vzul} : relative maximum current at v_{th} harmonic

S_{kV} : maximum apparent power at the PCC

Ordinal number ν	$i_{\nu \text{ zul}} [\text{A/MVA}] (1)$	Ordinal number ν	$i_{\nu \text{ zul}} [\text{A/MVA}] (2)$	
3	4		10 kV	20 kV
5	2,5	5	0,115	0,058
7	2	7	0,082	0,041
9	0,7	11	0,052	0,026
11	1,3	13	0,038	0,019
13	1	17	0,022	0,011
17	0,55	19	0,018	0,009
19	0,45	23	0,012	0,006
23	0,3	25	0,01	0,005
25	0,25	>25 or even	0,06/ ν	0,03/ ν
>25	$0,25 \cdot 25/\nu$	$\mu < 40$	0,06/ ν	0,03/ ν
$\nu \in \mathbb{N}$	1,5/ ν	$\mu > 40$	0,18/ ν	0,09/ ν
$\nu < 40$	1,5/ ν			
$\nu > 40$	4,5/ ν			

A.9.4.3 Interharmonics and mains signalling

In *low and medium voltage grids*, ripple control systems are usually operated between 100 and 1500 Hz. The local frequency has to be asked for at the DNO. The transmission level ranges usually from 1 % to 4 % of the grid voltage. Mains signalling systems are dimensioned for a load, which corresponds to the 50 Hz rated power of the public grid in which the feeding-in of the control voltage occurs.

DG units present an additional load to this signalling system:

- via the DG system itself
- via the higher load which can be connected to the grid because of DG system

This interference may cause inadmissible disturbance of the mains signalling at the PCC. The transmission level at the PCC may not be lowered by more than 10 to 20 % (dependent on the particular conditions as signalling frequency, the kind of the grid, the kind of the receiver and so on), whereas loads and generating units have to be considered according to their impedance.

Besides the limitation of the level decrease, inadmissible interference voltage can not be generated. In detail:

- The interference voltage caused by a DG unit, whose frequency is close to the one used for ripple control, may not exceed the value of 0,1 % U_n .
- The interference voltage caused by a DG unit, whose frequency lies on the neighbouring frequencies of ± 100 Hz towards the local used ripple control frequency or lies with it in immediate vicinity, may not add up to more than 0,3 % U_n at the PCC.

These limit values, as well as qualified details, can be gathered from “Tonfrequenz-Rundsteuerung – Empfehlungen zur Vermeidung unzulässiger Rückwirkungen, 3. Ausgabe, 1997, Editor: VDEW”.

In the case that a DG unit affects the operation of the mains signalling system due to exceeding the limits, the operator of the DG unit has to agree on arrangements for the settlement together with the DNO. This applies even if the interference has been noticed on a later point in time.

A.9.4.4 Flicker

In *low voltage grids*, requirements of EN61000-3-3 or EN61000-3-11 must be met.

In *medium voltage grids* the maximum values for long term flicker are the following:

- A_{lt} 0,1
- P_{lt} 0,46

A.9.5 Voltage

A.9.5.1 Voltage rise

In *low and medium voltage grids*, the rise of the voltage with DG units may not exceed the value of 2 % at the worst case PCC, compared to the voltage without DG supply. In *low voltage grids*, because of the requirement to comply with the limits of supply voltage in the grid (DIN IEC 60038), the DNO may ask for a voltage rise lower than 2 %.

With only one PCC, this condition is to be evaluated using the short-circuit capacity relationship:

$$k_{kl} = \frac{S_{kv}}{\sum S_{Amax}} \geq 50$$

S_{kv} : short-circuit power at the PCC

S_{Amax} : Maximum apparent power of all given or planed DG units which are connected to that point.

For the calculation of S_{Amax} of *wind energy* converters, the maximum apparent output for one minute has to be used. If a DG unit has a special power limitation, this has to be taken into account. For a precise calculation of the voltage rise at the PCC the complex impedance of the grid, with its phase angle, has to be provided. With meshed networks and/or for the operating of multiple DG units which are dispersed in the grid, the rise of the voltage is to be determined usually with the aid of complex load flow calculation. When operating all DG units, the voltage rise has to be below 2 % at the worst case PCC.

A.9.5.2 Voltage variation

The operation of a DG unit is acceptable if it is verified that the system complies with the standards EN 61000-3-3 or EN 61000-3-11. If this proof is not available, the variations of voltage caused by hooking up and turning off are acceptable, if the values in the following table are not exceeded at the PCC.

	Max. Voltage Variation	Max. frequency: once in
Low Voltage	3%	5 min.
Medium Voltage	2%	1,5 min.

If there are only few operating cycles, for example one per day, the DNO may allow a higher variation of voltage. The voltage variation can be estimated via:

$$\Delta u_{\max} = k_{i,\max} \cdot \frac{S_{nE}}{S_{kV}}$$

$k_{i,\max}$: maximum inrush current in relation to the nominal current

S_{kV} : Short-circuit power at the PCC

S_{nE} : Nominal apparent power of the DG unit that is to be connected

This calculation gives an upper assessment and is basically a safe bet.

In *low voltage grids*, the value for the factor $k_{i,\max}$ is given in the manuals of the DG units respectively with wind energy systems in the inspection report.

In *medium voltage grids* the following estimates apply for the factor $k_{i,\max}$:

- synchronous generator: 1
- asynchronous generator connected to the grid within +/-5% of synchronous rotational speed: 4
- asynchronous generator started as motors via the grid (if inrush current is not specified): 8

Even by switching asynchronous machines with approximately synchronous rotational speed to the grid, very short time voltage variations may occur because of internal transients. Such variations may reach up to twice the acceptable value (6% in LV, 4% in MV), when they last not longer than two periods and when the following variation of voltage does not exceed [(1):3 %, (2): 2 %] of the output voltage before connecting up the asynchronous machine. As a consequence with asynchronous machines the short time disturbance of the grid voltage may be higher than the “standard” value.

A simultaneous switching operation of several generators at the PCC leads to multiplying the effect caused by one generator. This should be avoided. A technical possibility for this is the time grading of the individual switching operations. Here, the time between two switching operations is selected in accordance with the amplitude of the caused voltage variation and has to be at least 5 min. in *low voltage grids* and 1,5 min. in *medium voltage grids*, with the maximum acceptable apparent power conditions of the DG unit. A period of 40 seconds (*LV*) and 12 seconds (*MV*) is acceptable with an apparent power of the DG unit lower than half of the acceptable value.

A.9.5.3 Unbalance

In *low voltage grids*, to limit unbalance, DG units may only be connected to one phase up to a capacity of 4,6 kVA (with *photovoltaic* systems up to 5 kWp). Where several single-phase systems are connected to one PCC, a balanced distribution of the supplied power in the three phases has to be aimed.

A.9.6 Behaviour During Fault Conditions on the Grid

A.9.6.1 Islanding

In *low voltage*, three phase voltage monitoring for single phase systems of fail safe interface must be provided according to the following paragraph.

In *low voltage PV* systems, a “ENS” Fail safe interface device must be provided, for systems up to 30 kVA monitoring voltage, frequency and impedance of the grid.

A.9.6.2 Overvoltages

In both low and medium voltage grids disconnection is required if maximum voltage is exceeded.

A.9.6.3 Autoreclosures

In *low voltage grids*, for larger systems (“large” defined by DNO) and systems with a synchronous generator without inverter the disconnection time of the protection unit must be shorter than the reclosure time. As an alternative protective measures for the reclosure must be provided.

In *medium voltage grids*, the operator of DG unit has to take care that the DG unit can not be damaged by an auto reclosure.

A.9.6.4 Short circuits

If the DG unit leads to a short circuit current of the grid higher than the rated short circuit current the short circuit of the distributed generator has to be limited.

A.9.6.5 Lightning protection

No special requirements for DG.

A.9.6.6 DC – injection

In *low voltage grids PV* installations, DC currents due to a fault in the inverter must lead to disconnection within 0,2 s. A DC current of max. 1 A is the criterion for disconnecting.

A.9.7 TESTING

Tests for impedance measurement of the grid, residual currents and dc injection are provided for low voltage PV installations.

A.9.8 COMMISSIONING

A.9.8.1 Basic requirements

For both *low and medium voltage grids*, in the proposal for the start-up the builder of the system has to confirm that the design of the DG unit fulfils the relevant standards and complies with all guidelines.

The first-time parallel operation is to be adjusted with the DNO the following procedure applies:

- Inspection of the system.
- Comparison of the built system with the design specification.
- Check-up of the accessibility and operation of the disconnection device, which has to be accessible any time (does not apply for systems with ENS).
- Comparison of the design of the metering device with the contractual and technical instructions.
- In *low voltage grids* only: start-up control of the meters for supply and delivery.

In addition to this, an inspection of the operation of the disconnection unit has to be undertaken. It has to be verified that

- the disconnection unit is activated by the required set points.
- the disconnection times are met.

If the disconnection unit is a type tested device and a test report is available (with wind energy systems for example complying with “Technische Richtlinien für Windenergieanlagen – Teil 3: Bestimmung der elektrischen Eigenschaften, Editor: Fördergesellschaft Windenergie e.V., Kiel”) the inspection effort can be reduced.

In *low voltage grids*, with DG units having an “ENS” the system builder verifies the disconnection function following these simplified steps:

- During grid parallel operation the phase conductor is disconnected at a convenient point, after having bypassed this point with a resistor of 0.5 Ohm. Even with a three-phase ENS a single-phase inspection is sufficient.
- It has to be checked if the switch is opening and the ENS displays a grid failure.

The DNO may seal the protection device or secure it, or let it secure otherwise, to avoid unintentional changes (for example protection of the code word).

A.9.8.2 Procedures

There is a standard form for report on commissioning available for both *medium and low voltage grid* connected DG. This form has to be sent to the DNO.

A.9.9 OPERATION AND COMMUNICATION

A.9.9.1 Information Exchange DG/Grid Operator

In *low and medium voltage grids*, there is a form to register the DG unit with the DNO, plan of the site, technical data of the system, circuit diagram of the system, description of the protection measures, short circuit capability.

A.9.9.2 Monitoring power and voltage (metering)

See chapter 1.2.4.

A.9.9.3 Maintenance requirements

In *low voltage grids*, regular checks by a skilled person are required, proof via protocol. The exception are systems with fail safe interface (“ENS”), they do not need regular checks.

In *medium voltage grids*, regular checks by a skilled person are required, proof via protocol.

A.10 Grid Connection Criteria and Protection Practices for DG in Austria

A.10.1 Level of DG

In Austria distributed generation has already been an issue since the early days of the development of an electricity supply. At that time the electricity supply was mainly based on small hydro power plants which supplied electricity to local networks. Hydro power was consequently developed and today, about 60% of Austria’s annual electricity consumption is generated by hydro power plants, which is the highest figure of all European Union member states.

Although most of the electricity is produced in large hydro schemes, about 8 % of the annual electricity is generated in small hydro power plants with an installed capacity of less than 10 MW. In total there are about 2.000 installations with an installed capacity of more than 850 MW in operation, generating about 5.000 GWh annually.

With the opening of the electricity market in 2001 the changes in the institutional context and new developments in the field of RES have led to an increased interest in DG. Triggered by new support mechanisms which were introduced to fulfil the goal of the Electricity Law to increase the share of RES, more than 2.400 new installations with a capacity of almost 500 MW were connected until the end of 2003.

The framework for the promotion of electricity from RES is laid down in the Green Electricity Act (“Ökostromgesetz”), which came into effect on 1.1.2003. This law provided a change of the

legislative responsibilities (federal instead of provincial) and introduced a system of long-term guaranteed feed-in tariffs together with a purchase-obligation for electricity dealers for electricity from RES. In addition to feed-in tariffs and purchase-obligation, the Green Electricity Act fixed minimum percentage targets for RES-electricity which have to be reached until the year 2008: 4 % of “new” green electricity (not including small hydro) and 9 % electricity from small hydro.

A.10.1.1 Development of the grid-code and national regulations

Austria implemented the European Union Electricity Directive (96/92/CE, “common rules for the internal market in electricity”) through a federal law, the “Elektrizitätswirtschafts- und organisationsgesetz” (EIWOG). The first version which met the basic requirements of the EU directive was published in 1998, comprehensive amendments were issued in 2000 (EIWOG 2000). This law also set the final date for the full liberalisation of the Austrian electricity market, which became effective on 1.10.2001.

Based upon the legislations of the EIWOG 2000 new authorities in the electricity sector have been set up for the regulation and monitoring of the development from the former monopolistic market to a fully liberalised market. Among these authorities, the new regulatory body, Energie-Control GmbH (E-Control Ltd. www.e-control.at) is not only responsible for monitoring the competition and supporting the Federal Ministry but has also taken over the development of the rules governing the function of the market.

In a liberalised electricity system, a special framework of rules is necessary to ensure the secure interoperation of the networks as well as the connected facilities. In Austria this basic framework is defined in the “Technical and organisational rules for operators and users of transmission and distribution networks (TOR)”. These TOR are also part of the so called “Market rules” for the liberalised electricity market, which have de facto the status of a law, since they are the implementation of the EIWOG.

Already in the forefront of the opening of the electricity market on 1.10.2001, the Austrian utilities’ association (“VEÖ” www.veoe.at) organised working groups which elaborated the basic framework for these rules. After discussions with the involved stakeholders, the first issue of the TOR was transferred to E-Control Ltd. and published in 2001.

The TOR define the basic framework for operators and users of electricity networks and consist of the 6 main parts:

- Part A General, terms, references
- Part B Technical rules for transmission networks (voltage level ≥ 110 kV)
- Part C Technical rules for distribution networks
- Part D Special rules, including
 - .1 Limits for the assessment of disturbance relevant equipment
 - .2 Recommendations for the assessment of network interferences
 - .3 Ripple control: Recommendation to prevent impermissible perturbations
 - .4 Parallel operation of generators with distribution networks
- Part E Measures to prevent large outages and black outs
- Part F Technical rules for metering and data transmission

At the moment working groups consisting of experts from E-Control and the utilities association VEÖ are working on a revision of the TOR, which is scheduled to be finalised in 2005.

