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Utility aspects of grid connected photovoltaic power systems

Task V
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PVPS

PHOTOVOLTAIC POWER SYSTEMS PROGRAMME

IEA PVPS

International Energy Agency

Implementing Agreement on Photovoltaic Power Systems

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Grid Interconnection of Building Integrated

and Other Dispersed Photovoltaic Power Systems

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UTILITY ASPECTS OF GRID CONNECTED PHOTOVOLTAIC POWER SYSTEMS

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FOREWORD

The International Energy Agency (IEA), founded in November 1974, is an autonomous body within the framework of the Organisation for Economic Co-operation and Development (OECD) which carries out a comprehensive programme of energy co-operation among its 23 member countries. The European Commission also participates in the work of the Agency.

The IEA Photovoltaic Power Systems Programme (PVPS) is one of the collaborative R&D agreements established within the IEA, and, since 1993 its participants have been conducting a variety of joint projects in the applications of photovoltaic conversion of solar energy into electricity.

The members are: Australia, Austria, Canada, Denmark, European Commission, Finland, France, Germany, Israel, Italy, Japan, Korea, Mexico, the Netherlands, Norway, Portugal, Spain, Sweden, Switzerland, Turkey, the United Kingdom and the United States.

This report has been prepared under the supervision of PVPS Task V by

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in co-operation with experts of the following countries:

Australia, Austria, Denmark, Germany, Italy, Japan, the Netherlands, Portugal, Switzerland, the United Kingdom and the United States

and approved by the PVPS programme Executive Committee.

The report expresses, as nearly as possible, an international consensus of opinion on the subjects dealt with.

SHORT ABSTRACT AND KEYWORDS

This report summarises the state off the art on the interface and the interaction of a grid connected PV-system and the utility power network. A total of 11 relevant topics are described in this report. Summaries of these topics are given at the beginning of every chapter.

Keywords: Harmonics, AC modules, multiple inverters and the AC grid, grounding of equipment in PV systems, ground-fault detection, array disable, overvoltage protection, islanding, Electro magnetic compatibility (EMC), external disconnect, re-closing, isolation transformer and DC-injection

1. INTRODUCTION

Task V is a working group of the International Energy Agency (IEA), Implementing Agreement on Photovoltaic Power Systems (PVPS). The title of the working group is “Grid Interconnection of Building Integrated and Other Dispersed Photovoltaic Power Systems”

The main objective of Task V is to develop and verify technical requirements that may serve as pre-normative technical guidelines for the network interconnection of building-integrated and other dispersed Photovoltaic (PV) systems. The developments of these technical guidelines aim at a safe, reliable and low cost interconnection of PV systems with the electric power network. Task V considers PV systems connected with the low-voltage network with a typical peak power rating between 100 Watt and 50 kiloWatt.

Task V has three subtasks:
10 Review of PV guidelines, grid structures and PV experiences
20 Theoretical studies on utility aspects of PV systems
30 Experimental tests using the Rokko Island and/or other test facilities

Subtask 10 defines the status quo of grid connected PV systems. A survey on present day guidelines gave information on the interconnection of PV systems with the utility network. A second survey showed the different network structures of the participation countries. Subtask 10 identified present day and possible near future problems regarding the network connection of PV systems. The scope of work of subtask 20 was to analyse these problems and to draft possible recommendations for improvement. Some problems, however, appeared to be too complex and additional experimental work had to be done. These experiments are co-ordinated in subtask 30.

This report gives the results of the topics studied in subtask 20. All chapters have an identical structure to allow for an easy access to the information given. Following sections can be found in every chapter:

- Summary
- Introduction
- Scope of Work
- Theoretical results
- Experimental results
- Conclusions
- Recommendation for future work

Chapter 2 of this report describes the selection process of the study topics. The chapters 3 till 13 give the information and results of the selected study topics. Every chapter is written as a single entity and can be studied and interpreted without the need for consulting other chapters. The authors, however, advise the reader to study the whole report rather then a single chapter as many of the topics are directly or indirectly linked with another. Final conclusions and recommendations are given in chapter 14. The addresses of the authors are given in chapter 15.

This report is intended for readers familiar with the technical concept of PV systems and/or readers with an electrotechnical background.

2. SELECTION PROCESS OF THE TOPICS

PV systems are a relative new technology. The operational experience with PV systems itself is at an acceptable high level and today's installed PV systems are of a good quality and are able to operate without any problems for many years. The price level of the PV modules and the Balance of System costs (inverter included) have decreased significantly. The use to PV systems connected in parallel with the utility electric power network has become very favourable and is often supported by incentives from utilities and/or governmental bodies.

Before connecting a PV system to the power network, the DC voltage of the solar modules must be converted into an AC voltage. Some protection systems are required preventing damages in the PV system caused by the utility network and vice versa. Other important aspects are the electrical installation procedures, electrical interference between network and one or more PV systems, EMC and harmonics. For some topics PV does put special constraints on the solution that are normally used by the utilities. Hence, international work is required on utility aspects of grid connected PV systems.

In the fall of 1994, the experts in Task V made a survey on technical grid-related issues that need attention of Task V. This revealed approximately 30 topics, all of them related to the electrical aspects of PV systems and power networks. The topics are ordered in the following categories:

- PV system related
- Safety aspects
- Grid related

Task V was not able to study all these topics and a selection process was started to identify the topics that needed attention first. A pre-selection has been made in the beginning of 1995. A final selection has been made in the spring meeting in 1995 and resulted in a selection of 12 topics. The scope of work and the required output of the research has been defined for all the selected topics.

The research on the selected topics has been organised by a lead country that was assisted by one or more co-working countries.

The progress and results of every topic has been discussed at every Task V meeting. Discussions that followed these presentations helped the lead country to have an open and world-wide perspective of the problem and possible counter measures.

2.1 Topics of research

Table 1 shows the selected topics for study including the lead country and co-working countries.

Table 1 Overview of selected topics for research

Topic	Lead country	Co-working countries
Harmonics	Italy	UK, DK
AC Module	The Netherlands	USA, CH, JP, UK
Multiple inverters	Japan	ITA. CH UK, USA
Grounding of equipment	The United States	NL
Ground fault detector	The United States	NL
Overvoltage protection	The Netherlands	USA
Islanding	Austria	JP, UK
EMI of inverter and Array	Austria	NL
External disconnect	The United Kingdom	GR
Reclosing	Italy	JP
DC injection and isolation transformer	Germany	UK

The names, companies and addresses of the representatives of all participating countries are listed in chapter 15.

3. HARMONICS

3.1 Summary

The harmonic problem has assumed a particular relevance starting from the 1960s with the increasing use of static converters, which directly effect the quality of the electricity supply.

In general, the harmonic problem can be defined as that particular disturbance that, originated by the presence of non-linear components in the electrical systems, determines a permanent modification of the voltage and current sinusoidal wave shapes, in terms of sinusoidal components at a frequency different from the fundamental.

PV generators are connected to the distribution network through static converters and are therefore potentially able to cause harmonics, so downgrading the quality of electricity and altering the performances of other equipment sensitive to voltage harmonics. On the other hand, static converters themselves are sensitive to harmonics and may operate incorrectly as a result of the harmonic voltage distortion.

The chapter investigates the harmonic phenomena as applied to PV systems, taking into account aspects relevant to the generation (emission) and to the effects (susceptibility). The chapter also gives an overview of the present international rules relevant to harmonics and reports some measurements realised in Denmark from November 1996 to September 1997 about the impact from the PV installations on the local voltage distortion.

The work done has also showed the necessity to further investigate the effects on harmonics in case of multiple PV systems operation

3.2 Introduction

The harmonic problem has assumed a particular relevance starting from the 1960s with the increasing use of static converters, which directly effect the quality of the electricity supply.

PV generators are connected to the distribution network through static converters and are therefore potentially able to cause harmonics, downgrading the quality of electricity and altering the performances of other equipment sensitive to voltage harmonics. Also static converters themselves are sensitive to harmonics and may operate incorrectly as a result of the harmonic voltage distortion. Furthermore, regarding small-sized inverters that are the subject of TASK V, international standards presently in force are concerned about the harmonic emission levels for a single unit. These standards state nothing about the cumulative impact that the simultaneous operation of multiple inverters can have on the harmonic content of the electricity network.

This is because there is no unequivocal relationship between the voltage distortion caused by users and the general voltage distortion level in the distribution network because of the cumulative effect of non-linear loads, the diversity in the size and phase of harmonic components, and the grid harmonic impedance. However, if the grid impedance is well defined, then the voltage distortion caused by individual harmonic sources could be calculated. Unfortunately for most applications this is not financially viable.

This Chapter investigates the harmonic phenomena as applied to PV, taking into account both generation and effects, and gives an overview of the international rules relevant to harmonics.

3.3 Scope of work

Based on the experience gained by the various participating countries on the operation of PV systems connected to the LV network through static converters, the scope of this chapter is to:

- give information on harmonic generation and harmonic effects
- give information on rules/standards relevant to harmonics
- give information on methods that can be utilised to assess/predict the harmonic voltage distortion of the distribution network
- summarise some typical performance figures for PV equipment based on the results of a limited survey carried out under Task V
- give information on interactions between multiple inverters as regards their impact on the harmonics contents
- outline some recommendations for future work aimed at measuring harmonics in as many PV-plants with multiple inverters as possible in a systematic form.

In addition, a short paragraph is dedicated to a possible future PV systems utilisation as active filters for harmonic reduction in order to improve the quality of the electric service so adding value to the PV energy and making PV systems more attractive.

3.4 Theoretical results

In this section the overall effects of harmonics are reviewed, so that their relevance to PV can be assessed. Moreover, as only ‘small’ units of up to 50kW need be addressed for the purposes of Task V, only guidelines relevant to this situation will be illustrated.

In general, the harmonic problem can be defined as that particular disturbance that, originated by the presence of non-linear components in the electrical systems, determines a permanent modification of the voltage and current sinusoidal wave shapes, in terms of sinusoidal components at frequencies which are multiples of the fundamental.

In the following, the aspects relevant to the generation (emission) and to the effects (susceptibility) that the harmonics have on equipment will be illustrated.

3.4.1 Harmonics generation

In general, non-linear loads, even if they are supplied by three symmetrical sinusoidal voltages, inject deformed current into the network. The harmonic voltages developed are dependant upon the harmonic source impedance which itself is non-linear.

The harmonic content in these ideal supply conditions is characteristic for the type of load but, in practice, due to the supply waveform already containing harmonic voltages, further harmonics appear in the harmonic spectrum of the injected current wave shape. The main types of distorting equipment and the characteristic harmonics of the injected current are mentioned below.

Line-commutated converters

Under ideal operation conditions (ac-side sinusoidal voltages, steady direct current Id, instantaneous commutations), the characteristic harmonics that are present in the current from a line-commutated converter have a module equivalent to

$$I = \frac{\sqrt{6}}{n\pi} I_d \qquad n = 6k \pm 1 \qquad \text{for 6 - pulse bridge}$$

$$I = \frac{2\sqrt{6}}{n\pi} I_d \qquad n = 12k \pm 1 \quad \text{for 12 - pulse bridge}$$

The presence of inductance on the ac-side, the presence of harmonics in the supply voltage, errors in the control of the firing-angle, are all elements that create additional and unforeseen harmonics.