A.10.1.2 National standardisation bodies and organisations

ÖNORM (Österreichisches Normungsinstitut, Austrian Standards Institute) is the national standardisation body (www.on-norm.at). Standards in the field of electrical engineering are elaborated by the ÖVE (Österreichischer Verband für Elektrotechnik, Austrian Electrotechnical Association). According to the Federal Law on safety measures and standardisation in the field of Electrical Engineering (ETG 1992), BGBl. 45/1993, the ÖVE is mentioned as the authority in charge of the elaboration and publication of the Austrian Regulations for electrical engineering.

The standards are elaborated by Working Groups, which are organised in form of committees (FNA) and subcommittees (FNUA) within the ÖVE. The following have a direct relation to DG issues:

- ÖVE FNA- E: Electrical low-voltage installations

Scope:

Standardisation of definitions, requirements and testing specifications for erection and operation of electrical power systems with nominal voltages up to 1kV A.C. and 1,5kV D.C., including batteries and electrochemical sources

Subcommittees:

- FNUA E 01: General issues, selection, erection and testing
- FNUA E 03: Photovoltaic energy conversion
- FNUA E 06: Electric and electronic installations
- AG E 07 661: Testing of electric installations

International relationship:

IEC/CLC TC 82: Solar photovoltaic energy systems
IEC/CLC TC 21/TC21X: Secondary cells and batteries
CLC TC 44X Safety of machinery – electrotechnical aspects
IEC/CLC TC 64: Electrical installations and protection against electric shock
IEC/CLC TC 8/TC8X: System aspects of electrical energy supply
IEC TC 105: Fuel cell technologies

- ÖVE FNA-EMV: Electromagnetic compatibility
 Scope:
 Standardization of definitions, basic requirements and testing specifications in the field of electromagnetic compatibility (EMC) for high frequency equipment, ignition systems, consumer equipment, electrical installations, lightning, information and communication and high voltage installations.
 International relationship:
 IEC TC 77: Electromagnetic compatibility
 CLC TC 210: Electromagnetic compatibility
 IEC TC ACEC: Advisory committee on electromagnetic compatibility
 IEC TC CISPR: International special committee on radio interference

- ÖVE FNA-BL: Lightning protection
 Scope:
 Standardisation of installations for lightning protection for structures and buildings as well as for persons, installations and contents in or on them
 International relationship:
 IEC/CLC TC 81: Lightning protection

- ÖVE FNA-H: High voltage technology
 Scope:
 Standardisation of definitions, requirements and testing specifications for erection and operation of installations, switchgear, fuses, insulation, surge arrestors, short circuit currents and lightning in the field of high voltage technology
 International relationship:
 IEC/CLC TC 81: Lightning protection
 IEC/CLC TC 99/TC 99X: System engineering and erection of electrical power installations in systems with nominal voltages above 1kV A.C. and 1.5kV D.C., particularly concerning safety aspects

A.10.1.3 Other organisations relevant for DG:

Since 2001 E-Control (www.e-control.at) is responsible for monitoring, supporting and regulating the Austrian electricity market.

In the liberalised electricity market E-Control has taken over the coordination of the national grid code (TOR – General technical and organisational rules for operators and users of transmission and distribution grids according to the Austrian electricity act ElWOG) which provides the basic guidelines for access, connection and operation of distributed generation.

The grid code is developed by a Working Group (AG TOR), consisting of experts from E-Control and the Austrian Utilities Association. The grid code is incorporated in the market rules for the liberalised electricity market which on a legal basis implement the regulations stated in the national law (ElWOG, Austrian electricity act).

A.10.2 PRINCIPAL REQUIREMENTS OF THE NETWORK

General requirements – independent of the technology

A.10.2.1 Maximum DG Power

The point of coupling for the generator has to be set taking into consideration the given grid situation, the capacity and operational mode of the generator so that the generator does not produce any impermissible impact in the grid (TOR D4:2001 Section 4).

There is no explicit limit given (TOR D2:2004 Section 9.2) for the maximum generation capacity which may be connected to a certain point of coupling. However several factors naturally restrict the generation capacity that may be connected. The most important parameter is the voltage increase from the feed-in of a dispersed generator.

The relative voltage increase shall not exceed the following values at the point of common coupling mostly affected (where the increase is the most significant):

- In *LV networks*: $\Delta u_{\max} = 3 \%$
- In *MV networks*: $\Delta u_{\max} = 2 \%$

Remark: In certain cases the network operator may allow higher limits depending on the network and its operation or in contrary is obliged to impose more restrictive limits to take into account the impact of other generators.

A.10.2.2 Short circuit capacity

There is no general statement mentioned in the documents giving a direct relation between the short-circuit capacity of the grid and the generation capacity which may be connected, however some indirect references relate to the short circuit capacity of the grid (TOR D2:2004 Section 9.2):

Regarding the disturbances introduced by parallel operation of generators, the following factors which directly depend on the grids short-circuit capacity need to be taken into account for an assessment of the grid-connection of the generator:

- Voltage increase
- Voltage change as a result of a switching operation
- Flicker
- Harmonics
- Commutation notches
- Unbalance
- Reactive power compensation
- Disturbances on signal transmission on the grid (mains signalling)

Details on the specific items are explained in the section 'Power Quality'.

A.10.2.3 Stability

Stability is not directly addressed in the documents, since this is a rather general matter of grid-operation. However TOR D2 and D4 contain some valuable information on the interrelations between grid stability, voltage control and DG. Below some highlights (TOR D4:2001 Section 2) are presented:

The operational mode of the generator including the de-coupling from the grid has to be designed in a way to guarantee the duties of the grid operator towards the grid-users as well as the safe operation of the generator itself. In case of a grid fault on one hand the generator should operate as long as possible in parallel in order to support the operation of the grid, on the other hand has to be de-coupled early enough, if it is required for the clearance of the fault and the protection of the generator.

- For this purpose the protection concept of the generator has to be adapted to the grid's protection scheme.
- Regarding improved stability, the continuous parallel operation of larger generators (e.g. with capacities in the MW range) can be favourable during disturbed grid situations. For this purpose a contribution to ancillary services (e.g. black start capability, stability, extended voltage and frequency control, load flow regulation, under the premise that the grid operator has access to the generator) has to be arranged from case to case between grid operator and the generator.
- According to the grid conditions the generator has to contribute to the voltage stability by simultaneous delivery or consumption of reactive power. For more details see the section 'Power Quality'

Below are some highlights on voltage control, reactive power flow and compensation (TOR D4:2001 Section 9.1)

- For an assessment of the voltage control problematic caused by the feed-in of active power by a generator, the duties of the grid operator – especially towards the customers – have to be taken into account. Consequently the properties of the grid as well as the amount of reactive power feed-in or consumption by the generator have to be considered.
- Since voltage regulation is currently usually performed only at the HV/MV substations, the grid operator must ensure that under low load conditions the voltage does not exceed the upper limits, and under high load the voltage does not fall under the lower limit. This requirement must be met taking into account the impact of distributed generators.
- In order to assess a generator's contribution to voltage control, the type of the unit and the way it is operated have to be considered. Wind and Photovoltaic installations for example cannot deliver a reliable contribution to the voltage control due to their fluctuating nature, whereas a contribution of Combine Heat and Power installations in winter and of small hydro power during high-tariff periods can be expected.
- Furthermore it has to be considered that the feed-in under low load conditions can result in an additional voltage rise which can encroach upon the available reserve. The feed-in of an additional generator is therefore possible only if the available margin allows it.
- This voltage problem can nevertheless be alleviated with some efforts, e.g. by implementing voltage or reactive power control schemes.
- In order to ensure admissible voltages for all customers, the operating voltage at each PCC must be maintained within a certain range.
- During the operation of a generation unit, the voltage at a particular point (to be agreed

between the network operator and the operator of the unit) shall not constantly go outside of the range defined by an upper limit and a lower limit (U_{min} and U_{max}). These limits as well as the conditions under which an exception can be tolerated are stated by the network operator.

- The compliance with the above mentioned limits mainly depends on the effectiveness of the active and reactive power control, as well as the voltage regulation of the generator.
- By complying with the above mentioned limits for the operational voltage any impermissible voltage jumps can be avoided, even during load-shedding in the grid.

Specific matters regarding reactive power feed-in, reactive power interchange and voltage regulation are described in further detail (TOR D4:2001 Section 9.2):

- The type of regulation (active/reactive power, voltage or power factor) as well as the reactive power injection/consumption range has to be agreed upon with the network operator.
- In order to achieve the required quality of supply and voltage stability, the measured voltage can be used for the reactive power regulation. In that case the regulation is not based on a constant power factor but on another control scheme. In some cases the limitation of the active power feed-in can be necessary.
- The reactive power or voltage regulation of each generator must be designed in a way to ensure that other generating units can operate in parallel without problems.
- The network operator may request a monitoring system to verify the correct operation of the control scheme.
- Instead of a controlled reactive power injection other ways of reactive power interchange can also be arranged with the network operator, depending on the permissible voltage levels in the grid.

A.10.3 ELECTRICAL INTERCONNECTION REQUIREMENTS

Installation

Grid interconnection (TOR D4:2001 Section 4)

During the planning phase, the grid operator and the applicant (operator of the generator) decide on the suitable point of coupling for the planned installation. For that purpose the grid operator has to provide the applicant with all necessary technical information relevant for the interconnection with the grid. This includes e.g.

- Expected minimum and maximum short-circuit power at the PCC
- Agreed supply voltage
- In MV grids: Minimum and maximum operational voltage
- Information on insulation coordination
- Information on neutral point treatment, if necessary contribution to earth current compensation
- Protective concept
- If applicable information on contribution to voltage control
- Metering, communication
- Allowable power quality disturbances

In general generators may not be connected by means of a plug-connection, except if the connectors are of a touch-protected type and the whole installation is specially designed for this purpose.

Earthing and potential equalisation (ÖVE/ÖNORM E2750:2004 4.1.5)

For PV installations:

All metal parts of the system (frames, mounting structures) not conducting operational currents must be connected to the earthing arrangement of the building or dedicated earth electrodes.

Lightning and over-voltage protection (ÖVE/ÖNORM E2750:2004 4.1.6)

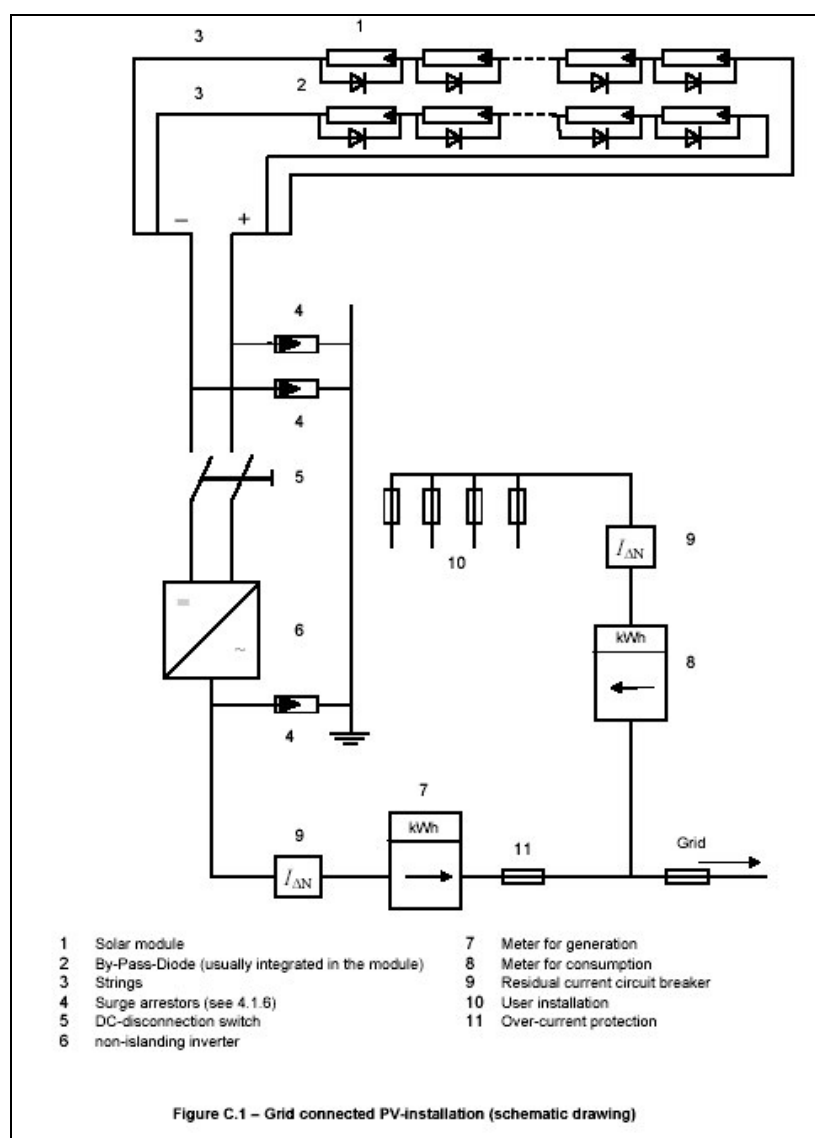
For PV installations:

See relevant item in the section “Behaviour during fault conditions in the grid”.

Design examples (ÖVE/ÖNORM E2750:2004 Annex C)

For PV installations:

Included in the standard is a schematic diagram of a typical grid-connected PV-installation:



Protection issues (TOR D4:2001 Section 2)

To guarantee the safe operation of the generator and to protect the grid and other grid users, the protection concepts of the generator and the grid have to be coordinated. In particular it is important to avoid an asynchronous re-connection of synchronous generators and a disruption of other grid users by an uncontrolled operation of the generating unit.

This is achieved with the help of a de-coupling protection which ensures a safe and controlled disconnection of the generator from the grid in case of a fault. In many cases the de-coupling protection is furthermore part of the protective measures for work on faulty grid sections.

De-coupling protection (TOR D4:2001 Section 5)

The de-coupling protection has to be defined in accordance with the requirements of the grid operator and has to contain adequate contactors. In case of a disturbance the contactors must be designed to be immediately triggered and has to disconnect all poles. In installations designed for islanded operation the special safety requirements for disconnection and earthing of the PEN conductor have to be considered.

The contactor has to be dimensioned for the maximum short-circuit power which can be expected. If fuses are used for short-circuit protection the switching capability of the de-coupling switch can be reduced.

The proper functioning of the de-coupling contactors has to be revisable.

Properties and function of the de-coupling protection (TOR D4:2001 Section 7)

Purpose of the de-coupling protection and the allocated contactors is to disconnect the generator from the grid as fast as required. The protection function can be either implemented in separate devices or integrated in one single device. The proper function of the de-coupling protection has to be checkable by using analogue input parameters independent on the operational mode of the generator.

For LV and MV grids and rotating generators:

In general, the following functions have to be implemented in the de-coupling protection:

- Voltage monitoring, 3-phase, frequency independent. The delay time has to be adjustable at least in the range of 0,1 to 5 s with steps of 0,1 s.
 - Under-voltage protection, adjustable between 0,7 and 1,0 U_N
 - Over-voltage protection, adjustable between 1,0 and 1,3 U_N
- Frequency monitoring, single or 3-phase, voltage independent, adjustable at least in the range between 0,7 and 1,3 U_N . Measurement period should be shorter than 140 ms. The delay time should be adjustable to instantaneous.
 - Under-frequency protection, adjustable between 47 Hz and 50 Hz with steps < 0,2 Hz
 - Over-frequency protection, adjustable between 50 Hz and 53 Hz with steps < 0,2 Hz

Note: U_N is the nominal voltage of the protection device.

In certain cases it can be necessary to implement additional functions (e.g. vector shift or load-jump protection) to guarantee a safe function of the de-coupling protection.

In MV networks with an isolated or impedance earthed neutral system normally phase to phase voltages are used for voltage and frequency protection whereas for rotating generators in LV networks the phase-to-neutral voltages are used.

For LV and generators up to 30 kVA:

For the de-coupling protection of inverters in the LV grids with a nominal voltage of 400/230 V the following protection functions are required:

- For single phase inverters and 3-phase installations:
 - 3-phase under voltage protection for the phase-to-phase voltages (400 V).
Note: This applies to all single phase generators in 3-phase installations.
 - Single phase-to-neutral over voltage protection for the phase where the generator is connected (230 V).
- For 3-phase inverters:
 - 3-phase under-voltage protection for the phase-to-neutral voltages (230 V)
 - 3-phase over-voltage protection for the phase-to-neutral voltages (230 V)
- For single phase inverters and single phase installations:
 - Single phase under-voltage protection (230 V)
 - Single phase over-voltage protection (230 V)

In LV networks and systems with inverters which have a nominal apparent power of less than 4,6 kVA (single phase) or 30 kVA (3-phase), the protection can also be implemented in form of an ENS/MSD which has been certified according to the German standard VDE 0126.

Note: Currently there are fixed limits for under-/over-voltage trip points defined in the standard (-15%/+10% U_N), which refer to the present voltage band (-10%/+6% U_N). If these values are changed, the reduced safety margins to the trip points have to be considered.

If several single-phase inverters with a total apparent power of more than 4,6 kVA are connected to a single PCC, all inverters have to be de-coupled together, in order to prevent an unbalance of more than 4,6 kVA.

Remark: Some specific requirements are under discussion right now and will probably be changed in the next revision of TOR D4.

For LV and MV grids:

The settings of the de-coupling protection are stated by the grid operator in the framework of the overall protection concept. The settings of the de-coupling protection can be changed afterwards if required for the reliable operation of the grid. All settings of the voltage protection refer to the agreed supply voltage.

For grids with automatic re-closure:

If a generator is connected to a line with an automatic re-closure in a substation of the grid operator, trip levels and time delays have to be set in a way to allow a safe clearance of faults.

The total time for disconnection including the contactors has to be adjustable to be below 200 ms.

Protection measures in LV-installation with parallel operation of generators (TOR D4:2001 Section 14.2)

For LV installations:

According to the Austrian Electrotechnical Law (“Elektrotechnikgesetz” ETG, and “Elektrotechnikverordnung ETV”) the requirements of ÖVE/ÖNORM E8001 (ÖVE EN1) regarding protective measures have to be fulfilled.

Note: Within installations designed for islanded operation it must be ensured that all requirements regarding protection against electric shock are met even when the connection to the grid is lost.

For generators utilising inverters without galvanic separation, it has to be considered that a fault in the DC circuit can be additionally fed via the inverter and therefore has to be detected by suitable protection system. For this purpose an all-current sensitive residual current circuit breaker is mandatory between the inverter and the grid.

Examples of de-coupling protection systems (TOR D4:2001 Section 14.2)

The annex of the document includes 8 examples of de-coupling protection systems for different kinds of generation systems and applications, as well as schemes of generation systems with UPS functionality.

DNO requirements: Settings of the de-coupling protection

- Under voltage protection: $0,7 - 0,9 U_N$
- Over voltage protection: $1,06 - 1,2 U_N$
- Delay time: Instantaneous to 5 s, depending on the operating mode of the network.

In MV networks the settings are individually determined with the help of load flow calculations.

- Under frequency protection: $48 - 49,5 \text{ Hz}$
- Over frequency protection: $50,5 - 52 \text{ Hz}$

In specific cases also short-circuit and overload protection

DNO requirements: Automatic re-closure after grid disturbances or faults

A delay time of 3 – 5 min is recommended after the recovery of the grid-voltage before reconnection to the grid.

DNO requirements: Additional protection devices

A vector shift relay is recommended for larger units, and is usually installed for synchronous generators larger 100 kVA.

Protection against electric shock (ÖVE/ÖNORM E2750:2004 Section 4.1.300)

For PV-installations:

The protection system has to be designed in accordance with ÖVE/ÖNORM E 8001-1 (“Erection of electrical installations with rated voltages up to 1000 V AC and 1500 V DC”).

For generators operating in parallel with the grid, the protection requirements are fulfilled by the protective equipment installed in the grid, provided that the inverter is of a “non-islanding” type. If inverters without galvanic separation are being used, an all-current sensitive residual current circuit breaker (RCCB) has to be installed. This function may as well be integrated in the inverter. The RCCB has to disconnect the inverter within 0,2 s at DC-residual current jumps of $\geq 30 \text{ mA}$.

Inverter (ÖVE/ÖNORM E2750:2004 Section 4.3)

For PV-installations:

The AC side of the inverter has to be protected against over-currents and short-circuits.

Grid coupled PV-installations must not continue operation in case of a grid interruption or disturbance. This requirement is met by

- Using “non-islanding” inverters which has passed the test defined in Annex A or B of ÖVE/ÖNORM E2750
- Installation of an accessible disconnection switch

Parallel operation with the grid (ÖVE/ÖNORM E2750:2004 Section 4.4)

For PV-installations:

Basically when using “non-islanding” inverters according to Annex A or B, a PV installation does not require the installation of an accessible disconnection switch, if the total apparent power of the system does not exceed 30 kVA. For larger systems or when using other inverters, the grid operator may require the installation of an accessible disconnection switch.

To protect staff carrying out work in the grid, devices for surveillance of the grid voltage with allocated switches are required. If the grid voltage exceeds $1,11 U_N$ or falls below $0,85 U_N$ the inverter has to be disconnected within 0,2 s. When using “non-islanding” inverters this function is confirmed by the type testing sequence defined in Annex A or B.

In any case the inverter may not re-connect earlier than 20 s after normal voltage conditions are restored.

In accordance with the grid operator the settings for the voltage margins may be modified if required.

Sizing rules

No information is given in the documents.

Measurements

Metering (TOR D4:2001 Section 13)

Type and design of the metering (transducers and energy meters) and control equipment are based upon the contracts for delivery and production of electricity and have to be agreed between grid operator and generator.

Delivered and produced energy have to be metered separately.

If needed a data exchange has to be designed in accordance with the requirements of the grid operator.

Synchronisation

Start-up facilities and conditions (TOR D4:2001 Section 10)

Generators (except asynchronous generators) or grid sections with loads and generators able to operate as an island must always be connected via synchronisation equipment.

The settings of the synchronisation have to be coordinated with the operational conditions of the grid and are fixed by the grid operator.

During switching on the generator must not influence the grid in an impermissible way (For details refer to TOR D2, Recommendations for the assessment of power quality disturbances).

Inverters may only be connected with their AC side in idle mode. For inverters in installations able to operate as an island, the requirements for synchronous generators have to be met. Non self-excited asynchronous generators may only be switched-on in the range of 95 to 105% of their synchronous speed. Self-excited asynchronous generators in installations able to operate as islands have to meet the requirements for synchronous generators. If the maximum permissible voltage dip according to TOR D2 is exceeded, separate measures to limit the current have to be taken.

Synchronous generators may be switched to the grid only under the following conditions:

- Voltage difference below 10% of the agreed nominal voltage
- Phase angle deviation below 10°
- Frequency deviation below 1% of the current grid frequency

The re-closing of the generator after a disconnection due to a grid disturbance is not allowed until the grid voltage has again reached permissible values. The time delay for re-closure has to be agreed upon with the grid operator. An accidental generation of voltage in a separated part of the network has to be prevented in any case.

Accessible disconnection switch

Disconnection switch (TOR D4:2001 Section 6)

For operational and safety reasons all generators have to be equipped with a disconnection switch accessible to the grid operator. The switch has to be capable of disconnecting and load switching and can be identical with the switch dedicated to the de-coupling protection.

In LV networks (400/230 V) the disconnection switch can be omitted if

- single phase inverters up to 4,6 kVA or
- 3-phase inverters up to 30 kVA,

equipped with a MSD/ENS system according to the German standard VDE 0126 are used.

Remark: This item is going to be changed to comply with ÖVE/ÖNORM E 2750:2004.

Parallel operation with the grid (ÖVE/ÖNORM E2750:2004 Section 4.40)

For PV-installations:

Basically when using “non-islanding” inverters according to Annex A or B, a PV installation does not require the installation of an accessible disconnection switch, if the total apparent power of the system does not exceed 30 kVA. For larger systems or when using other inverters, the grid operator may require the installation of an accessible disconnection switch.

Other topics

Neutral point treatment of generators in the LV grid (TOR D4:2001 Section 8)

Asynchronous generators are usually operated in delta connection. When using star connection the neutral point has to be isolated.

Synchronous generators may also be operated with isolated neutral. The connection of the generator's neutral to the grid is only permissible if the total harmonic current in the neutral conductor is lower than 20% of the rated current.

POWER QUALITY

Power factor / compensation

Reactive Power Compensation (TOR D4:2001 Section 9.2)

Installations consuming reactive power (e.g. asynchronous generators or other special types of generators) which cannot be provided by the network require compensation (i.e. capacitor banks). Amount and way of compensation as well as rating, connection and control of the compensation equipment have to be agreed upon with the network operator.

In order to avoid resonances and mains signalling disturbances additional measures can be necessary.

The reactive power compensation for installations using asynchronous generators is generally located directly at the generator. These capacitors must not be connected to the network without the generator. Particular attention shall be paid to the possibility of self-excitation under certain circumstances.

If there are large variations of reactive power (i.e. wind turbines with asynchronous generators), the compensation must be controlled accordingly.

DNO requirements:

The power factor is fixed individually by the network operator together with the operator of the generator, taking into account the local network situation and the local demand for reactive power. Usually the following power factors are required if there are no special considerations at the point of coupling (network configuration and short circuit capacity):

- Synchronous generators: 0,9 leading
- Asynchronous generators: compensated to 1
- Inverters: set to 1

Regarding the increasing importance of reactive power (also in terms of money) in the networks, a common required power factor of 0,9 leading is under consideration at the moment, independent of the used generation technology.

In specific cases different power factors are required for summer and winter, depending on the load of the network or grid voltage, respectively.

If the generator is connected to a point with a low short circuit capacity the generator may also be required to consume reactive power in order to limit the voltage increase due to the feeding. In this case the generator has to pay for the consumed reactive power. Otherwise, the active power injection has to be limited to avoid an impermissible voltage increase.

Harmonics

Harmonics (TOR D2:2004 Section 9.2.5)

Emission limits

In order to comply with limits for voltage harmonics stated in EN 61000-2-2, limits for harmonic current emissions are specified for every generator. The limits applied for generators are 50% of those limits calculated for loads respectively.

- **Emission limits for individual harmonic currents I_v**

The individual harmonic current limits depend on the ratio between the short circuit capacity of the grid and the size of the generator and are given by the following formula:

$$\frac{I_v}{I_{gen}} = \frac{1}{2} \frac{p_v}{1000} \sqrt{\frac{S_{SC}}{S_{Gen}}} \quad (\text{The factor } 1/2 \text{ represents the 50\% limit applied for generators vs. loads})$$

I_{gen} current corresponding to the apparent power of the generator

I_v individual harmonic v of the injected current

S_{SC} short-circuit power of the grid at the PCC

S_{Gen} apparent power of the generator unit

The factor p_v is given in the following table:

v	3	5	7	11	13	17	19	>19
p_v	6(18 [*])	15	10	5	4	2	1.5	1

*) For grids with neutral (LV), the 3rd harmonic circulating in the neutral results from the sum of the 3rd harmonic currents flowing in the 3 phases. The parenthesis corresponds to the limit for the neutral.

Table A10.1: Harmonic limits

In fact, these limits were established for each harmonic relevant for power converter.

- **Emission limits for the total harmonic distortion $THDi_{Gen}$**

In addition to the individual limits given above, the total harmonic distortion of the current $THDi_{Gen}$ is also limited:

$$THDi_{Gen} = \frac{\sqrt{\sum_{v=2}^{40} I_v^2}}{I_{Gen}} \leq \frac{20}{1000} \sqrt{\frac{S_{SC}}{S_{Gen}}}$$

Remark: The $THDi_{Gen}$ is in general not identical to the $THDi$ which is normalised to the fundamental current instead of the generated current. Both are simply linked by

$$THDi_{Gen} = THDi \frac{I_1}{I_{Gen}}.$$

Explanations

A harmonic assessment is only required for generation units which feed-in through converters or inverters.

For self-generators, special attention shall be paid to the fact that the assessment is made separately for generators and consumers in order to avoid an inadmissible quality of supply by setting a too high emission limits. In this case more restrictive limits have to be set.

Harmonics (ÖVE/ÖNORM E2750:2004 4.3.3)

For PV installations

Inverters for grid-connected PV installations have to comply with the limits stated in the relevant international standards. For single phase inverters with an apparent power up to 4,6 kVA installed in systems with a total power below 30 kVA the limits of EN 61000-3-2 for “Class A” devices are applicable. Larger inverters (> 4,6 kVA) and systems with a total power at the PCC of more than 30 kVA shall be assessed according to TOR D2.