Self-commutated converters

A technique commonly used to control a static self-commutated six-phase-bridge inverter is to synthesise a fundamental frequency wave shape by modulation. The traditional PWM (Pulse Width Modulation) technique synthesises a sinusoidal wave shape through a fp frequency carrier modulated by a sinusoidal wave at the fundamental frequency f_0.

The orders of the characteristic harmonics of the six-phase bridge wave shape are:

mf		3mf	....
mf ± 2	2mf ± 1	3mf ± 2	....
mf ± 4	2mf ± 5	3mf ± 4	....
....	....	....	....

with

$$mf = \frac{f_p}{f_o} \qquad \text{odd and integer}$$

The experience gained within Task V on inverters used to connect PV generators to the LV network has shown that the harmonics injected are a few percent of the rated current (see Task V - Subtask 10: “Report on interconnection equipment”).

Residential loads

The main disturbing loads are:
- television receivers
- thyristor-controlled devices (lamp dimmers, ...)
- fluorescent lamps
- computers

Although the residential loads connected to the LV network have a limited power, their large number significantly contributes to network harmonics. The individual harmonic current content from equipment can approach 100% and if these are in phase with other generators can cause distortions on the network voltage of around 4% with the present utilisation of electronic devices. The distortion is likely to increase further as these devices proliferate.

Transformers

Transformers operating under normal conditions do not significantly contribute to supply harmonic components in the network. However, during energisation (even and odd harmonics) or during operations out of their normal operation, they can give a significant contribution to the harmonic pollution of the network range (3rd - 5th - 7th).

3.4.2 Harmonic effects

Harmonic effects can cause losses in the utility network and possible damage to equipment connected to it. Although PV systems are typically small, as the effects of harmonics are cumulative they should not be ignored. Modern inverter equipment operating on PWM switching is typically very good, producing very little harmonics (see summary table from subtask 10.3 in section 3.4). However, it has been seen in examples such as TV sets, that many small source of harmonics can have a significant effect on the overall levels in the utility network.

The main effects of voltage and current harmonics on the various network components are:
- excessive voltages and currents as a consequence of parallel and series resonance;
- reduction of the system efficiency;
- damage to the insulation of the system components with the consequent reduction of the components' life;
- incorrect operation of the electrical system components.

Resonance

The presence of capacitors in a system may cause parallel resonance with possible damage to components and in particular to the capacitors themselves.

In fact, if the frequency corresponding to the parallel resonance coincides with that of the current generated by the non-linear load, an amplification of the voltages occurs across the resonant branch whose magnitude depends on the resistive parameters of the system that act as dampers. Besides parallel resonance, which is characterised by having a high impedance to the harmonic sources at the resonance frequency, there may also be series resonance, characterised by having a low impedance to the voltage harmonic sources present in the network.

Effects on rotating machines

Harmonics cause two types of problems for the rotating machines:
- the first one is related to the alternative electromechanical torque’s and may cause stress to the mechanical components,
- the second one is connected to the increase in both iron losses (a few % points) and copper losses, where it can cause a noticeable increase in the temperature of the windings.

Effects on transformers

The main effect of harmonics on transformers is an increase in iron and copper losses. Of course, such effects are more pronounced in the case of transformers supplying non linear loads such as static converters. Another important effect to be considered is the possible circulation of zero-sequence harmonic currents in the delta-windings which may cause overheating of the transformer.

Effects on capacitors

The main effect of harmonics on capacitors is to increase losses with a consequent increase in temperature leading to thermal failure. Moreover, the capacitors noticeably affect the voltage distortion in the nodes they are connected to, particularly during resonance conditions; in this case, the increase of the harmonic currents with the consequent increase of the losses and the possible destruction of the capacitors themselves can be determined.

High voltage capacitors are particularly susceptible to small overvoltages. It is common practice to insert an inductor in series with power factor correction capacitors to detune the capacitive node. Harmonic currents which are close in frequency to the resonant frequency can cause sufficiently high voltages at the capacitor terminals to damage it.

Effects on cables.

As far as cables are concerned, current harmonics produce an increase in losses because of the Joule effect caused by the frequency related increase in the ac resistance of the cable. As a result, a significant decrease of the cable life might occur. A further but typically less serious effect is an increase in I^2R losses.

Effects on relays, switches and fuses.

Harmonics can influence relays in various ways with possible consequent malfunctioning. Relays that are sensitive to voltage and the current peak values and/or the voltage and the current zero crossing, are clearly affected by the presence of the harmonic distortion. (It seems that 10÷20% harmonics are necessary to have malfunctions in the relay operation.) The harmonic components can have a non negligible effect on the operation of the switches, since they can cause high derivative current, so making the current interruption more difficult. Harmonic currents can cause excessive heating of the fuses, degrading their operating characteristics.

Effects on static converters

Static converters generate harmonics but they can also be affected by the presence of voltage harmonics in the network. In fact, capacitors, filters and snubbers can be liable to a thermal stress stronger than that established in the design because of the harmonic currents supplied by the network. Moreover, the harmonics present in the network can adversely effect the control of the static converters when the control itself is based on the zero crossing detection, causing, for instance, misfiring or commutation failure.

Effects on meters and electronic appliances

Harmonics affect the operation of the energy meters, particularly the Ferraris disc type, altering their precision. In fact, harmonics generate additional torque's that cause an increase in the disk speed. In particular, it has been noticed that in case of thyristor-controlled loads, the meter indication is higher than expected by a few percentage points because the 50 Hz supply current is greater due to the harmonic component:

$$I_{50supply} = I_{50load} + I_{hload}$$

So the meter tends to run fast. Finally, appliances such as television sets, PCs or other electronic equipment, contribute to the generation of harmonic disturbances, but they can also be affected by the presence of harmonics in the distribution network. For instance, computers generally require an ac current containing harmonics of not more than 5%, to avoid possible unstable operation.

3.4.3 Outline of the present international rules

In the following, an outline of the present situation of international rules relevant to harmonics is presented.

PVs are not covered by specific standards. However the generic standards can often be interpreted and applied. In general the European standard EN 60555 is used which requires Total Harmonic Distortion THD to be less than 5% and places limits on the size of any one harmonic. In the UK, for instance, these limits apply to small power devices without restriction. However, in the case of bigger powers, there is a requirement to investigate the already existing levels on the line, as the final level will be the cumulative effect of existing and new levels. Although not covered in the standards this might also be the case for multiple installations of small inverters where the currents would also be cumulative.

The table below summarises the standards effective in the Countries involved in Task V and was collected as part of the Subtask 10.1 activity.

Table 1 Overview of harmonic standards in countries

Country	Harmonics standards
Austria	Inverters have to comply with OVE-B/EN60555 Referenced from Austrian PV Guideline ONORM/OVE2750 Par. 3.3.7
Germany	Specific limits set for specific current harmonics European standard EN60555 part 2/3/ Specific limits for voltage harmonics: each specific harmonic must stay below 5% VdEW: fundamentals on harmonics
Italy	Static converters connected to the LV grid with a current < or =16A have to comply with National Standards CEI 77-3 corresponding to EN60555-2
Japan	Current THD less than 5%, each individual harmonic less than 3%
Netherlands	IEC 1000series
UK	Limits for harmonics are set out in the Electricity Council publication 'Engineering Recommendation G.5/3 - Limits for Harmonics in the United Kingdom Electricity Supply System'. These limits are for overall harmonic distortion and for the total level of each individual harmonic. The limits are for voltage distortion and current limits may be derived from them. The amount of new harmonic current which can be accepted will depend

Country	Harmonics standards
	upon existing distortion levels and any local resonant effects. EN 60-552-2 (BS5406: Part 2) is referred to from G.5/3 for single phase system and supplies limits for harmonics caused by household appliances and similar electrical equipment. Limits are tabulated against harmonic order for equipment connected at 240V or 415V mains. Its requirements are tighter than those of G.5/3. If met, the apparatus will automatically satisfy G.5/3. Values for LV: THD < 5%, Any Single Harmonic < 2%.
USA	Harmonics for all loads and generation is generally covered by IEEE Guideline for Harmonic Control and Reactive Compensation of Static Power Converters (<5% THD and <2% any one harmonic of current injected into utility grid).

3.4.3.1 IEC standards

A set of standards on electromagnetic compatibility has been developed within IEC; amongst them, an important chapter is reserved for harmonics. In particular, starting from April 1995, EN 61000-3-2 has superseded EN 60555-2, even if PV systems which have complied with EN 60555-2 before 1998/06/01 will be allowed to be placed on the market until 2001/01/01.

The above mentioned standards on the electromagnetic compatibility can be subdivided into:
- sections that define the environment from the EMC viewpoint and establish the compatibility levels that the distributors must guarantee;
- sections that define the emission levels into the networks;
- sections that define the immunity levels of the appliances.

In the following, the existing IEC standards and/or IEC projects of standards relevant to the harmonics will be illustrated.

Standards defining the environment from the EMC viewpoint

1000 - 1 - 1 (1992): Application and interpretation of fundamental definitions and items. Scope: to describe and interpret various terms considered to be of importance to concepts and practical application in the design and evaluation of EMC

1000 - 2 - 1 (1990): Description of the electromagnetic environment for low-frequency conducted disturbances and signalling in public power supply systems. Scope: to deal with conducted disturbances in the frequency range up to 10 kHz with an extension for mains signalling systems. In particular, chapters 5 and 6 deal with the harmonics and inter-harmonics and describe the phenomena, the source of disturbances and the effects.

1000 - 2 - 2 (1990): Compatibility levels for low-frequency conducted disturbances and signalling in public low-voltage power supply systems. Scope: to give numerical compatibility levels for low voltage ac. distribution systems with a nominal voltage up to 240 V single-phase, or 415 V three-phase and a nominal frequency of 50 Hz or 60 Hz. In particular, the section does not assess the permissible interference emission from specific items of equipment or installations, but it wants to give information on the levels of disturbances of various types that can be expected in public low-voltage power supply systems. Chapters 2 and 3 are dedicated to harmonics and set the compatibility limits for each harmonic voltages, according to table 2.

Table 2 Compatibility levels for individual harmonic voltages in the low-voltage network.

Odd harmonics non-multiple of 3		**Odd harmonics multiple of 3**		**Even harmonics**	
Harmonic order n	Harmonic voltage %	Harmonic order n	Harmonic voltage %	Harmonic order n	Harmonic voltage %
5	6	3	5	2	2
7	5	9	1.5	4	1
11	3.5	15	0.3	6	0.5
13	3	21	0.2	8	0.5
17	2	>21	0.2	10	0.5
19	1.5			12	0.2
23	1.5			>12	0.2
25	1.5				
> 25	0.2+0.5x25/n				
The THD of the supply voltage (including all harmonics up to the order 40) shall be ≤ 8%					

A similar standards concerning the medium voltage is going to be completed very soon. Up to now, only an IEC 77A (Secretariat) 88 project exists: Compatibility for low-frequency conducted disturbances and signalling in public medium-voltage power supply systems.

1000 - 2 - 4 (1994): Compatibility levels in industrial plants for low-frequency conducted disturbances. Scope: to give requirements for the compatibility levels for industrial and non-public networks. The standard applies to low-voltage and medium-voltage ac. power. Chapter 5.5 is dedicated to harmonics and sets the compatibility limits for each harmonic according to the class of the industrial environment.

Standards defining the emission levels into the networks

1000 - 3 - 2 (1995): Limits for harmonic current emissions (equipment with input current ≤ 16 A per phase). Scope: to set limits for harmonic emissions of equipment in order to ensure that harmonic disturbance levels do not exceed the compatibility levels defined in IEC 1000-2-2. The standard is applicable to electrical and electronic equipment having an input current up to and including 16 A per phase, and intended to be connected to public low-voltage distribution systems.

Standard classifies equipment in 4 classes:

Class A: balanced three-phase equipment and all other equipment, except that stated in one of the following classes.

Class B: portable tools.

Class C: lighting equipment, including dimming devices.

Class D: equipment having input current with a “special wave shape” and an active input power P ≤ 600 kW.

PV systems should be classified as Class A equipment, whose limits are shown in table 3.

Table 3 Emission limits for Class A equipment

Harmonic order, n	Maximum permissible harmonic current, A
Odd harmonics	
3	2.30
5	1.14
7	0.77
9	0.40
11	0.33
13	0.21
$15 \leq n \leq 39$	0.15 15/n
Even harmonics	
2	1.08
4	0.43
6	0.30
$8 \leq n \leq 40$	0.23x8/n

Project n. 1000-3-4 : Limits for harmonic current emissions (equipment with input current > 16 A per phase). This publication has been prepared in the form of a technical report by SC 77A. Scope: to set limits for harmonic emissions of equipment in order to ensure that harmonic disturbance levels do not exceed the compatibility levels defined in IEC 1000-2-2. The standard is applicable to electrical and electronic equipment having an input current exceeding 16 A per phase, and intended to be connected to public low-voltage distribution systems. Furthermore, it is stated that:

- connection of this equipment to the supply generally needs either notification to or consent by the supply authority,
- there is no guarantee that the connection of equipment complying with the standard will be permitted in all cases, as the consent to connect equipment to the supply depends on the level of disturbances caused by the equipment and the local network load conditions

1000 - 4 - 7 (1991): General guide on harmonic and inter-harmonics measurements and instrumentation, for power supply systems and equipment connected thereto. Scope: to give criteria on measurement instrumentation for testing individual equipment or for measurement of harmonic voltages and currents in supply systems. The section also considers

- frequency-domain and time-domain instrumentation,
- tentative recommendations for the statistical analysis of harmonic measurements in order to make the comparison of results easier,
- indications of how handling fluctuating and rapidly changing harmonics in order to compare the results with stated limits, acceptance or reference values.

Finally, an **IEC 82/1727 (1994)** standards project exists: "Characteristics of the utility interface for photovoltaic systems" whose chapter 4.4 briefly mentions harmonics, making reference to the IEC standards in force and suggesting indicative values for the harmonic voltage distortion.

3.4.3.2 IEEE standards

IEEE has recently published (1992) the following standard: IEEE 519 - "IEEE recommended Practice and Requirements for Harmonic Control and Electrical Power Systems" that attempts to establish criteria for the design of electrical systems that include both linear and non-linear loads and sets the quality of power that has to be provided at the interfacing point.

In particular, the standard contains:

- the harmonic current emission limits under the customers responsibility (in the Recommended Practices for Individual Consumers). The limits are based on the size of the load with respect to the size of the power system to which the load is connected as shown in table 4.

Table 4 Current distortion limits for general distribution systems (120V up to 69kV)

Maximum Harmonic Current Distortion in percent of IL Individual Harmonic Order (Odd Harmonics)						
Isc/IL	**< 11**	**11≤n<17**	**17≤n<23**	**23≤n<35**	**≥35**	**TDD**
<20*	4.0	2.0	1.5	0.6	0.3	5.0
20<50	7.0	3.5	2.5	1.0	0.5	8.0
50<100	10.0	4.5	4.0	1.5	0.7	12.0
100<1000	12.0	5.5	5.0	2.0	1.0	15.0
>1000	15.0	7.0	6.0	2.5	1.4	20.0

Even harmonics are limited to 25% of the odd harmonic limits above

*All power generation equipment is limited to these values of current distortion, regardless of actual Isc/IL

TDD Total Demand Distortion in % of maximum demand load current

aximum short-circuit current at the interfacing point

IL : fundamental frequency component of the maximum demand load current at the interfacing point

- The voltage distortion limits under the utility responsibility (in the Recommended Practices for Utility) as shown in table 5.

Table 5 Voltage Distortion Limits

Bus Voltage	**Individual Voltage Distortion (%)**	**Total Voltage Distortion THD (%)**
69 kV and below	3.0	5.0
69→161 kV	1.5	2.5
161 kV and above	1.0	1.5

In general, the problem of harmonic distortion is faced by comparing the features of the network in the connection point of the distorting load, to the features of the distorting load, as it is underlined in note 1 of the IEC project n° 1000-3-4.

3.4.3.3 European Community standards

The European Community has established that it was necessary to give a unique definition of the essential features of the electricity supply from the viewpoint of EMC and, to this end, it has formed a Task Force (BTTF) with the purpose of defining the features of the electricity supplied through the low and medium voltage networks.

The effort resulted in the document: EN 50160 "Voltage characteristics of electricity supplied by public distribution systems" 11-94. This document refers to "normal operation condition of the distribution system" and considers two groups of features of the supplied voltage: for the first group quantitative information is given, for the other indicative values are given. The following items belong to the first group:
- frequency
- width
- flicker
- harmonic distortion
- phase symmetry
- content of the signals transmitted by the distributor for operation functions

The values of the above mentioned features are generally specified for established time intervals, with a 95% probability that it is not exceeded. (The criterion used is that the established value must not be exceeded in 95% of the 10 minutes under control for one week). In particular, harmonics limits have been fixed for both low and medium voltage. The second group includes:
- fast voltage variations
- voltage temporary dips
- interruption to electric power supply
- overvoltages
- inter-harmonics

The electricity features belonging to the second group are unforeseeable and difficult to be quantified: therefore, indicative or still under consideration values are given. At last, two important specifications on the application field of the EN 50160 standards are the following:
- the standard may be superseded in total or in part by the terms of a contract between the individual customer and the electricity supplier
- The voltage characteristics given in the standard are not intended to be used as electromagnetic compatibility levels or user emission limits.

3.4.4 Harmonics composition law

As it has been seen in the previous paragraphs, each single inverter connecting a PV generator to the distribution network must comply with the constraints stated by the relevant rules/standards (i.e. IEC 1000-3-2, IEEE 519). At the same time, the utility must supply an electric energy with a well-established service quality stated, for example, by EN 50160 in order to allow a normal operation for all sensitive equipment connected to the distribution network. This leads to the need of utilities to know the harmonics composition law. Unfortunately, the knowing of how each individual harmonic contributes to the total harmonic distortion is not easily to establish because it depends on factors as
- the harmonic phase angles between the various inverters,
- the harmonic phase angles compared with the background distortion,
- the level of background distortion either generated at the same voltage level or imposed from other voltage levels,

- the ability of transferring harmonics between different voltage levels,
- the uncertainty in determining the harmonic impedances of the network,
- the variation of the loads and their impact on the harmonic impedances,
- the presence of capacitors or filters.

At the moment, a very interesting guidance for assessing the system harmonic impedance is available as technical report from working group CC02 CIGRE 36.05/CIRED 2 (1994) "Guide for assessing the network harmonic impedance". In particular, it provides guidelines to take into account the considered network (LV, MV or HV), the disturbing load importance (small or great contribution to the network pollution), the analytical and computational tools available. Moreover, this guide contains an exhaustive bibliography on the matter.

3.4.5 Active filters

In general, filtering systems used for the harmonic reduction can be classified in passive systems and active systems. The first ones are basically devices that are a preferred, low-impedance way, for the current harmonics generated by the system to be filtered. In general, these passive systems have the problem of their interaction with the distribution network that can lead to resonances close to some harmonics.

The active systems, on the contrary, are the most innovative means through which a harmonic cancellation effect of the disturbing system is obtained, essentially by generating additional current harmonics through another static converter. Of course, these active systems require both appropriate control techniques and commutation frequencies. Some applications of the aforementioned active filters can be found in the following papers:

- C. Pincella et al.: "Development of an electronic based power conditioning prototype to improve power quality" - 13th CIRED Conference 1995;
- M.B. Brennen et al.: "Low cost, high performance active power line conditioners" - PQA 94 - Report n. D-2.08

Although there are no examples of PV systems combining the electric energy generation with the filtering action, this innovative utilisation could make PV systems attractive from the point of view of the quality service.

3.5 Experimental Results

3.5.1 Single inverter

The table below shows the harmonic performance of some currently available inverters, the data for which was collected as part of a non-exhaustive survey carried out under Task V in Subtask 10-3. In general the inverters are less than 50kW and as such can be built using PWM technology. This gives a good quality sinewave compared with the more traditional line-commutated thyristor devices. A typical achievement can be seen to be less than 5% Total Harmonic Distortion with any one harmonic less than 3%, which meets the current European standard EN 60555-2.

Table 6 Overview inverter and harmonics

Inverter power	Harmonic current	Control method of harmonics
2 kW	Total <5%, Each <3%	Current control by means of microcontroller
2.5 kW	Total <2%, (P>P10%), <1%(PN)	PWM with pure sinewave reference
700W	Total <3% (P>0.5 PN)	PWM with pure sinewave reference
30 kVA	Total 2%	High PWM switching frequency small L-C filter current control (180° displacement)
15 kVA	Total <4%, Each <2%	Filtering on the ac side
4 kW	Total <1%	Filtering on the ac side
3-5 kW	Total <5%, Each <3%	Reference sine wave
10-20 kW	Total 3%, Each 2%	Current control using PWM switching
2-100 kW	Total 3%, Each 2%	Current control using hysteresis comparator
5 kW	Total ≤5%, Each ≤3%	Internal sinusoidal waveform reference table, 20kHz current amplitude control
10-100 kW	Total 4%, Each <1%	PWM high frequency, multiple 3 phases bridges phase lagged to suppress the carrier frequency
40 kW	Complies with G5/3	4 step compensation unit designed as filter for 5th, 7th, 11th, 13th harmonics
5 kW	Total <5%, Each <2%, At rated output	Waveform synthesization method (referenced waveform, with high frequency filters included as part of the transformer to filter switching frequencies)
2.2 kW	Total <5%, Each <3%, At rated output	Waveform synthesization method (referenced waveform, with high frequency filters included as part of the transformer to filter switching frequencies)
3-4 kW	Total <5%, Each <2%, At rated output	Waveform synthesization method - utility waveform referenced with high frequency filters included for switching frequencies
17kW	Total <5%, Each <2%, At rated output	Waveform synthesization method - referenced waveform, with high frequency filters including transformer for switching frequencies
50 kW	Total <3%, Each <2%, At rated output	Waveform synthesization method - referenced waveform, with high frequency filters for switching frequencies
2.4-3.2 kW	Total <5%, Each <3%, At rated output	Waveform synthesization method - referenced waveform, with high frequency filters for switching frequencies

3.5.2 Multiple inverter

In the autumn of 1996/spring of 1997 the power distribution company VOK installed photovoltaic (PV) systems at 29 existing private single houses in the neighbourhood known as “Søringen” in Brædstrup, Denmark. The installations are divided onto 29 single houses, equalling 80% of the houses of the neighbourhood. The project has received funding from the Danish Energy Agency, ELFOR and ELSAM.