Interharmonics

Influence on signal transmission in distribution networks (TOR D2:2004 Section 9.2.9)

Generating units can present two types of disturbances for signal transmission:

- Attenuation of the signal due to the fact that the generator may present lower impedance (asynchronous generators, capacitor compensation) at the transmission frequency. This attenuation may be inadmissible, in particular for low transmission frequencies.
- Moreover, the additional consumers that can be connected to the network may also have such an effect.
- Production of disturbances in the frequency domain used for signal transmission (e.g. for power converters)

Solutions to reduce the disturbances in the range 100 Hz up to 2 kHz are indicated in the document “TOR D3 – Audio frequency ripple control, guidelines to avoid impermissible interferences”.

Attention shall be paid to the fact that the disturbances induced by the generating units shall not prevent the normal operation of signal transmission devices between 3 kHz and 95 kHz. For further details EN 50065 (“Signalling on low-voltage electrical installations in the frequency range 3 kHz to 148,5 kHz”) is referenced.

Flicker

Flicker (TOR D2:2004 Section 9.2.4)

Emission limits

The maximal long-term flicker indicator P_{lt} (2 hours interval) taking into account the whole feed-in at the PCC mostly affected is:

$$P_{lt_max} = 0,46$$

Assessment

a) Network with a single flicker relevant generator

When the flicker contribution value c and the flicker angle φ_f are known (for example from the test report of a wind turbine), the long-term flicker indicator can be calculated as follows:

$$P_{lt} = c \frac{S_{Gen}}{S_{SC}} \left| \cos(\psi + \varphi_f) \right| \quad (\text{see “explanations” for the sign +) where}$$

S_{Gen} : measured apparent power of the unit

S_{SC} : short-circuit power at the PCC

c : flicker value for the unit (given by the constructor or measured)

ψ : angle of the grid impedance

φ_f : flicker angle

In the case that the flicker angle is not available, the cosine factor can be taken as 1:

$$P_{lt} = c \frac{S_{Gen}}{S_{SC}}$$

- b) Network with several flicker relevant generators/units connected to a single PCC
For installations comprising n units with a measured power $S_{gen,i}$, the long-term flicker indicator $P_{lt,i}$ must be calculated according to a). The resulting flicker indicator can be yielded by:

$$P_{lt} = \sqrt{\sum_{i=1}^n P_{lt,i}^2}$$

For an installation with n identical generators, the previous formula gives:

$$P_{lt} = \sqrt{n} \cdot P_{lt,i} = \sqrt{n} \cdot c \cdot \frac{S_{Gen}}{S_{SC}}$$

The resulting long-term flicker indicator must be under the above given limit.

- c) Influence of several flicker relevant generators connected to different PCCs
- Connection to a network by a unique junction
 $P_{lt,jk}$ is the flicker factor at the PCC k resulting from the feed-in of the generator j. The resulting flicker factor can be calculated as following:

- 1) For each generator j, $P_{lt,jj}$ is calculated as explained in a) or b)
- 2) For each generator j, the flicker factor at the point k ($P_{lt,jk}$) is calculated as following:

$$\begin{aligned} \text{i. } S_{SCj} < S_{SCk} : P_{lt,jk} &= P_{lt,jj} \cdot \frac{S_{SC-j}}{S_{SC-k}} \\ \text{ii. } S_{SCj} \geq S_{SCk} : P_{lt,jk} &= P_{lt,jj} \text{ where} \end{aligned}$$

S_{SC-j} : short-circuit power at PCC j

S_{SC-k} : short-circuit power at PCC k

- 3) The resulting flicker factor at point k is then calculated by: $P_{lt-k} = \sqrt{\sum_{j=1}^n P_{lt-jk}^2}$

This resulting factor must be under the above mentioned limit.

- Complex topology

For more complicated topologies like meshed grids or ring topologies e.g., the resulting flicker factor has to be estimated by simulations.

Mitigation solutions

In case of non compliance with the requirement, the following solutions may be used:

- Choice of a generator with smaller flicker contribution value
- Connection of the unit to a PCC with a greater short circuit power
- Installation of dynamic compensation

Explanations

A flicker assessment is usually only necessary for wind turbines since the flicker contribution factor can reach a value of 50 for asynchronous generators.

In contrary to the time aggregation (superposition) used in $P_{lt} = \sqrt{\sum_{j=1}^{12} \frac{P_{st}^3}{12}}$, the root mean square is used here to reflect the stochastic nature of this effect.

In contrary to the formulas used for voltage rise and voltage change, the cosine term is with a “+” sign which means that the injected active power P and the consumed reactive power Q are positive. This allows taking the flicker angle directly from the test report of the generator.

Voltage scheduling, variation and control

Voltage increase (TOR D2:2004 Section 9.2.2)

Limits

The relative voltage increase resulting from the feed-in of a generator shall not exceed the following values at the most affected point (where the highest increase can be expected):

LV: $\Delta u_{\max} = 3 \%$ MV: $\Delta u_{\max} = 2 \%$
--

Remark: the network operator may allow higher limits depending on the network and its operation or in contrary impose tougher limits to take into account the effect of other generators. In this case the network operator has to provide evidence for the lower limits (e.g. by grid data or load-flow calculations).

Assessment

a) Feed-in at a single PCC

$$\Delta u = \frac{S_{Gen_max}}{S_{SC}} \cdot \cos(\psi - \varphi)$$

S_{Gen_max} : maximal apparent power of the unit

S_{SC} : short-circuit power of the grid at the PCC

ψ : angle of the grid impedance

φ : angle between active and apparent power of the generator (at the maximum apparent power)

b) Feed-in at a several PCCs and more complex cases

For more complex situations (more than one generation unit or meshed networks) the stationary voltage increase has to be determined with the help of load flow simulations.

Mitigation solutions

The document mentions some possible solutions if the requirements are not met:

- Connect the unit to a PCC with more short circuit power
- Reinforcement of the network
- Control of reactive power
- Limitation of the maximum power

Explanations

This assessment shall be done for the whole network and not only for the PCC to which the DG unit is connected to. The experience showed that admissible variations are obtained when the emission limits are observed by all generators

In theory the voltage increase can also be negative in case the installation consumes a great amount of reactive power. Usually such a situation is nonetheless avoided because of the additional losses due to the reactive power consumption.

A stationary voltage increase caused by generators close to a transformer substation is partly compensated by tap-changing transformers.

The cosine factor should in practice not be lower than 0,1 (even when the calculation leads to a smaller value)

Voltage variations resulting from switching (TOR D2:2004 Section 9.2.3)

Emission limits

The relative voltage change d resulting from generator switching (start or pole changing) may not exceed the following values:

For voltage variations with a frequency of less than $0,1^{-1}$ min (1 change in 10 minutes):

LV: $d_{\max} = 3 \%$ MV: $d_{\max} = 2 \%$
--

For voltage variations with a lower frequency (less than $0,01^{-1}$ min) a higher limit can be applied:

LV: $d_{\max} = 6 \%$ MV: $d_{\max} = 3 \%$
--

Assessment

The assessment can be done with the following formula:

$$d = \frac{\Delta S}{S_{SC}} \cos(\psi - \varphi)$$

ΔS : load change (depends of the type of generation)

S_{SC} : short-circuit power of the grid at the PCC

ψ : angle of the grid impedance

φ : angle between current and voltage for the load variation

For the load change, the reference values given below are to be used:

- Feed-in through inverters: The load change ΔS corresponds approximately to the nominal power.
- Feed-in through synchronous generators: A load change $\Delta S=0$ shall be taken due to the behaviour of such machines under normal synchronisation procedures. During switch-off the load change equals approximately the rated capacity of the generator.
- Feed-in through asynchronous generators: For asynchronous generators started as motors, the load change can be up to 10 times the nominal power. In the case of the exact value is not known, usually a factor of 8 is taken. For asynchronous generators being started connected at synchronous speed, the load change is usually smaller than four times the nominal power. For a pole changing operation, the load change is similar to the one taken for a start (first case)

For wind turbines, the test report gives the “network depending switching factor k_ψ ” for various grid angles. The voltage change can then be calculated by:

$$d = \frac{k_\psi \cdot S_{Gen_max}}{S_{SC}}$$

The obtained value must be under the limits stated above.

In the case that the grid angle is unknown, an estimate can be done, or a value of 1 can be taken for the cosine (worst case).

Mitigation solutions

Mitigation possibilities depend on the type of generation:

- Use of inductors, resistances, transformers or electronic converters for asynchronous machines (after the connection, the element is by-passed)
- Special design of the asynchronous generator
- Connection of the unit to a PCC with a higher short circuit capacity

Explanations

This assessment is mainly relevant for asynchronous generators.

Simultaneous switching operations in a generation unit with several generators shall be avoided in order to reduce the disturbances. For that purpose, switching procedures shall be delayed (>1 min).

Unbalance

Single phase generators (TOR D2:2004 Section 9.2.7)

Applicable only to generators connected to LV networks:

For LV networks, several single phase generating units of a plant have to be connected in a way that the unbalance under operation is kept below 4,6 kVA.

Explanation

Unbalance is above all significant for installations (photovoltaic installations e.g.) which consist of many single phase generators. On the LV, the connection of single phase inverters with a rated power up to 4,6 kVA is allowed.

Grid inter-connection (ÖVE/ÖNORM E2750:2004 Section 4.4.3)

For PV installations:

To avoid voltage unbalance, single phase inverters may only be used up to a rated power of 4,6 kVA. If several inverters are connected to a single PCC, the power shall be distributed equally to the individual phases. If the total unbalance is below 4,6 kVA, inverters may be connected without a common de-coupling switch up to a total system power of 30 kVA.

If the capacity exceeds 30 kVA, the grid operator may require a common de-coupling and an accessible disconnection switch, which can be identical with the de-coupling contactor.

Other

Commutation notches (TOR D2:2004 Section 9.2.6)

For generators using line-commutated inverters

Emission limits

A commutation notch is defined in the TOR as a periodic voltage transient which occurs during the commutation of line commutated converters. The relative depth of a commutation notch is the highest voltage difference between the fundamental waveform and the observed waveform, normalised with the fundamental peak voltage.

The limits for the relative depth of commutation notches are the half of the limits for loads:

LV: $d_{\text{com}} = 0,05$ MV: $d_{\text{com}} = 0,025$

Explanations

Commutation notches are only relevant for installations with line commutated converters.

A.10.4 Behavior During Fault Conditions on the Grid

Unintentional islanding

De-coupling protection (TOR D4:2001 Section 5)

The topic is not explicitly covered in the grid-code (TOR). However the protection against unintentional islanding is fulfilled by the de-coupling protection. For details see the section on protection issues.

Inverter (ÖVE/ÖNORM E2750:2004 Section 4.3)

For PV-installations:

Grid coupled PV-installations must not continue to operate in case of Loss of Mains. This requirement is met by either

- using “non-islanding” inverters which has passed the test defined in Annex A (ENS/MSD according to the German draft standard VDE0126:1999) or B (type test procedure for “non-islanding inverters”) of ÖVE/ÖNORM E2750 or
- the installation of an accessible disconnection switch.

The conformity of a “non-islanding” inverter has to be proven by an accredited institution according to the type testing procedures below:

Automatic disconnecting facility (ENS) (ÖVE/ÖNORM E2750:2004 Annex A)

For PV-installations:

Note: The requirements and type-testing procedures are taken from the German draft standard VDE 0126:1999 (“Automatic disconnecting facility for photovoltaic installations with a rated output $\leq 4,6$ kVA and a single-phase parallel feed by means of an inverter into the public low-voltage mains”).

However there are some modifications concerning the settings for the over- and under-voltage protection ($0,85 U_N$ and $1,13 U_N$) and a less restrictive criterion for the detection of impedance jumps (1Ω).

Type test procedure for “non-islanding inverters” (ÖVE/ÖNORM E2750:2004 Annex B)

For PV-installations:

Background:

The procedure described here simulates Loss-of-Mains conditions with a simultaneous balance between load and generation in the islanded part of the grid. For the purpose of testing a balanced RLC circuit is used to simulate worst case conditions for a possible islanding situation. A non-islanding inverter must disconnect from the grid even under such conditions.

Requirements:

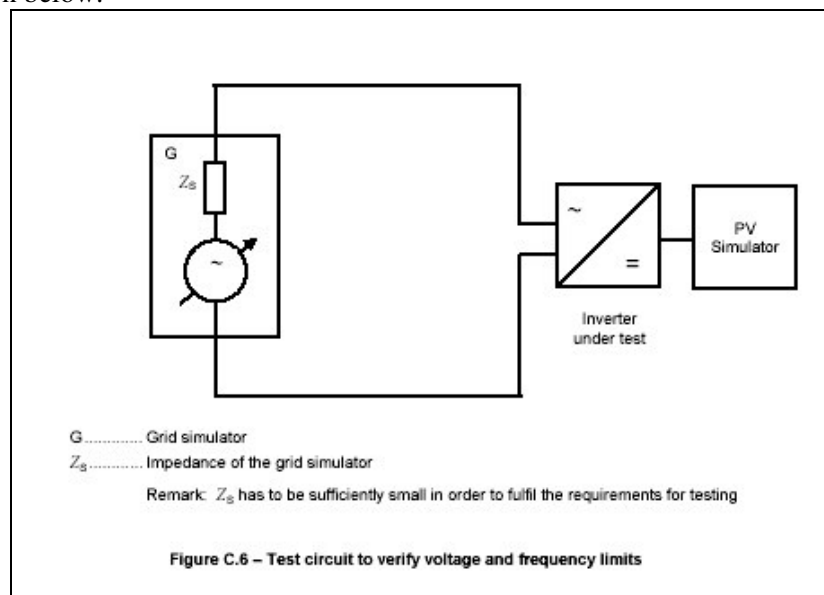
In detail a non-islanding inverters must disconnect from the grid under the following conditions:

- Over- and under-voltage: Voltages below 85% or above 113% of U_N must lead to a disconnection, within 0,2 s after their occurrence.
- Frequency deviations of more than 0,3 Hz must lead to a disconnection within 0,2 s.
- Loss-of-mains and balanced load to generation ratio, where the inverter must disconnect within 5 s.

After an event that has caused a disconnection, voltage and frequency conditions should be within their normal range for at least 20 s before the inverter is allowed to automatically reconnect to the grid.