The composite capacity of the PV installations in the neighbourhood totals 60 kWp divided onto 60 identical installations of 1 kWp each and each with a 1-phase grid connection via a Sunny Boy SWR 850 inverter. The primary objectives of the project have been to study the following:

- The system’s impact on the grid, in particular the significance of the installations on the voltage quality.
- The consumer conduct when posing as producers of their own electricity.
- Architectural and structural aspects of integrating PV installations into building structures.
- Tariff questions.

The report in Appendix A describes the impact of the installations on the grid with particular focus on the significance of the installations on the voltage quality. The possible impact from PV cells on voltage quality has been examined by measurements and subsequent analysis of the current and voltage distortion before, during and after the PV installations were put into service.

According to the measurements there seems to be no detectable impact from the PV installations inside the neighbourhood on the local voltage distortion. Furthermore, all the voltage distortions measured lie significantly below the upper limits as recommended by recommendation R16 issued by the Research Association of the Danish Electricity Utilities. On the basis of a comparison of the voltage distortion, current harmonics and grid impedances it is found that most of the local voltage distortion by far is caused by external sources. It has even been possible to identify one of the external sources by means of fast measurement campaigns.

Finally, the measurement of harmonic currents has demonstrated that the most significant share of the local contribution to the voltage distortion is caused by TV sets, and only to a limited extent by the PV installations.

The concentration of PV installations found in “Søringen” must be considered to be as close to the maximum to be realised within a geographically limited residential area. The risk that a similar concentration of photovoltaic cells in other confined areas would give an unwanted impact on the voltage quality cannot be excluded, if the grid in that area had a significantly lower short-circuit power than is the case for “Søringen”.

3.6 Conclusions

The report has illustrated the harmonic problem taking into account both generation and effects, as well as the international rules relevant to harmonics. The main findings reached can be summarised as follows.

- The control of static converters equipping PV generators may be sensitive to harmonics and they may operate incorrectly as a result of the harmonic voltage distortion. The compatibility levels for the public low-voltage power supply systems are established by IEC 1000-2-2

- PV generators are connected to the distribution network through static converters and so through equipment potentially able to cause harmonics. Limits for harmonic current emissions for PV systems with rated current ≤ 16 A per phase are established by IEC 1000-3-2 that leaves unchanged the EN 60555-2 limits. On the other hand, PV systems with rated current > 16 A per phase, should comply with future IEC 1000-3-4. In general the existing standards seem adequate and are not overly restrictive on the manufacturers of inverters who can meet the criteria without the need for costly special procedures.
- The present work has showed a need for investigating more deeply the effect of multiple inverters on the harmonic levels. Measurements realised in Denmark from November 1996 to September 1997 showed that seems to be no detectable impact from the PV installations on the local voltage distortion. On the basis of a comparison of the voltage distortion, current harmonics and grid impedances it was found that most of the local voltage distortion by far was caused by external sources.
- PV systems could operate, in the future, as active filters to reduce harmonics on the distribution system. Although there are no examples of PV systems combining the electric energy generation with this active filtering action, this innovative utilisation could make PV systems attractive from the point of view of the quality service.

3.7 Recommendation for future work

At the last Task V meeting it was agreed that the work on harmonics from single inverters could not be separated from the work on the effects of multiple inverters. In the same way, it is recommended that the harmonics effects of multiple inverters be investigated under Subtask 30, as a combined set of tests. This also seems more appropriate as the effects of single inverters are for the main part covered in the manufacturers literature, and harmonics as a general effect is fairly well recognised if not understood in detail.

Recommended tests on multiple inverters should be aimed to investigate the effect of combination of the output from multiple units. In particular, the following aspects should be considered:

- can inverters of the same type ‘synchronise’ and directly reinforce the same individual harmonics causing them to exceed limits quicker than anticipated ?
- is there an averaging or ‘filtering’ effect that can take place to ‘reduce’ the expected effect and even smooth and to some extent cancel existing harmonics ?
- are there external harmonic effects from the utilities that could damage the inverter or lead to unsafe operation ?

4. AC-MODULE

4.1 Summary

An AC Module is an integrated combination of a single solar module and a single inverter. The inverter converts the DC energy from the module into AC energy and feeds this energy into the AC network. The main advantage of AC Modules is the modularity. Complicated DC wiring is not required and the solar power is directly available as AC-power.

This modularity allows for very simple systems that can easily be expanded by simply paralleling several AC Modules at the AC side. An AC Module is an electric product and comparable to other appliances. It is expected that AC Modules will become available at the hardware store, and that people will buy and install them without consulting a certified electrical engineer.

This “plug and play “ idea of AC Modules has raised several questions by experts from electrical safety bodies and utilities. Plug and play means that the AC Module is equipped with a standard AC-plug that allows for a direct plug-in to a regular outlet in the electrical installation of a building. Some national and international safety standards do not allow this, other standards are unclear

A survey revealed that only a restricted number of countries are actually developing and/or using AC Module systems. Other countries have no objections to AC Modules but wait for other countries to gain hands-on experience. Nevertheless it is expected that AC Modules will be used World-wide within a few years.

The most important unresolved question is how to connect an AC Module to the network. Manufacturers are, of course, in favour of allowing the AC Modules to be connected to a regular outlet. This allows easy installations and reduces the costs. Safety standards, however, do not always allow this and/or utilities do not like the idea of having generators connected at normal feeders of an electrical installation. There is also a non-technical but realistic aspect to this discussion. When AC Modules become available at the hardware store, people will buy AC Modules. It can be expected that people will not install a separate feeder just for one or two AC Modules, mandatory or not, and will connect the AC Module to a regular outlet.

The Netherlands have issued a pre-draft guideline that AC Modules (or other types of small generators) may be connected to normal feeders if the generated power is below approximately 500 W. This philosophy is also under discussion in Switzerland. However, some countries for example Australia and USA, have strict regulations not to allow AC Modules or other types of small generators to be connected to a regular feeder; a separate feeder is always necessary.

There are two certification standards for AC Modules available in the world. Both these standards provide a set of rules to guarantee the electrical, mechanical safety of an AC Module. The Dutch standard is issued by KEMA, in the USA is issued by Underwriters Laboratories (UL). UL and KEMA are working to harmonise both these standards.

AC Modules have recently been introduced as a commercial product, application can be found in a limited number of countries. It is expected that this number will grow dramatically in the next few years.

Although AC Modules have been available on the market for some years now, there is still a lot of discussion on methods for interconnecting AC-Modules with the network. Is a separate feeder necessary for the connection of an AC Module with the AC-grid, or is the “Dutch-way” an option? Also, the method of interconnection is an important topic; is there a need for an AC-marshalling box or is an AC-cord with (special) plugs an option, and what about the connection to the AC-mains supply, bolted terminals or a separate plug?

When AC-Modules will become as popular as expected, these issues have to be settled. Present day standard should be (better) adopted for AC-Modules.

4.2 Introduction

An AC Module is an integrated combination of a single solar module and a single inverter. The inverter converts the DC energy from the module into an AC energy and feeds this energy into the AC network. The control in the inverter continuously measures the value of the network voltage and frequency and inhibits the inverter if these values are outside of a predetermined window.

The inverter is installed in a weather proof encapsulation and is mounted on the rear side of the module, or on the support structure at a short distance from the module. This is illustrated in figure 1. The AC outlet is connected to the electrical installation of the building.

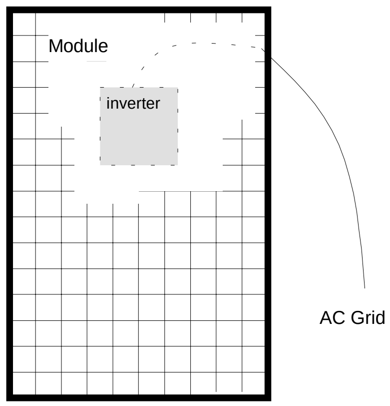

Figure 1 Schematic diagram of an AC Module

The concept of AC Modules actually originates from the early days of development of terrestrial PV modules, but developments of hardware didn’t emerge until the early nineties. Development started mainly in the Netherlands and in Switzerland. AC Modules have been commercially available since 1996. Present-day AC modules have a rated peak power ranging from 100 to 300 Watts. AC Modules with slightly higher power output are expected in the near feature. The main advantages of AC Modules are:

- Modular : An AC Module is an electrical product and is fully assembled in the factory. The electrical connection to the network is very simple by means of a 2-wire connection and in some situations also an equipment ground. (plug or bolted). Additional AC Modules can easily be added to the system and connected in parallel without concerns for module orientation and size.
- No DC cabling : DC cabling and DC marshalling boxes are not required as the dc wire is integrated in the AC Modules, or is a simple point to point wire between the module and the inverter.

- Easy installation : The interconnection of AC Modules is on the AC side. People are very familiar with AC installations and materials are widely available and very cost effective.
- No shading losses : All modules have an inverter with a built in maximum-power-point-tracker. Hence, mismatches due to module differences and shading are eliminated.

4.2.1 Definition of an AC Module:

An AC Module is an electrical product and is the combination of a single module and a single power electronic inverter that converts light into electrical alternating (AC) power when it is connected in parallel to the network. The inverter is mounted on the rear side of the module or is mounted on the support structure and connected to the module with a single point to point DC-cable. Protection functions for the AC side (e.g. voltage and frequency) are integrated in the electronic control of the inverter.

This definition implies that the string-inverter concept cannot be categorised as a (special version) of an AC Module. A string-inverter has DC wiring to connect the modules in a string, and in some situations, also to connect two strings in parallel. The string-inverter concept is therefore an electrical installation comparable to conventional PV systems.

Because of these advantages, it is foreseen that AC Modules will be available at the hardware store and that people will buy and install them without consulting a qualified electrical engineer. AC Modules are the “plug and play” devices of solar power.

This “plug and play “ idea of AC Modules has raised several questions by experts from electrical safety bodies and utilities. Plug and play means that the AC Module is equipped with a standard AC-plug that allows for a direct plug-in to a regular outlet in the electrical installation of a building. Some national and international safety standards do not allow this, other standards are unclear.

4.3 Scope of work

The aim of this study was to survey the status of AC Modules in the participating countries. The following information was required:

1. Status of the development of AC Modules
2. Use of AC Modules
3. Presence of any guidelines and interconnect requirements for AC Modules

4.4 Theoretical results

4.4.1 Results from the survey

A survey under the participation countries revealed following information. The numbering corresponds with the numbered questions above.

Portugal

1. No manufacturers of AC Modules and no ongoing developments.
2. The first application of AC Modules is a multi kilowatt AC Module PV system that will be constructed in co-operation with a Dutch consultancy firm. The system is funded by the EC under a THERMIE grant. The system is planned to be operational in 1998.
3. There are only general guidelines for the connection of distributed power generators to the utility network, and they are primarily intended for rotating machines. A task force is working to update the guidelines so that it also covers other kinds of generators, e.g. wind and PV systems.

Italy

1. No manufacturers of AC Modules and no ongoing developments.
2. There are no installations with AC Modules as present standards do not allow privately owned generators to be connected to the network.
3. The guidelines for dispersed generator units make it impossible to use AC Modules due to the additional costs of the required external switch and separate protection devices. A working group is actively drafting a new guideline. It is expected that this guideline will allow small generator units to be connected to the network.

Germany

1. There are some manufacturers working on the concept of AC Modules. The string inverter concept is however more fouvered more in Germany.
2. There are some installations with AC Modules present.
3. There is no discussion on whether AC Modules may be connected or not, as they are considered identical to conventional PV systems.

Denmark

1. No manufacturers of AC Modules and no ongoing developments.
2. No installation with AC Modules.
3. No special regulations for AC Modules.

Australia

1. One manufacturer recently started developing AC Modules. These AC Modules are expected to be commercially available at the end 1999.
2. Some PV-systems with AC Modules have been installed recently as demonstration projects.
3. AC Modules have to follow the normal guidelines for dispersed generator units. This implies that AC Modules have to be connected to the main fuse box by a separate feeder. AC Modules must be tested before they may be connected to the network.

Switzerland

1. Two manufacturers are developing and selling AC Module inverters.
2. Several systems with AC Modules are in operation, with a total power of approximately 15 kW. At the end of 1997 a 13.5 kW AC Module system was installed to gain more knowledge on AC Module systems.
3. AC Modules have to comply with the standard guidelines for dispersed generator units. There is some discussion to reduce the protection requirements for systems with a rated capacity up to 2 kW. There is also a tendency, comparable to the situation in the Netherlands, to allow AC Modules connected to a regular outlet of the electrical installation, without the use of a separate feeder running from the main fuse box. This discussion is however still in its early stages.

Japan

1. There is no product at the present.

2. Some experimental installations are present.
3. Japan recognised that some adjustments have to be made to the present guidelines.

<u>United Kingdom</u>

1. One manufacturer started developing AC Modules.
2. A few installations are present for experiments.
3. A working group started drafting a guideline for dispersed generator units below 5 kVA. These generators may be single phase connected. The guideline will cover all types of generators connected to the network through inverters.

<u>Austria</u>

1. Currently no manufacturer is developing AC Modules
2. Several test systems with AC Modules are in operation
3. AC Modules have to comply with the standard guidelines for PV systems (ÖVE 2750). Standard islanding protection devices (ENS or three-phase monitoring) have to be applied. Physical disconnection by a relay or the like is mandatory.

<u>The Netherlands</u>

1. Two AC Modules have been commercially available since 1996. Different types are available to cover 50Hz and 60Hz applications as well as 115 and 230 V. Further developments are continuing to optimise the existing AC Module and to develop new products.
2. Many systems with AC Modules are installed. In many of these applications several AC Modules are connected in parallel to form systems with total rated capacities of several hundred watts to multi-kilowatts. The number of installations with AC Modules will increase significantly within the next few years.
3. The “guidelines for dispersed generators” have a special section for inverter connected generators (AC Modules or other types of small generators) below 5 kVA. A limited number of protection devices are required for these generators. In the Netherlands there is a consensus to allow a total of 2.25 A of generator power to be connected to a regular feeder(s) in the electrical installation of a building. This is based on a copper cross section of 2.5mm^2 and a main fuse of 16 A. This allows the “Plug and Play” principle. A special safety standard is issued for the evaluation of the electrical and mechanical safety and EMC-CE directive of an AC Module. AC Modules can be tested at KEMA in Arnhem

<u>United States of America</u>

1. Several developments are under way. The peak power capacity of AC Modules varies between 100 and 300 Watt.
2. Over a hundred AC Module systems are now installed in the USA.
3. As all electrical products AC Modules have to be UL-listed (Underwriters Laboratories) before utilities allow these devices to be connected to the network. UL is preparing a standard to include safety aspects for AC Modules. AC Modules have to be connected by means of a separate and dedicated feeder circuit directly connected to the main service panel. The National Electric Code (NEC) section 690-6 was written to include AC Modules in the 1999 code. An important aspect is the sizing of the conductors in the service entrance and the feeder circuits, as overloading of circuits or parts of circuits is be prohibited under all circumstances.

4.4.2 Conclusions from the survey

From this survey and from discussions held with experts in and outside Task V, it can be concluded that only a restricted number of countries are actually developing and/or using AC

Module systems. Other countries have no objections to AC Modules but wait for other countries to gain hands-on experience. Nevertheless it is expected that AC Modules will be used World-wide within a few years.

The most important unresolved question is how to connect an AC Module to the network. Manufacturers are, of course, in favour of allowing the AC Modules to be connected to a regular outlet. This allows easy installations and reduces the costs. Safety standards, however, do not always allow this and/or utilities do not like the idea of having generators connected at normal feeders of an electrical installation.

The main reasoning is the possible overloading of a part of the electric wiring. This is illustrated in the exhibit in figure 2. In this exhibit the feeder has a 16 A fuse. Assuming that the PV system has a current generating capacity of 5 A, an appliance connected at the end of this feeder can draw 16 + 5 = 21 A of current from this feeder. Since the sizing of the wires will be based on the 16 A fuse (2.5 mm^2), this part of the feeder may be overloaded. The safety standards IEC 364 do not allow this.

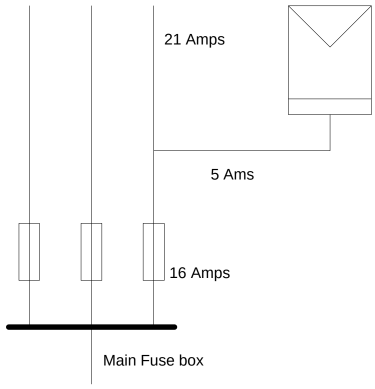

Figure 2 Connection of an AC Module to a normal feeder

Although this situation is not allowed, one can argue that this will not cause any harm if the PV-current is restricted. A fuse or mini-circuit breaker does not disconnect the feeder for currents that are a little above the rated current, as shown in figure 3.

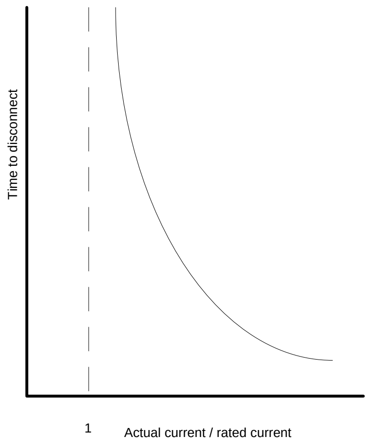

Figure 3 Characteristic fuse

The safety standards have integrated this aspect in the sizing of cables and fuses. For a current that is slightly higher than the rated current the time to disconnect is long. Hence, the wiring must and is capable of carrying this current without overheating. From this it may be concluded that the (thermal) sizing of the wires is adequate to carry some additional current, and use of this safety factor is being considered for AC Modules.

Also the probability of having one load or a combination of loads turned on with a total current above the rated fuse level is very low. Following this interpretation it may be concluded that a restricted amount of generator current may be connected to a normal feeder.

There is also a non-technical but realistic aspect to this discussion. When AC Modules become available at the hardware store, and the price level falls as expected, people will buy AC Modules. It can be expected that people will not install a separate feeder just for one or two AC Modules, mandatory or not, and will connect the AC Module to a regular outlet. The question is how to limit the number of AC Modules they will connect to normal feeders.

Knowing that there is some spare capacity in the wires, and that it is likely that people will plug the AC Module into a regular outlet. In the Netherlands a guideline has been issued allowing AC Modules (or other types of small generators) to be connected to normal feeders. The total sum of generated power must be below 500 Watt. This guidelines states that generator(s) may be connected to normal feeder(s) if the total sum of the current generated by the PV-systems and/or other types of generators is $\leq$2.25 A. This is only allowed if the feeder has a 16 A fuse and wire cross section of 2.5 mm^2. If the sum of the generator current exceeds 2.25 A, then a separate feeders must be installed. This philosophy is also under discussion in Switzerland.

Some countries e.g. Australia and USA, have strict regulations not to allow AC Modules or other types of small generators to be connected to a regular feeder; a separate feeder is always necessary.

4.4.3 Safety standards for AC Modules

There are two certification standards for AC Modules available in the world. Both these standards provide a set of rules to guarantee the electrical, mechanical, harmonics and radio interference of the an AC Module. The Dutch standard is issued by KEMA, in the USA the standard is issued by Underwriters Laboratories (UL). UL and KEMA are working to harmonise both these standards.

The standards define the minimum requirements for:

- Electrical safety (shock)
- Ground and ground connection
- Mechanical construction and materials used
- Electromagnetic interference
- Fire and casualty hazard

A special but very important test is the evaluation of the performance of the islanding protection devices. This protection prevents the injection of electric power in the network, when the network is outside a certain voltage and/or frequency window. This test is extremely important as AC Modules will be used by untrained individuals.

4.5 Experimental results

The number of experimental tests that have been performed on the AC Modules is limited. The experimental installations throughout the world have shown that the AC Module concept meets it's expectations.

Some people have argued that the life-time of the inverters for AC Modules will be too low due to high temperatures. The field experience with the commercially available AC Modules however has shown that the temperature-problem is well controlled. Accelerated temperature ageing tests performed at ECN in the Netherlands have demonstrated this.

When many AC Modules are connected in parallel harmonics may become an issue. The harmonics produced by an inverter may cause a mal-operation of a neighbouring inverter, or the sum of harmonics produced by the paralleled AC Modules may result in an excessive distortion of the network voltage. Experimental results to date are not conclusive. Preliminary results from Rokko island in Japan, showed that harmonics do not add up as a linear function of the number of paralleled inverters. However preliminary results from tests conducted in the UK indicate that for the special case of the same type and manufacture of inverter connected to a common point (i.e. no network impedance) the harmonics can add arithmetically.

4.6 Conclusions

AC Modules have recently been introduced as a commercial product. The number of PV installation with AC Modules in the world is still small, however, many installations can be found in The Netherlands and in the USA. It is expected that this number will grow dramatically in the next few years.