Testing procedure to verify voltage and frequency trip limits:

The correct function of the voltage and frequency limits is verified with the help of the test circuit shown below:



The output of the inverter is connected to a simulated AC source (grid-simulator), which is adjusted to nominal conditions for grid voltage and frequency. It is not required to operate the inverter at rated power for this test.

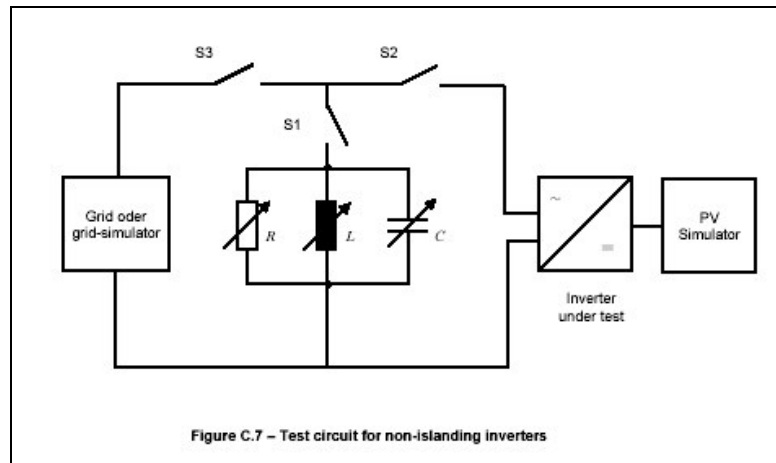
By slowly raising/lowering the voltage to the above stated limits the correct setting of the limits is verified. The trip time is measured by applying a voltage jump down/up to the limits and measuring the time needed for disconnection.

After the disconnection the grid voltage is restored to its nominal value and the time for re-connection is determined.

The same procedure is performed to check the frequency limits, respectively.

Testing procedure to verify non-islanding:

Purpose of this test is to determine that the inverter is not able to operate without the grid, even under worst case islanding conditions. A RLC circuit as shown in the figure below is used to simulate an islanded load with balanced load to generation ratio. The output power is determined by the DC source (PV simulator)



At the beginning the RLC circuit is adjusted to have a quality factor of at least 2. Balanced conditions for active and reactive power are achieved by tuning the individual components of the RLC load, taking into account the reactive power consumed or produced by the inverter. The aim is to zero out the fundamental component of the current at the switch S3. With the inverter operating at stable conditions S3 is opened to initiate the test. After each successful test, the RLC load is adjusted by about 1% in the range of about 5% and the same test is repeated. For each single test the time needed for disconnection is recorded. The whole sequence is performed for 25%, 50% and 100% of the rated power respectively.

Over-voltages

No specific recommendations on the behaviour of generators during over-voltages are provided in the documents.

Auto-reclosures

Settings of the de-coupling protection (TOR D4:2001 Section 7.3)

If a generation unit is connected to a line with an automatic re-closure facility, trigger level and delay time have to be set in order to allow a safe clearance of electric arcs during the dead period.

Short circuits (TOR D4:2001)

No specific recommendations on the behaviour of generators during short-circuits are provided in the TOR documents.

Inverter (ÖVE/ÖNORM E2750:2004 Section 4.3)

For PV-installations:

The AC side of the inverter has to be protected against over-currents and short-circuits.

Lightning protection (TOR D4:2001)

No specific recommendations on the protection of generators against lightning are provided in the documents.

Lightning and over-voltage protection (ÖVE/ÖNORM E2750:2004 4.1.)

PV installations on buildings may require a lightning protection according to ÖVE/ÖNORM E8049 (Protection of structures against lightning).

In buildings without an external lightning protection surge arrestors of type 2 according to EN 61643-1 (Surge protective devices connected to low-voltage power systems) have to be installed between the DC conductors and the equipotential conductor within 3 m of the grommet into the building. Also the inputs of the inverter have to be protected with surge arrestors which have to be coordinated with the previous ones. In regions with a low risk of lightning (ÖVE/ÖNORM E8001-1, Annex A), external surge arrestors may be omitted, if they are integrated in the inverter and the manufacturer confirms them to be sufficient.

On buildings with an external lightning protection the requirements of ÖVE/ÖNORM E8049-1 (Protection of structures against lightning), ÖNORM E 2980 (Lightning protection systems) and ÖVE/ÖNORM E 8001 (Erection of electrical installations with rated voltages up to AC 1000 V and DC 1500 V) have to be fulfilled. The PV array should be mounted in the protective zone of the lightning rods and shall not be connected to the external protection in order to avoid a direct lightning strike.

DC – injection (TOR D)

No specific recommendations on the topic are provided in the documents.

Inverter (ÖVE/ÖNORM E2750:2004 Section 4.3)

For PV-installations:

Direct current interferences on the AC side of the inverter, which could have a negative impact on safety and protective systems (e.g. residual current circuit breakers or other sensitive equipment), have to be avoided. This can be achieved either by

- an isolating transformer (integrated in the inverter e.g.) or
- DC current monitoring at the AC side with a fast disconnection in case of a DC current larger than 5% of the rated (AC) current, or 1 A at most.

A.10.5 Testing and Conformance Assessment

Assessment of grid interferences (TOR D2:2004 Section 9.2)

The document describes the assessment of various types of grid interferences caused by generators in MV and LV grids. For further details see the Power Quality section in the questionnaire.

Automatic disconnecting facility (ENS) (ÖVE/ÖNORM E2750:2004 Annex A)
Type test procedure for “non-islanding inverters” (ÖVE/ÖNORM E2750:2004 Annex B)

In the annexes mentioned, testing procedures for the conformity assessment of the loss-of-mains protection function of PV inverters are described. For further information see the relevant section in the questionnaire

COMMISSIONING

Basic requirements

Commissioning and initial start-up (TOR D4:2001 Section 12)

Commissioning and initial start-up has to be coordinated with the grid operator.

The grid operator reserves the right to be present for the inspection of the following points:

- Function and accessibility of the disconnection switchgear
- De-coupling protection, including the verification of the settings and preparation of an inspection sheet, check of the proper tripping of the contactors
- Functional test of the compensation equipment
- Compliance with the limits for permissible grid interferences
- Compliance with the start-up conditions
- Reactive power and voltage control
- Measurement equipment

The operator of the generator has to document the test of the de-coupling protection equipment and prove the compliance with the requirements.

Inspection sheets (ÖVE/ÖNORM E2750:2004 Section 4.4.3)

For PV installations:

Templates for sheets for initial and recurring inspections have to be available at the site of the installation.

Procedures (TOR D)

No detailed procedures are defined for commissioning of DG units.

A.10.6 Operation and Communication

Information Exchange DG/Grid Operator

Operation and information exchange (TOR D4:2001 Section 14.1)

The contract between grid operator and operator of the generator shall contain the following items for the purpose of a safe operation of the unit:

- Person authorised for executing switching operations at the de-coupling protection
- Way of ensuring the proper function of the de-coupling protection and the allocated contactors (recurring inspections by the plant operator or an authorised person), documentation of the inspections
- Notification and recording of faults and disturbances occurring at the generator
- Exchange of information on the operational state and measured parameters (power, voltage...)

Monitoring power and voltage (metering)

Metering (TOR D4:2001 Section 13)

Type and design of the metering (transducers and energy meters) and control equipment are based upon the contracts for delivery and production of electricity and have to be agreed between grid operator and generator.

Delivered and produced energy have to be metered separately.

If needed, a data exchange has to be designed in accordance with the requirements of the grid operator.

Maintenance requirements

No information is provided in the documents.

DG technology specific requirements (TOR D)

The requirements stated in the TOR documents apply to all generators, independent on the used generation technology or energy source.

(ÖVE/ÖNORM E2750:2004)

The requirements stated in the TOR documents apply to all generators, independent on the used generation technology or energy source.

This national standard defines the requirements for the installation and safety of grid connected PV installations. The specific issues related to grid connection are coordinated with the requirements of the TOR.

Additional DNO recommendations

In general Austrian DNOs use the TOR D2 (Recommendations for the assessment of network interferences) to assess the potential connection of DG units and their impact on the Power Quality of the network. Usually the maximum permissible voltage increase due to the DG is being used as the main criterion to calculate if the generator may be connected or not.

Regarding protection and other electrical interconnection issues DNOs use the TOR D4 (Parallel operation of generation units connected to distribution networks) to define the requirements for the connection of generators.

Since both documents are comprehensive and cover almost all needs, there are no specific documents which are issued by the DNOs concerning DG. However there are some topics which are not fully specified particularly in TOR D4, such as protection settings or power factor compensation and voltage control. These requirements are usually determined by the DNO case by case depending on various factors of which the capacity of the DG, the short circuit capacity of the network and the reactive power balance in the local network have been identified during the survey among Austrian DNOs.

Table A10.1 summarises the results of the survey and presents the DNO specific requirements for grid interconnection of DG in Austria. Furthermore also the recommendations of the Austrian Utilities Association (VEÖ) for their members are given at the end of Table A10.1.

In general it can be concluded that all Austrian DNOs observe the recommendations given by the TOR and set up their contracts on the basis of the TOR guidelines. Regarding protection, the same basic requirements are used; the settings are in most cases determined individually.

Differences do exist regarding reactive power compensation. Today, the power factor is set individually by the DNO for larger units (usually 0,9 leading, depending on the generation technology). Smaller generators (less than 20 kW) do not require a compensation in most cases, however this requirement depends on the DNOs own procedures.

So far there are no common requirements for voltage and power factor control capabilities of large distributed generators (MW range) defined in the TOR. Whether such systems have to be implemented or not is determined by the DNO.

Table A10.1 Summary of DNO specific requirements for grid interconnection of DG in Austria:

DNO	Grid Voltage level	Settings of the de-coupling protection						Requirements for PF (compensation)				No. (#) and capacity of DG connected in the DNO's network
		Min-max voltage (typ.)	Delay time ³ (typ.)	Min-max frequency (typ.)	Delay time ³ (typ.)	Re-closing delay	Other protective functions	ASM	SM	Static inv.	Var. power factor	
		[U _N] ⁴	[s]	[Hz]	[s]	[s]						
DNO 1	LV	0,80 – 1,10	0	49,5 – 50,5	0	180	none	1,0 ⁵	1,0	1,0 ⁵	- ⁶	# ~ 850 – 870
	MV	0,80 – 1,10	0	49,5 – 50,5	0	180						# ~ 30 – 50
DNO 2	LV	0,85 – 1,10	0	49,7 – 50,3	0	300	VSR ^{7,8}	0,9	0,9	0,9	-	# 156
	MV	0,85 – 1,10	0	49,7 – 50,3	0	300		lead	lead	lead		# 64
DNO 3	LV	0,80 – 1,20	0	49,5 – 50,5	0	> 60	VSR ⁷	0,9	0,9	0,9	⁹	# ~ 390
	MV	0,80 – 1,20	0	49,5 – 50,5	0	> 60		lead	lead	lead		(60 MW)
DNO 4	LV	0,90 – 1,06	0,2 – 0	48,0 – 50,5	0	> 300	VSR ¹⁰	1,0 ¹¹	0,9	1,0 ¹¹	- ¹²	# ~ 1200
	MV	¹³	0,2 – 0	48,0 – 50,5	0	> 300			lead ¹¹			(250 MW)
DNO 5	LV	0,70 – 1,10	0,1	48,0 – 51,0	0,1	300-900	VSR ⁷	1,0	1,0	1,0	-	# ~ 350
	MV	0,70 – 1,10	0,1	48,0 – 51,0	0,1	300-900						
DNO 6	LV	0,90 – 1,10	0,1	47,5 – 51,0	0,1	180	VSR ⁷	1,0	1,0	1,0	-	(~ 300 MW)
	MV	¹⁴	¹⁴	47,5 – 51,0	0,1	180 ¹⁵						

³ A value of 0 (zero) means instantaneous/without intentional delay.

⁴ Usually the setting refers to the agreed supply voltage.

⁵ No compensation required for installations with a capacity lower than 20 kW.

⁶ DNO1: Under discussion for larger units (SM > 1,5 MVA), some projects already in planning stage, where a variable PF is part of the contract.

⁷ Vector shift relay recommended as a generator protection (set to 6°- 8°).

⁸ DNO 2: Required in specific cases for islanding protection.

⁹ DNO 3: In specific cases, depending on the grid situation, a different PF is required for summer/winter, or a voltage dependent PF, respectively.

¹⁰ DNO 4: Vector shift relay required for synchronous generators > 100 kVA.

¹¹ DNO 4: A PF of 1,0 is required under normal grid conditions (short-circuit capacity). For points of coupling s with a low short-circuit capacity, lagging power factors may be required to reduce voltage increase. In this case the DG operator has to pay for the consumed reactive power.

¹² DNO 4: Under discussion for larger units.

¹³ DNO 4: The settings are determined case specific with the help of load-flow calculations.

¹⁴ DNO 6: If there is a remote fault (residual voltage between 15 and 60 % of U_N) wind farms shall remain connected and supply the maximum possible apparent power for up to 3 seconds. These requirements are identical to the "Regulations for grid-connection of wind farms" issued by the German grid operator E.ON-Netz.

¹⁵ DNO 6: If there are several units connected to a single point of coupling (e.g. wind farms), the reconnection shall take place in stages.

DNO	Grid Voltage level	Settings of the de-coupling protection						Requirements for PF (compensation)				No. (#) and capacity of DG connected in the DNO's network
		Min-max voltage (typ.)	Delay time ³ (typ.)	Min-max frequency (typ.)	Delay time ³ (typ.)	Re-closing delay	Other protective functions	ASM	SM	Static inv.	Var. power factor	
		[U _N] ⁴	[s]	[Hz]	[s]	[s]						
DNO 7	LV	0,70 – 1,20	0,2 – 0,2	48,0 – 52,0	0,2	> 300	VSR ^{7 16}	1,0 ⁵	^{5 17}	^{5 17}	- ¹⁸	No information
	MV	0,70 – 1,20	0,2 – 0,2	48,0 – 52,0	0,2	> 300						
DNO 8	LV							0,9	0,9	0,9	- ¹⁹	# ~ 300
	MV							lead	lead	lead		
DNO 9	LV	0,7/0,8–1,1	0/2 – 1,0 ²⁰	49,8 – 51,0	0		²¹	1,0 ⁵	1,0 ⁵	1,0 ⁵	-	No information
	MV	0,7/0,8–1,1	0/2 – 1,0 ²⁰	49,8 – 51,0	0							
VEÖ Guidelines (Austrian utility association)	LV	0,7-0,9 1,06-1,2	0 – 5	48-49,5 50,5-52	0	180 – 300	VSR ⁷	comp. to 1	0,9 lead	1	²²	Austria total: # ~ 4000 (1.350 MW)
	MV	individual	individual	48-49,5 50,5-52	0	180 – 300						

¹⁶ DNO 7: If a vector jump relay is installed, the frequency protection may be omitted.

¹⁷ DNO 7: The unit shall be technically capable of operating with a PF of 0,9 (cap). The specific PF is determined individually for each unit.

¹⁸ DNO 7: For large units, a PF control is arranged with the unit's operator.

¹⁹ DNO 8: For specific units, a variable PF over the billing period (usually 1 month) is possible.

²⁰ DNO 9: The delay time of 2 s applies for 0,8 U_N, at 0,7 U_N the protection has to react without intentional delay.

²¹ DNO 9: Only if specifically required for the operation of the grid.

²² VEÖ: In specific cases different PF for summer/winter; For large DG, remote controllable PF control under discussion; For points of coupling with a low short-circuit capacity, lagging power factors may be required to reduce voltage increase. In this case the DG operator has to pay for the consumed reactive power.

A.10.7 Outlook

Documents under revision

The whole TOR are currently revised and updated by the Austrian regulator together with experts from the utility association. The revision of TOR D2, which defines Power Quality relevant requirements and procedures is already finalised and incorporated into this report. The new edition of the DG relevant document TOR D4 on interconnection issues is currently under review and is expected to be published at the beginning of 2005.

The project of updating the Austrian grid code is scheduled to be finalised in 2005.

The national standard for grid connected PV installations was completely revised in 2003 and 2004. The update included above all the definition of requirements for inverters without galvanic separations, adaptation to new standards for lightning protection and new requirements for loss of mains protection systems. The standard was also adapted to new provisions of the TOR regarding protection, harmonic current emissions and others.

A.10.8 Conclusions

In the report, the technical rules for the grid connection of distributed generators to distribution grids in Austria have been described. The information presented is based on an analysis of the relevant documents, particularly the national grid code and national standards.

In Austria, the fundamental framework is laid down by the TOR, the “General technical and organisational rules for operators and users of transmission and distribution grids”. The TOR series of documents represent the Austrian grid code and are comprised of 6 parts and 9 documents. The basic aim of the grid code is to ensure the secure interoperation of the networks as well as the connected facilities under the conditions of the liberalised electricity market.

Two parts of the Austrian grid code are dedicated to distributed generation, namely TOR D2 and D4, which deal with the impact of loads and generators on the Quality of Supply and the parallel operation of generation units connected to distribution networks, respectively. TOR D2 describes procedures for the assessment of network interferences as voltage increase, fluctuations, flicker, harmonics and other phenomena. It is generally used to assess the potential connection of a generator at a certain point.

The detailed connection requirements are usually determined jointly between the DNO and the operator of the plant, based on the requirements and definitions of the TOR. For – in comparison with the short circuit capacity of the network – small generators, there are simplified practises for the assessment of the connection and standardised requirements for protection. The connection of larger units is usually assessed case by case, taking into account the network configuration at the envisaged point of coupling, capacity and technology of the plant and the operating conditions.

A.11 Grid Connection Criteria and Protection Practices for DG in Norway

A.11.1 Summary regarding increasing amount of Distributed Generation

Historically, Norway has been self supplied with electric power. Norway has a household and an industry that is built around electric power supply. The power supply has been “unlimited” and the prices have been low.

Norwegian power supply is mainly hydroelectric power. A lot of Norwegian lakes and rivers have been used for this purpose. Hydroelectric power production is environmentally clean but the disadvantage is the building of large dams and the areas that become flooded when the dams are built.

The last 5 – 6 years the Norwegian power consumption has passed the production and Norway has imported more power than we have exported. The exception are years with more rain and snow than normal.

A.11.2 Hydroelectric power plants

10 years ago we saw the start of an increasing interest from private landowners to build smaller power plants. This was mainly smaller hydroelectric power plants (50 – 1000 kVA) connected to the high voltage distribution grid (11 / 22 kV). The number of plants was increasing slowly until year 2000/2001 when the interest accelerated. Together with the increasing interest, the size of the generators became larger. Today most plants are at least 2 – 3 MVA and some even > 10 MVA.

This has given the power companies more challenges regarding the power distribution. The plants are connected to a grid that isn't dimensioned to handle the flow. On the other hand we have the protection systems and the protection philosophy that are no longer suitable for the new situation.

Norway faces a large challenge regarding how to handle all the distributed power plants, connected, mainly to a grid not dimensioned to handle the increased power flow.

A.11.3 Wind power

Wind power has become a popular addition to the Norwegian power production. The Norwegian coastline is suited for wind power production. When we are looking at the wind power projects, we see a different approach than what we are seeing regarding the smaller hydroelectric power plants. From single windmills connected to the distribution grid, the tendency now is that we are building “parks” with a large number of windmills. The power is fed into the transmission grid (>66 kV) and we are therefore better suited to handle the transmission.

Because of the physical size of the windmills, many projects have been stopped for environmental reasons. We are looking at several new “parks” along the coastline. The western part and in Finnmark, the northern part of Norway we will have a considerable amount of wind power production a few years from now.

A.11.4 Challenges

The Norwegian distribution grid is today not prepared to handle the increasing amount of distributed production. One factor is the capacity that has to be increased. Another factor is the dynamics of the power system. We need a more dynamic power system to be able to take full advantage of the new types of production.

We need to do more dynamic analysis of the power system. This has not been done enough on the 11 / 22 kV grid.

The balance between the transmission ability and the production capacity in another interesting area. Here, wind power is a challenge.

Our requirements regarding power quality and delivery is becoming more difficult to fulfil with the increasing amount of distributed power production.

Our main goal must be to become able to take the advantage of the new situation.

A.12 Grid Connection Criteria for DG in the United States

A.12.1 Introduction

The United States is divided into several regions in which electric power systems are coordinated. One example is the Western Electric Coordinating Council (WECC). Electric utilities within each region govern their own interconnection policies. All electric utilities must abide by Federal Energy Regulatory Commission (FERC) regulations; however technical requirements are typically based upon published IEEE Standards.

Cinergy PSI references voltage standards for the United States in their document, *Cinergy Connection of Generation Facilities Agreement* (cinergypsi.com). Low Voltage is defined as less than or equal to 1 kV. MV is defined as the range of 1 kV to 35 kV. When dealing with DG, we generally limit it to the MV and LV range. DG capacity of the DG unit determines the level of protection and criteria needed. In IEEE Standard 1547 [117], we shall not be discussing connection with HV.

A.12.2 IEEE Standard 1547: Interconnection Distributed Resources

IEEE Standard 1547 benchmark standards applied to interconnection of Distributed Generation. It is divided into four part series:

- IEEE Std 1547-2003: IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems.
- IEEE P1547.1TM Draft Standard For Conformance Test Procedures for Equipment Interconnecting Distributed Resources with Electric Power Systems.
- IEEE P1547.2TM Draft Application Guide for IEEE Std 1547-2003, IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems.
- IEEE P1547.3TM Draft Guide for Monitoring, Information Exchange, and Control of Distributed Resources Interconnected with Electric Power Systems.

To date, IEEE Standard 1547.2 and Standard 1547.3 have not yet been completed. The United States uses IEEE Standard 1547 as the national guideline.

The term Distributed Resources is used by IEEE Standard 1547. IEEE defines this as “Sources of electric power that are not directly connected to a bulk power transmission system. DR includes both generators and energy storage technologies.” Thus, this standard not only applies to Distributed Generation but also to energy storage units.

A.12.3 Connection Criteria

There are several areas that must be addressed for interconnection:

- Voltage regulation: The DG facility does not actively regulate the voltage at the Point of Common Coupling, or PCC. The DG shall not cause the EPS service voltage to go outside the requirements of ANSI C84.1-1995, Range A.
- Synchronization: The DG facility shall not cause a voltage fluctuation at the PCC greater than +/- 5 % of the prevailing voltage level of the EPS at the PCC. It must also meet the flicker requirements.
- Inadvertent energization of the area EPS: The DG facility shall not energize the Area EPS when it is already de-energized.
- Monitoring: If the DG facility is more than 250 kVA, the unit must monitor its connection status, real power output, reactive power output, and voltage at the point of DG connection (at the PCC).
- Isolation device: A readily accessible, lockable, visible-break isolation device shall be located between the EPS and DG unit only if required by the EPS operating practices.
- Protection from electromagnetic interference: The interconnection system shall be able to withstand electromagnetic interference (EMI) environments in accordance with IEEE Standard C37.90.2-1995. The EMI shall not result in a change in state or misoperation of the interconnection system.
- Surge withstanding and paralleling device: The interconnection system shall be able to withstand voltage and current surges in accordance with IEEE Standard C62.41.2-2002 or IEEE Standard C37.90.1-2002. In addition, the paralleling device shall be capable of withstanding 220 % of the interconnection system rated voltage.

A.12.4 Interconnection Costs

The PCC is the connection point that defines the boundary between the DG customer and the electric utility. In general, the interconnection costs are paid for by the DG facility. This would include the system upgrades to accommodate for interconnection.

A.12.5 Protection Practices

There are several protection practices that are advised in the IEEE Standard 1547. The three main factors are voltage, frequency, and harmonics.

- *Voltage.* The protection functions of the interconnection system shall detect the effective (rms) or fundamental frequency value of each phase-to-phase voltage. In the case that the transformer connecting the Local EPS to the Area EPS is a grounded wye-wye configuration or single-phase installation, the phase-to-neutral voltage shall be detected.

Using the Table A12.1 provided below, if the voltage falls within the range listed, the DG facility shall cease to energize the EPS within the clearing time indicated. This clearing time is the time between the start of the abnormal condition and the DG ceasing to energize the EPS.

For DG less than or equal to 30 kW in peak capacity, the voltage set points and clearing times shall be either fixed or field adjustable. For DG greater than 30 kW, the voltage set points shall be field adjustable.

Table A12.1: Interconnection system response to abnormal voltages

Voltage range (% of base voltage)	Clearing Time (seconds)
$V < 50$	0.16
$50 < V < 88$	2.00
$110 < V < 120$	1.00
$V > 120$	0.16

- *Frequency.* Using the Table A12.2 below, if the frequency falls within the given range, the DG shall cease to energize the EPS within the clearing time indicated. As stated above in the voltage protection, the clearing time is the time between the start of the abnormal condition and the DG ceasing to energize the EPS. If the DG is less than or equal to 30 kW in peak capacity, the frequency set points and clearing times shall either be fixed or field adjustable. Otherwise, for DG greater than 30 kW, the frequency set points shall be field adjustable.

Table A12.2: Interconnection system response to abnormal frequencies.

DG Size (capacity)	Frequency Range (Hz)	Clearing Time (Seconds)
≤ 30 kW	> 60.5	0.16
	< 59.3	0.16
> 30 kW	> 60.5	0.16
	$< (59.8-57.0)$	Adjustable 0.16- 300
	< 57.0	0.16

- *Harmonic Distortion.* The Table A12.3 below describes the maximum harmonic distortion for a DG facility. These conditions are set while a DG is serving a balanced load and determined exclusive of the harmonic currents due to the harmonic distortion present in the EPS before the DG is connected.

Table A12.3: Maximum harmonic current distortion in percent of current.

Individual harmonic order h (odd harmonic)	$h < 11$	$11 \leq h \leq 17$	$17 \leq h \leq 23$	$23 \leq h \leq 35$	$35 \leq h$	Total Demand Distortion (TDD)
Percent (%)	4.0	2.0	1.5	0.6	0.3	5.0

A.12.6 Islanding

Islanding is typically not allowed for any Distributed Generation. For unintentional islanding, the DG facility that energizes the Area EPS through the Point of Common Coupling, the safety interconnection equipment must be able to detect this island. Within two seconds, the DG facility must cease to energize the Area EPS. Intentional islanding has not been fully addressed.

A.12.7 Status of DG in the United States

The progress of DG in the United States was investigated in a recent article [118]. Below is a discussion of the current technologies in the market as well as the future of DG in the United States as evaluated in this article.

A.12.7.1 Current DG

In the current market, the following combinations have been dominant:

- Wind generators with induction generator.
- Diesel prime mover with synchronous generator.
- Natural gas primer mover with synchronous generator.
- Gas turbine prime mover with synchronous generator.

The market has recently expanded to include smaller-sized combinations:

- Natural gas turbine prime mover combined with a high-frequency rectifier and static inverter to produce 60 Hz output. The units require several seconds to reach nominal output power and employ a lead acid battery to provide energy for transients.
- Natural gas powered fuel cells combined with gas reformers. The proton exchange membrane (PEM) fuel cells require natural gas to pass through the reformers to produce hydrogen. Implementation sometimes requires lead acid batteries to handle transients.
- Wind powered generators using an AC inverter instead of an induction generator. The AC inverters improve the system power factor, increase efficiency, and increase the power range.
- Solar energy, using more technically advanced solar cells combined with advanced power electronic converters to integrate utility.
- Wave energy converted from hydraulic machinery using power electronic converters to connect directly into local distribution system.

A.12.8 Future of DG and Barriers

The technological advances that lower the capital cost for DG in combination with new approaches by FERC provide a promising future for DG. The popularity of DG can also be linked to demanding requirements by industry and commerce for a more sustained reliability from the electric delivery system.

Utilities view DG as an opportunity to enhance their reliability and customer service. It can also provide offset peak loads for efficient system utilization. In other examples, such as those pertaining to Bonneville Power Administration, DG is also looked to as a method to defer new transmission and/or distribution construction.

The main barrier to the number and types of distributed generators introduced in the United States are the economic constraint limits.