The main unresolved question is the integration of AC Modules with the network. Nearly all countries demand a separate feeder between the AC Module (or other energy source) and the main fuse box. The Netherlands has drafted a pre-standard to allow a maximum of 2.5 A of generator power to be connected at normal feeders and outlets. Switzerland is thinking about a comparable approach.

4.7 Recommendation for future work

Although AC Modules have been available on the market for some years now, there is still a lot of discussion on methods for interconnecting AC-Modules with the network. Is a separate feeder necessary for the connection of an AC Module with the AC-grid, or is the "Dutch-way" an option? Also, the method of interconnection is an important topic; is there a need for an AC-marshalling box or is an AC-cord with (special) plugs an option, and what about the connection to the AC-mains supply, bolted terminals or a separate plug?

When AC-Modules will become as popular as expected, these issues have to be settled. Present day standard should be (better) adopted for AC-Modules

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5. MULTIPLE INVERTERS AND AC GRID

5.1 Summary

As small PV power generation systems become more common, it will be necessary to investigate several effects that are not significant for single inverter systems. For example, if a large number of dispersed PV generators are connected to a branch of the low voltage distribution system, then the reverse power flow to the higher voltage power system will substantially increase during periods of light load and maximum daylight. This may cause a significant voltage rise in the distribution lines, particularly at the ends. Also, the PV systems will supply a part of the fault current in the event of a distribution line fault. This additional fault current will decrease the fault current flowing at the substations and might cause fault detection relays in substations to malfunction. It is thus necessary to identify effects that may occur when connecting large numbers of PV systems, and to establish countermeasures.

The main conclusions of are:
- The voltage at the customer’s terminals may exceed the upper statutory limit because of reverse power flow from PV systems during light-load hours in the daytime. Leading power factor operation of the PV system is an effective countermeasure to prevent the voltage rise without reducing effective power.
- If each customer supplied by a distribution transformer installs PV systems with a capacity equal to or above their contracted power, the reverse current flowing through the transformer could exceed the transformer capacity because of simultaneous power generation change of the PV systems and transformer design concept. It would be necessary to consider replacement of the transformer or installation of an energy storage facility in such situation. If a diversity figure is used such as ADMD for distribution system design purposes, restricting generation to the ADMD could be an effective countermeasure.
- In the event of short-circuit fault condition in the distribution line, the increase in short-circuit capacity of the distribution line and the malfunction of OCRs or fuses in the distribution system may occur as part of short circuit current is supplied from PV systems. It would be necessary
- to develop a new fault detection system for the PV system. A method of detecting the voltage phase change occurring in the fault condition may be one useful option.

The effects anticipated to occur when a large number of PV power generation systems are interconnected with distribution lines were investigated (excluding harmonics and islanding that are covered in other chapters). The theoretical results and experimental result regarding the effects and countermeasures are reported. Recommendations for future work are as follows.
- Development of a new fault detection for PV systems to detect a short-circuit fault occurring at an end of a long distribution line, with a high resistance, or during distribution line overload.
- Further studies on the effect on distribution line voltage variation caused by the wide-spread application of PV power generation, covering different application areas and the number of interconnected systems.
- It would also be important to study and encourage the application of various distribution line support systems which make the best use of the added values offered by PV power generation.

5.2 Introduction

As small PV power generation systems become more common, it will be necessary to investigate several effects that are not significant for single inverter systems. For example, if a large number of dispersed PV generators are connected to a branch of the low voltage distribution system, then the reverse power flow to the higher voltage power system will substantially increase during periods of light load and maximum daylight. This may cause a significant voltage rise in the distribution lines, particularly at the ends. Also, the PV systems will supply a part of the fault current in the event of a distribution line fault. This additional fault current will decrease the fault current flowing at the substations and might cause fault detection relays in substations to maloperate.

It is thus necessary to identify effects that may occur when connecting large numbers of PV systems, and to establish countermeasures.

5.3 Scope of work

This Chapter discusses some of the effects (excluding harmonics and islanding that are covered in other chapters) anticipated to occur when a large number of PV power generation systems are interconnected with distribution lines. According to discussion in Task V expert meeting, the following subjects were mainly taken into account. Namely, those are the effects of voltage variation, reverse power flow, increased short circuit capacity and operation default of OCR or fuse in substation. These principally concern the operation, and protection of the distribution systems. Methods of dealing with these effects and some demonstration tests performed in each country concerning such effects are described. While countermeasures on the PV side are principally discussed, countermeasures enacted by the utility are also described for some effects.

5.4 Theoretical results

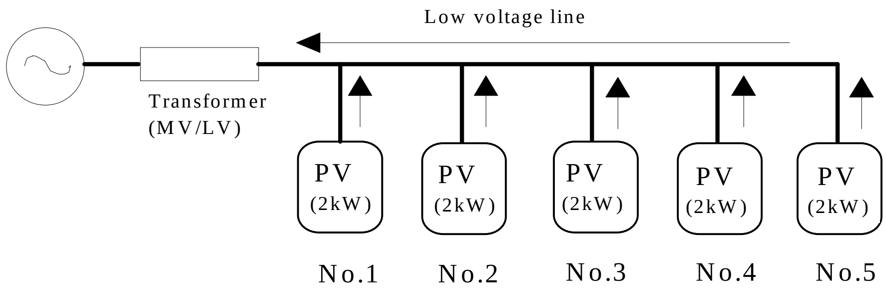
5.4.1 Effects and countermeasures in steady state operation

(1) Voltage variation

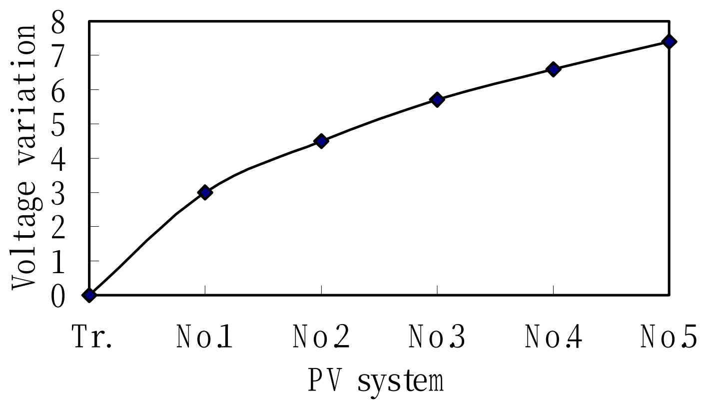
a. Effect

At present, the design and operation of power distribution systems is managed on the assumption that the power flows from the distribution substations to the customer, and that the systems are controlled to maintain the appropriate voltage levels at the customer. When the voltage drop in the distribution line is large, the customers voltage is controlled by adjusting the transformer taps or by installing voltage regulators.

If a large number of PV power generation systems are connected to distribution lines which are controlled in the manner described above, the voltage at the customer’s terminals may increase because of reverse power flow (refer to Fig.1). This increase will depend upon the relative sizes of the load and the power generation. Since the sending voltage on the secondary side of the distribution transformer is typically set at a value higher than the standard voltage under current operating procedures, the voltage at the end of a distribution line could exceed the upper limit even with slight reverse power flow, possibly created by the PV system during light-load hours in the daytime.



(a) State of reverse power flow



An experimental result of voltage rise at customer's terminals
(Each PV system is connected to 100V single phase line)

Figure 1 An experimental result on voltage rise of low voltage line

On distribution lines, the operating voltage at the line ends tends to drop. Voltage regulators may therefore, be installed on the line at mid-point, with the secondary voltage of the regulator set higher than the primary voltage. This voltage ratio is thus automatically changed as the line voltage fluctuates. If a large number of PV systems are interconnected to distribution lines provided with voltage regulators, they may operate frequently because of the voltage changes corresponding to solar irradiance changes. As the result, their service life-time may be shortened.

b. Countermeasure

Two countermeasures are conceivable to deal with a voltage rise due to reverse power flow. One is to operate the PV system at the leading power factor. The other is to limit the effective output of the PV system. Leading power factor operation has the advantage of controlling the voltage without restricting the effective power output of the PV system as shown in Fig.2. However, the effectiveness of this method depends on the ratio of resistance to reactance of the distribution line impedance. If the resistance component of the impedance is very large in comparison to the reactance, a large reactive power is required to maintain the proper voltage value. Attention must be paid to this factor because a large kVA inverter is necessary when the line resistance is large. The power factor of the entire distribution line may also be degraded if every PV system on the line supplies a large reactive power. The typical procedure adopted at present in dealing with this effect is to turn the inverter to leading power factor operation as soon as the upper voltage limit is reached, and then to limit the effective power output of the inverter when the voltage rise cannot be suppressed with the leading reactive power supply within the capability of the inverter.

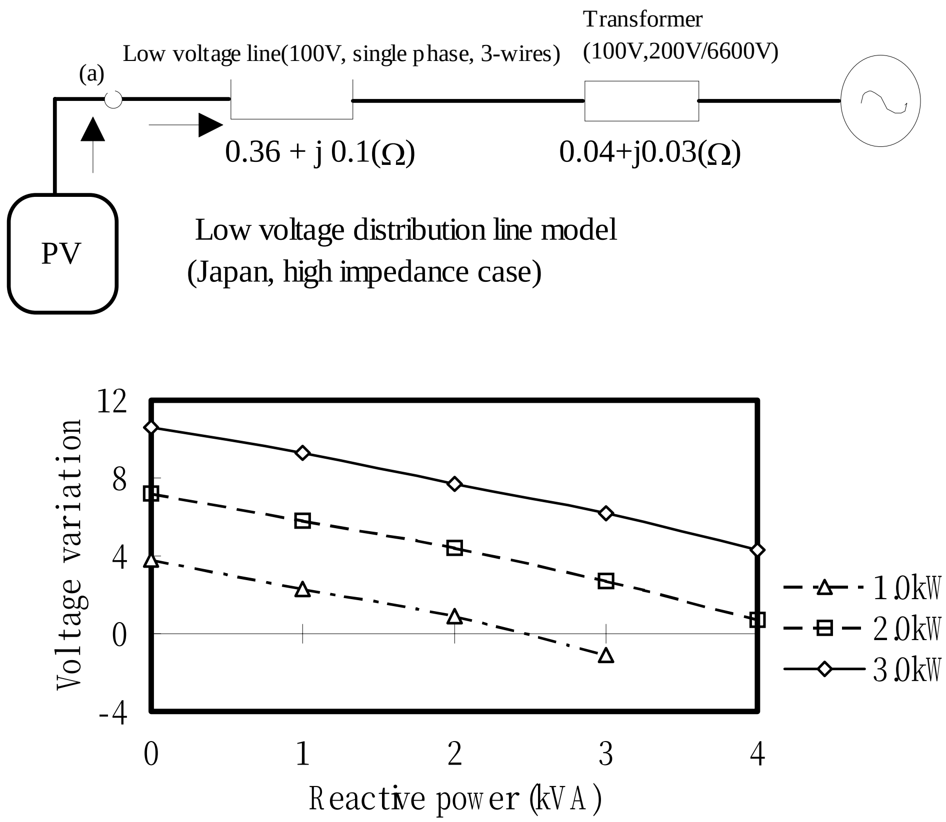


Figure 2 A calculation result on suppression of voltage rise by reactive power control of PV system. Parameter; Real power of PV system

Developing a 'bilateral' voltage regulator able to control voltage under reverse power flow as well as under 'normal' power flow could resolve the effect in managing distribution line voltage with voltage regulators.

(2) Reverse power flow

a. Effect

Usually, a distribution transformer supplies more than one customer. In this case, the maximum power flowing through such a transformer is normally less than the total sum of the contracted power of all those connected to that transformer because the peak power consumed by each customer does not occur simultaneously. For this reason and in view of economy in capital investment, the transformer capacity is selected at a value less than the total sum of the customers contracted power. Information concerning typical transformer capacity and customer's contracted power of residential area in some Task V participating countries are shown in table 1[1].

If each customer supplied by such a distribution transformer installs PV power generation systems with a capacity equal to or above their contracted power, the reverse current flowing through the transformer could exceed the transformer capacity because power generation by PV systems increases simultaneously on all the arrays with the solar irradiance (refer to Fig.3).

Table 1 Information of low voltage distribution line in residential area

Country	Capacity of MV/LV Transformers (kVA)	LV feeder per cabinet	Number of customer per feeder	Contracted power of a customer
Australia	450 - 700	6	-	100 Amp
Italy	400	4, 8	30	3, 5, 6, 10 kW
Japan	30	1	17	3, 5 kW
Portugal	50 - 800	2, 5, 8	100/Tr	3.3, 6.6, 9.9 kVA
UK	500	5, 6	80	1.5 kW (ADMD)

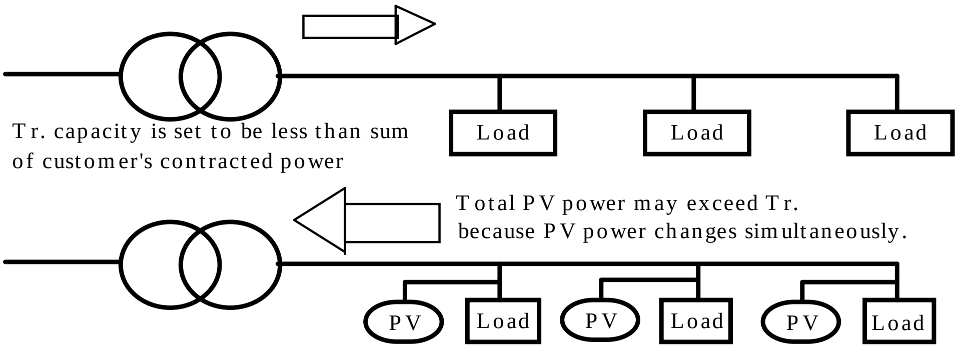


Figure 3 Effect of reverse power flow on transformer capacity

b. Countermeasure

If the reverse power passing the transformer exceeds the rated capacity, it must be replaced with a larger capacity transformer or additional transformers must be installed. Alternatively, an energy storage facility with a relatively small capacity could be installed to average the output variation, or to shift PV generation to peak load hours. However, these measures may be considered impractical on financial grounds, and the simple measure of limiting the amount of generation allowed by each customer would meet the same objective. For distribution system design purposes a diversity figure is used, 'after diversity maximum demand' or 'ADMD'. For housing with central heating which is not electrical, a typical ADMD is 1.5 kW and the number of consumers connected to a transformer is (transformer kVA/ADMD). If consumers were restricted to generating their ADMD, times a factor reflecting the total number of consumers likely to have PV systems, then both the transformer overload and voltage rise effect would be solved.

5.4.2 Effects and countermeasures in distribution line extreme conditions

(1) Increased short circuit capacity

a. Effect

When a short-circuit fault occurs on a distribution line, the short circuit current is restricted to 1.1 to 1.5 times the rated current. This is because the short-circuit current supplied by each PV array is some 1.2 times the rated current, and each inverter system has an over-current limiting function. It is therefore deemed that if the number of interconnected PV systems remains small, their effect on the distribution line would be negligible. However, if the number is increased, the short-circuit capacity of the distribution system may also be increased and the fault current during short-circuit become more substantial. If the value of short-circuit current exceeds the rupturing capacity of the over-current circuit breakers installed at the customers end, they may become incapable of clearing faults at the customers premises.

b. Countermeasure

PV power generation systems may be capable of detecting a short-circuit fault if equipped with an OCR and UVR, during most cases of a short-circuit fault occurring on distribution lines or at customers premises. However, voltage drop on distribution lines may be reduced when a short-circuit fault occurs at the end of a long distribution line, or a short-circuit fault occurs with a high resistance. In this case, the PV systems protective relays would be unable to detect such faults. The method of fault detection under such conditions must be studied further separately. For example distribution line voltage, phase changes abruptly and in steps as shown in Fig.4. It may be possible to sense this phase change to effectively detect faults which cannot be detected by an OCR or UVR[2].

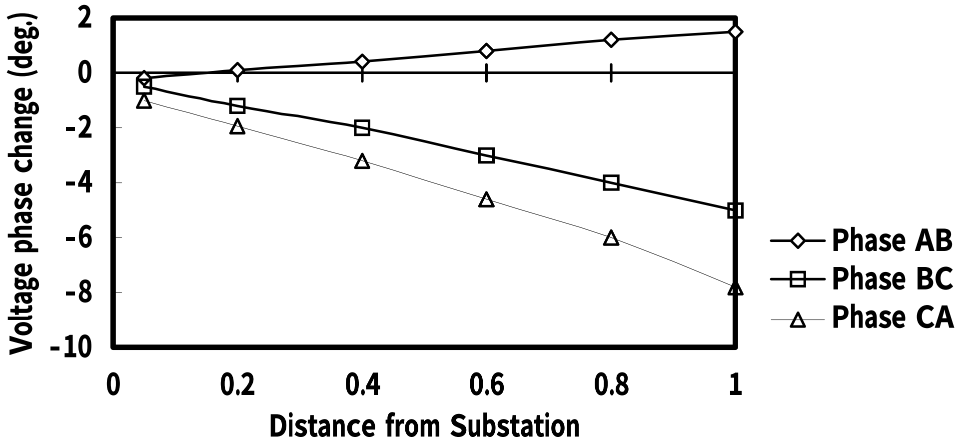


Figure 4 A calculation result on voltage phase change in case of short circuit fault with high resistance - 2 phase fault on MV(=6.6kV) line of Japan - Fault point ; end of line(3.8km from substation)

(2) Operation default of OCR in substation

a. Effect

All distribution lines are protected by OCR or fuse in the event of short circuit fault on the lines[1]. The PV power generation system may be unable to detect a fault by itself when a short-circuit fault occurs at the end of a long distribution line with a high resistance, or a distribution line overload occurs. If a large number of PV systems are interconnected to distribution lines and they are unable to detect a fault, the PV systems supply a part of the fault current or overload current to substantially reduce the fault current flowing through the substation as shown in Fig.5. This phenomena causes the OCR or fuse in the substation to default in its operation. However, in some countries the lv fault level is such that even at saturation levels of PV generation, the current contribution from the PV systems would be much less than that from the utility system. i.e. with a fault current from a 500kVA substation in the range 15,000-5,000A, and a contribution from say 500kW PV at around 1,000A, operation of a typical fuse protection would not be significantly affected.

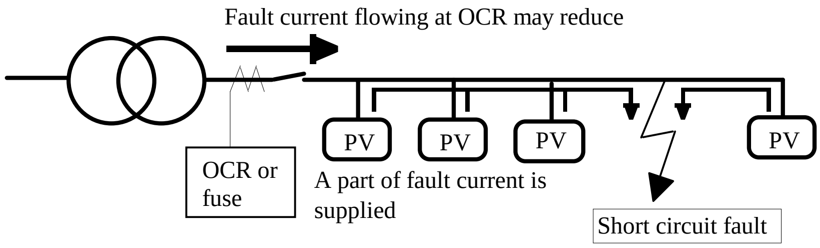


Figure 5 Fault current flow under short circuit fault of distribution line

b. Countermeasure

The countermeasures to be applied to PV power generation systems are the same as those presented in (1)-b. Substation OCR settings may be checked and revised depending on the actual situation.

5.5 Experimental results

5.5.1 Rokko Test Center

(1) Voltage variation test

It was confirmed that the speed of output change corresponding to the change of solar irradiance is relatively slow even when a large number of PV systems are interconnected and dispersed over a wide area. However, the gross magnitude of the change increases in proportion to the number of PV systems involved, a factor which increases the distribution line voltage variation[3]. According to experiences with Japanese distribution lines, the magnitude of the voltage variation increases with the number of PV systems involved, particularly with low voltage distribution lines, and the proper voltage range may be exceeded if no countermeasures are provided.

(2) Instantaneous voltage drop test

A maximum 40% drop with a 0.2 second duration was created on a distribution line and the operating performance of each PV power generation system in the grid interconnection operation was observed. Systems provided with a instantaneous current control on the inverter continued stable operation without generating over-current. The effectiveness of such an arrangement was therefore established. It was also demonstrated that systems not provided with this function (voltage control type) generated over-current and operation was interrupted by the OCR. As for reference, the same results have been obtained in a test of grid reclosing during islanding[4] .

(3) Distribution line short circuit fault test

The following facts were revealed by a short circuit test on a MV(=6.6 kV) distribution line:

The PV power generation system normally detects faults by its UVR. Under certain fault conditions where short-circuits were generated through high resistance, the voltage drop on the distribution line was minimal, and each system continued operation without detecting the fault by itself. This indicated that there were cases where the fault current passing through substations was reduced and the substation OCR defaulted [5]. As a countermeasure, a detection scheme which monitors the voltage phase change on the distribution line at the occurrence of a short-circuit fault was tested. It was verified that faults can be effectively detected except in some cases where the fault point was in the proximity of the substation.

5.5.2 CRIEPI Akagi testing centre

The voltage rise suppression method employing leading power factor operation was verified. The tests indicated that the kVA capacity of an inverter required to suppress the voltage rise by this scheme alone may amount to 1.8 times the real power output in the worst situation.

5.5.3 Gardner project

In the PV power generation demonstration project in Gardener City, implemented by New England Electric (USA), PV systems were installed on the roofs of 30 customers at dispersed locations. These were interconnected by real distribution lines to examine the distribution voltage variation caused by changes of solar irradiance. The test showed that the output variation of the entire setup, consisting of dispersed PV systems interconnected by distribution lines, was averaged, thereby reducing the rate of output change to almost 3% per second, although in extreme cases the voltage of an individual system may be reduced to 10% per second [6]. This led to the conclusion that voltage variation can be sufficiently compensated by voltage regulators installed on distribution lines with the stable operation of the distribution system remaining unimpaired. The test report comments that the tap change operations were performed so frequently that the service life-time and other factors of the voltage regulator may be adversely affected.