New momentum for DG is expected to come from the energy bill [119]. The energy bill will promote the use of renewable energy sources with tax credits for wind, solar, and biomass energy, including the first-ever tax credit for residential solar energy systems. The bill also expands research into developing hydrogen technologies. The concept of Stochastic Energy Source Access Management (SESAM) [120], shown in Fig. A12.1 below, makes use of the synergies of both renewable and hydrogen energy. It is aimed at solving a major problem with regards to the large-scale infrastructure integration of renewable energy sources due to their intermittent power output. The intermittency conflicts with the need to schedule the electric power output in a deterministic manner. At the core of the concept is the coupling of the stochastic source with diverse storage modules of complementary characteristics over a DC bus. Due to the dependence on the wind, power P_{ss} has a stochastic distribution. The power P_{st} exchanged with the storage can then be adjusted such that the power P_{ds} to the grid becomes deterministic. As complementary storage solutions hydrogen and a second form of storage for quasi-instantaneous power exchange are considered. These are arranged to form a multi-level storage that allows compensating for stochastic fluctuations over diverse time frames. A direct current bus allows for fast exchange of electric power between source and storage modules. An electricity infrastructure interface provides the capability to exchange electric power between the alternating current grid and the direct current bus, while a hydrogen infrastructure interface is connected to the hydrogen tank. The intermittent renewable source is so transformed into an emission-free plant with controlled deterministic output of electric power and hydrogen flows. Since SESAM effectively emulates the behavior of a plant with controlled fuel input, it can be readily integrated with given infrastructures and so promote the large-scale use of renewable energy.

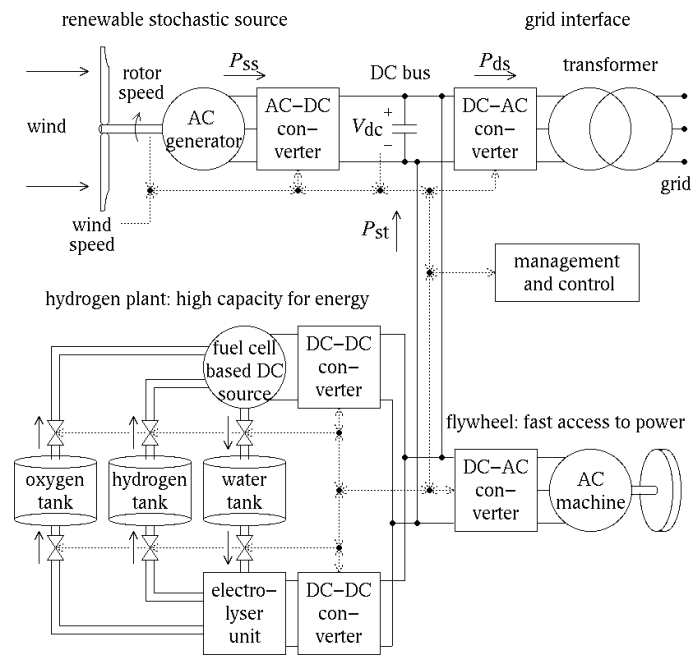


Figure A12.1: Stochastic Energy Source Access Management [120]

References

CHAPTER 1. Introduction

- [1] R. Belhomme, C. Naslin, G. Beslin, N. Albrieux, "Wind farms and networks – Main technical issues", Proceedings of International Conference on Power Generation and Sustainable Development, Liège, Belgium, 8-9 October 2001.
- [2] P. Bousseau, E. Gautier, I. Garzulino, Ph. Juston, R. Belhomme, "Grid impact of different technologies of wind turbine generator systems (WTGS)", European Wind Energy Conference (EWEC), Technical Session "Grid Integration", Madrid, Spain, June 16-19, 2003.
- [3] J. Martinon, P. Juston, J-L. Fraisse, "Dispersed generation and quality of supply on MV and LV systems", PQA'97 Europe, Session 2B, Stockholm, Sweden, 1997.
- [4] K.K. Jensen, "Guidelines on grid connection of wind turbines", Proceedings of CIRED'99, Paper No. 4/8, Nice, France, June 1-4, 1999.
- [5] J.L. Fraisse, P. Michalak, P. Juston, A. Grandet, "Technical conditions for the connection of generating facilities to the medium voltage network - Development of a 175 Hz active filter for independent power producers", Proceedings of CIRED'97, Vol. 1, Paper No. 5.14, 1997.
- [6] EURELECTRIC, "Connection rules for generation and management of ancillary services", report ref. 2000-130-0003, May 2000. Available : <http://public.eurelectric.org/>.
- [7] G. Robert, R. Belhomme, "Ancillary services provided by dispersed generation", CIGRE Symposium on Power Systems with Dispersed Generation, Athens, Greece, April 13-16, 2005.
- [8] R. Belhomme, P. Juston, P. Cholley, J.L. Fraisse, "Islanded operation of MV networks", in Proceedings of CIRED'99, Paper No. 4/9, Nice, France, June 1-4, 1999

CHAPTER 2. Current Connection Criteria and Protection Practices in various Countries for DGs

Key Considerations

- [9] N. Hatziaargyriou, T. Karakatsanis, G. Strbac, "Connection Criteria for Renewable Generation Based on Probabilistic Analysis", 6th PMAPS'2000, Sept. 25-28 2000, Funchal, Madeira, Portugal.
- [10] B. Borkowska, "Probabilistic Loadflow", IEEE Trans. on PAS, Vol. PAS-93, No. 3, May/June 1974, pp. 752-759.
- [11] "Present status of DG in selected European countries: National codes, standards, requirements and rules for grid-interconnection and operation", series of DISPOWER technical reports, 2005
- [12] "State of the art solutions and new concepts for islanding protection", DISPOWER Deliverable 2.2, 2005
- [13] R. Bründlinger et. al. "Unintentional islanding in distribution grids with a high penetration of inverter-based DG: Probability for islanding and protection methods", in Proc. of 2005 IEEE PowerTech Conference, St. Petersburg, 2005
- [14] "Identification of general safety problems, definition of test procedures and design-measures for protection", DISPOWER Deliverable 2.3, 2005
- [15] B. Bletterie, et. al. "Sensitivity of photovoltaic inverters to voltage sags – test results for a set of commercial products", in Proc. of 18th international conference on electricity distribution, CIRED, Turin, 2005
- [16] Informatie- en consultatiedocument Decentrale Opwekking, Economische gevolgen voor de elektriciteitsnetwerken van toename van decentrale opwekking, Dutch Office for Energy Regulation, The Hague, The Netherlands, February 2004 (in Dutch).
- [17] Standpuntendocument Decentrale Opwekking, Gevolgen van decentrale opwekking voor de regulering van elektriciteitsnetwerken, Dutch Office for Energy Regulation, The Hague, The Netherlands, May 2004 (in Dutch).

CHAPTER 3. International Standards

CHAPTER 4. Simplified Methods for DG Connections

Reactive Control Capability in Spain

- [18] OM May, 9th 1985, Administrative and Technical Specifications for Grid Connection and Required Performance of Hydraulic Power Plants up to 5000 kVA, and Electrical Self-Generation.
- [19] RD 2018/1997 Procedure for the Measurement of Electrical Energy Consumed and Transmitted.

- [20] OM April 12th 1999 Technical details for the Measurement of Energy Consumed and Transmitted.
- [21] RD 1663/2000, Connection Requirements for Photovoltaic Installations to the Low Voltage Grid.
- [22] REBT ITC-BT-40, Low Voltage generation facilities
- [23] Law 54/1997 09/27/1997. Law of Electrical Sector.
- [24] RD 436/2004, Methodology for payment of the Special Regime.
- [25] Red Eléctrica de España, Technical conditions for non dispatchable generators of the Special Regime. January 2004.
- [26] Ministry of Economy. Planning for electricity and gas sectors. September 2002.
- [27] UNE Report 206005 Calculation of wind farm reactive power regulation capacity. September 2004.

CHAPTER 5. Identification of new Requirements and Methods

Probabilistic Load Flow

- [28] R.N. Allan, B. Borkowska, C.H. Grigg, "Probabilistic Analysis of Power Flows", Proc. IEE, Vol. 121, No. 12, pp. 1551-1555, Dec. 1974.
- [29] R.N. Allan, C.H. Grigg, D.A. Newey, R.F. Simmons, "Probabilistic Load Flow Techniques Extended and Applied to Operational Decision Making", IEE Proc., Vol. 123, No. 12, Dec. 1976, pp. 1317-1324.
- [30] R.N. Allan, M.R.G. Al-Shakarchi, "Linear Dependence between Nodal Powers in Probabilistic AC Load Flow", Proc. IEE, Vol. 124, No. 6, June 1977.
- [31] R.N. Allan, A.M. Leite da Silva, R.C. Burchett, "Evaluation Methods and Accuracy in Probabilistic Load Flow Solutions", IEEE Trans on PAS, Vol. PAS 100, No. 5, May 1981, pp. 2539-2546.
- [32] R.N. Allan, A.M. Leite da Silva, "Probabilistic Load Flow Using Multilinearisations", IEE Proc., Vol. 128, Pt. C, No. 5, September 1981, pp. 280-287.
- [33] A.M. Leite da Silva, R.N. Allan, S.M. Soares, V.L. Arienti, "Probabilistic Load Flow Considering Network Outages", IEE Proc., Pt C, Vol.123, May 1985, pp.139-145.
- [34] A.M. Leite da Silva, V.L. Arienti, "Probabilistic Load Flow by a Multilinear Simulation Algorithm", IEEE Proc., Vol. 137, Pt. C, No. 4, July 1990, pp. 276-282.
- [35] A.M. Leite da Silva, S.M.P. Ribeiro, V.L. Arienti, R.N. Allan, M.B. Do Coutto Filho, "Probabilistic Load Flow Techniques Applied to Power System Expansion Planning", IEEE Trans. on Power Systems, Vol. 5, Nr. 4, Nov. 1990, pp. 1047-1053.
- [36] T.S. Karakatsanis, N.D. Hatziaargyriou, "Probabilistic Constrained Load Flow Based on Sensitivity Analysis", IEEE Trans. on Power Systems, Vol. 9, Nr. 4, Nov. 1994.
- [37] N.D. Hatziaargyriou, T.S. Karakatsanis, "Distribution System Voltage and Reactive Power Control Based on Probabilistic Load Flow Analysis", IEE Proc. Generation, Transmission and Distribution, Vol. 144, No. 4, July 1997, pp. 363-369.
- [38] N.D. Hatziaargyriou, T.S. Karakatsanis, "Probabilistic Load Flow for Assessment of Voltage Instability", IEE Proc. Generation, Transmission and Distribution, Vol. 145, No. 2, March 1998, pp. 196-202.
- [39] "Probabilistic Constrained Load Flow for Optimizing Generator Reactive Power Resources", N.D. Hatziaargyriou, T.S. Karakatsanis, IEEE Trans. on Power Syst., Vol. 15, Nr. 2, May 2000, pp. 687-693.

Islanding

- [40] R. H. Lasseter, P. Piagi, "MicroGrid: A conceptual Solution", in *Proc. of the 35th PESC*, pp. 4285-4290, Germany, 2004.
- [41] J. Peças Lopes, J. Tomé Saraiva, N. Hatziaargyriou, N. Jenkins, "Management of MicroGrids", JIEEC2003 Bilbao, 2003.
- [42] S. Barsali, M. Ceraolo, P. Pelacchi, "Control techniques of Dispersed Generators to improve the continuity of electricity supply", *Proceedings of PES Winter Meeting*, pp. 789-794, 2002.
- [43] Madureira, C. Moreira, J. Peças Lopes, "Secondary Load-Frequency Control for MicroGrids in Islanded Operation", in *Proc. International Conference on Renewable Energy and Power Quality ICREPQ'05*, Spain, March 2005.
- [44] J. Peças Lopes, C. Moreira, A. Madureira, F. Resende, *et al.* "DD1 – Emergency Strategies and Algorithms", MicroGrids project Deliverable DD1, October 2004.
- [45] G. Kariniotakis, *et al.*, "DA1 – Digital Models for Microsources", MicroGrids project deliverable DA1, 2003.
- [46] N. Hatziaargyriou *et al.*, "Modelling of Micro-Sources for Security Studies", in *CIGRE Session*, 2004.

Appendix A

A1. Grid Connection Criteria and Protection Practices for DG in France

- [47] Ministère de l'industrie, des postes et télécommunications et du commerce extérieur, "Arrêté du 14 avril 1995 relatif aux conditions techniques de raccordement au réseau public des installations de production autonome d'énergie électrique", *Journal Officiel de la République Française*, No. 103, pp. 6882-6891, May 1995. Available : <http://www.legifrance.gouv.fr> .
- [48] Ministère de l'économie, des finances et de l'industrie, "Arrêté du 21 juillet 1997 relatif aux conditions techniques de raccordement au réseau public des installations de production autonome d'énergie électrique de moins de 1 MW", *Journal Officiel de la République Française*, No. 202, pp. 12833-12834, August 1997. Available : <http://www.legifrance.gouv.fr> .
- [49] Ministère de l'économie, des finances et de l'industrie, "Arrêté du 3 juin 1998 relatif aux conditions techniques de raccordement au réseau public HTA des installations de production autonome d'énergie électrique de puissance installée supérieure à 1 MW", *Journal Officiel de la République Française*, No. 139, p. 9280, June 1998. Available : <http://www.legifrance.gouv.fr> .
- [50] Secrétariat d'Etat à l'industrie, "Arrêté du 30 décembre 1999 relatif aux conditions techniques de raccordement au réseau public de transport (réseau à 400 kV exclu) des installations de production d'énergie électrique de puissance installée inférieure ou égale à 120 MW", *Journal Officiel de la République Française*, No. 12, pp. 727-728, January 2000. Available : <http://www.legifrance.gouv.fr> .
- [51] Secrétariat d'Etat à l'industrie, "Arrêté du 15 avril 1999 relatif aux conditions techniques de raccordement des installations de production autonome d'énergie électrique aux réseaux publics HTA et BT non reliés à un grand réseau interconnecté", *Journal Officiel de la République Française*, No. 100, pp. 6398-6399, April 1999. Available : <http://www.legifrance.gouv.fr> .
- [52] "Loi No. 2000-108 du 10 février 2000 relative à la modernisation et au développement du service public de l'électricité", *Journal officiel de la République Française*, No. 35, pp. 2143-2159, February 2000. Available : <http://www.industrie.gouv.fr/frame0.pl?url=/energie/sommaire.htm> .
- [53] "Directive 96/92/EC of the European Parliament and of the Council of 19 December 1996 concerning common rules for the internal market in electricity", *Official Journal of the European Union*, No. L 027, pp. 0020 – 0029, January 30, 1997.
- [54] Ministère de l'économie, des finances et de l'industrie, " Décret n° 2003-229 du 13 mars 2003 relatif aux prescriptions techniques générales de conception et de fonctionnement auxquelles doivent satisfaire les installations en vue de leur raccordement aux réseaux publics de distribution", *Journal Officiel de la République Française*, No. 64, pp. 4589-4592, March 2003. Available : <http://www.legifrance.gouv.fr> .
- [55] Ministère de l'économie, des finances et de l'industrie, "Décret n° 2003-588 du 27 juin 2003 relatif aux prescriptions techniques générales de conception et de fonctionnement auxquelles doivent satisfaire les installations en vue de leur raccordement au réseau public de transport de l'électricité", *Journal Officiel de la République Française*, No. 151, pp. 11110-11113, July 2003. Available : <http://www.legifrance.gouv.fr> .
- [56] Ministère de l'économie, des finances et de l'industrie, " Arrêté du 17 mars 2003 relatif aux prescriptions techniques de conception et de fonctionnement pour le raccordement à un réseau public de distribution d'une installation de production d'énergie électrique ", *Journal Officiel de la République Française*, No. 93, pp. 7005-7008, April 2003. Available : <http://www.legifrance.gouv.fr> .
- [57] Ministre déléguée à l'industrie, "Arrêté du 22 avril 2003 modifiant l'arrêté du 17 mars 2003 relatif aux prescriptions techniques de conception et de fonctionnement pour le raccordement à un réseau public de distribution d'une installation de production d'énergie électrique ", *Journal Officiel de la République Française*, pp. 7904, May 2003. Available : <http://www.legifrance.gouv.fr> .
- [58] Ministère de l'économie, des finances et de l'industrie, Arrêté du 4 juillet 2003 relatif aux prescriptions techniques de conception et de fonctionnement pour le raccordement au réseau public de transport d'une installation de production d'énergie électrique", *Journal Officiel de la République Française*, No. 201, pp. 14896-14902, August 2003. Available : <http://www.legifrance.gouv.fr> .
- [59] R. Belhomme, C. Corenwinder, "Wind power integration in the French distribution grid -Regulations and network requirements", *Proceedings of NWPC'04 Nordic Wind Power Conference*, Chalmers University, Göteborg, Sweden, March 1-2, 2004.
- [60] RTE, and ARD, "Traitement des demandes de raccordement des installations de production décentralisées", Procedure text. Available : <http://www.edf.fr> , and , http://www.rte-france.com/html/fr/offre/offre_raccord_prod.htm .

A2. Grid Connection Criteria and Protection Practices for DG in Spain

- [61] OM May, 9th 1985, *Administrative and Technical Specifications for Grid Connection and Required Performance of Hydraulic Power Plants up to 5000 kVA, and Electrical Self-Generation.*
- [62] RD 2018/1997 *Procedure for the Measurement of Electrical Energy Consumed and Transmitted.*
- [63] OM April 12th 1999 *Technical details for the Measurement of Energy Consumed and Transmitted.*
- [64] RD 1663/2000, *Connection Requirements for Photovoltaic Installations to the Low Voltage Grid.*
- [65] REBT ITC-BT-40, *Low Voltage generation facilities*
- [66] Law 54/1997 09/27/1997. *Law of Electrical Sector.*
- [67] RD 436/2004, *Methodology for payment of the Special Regime.*
- [68] Red Eléctrica de España, *Technical conditions for non dispatchable generators of the Special Regime. January 2004.*
- [69] Ministry of Economy. *Planning for electricity and gas sectors..* September 2002.
- [70] UNE Report 206005 *Calculation of wind farm reactive power regulation capacity.* September 2004.

A3. Grid Connection criteria and Protection Practices for DG in Italy

A4. Grid Connection Criteria and Protection Practices for DG in Canada

Bibliography

- [71] IEEE Std. 1547 – Standard for Interconnecting Distributed Resources with Electric Power Systems
- [72] IEEE Std. 519 – IEEE Recommended Practice and Requirements for Harmonic Control in Electric Power Systems
- [73] IEEE Std. 929 – IEEE Recommended Practice for Utility Interface of Residential and Intermediate Photovoltaic (PV) Systems
- [74] IEEE Std. 242 – Recommended Practice for Protection and Coordination of Industrial and Commercial Power Systems
- [75] CSA C235 – Preferred Voltage Levels for AC Systems, 0 to 50,000 V
- [76] CSA C22-1 - Canadian Electrical Code
- [77] CEA 128 D 767 - Connecting Small Generators To Utility Distribution Systems (June 1992)

Internet Reference

British Columbia

<http://www.bchydro.com/policies/opentrans/opentrans796.html>

<http://www.bchydro.com/info/ipp/ipp992.html>

Alberta

http://www.energy.gov.ab.ca/ele/docs/alberta_dg_finalguide_july2002.pdf

[http://www.aquilanetworks.ca/downloads/regulation_ab/Current%20Tariff/Aquila%20\(Alberta\)%202003-08-01%20Terms%20and%20Conditions.pdf](http://www.aquilanetworks.ca/downloads/regulation_ab/Current%20Tariff/Aquila%20(Alberta)%202003-08-01%20Terms%20and%20Conditions.pdf)

<http://www.epcor-group.com/EPCOR+Companies/EPCOR+Distribution+and+Transmission/Edmonton+Distribution+Services/Distributed+Generation+Information/default.htm>

Saskatchewan

http://www.oatioasis.com/SPC/SPCdocs/spc_tradetariff.doc

<http://www.saskpower.com/services/nug/NUG25kV.pdf>

Manitoba

<http://oasis.midwestiso.org/documents/Mheb/queue.html>

Ontario

http://www.oeb.gov.on.ca/html/en/industryrelations/ongoingprojects_ministersdirective_connection.htm

Quebec

A5. Grid Connection Criteria and Protection Practices for DG in Greece

- [78] “Technical requirements for the connection of independent generation to the grid”. Public Power Corporation (PPC) of Greece, 2004.
- [79] S.A. Papathanassiou, N.D. Hatziargyriou, “Technical Requirements for the Connection of Dispersed Generation to the Grid”. *Proc. of IEEE-PES Summer Meeting 2001*, June 2001, Vancouver, Canada.
- [80] IEC 61000-1-1 (1992), Part 1: General – Section 1: Application and interpretation of fundamental definitions and terms.
- [81] European Norm EN 50160, “Voltage characteristics of electricity supplied by public distribution systems”. CENELEC, 1999.
- [82] N.Hatziargyriou, T.Karakatsanis, M.Papadopoulos, “Probabilistic load flow in distribution systems containing dispersed wind power generation”, *IEEE Trans. Power Systems*, Vol. 8, No. 1, February 1993.
- [83] N.G. Boulaxis, S.A. Papathanassiou, M.P. Papadopoulos, “Wind turbine effect on the voltage profile of distribution networks”. *Renewable Energy*, Vol. 25, No. 3, March 2002, Pages 401-415.
- [84] IEC 868-0 (1991), Part 0: Evaluation of flicker severity.
- [85] IEC 868 (1986): Flickermeter. Functional design and specifications. Amendment No. 1 (1990).
- [86] IEC 61000-4-15 (1997), Part 4: Testing and measurement techniques – Section 15: Flickermeter-Functional and design specifications.
- [87] IEC 61000-3-3 (1994), Part 3: Limits – Section 3: Limitation of voltage fluctuations and flicker in low-voltage supply systems for equipment with rated current ≤ 16 A.
- [88] IEC 61000-3-5 (1994), Part 3: Limits – Section 5: Limitation of voltage fluctuations and flicker in low-voltage power supply systems for equipment with rated current greater than 16 A.
- [89] IEC 61000-3-11 (2000), Part 3: Limits – Section 11: Limitation of voltage changes, voltage fluctuations and flicker in low voltage supply systems for equipment with rated current < 75 A and subject to conditional connection.
- [90] IEC 61000-3-7 (1996), Part 3: Limits – Section 7: Assessment of emission limits for fluctuating loads in MV and HV power systems – Basic EMC publication.
- [91] IEC 61400-21 (2001): Wind turbine generator systems - Measurement and assessment of power quality characteristics of grid connected wind turbines.
- [92] ANSI/IEEE Std. 519 (1992): Recommended Practice and Requirements for Harmonic Control in Electric Power Systems.
- [93] IEC 61000-3-2 (2000), Part 3: Limits – Section 2: Limits for harmonic current emissions (equipment input current ≤ 16 A per phase).
- [94] IEC 61000-3-4 (1998), Part 3: Limits – Section 4: Limitation of emission of harmonic currents in low - voltage power supply systems for equipment with rated current greater than 16A.
- [95] IEC 61000-3-6 (1996), Part 3: Limits – Section 6: Assessment of emission limits for distorting loads in MV and HV power systems.
- [96] IEC 61000-2-2 (1990), Part 2: Environment – Section 2: Compatibility levels for low-frequency conducted disturbances and signalling in public supply systems.
- [97] “Recommendation for the Connection and Parallel Operation of Generating Facilities at the MV Network”, VDEW, 2nd Edition, 1998 (in German).
- [98] IEC 725 (1981): Considerations on reference impedances for use in determining the disturbance characteristics of household appliances and similar electrical equipment.
- [99] Woyte, R. Belmans, J. Nijs, “Testing the islanding protection function of photovoltaic inverters”. *IEEE Transactions on Energy Conversion*, Vol. 18, No. 1, March 2003, pp. 157 –162
- [100] M.E. Ropp et. al., “Determining the Relative Effectiveness of Islanding Detection Methods Using Phase Criteria and Non-detection Zones”. *IEEE Trans. on Energy Conversion*, Vol.15, No.3, Sept. 2000, pp. 290-296.
- [101] W. Bower, M. Ropp, “Evaluation of Islanding Detection Methods for Utility-Interactive Inverters in Photovoltaic Systems”. Report SAND2002-3591, Sandia National Laboratories, 2002.
- [102] M.P. Papadopoulos, S.A. Papathanassiou, S.T. Tentzerakis, “Operating Problems in Wind-Diesel Power Systems with Extended MV Networks”. *Proceedings of EUWEC'96*, May 1996, Goteborg, Sweden.

- [103] S.A. Papathanassiou, M.P. Papadopoulos, "Mechanical Stresses in Fixed Speed Wind Turbines due to Network Disturbances". *IEEE Trans. on Energy Conversion*, Vol. 16, No. 4, Dec. 2001, pp. 361 –367.
- [104] E.ON Netz GmbH, "Supplementary Grid Connection Regulations for Wind Energy Converters", Dec. 2001. Available at <http://www.eon-netz.de>.
- [105] Consortium for Electric Reliability Technology Solutions (CERTS), "White Paper on Integration of Distributed Energy Resources - The CERTS MicroGrid Concept", 2002. Available at <http://certs.lbl.gov/>.
- [106] Georgakis, S. Papathanassiou, N. Hatziaargyriou, A. Engler, C. Hardt, "Operation of a prototype Microgrid system based on micro-sources equipped with fast-acting power electronics interfaces". *Proceedings of PESC'04*, June 2004, Aachen, Germany.

A6. Grid Connection Criteria and Protection Practices for DG in Croatia

A7. Grid Connection Criteria and Protection Practices for DG in Portugal

A8. Grid Connection Criteria and Protection Practices for DG in the Netherlands

A9. Grid Connection Criteria and Protection Practices for DG in Germany

A10. Grid Connection Criteria and Protection Practices for DG in Austria

- [107] Ministry of Economy and Labour, Section Energy and Mining, "ElWOG – "Elektrizitätswirtschafts- und Organisationsgesetz", *BGBI I 149/2002*, 2002, Available at <http://www.e-control.at>.
- [108] "Richtlinie 96/92/EG des Europäischen Parlaments und des Rates vom 19. Dezember 1996 betreffend gemeinsame Vorschriften für den Elektrizitätsbinnenmarkt", *Amtsblatt der Europäischen Union Nr. L 027*, S. 0020 – 0029, 30.1.1997.
- [109] Energie Control GmbH, "Technische und organisatorische Regeln für Betreiber und Benutzer von Übertragungs- und Verteilernetzen gemäß ElWOG – Teil D, Hauptabschnitt D2: Richtlinie für die Beurteilung von Netzzrückwirkungen, Version 2.0", *Marktregeln für Teilnehmer im Elektrizitätsmarkt*, 1 June 2004, Available at <http://www.e-control.at>
- [110] Verband der Elektrizitätsunternehmen Österreichs, "Technische und organisatorische Regeln für Betreiber und Benutzer von Übertragungs- und Verteilernetzen gemäß ElWOG – Teil D, Hauptabschnitt D4: Parallelbetrieb von Erzeugungsanlagen mit Verteilernetzen", *Marktregeln für Teilnehmer im Elektrizitätsmarkt*, 2001, Available at <http://www.e-control.at>
- [111] Österreichischer Verband für Elektrotechnik, "ÖVE/ÖNORM E2750 – "Photovoltaische Energieerzeugungsanlagen, Errichtungs- und Sicherheitsanforderungen", 2004, Available at <http://www.on-norm.at>.
- [112] Communication with the Austrian Utilities Association from 31.8.2004.
- [113] Discussions with various Austrian DNOs, 5.2004 – 6.2004.
- [114] Website of Energie Control GmbH, <http://www.e-control.at>
- [115] Website of the Austrian Energy Agency, "Erneuerbare Energie in Österreich: Wasserkraft, Österreichs bedeutendste Stromquelle", <http://www.eva.ac.at>.
- [116] CIGRE TF 38.06.03 Report "Economic and Technical Interaction between Dispersed Generation and Power System", Convener Goran Strbac

A11. Grid Connection Criteria and Protection Practices for DG in Norway

A12. Grid Connection Criteria and Protection Practices for DG in United States

- [117] IEEE Standard 1547-2003 for Interconnecting Distributed Resources with Electric Power Systems.
- [118] Lawrence, R.; Middlekauff, S.: The new guy on the block. *IEEE Industry Applications Magazine*. Volume 11, Issue 1, Jan-Feb 2005 Page(s):54 – 59.
- [119] Energy Policy Act of 2005, United States, August 2005.
- [120] Strunz, K.; Brock, E. K.: Hybrid plant of renewable stochastic source and multi-level storage for emission-free deterministic power generation. *Proceedings of the CIGRE/IEEE PES International Symposium on Quality and Security of Electric Power Delivery Systems*, Montreal, Canada, October 2003.