5.5.4 PV experimental programme of UMIST

Load flow studies have been performed for an example UK distribution system, to assess the impact of different levels of PV generation and load on the system voltage and flow profiles. It has been found that the level of PV penetration may be voltage limited, if no change is made to the current voltage control practice. Two scenarios were investigated: (i) the adjustment of the transformer turns ratio making use of the new European voltage standards and (ii) use of reactive power sinks to control the maximum voltage in the network.

(I) By setting the transformer turns ratio to +2.5%(1100+2.5%)/433 to reduce the voltage at the low voltage side, the effect of voltage rise at the end of the low voltage feeders was likely to be solved. It was observed that in this case, instead of the voltage being the limiting factor for the amount of PV generation that can be accommodated, the thermal rating of the transformer determines the level of penetration. Furthermore, it has been shown that this off-nominal turns ratio will not cause any voltage drop related problems under heavy load conditions. Again, thermal constraints are found to be the limiting factor, rather than the allowable voltage fluctuations.

(ii) Reactive sinks have been placed at critical locations in the network to control the voltage rise caused by the PV penetration. It was found that relatively large sinks would be required to maintain the voltage at the expense of increased real power losses. It should be remembered that the transformer taps were initially set for optimum operation of the distribution system and that they can usually only be changed by connections within the transformer. The Utility may be reluctant to make these changes.

5.6 Conclusions

The effects anticipated to occur when a large number of PV power generation systems are interconnected with distribution lines were investigated (excluding harmonics and islanding that are covered in other chapters). The theoretical results and experimental result regarding the effects and countermeasures are reported.

The voltage at the customer's terminals may exceed the upper statutory limit because of reverse power flow from PV systems during light-load hours in the daytime especially. Leading power factor operation of the PV system is an effective countermeasure to prevent the voltage rise without reducing effective power.

If each customer supplied by a distribution transformer installs PV systems with a capacity equal to or above their contracted power, the reverse current flowing the transformer could exceed the transformer capacity because of simultaneous power generation change of the PV systems and transformer design concept. It would be necessary to consider replacement of the transformer or installation of energy storage facility in such situation. If a diversity figure is used such as ADMD for distribution design purpose, restriction to generating the ADMD could be an effective countermeasure.

In the event of short-circuit fault condition in the distribution line, increase in short-circuit capacity of the distribution line and operation default of OCR or fuse in the distribution system may be occurred by supplying a part of short circuit current from PV systems. It would be necessary to develop a new fault detection system to be provided on the PV system side. A method of detecting the voltage phase change occurring in the fault may be one useful option.

5.7 Recommendation for future work

Regarding 5.3.2, it is possible that faults cannot be detected by the PV power generation system itself, when a short-circuit fault occurs at an end of a long distribution line, with a high resistance, or during distribution line overload. It would therefore be necessary to develop a new fault detection system to be provided on the PV system side.

The studies on the effect on distribution line voltage variation by the wide-spread application of PV power generation, discussed in Section 5.4.3, are on an example of a distribution line. It is, therefore, necessary to conduct further studies on cases of various application modes by changing the application area and the number of interconnected systems.

The studies of 5.4.4 could be expanded to include models of different countries distribution networks to check the validity of the results for these other situations.

It would also be important to study and encourage the application of various distribution line support systems which make the best use of the added values offered by the PV power generation system. For example, a reactive power control system for each inverter which is operated at the lagging power factor during heavy load to compensate for the voltage drop of the distribution lines.

5.8 References

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- Y. Takeda et al.,”Test and Study of Utility Interface and Control Problems for Residential PV Systems in Rokko Island 200kW Test Facility”,20th IEEE PVSC(1988), pp.1062-1067
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6. GROUNDING OF EQUIPMENT IN PV SYSTEMS

6.1 Summary

When rules for early power generation and electrical distribution systems were being developed in the late 1890 to early 1900's, grounding requirements were limited to lightning protection. In the United States, the National Electrical Code (NEC) and it's grounding requirements was first published in 1897. Most other countries throughout the world, often independently, developed other versions of electrical codes to address safety and grounding issues for electrical generation and distribution systems. The resulting grounding techniques and requirements vary from country to country. Optimised grounding for personnel protection does not optimise fire safety of a system and grounding for fire safety does not optimise personnel safety. Grounding to provide protection for equipment would require a third set of requirements. Photovoltaic (PV) systems, as distributed current sources, require additional grounding considerations. Distributed leakage paths, multiple fault paths and new roles for fuses and circuit breakers are among a few of the new issues that need careful consideration for PV applications. Codes for PV have closely followed the national practice for AC power systems in each country, but many PV codes are being developed as separate documents, rather than being included into existing codes. Grounding of batteries associated with PV power sources adds another consideration when grounding the PV array.

System and equipment grounding practices and requirements vary widely with applications, among the countries, and sometimes within individual countries and a survey of participating IEA countries revealed requirements and practices. Codes in the USA require equipment grounding of all systems, and system grounding for systems with voltages over 50 volts (open circuit module voltage). European and Japanese codes require equipment grounding, but do not require system grounding and most of their PV systems do not have grounded current-carrying conductors on the DC side.

The grounding of power systems is complicated by the introduction of current-limited PV sources interconnected with batteries and conventional voltage-source electromechanical generators. Two universal conclusions for grounding were: a) most codes and standards generally require equipment grounds for all metal surfaces that might become energised, b) when system grounds are used, single-point grounds are required. The ungrounded system provides the best fire hazard reduction because multiple ground faults are needed to create a fire hazard. Ungrounded systems allow easy ground fault detection and simple PV array disable.

The grounded PV system generally provides the best personnel protection from electrical shock because the voltages to ground are well defined. The system grounding ensures a solid or known PV array ground through properly sized conductors. The distributed capacitance to ground, of the PV modules and wiring, does not build static charges and the system voltage is stable and known in the grounded PV system. With proper design, both grounded and ungrounded PV systems can achieve good personnel, fire and equipment safety.

6.2 Introduction

When rules for early power generation and electrical distribution systems were being developed in the late 1890 to early 1900's, grounding issues were the subject of many hot debates. The requirements were not agreed upon at that time, and the end result has been substantially different grounding requirements and codes in the different countries throughout the world. In the United States, the National Electrical Code (NEC) was first published in 1897. Most countries throughout the world, often independently, developed other versions of electrical codes to address installation, safety and grounding issues for electrical generation and distribution.

Grounding techniques and requirements, like language, vary from region to region and from country to country. Optimised grounding for personnel protection does not optimise fire safety of a system and grounding for fire safety does not optimise personnel safety. Grounding to provide protection for equipment would sometimes require a third set of requirements. Photovoltaic (PV) systems, as distributed current sources, require different grounding considerations than conventional voltage sources. Distributed leakage paths, multiple fault paths and new roles for fuses and circuit breakers are among a few of the new issues that need careful consideration for PV applications.

The very first grounding requirement in the first NEC was a mandatory earth or ground requirement for lightning protection. The first grounding debate began a few years later when it was suggested that the secondary distribution circuit of ac utility grids be grounded. It was immediately argued that grounding secondary circuits carrying hazardous voltages increased the probability of shocks. Counter-arguments cited the added safety features that limited the maximum voltage imparted on the secondary distribution, should a primary line fall on or cross with the secondary line. The discussions and arguments have continued and international standards have never been written. The PV industry, with its large surface area, possible leakage and distributed wiring integrated into a power source, is now poised to further complicate the issue of grounding electrical systems throughout the world.

PV codes and PV system grounding requirements have followed applicable codes for electrical power systems. In the USA, Article 690 was added to the (NEC) in 1984 for PV systems, but NEC grounding practices were used in PV systems before 1984. European codes for PV have also followed the national practice of each individual country for ac power systems, but the PV codes are being developed as separate documents rather than being included into existing codes. Grounding of batteries, especially in high voltage systems that are associated with PV power sources adds yet another dimension to grounding the PV array.

PV power systems range in size from a single module, typically a 12-V, 30-50W, system through multi-kilowatt systems sometimes including storage batteries, to multi-megawatt systems, operating at thousands of volts and connected to a utility grid. System and equipment grounding practices and requirements vary widely with applications, among the countries, and sometimes within individual countries. Codes in the USA require equipment grounding of all systems, and system grounding for systems with voltages over 50 volts (open circuit module voltage). European and Japanese codes require equipment grounding, but do not require system grounding and most of their PV systems do not have grounded current-carrying conductors on the dc side.

Subtask 20 of the International Energy Agency Implementing Agreement for a Co-operative Programme on Photovoltaic Power Systems (PVPS) has embarked on a project to identify subjects and issues associated with photovoltaic (PV) systems that still need further research. Grounding of Equipment was considered a Priority 1 topic. This chapter will present and analyse the grounding issues associated with PV power systems. The purpose of grounding for surge protection, ground fault issues, personnel safety and fire safety will be addressed. This chapter will closely parallel chapter 7 that addresses Ground-Fault Detection for PV power systems.

6.3 Scope of Work

This chapter will illustrate the characteristics of grounded and ungrounded PV power systems and discuss the advantages and disadvantages for each. The grounding methods and configurations as used in various IEA countries will be illustrated. The advantages for grounding or not grounding will be addressed. This chapter will focus on three general categories associated with grounding. Those categories are:

- Safety (Fire and Personnel)
- Equipment (Performance and Design)
- Lightning and Surge Protection

The grounding methods and requirements will be illustrated and compared. Grounding issues will be discussed with respect to system performance, electromagnetic interference and over voltage protection". Particular attention will be given to determining optimal grounding locations, wiring practices, grounding methods, and array grounding in PV systems. Grounding methodologies for lightning and EMI protection will be described as will general practices and guidelines for installing grounding conductors and ties to earth.

6.3.1 Background

PV power systems range in size from a typical single module, 12-V, 30 to 50-W, system through kilowatt systems sometimes using storage batteries, to multi-megawatt systems, operating at thousands of volts and connected to a utility grid. System and equipment grounding practices and requirements vary widely with applications, among the countries, and sometimes within a country. Codes throughout the world require equipment grounding of systems generally above a specified voltage and for most stationary applications. The installation codes and standards in the USA and several other countries require system grounding for systems with voltages over 50 volts (open circuit module voltage) [DE1][IT1][JP1][US1][US2][US3][UK1]. European and Japanese codes require equipment grounding, but do not require systems grounding and most of their PV systems do not have grounded current-carrying conductors on the dc side[DE1][IT1][JP1][UK1]. In the UK, the majority of new domestic electrical supplies provided by the Regional Electricity Companies (REC) are of the Protective Multiple Earthing or PME type where the supply cables have a combined neutral and earth (CNE) metallic outer sheath but residences are supplies separate neutral and earth conductors as described later in this chapter [UK1].

6.3.2 General

Grounding or "earthing" various metal parts and conductors of an electrical system is required to minimise electrical shock hazards, minimise fire hazards associated with ground faults, minimise damage to equipment from faults and induced surges, and to reduce the incidence of electromagnetic interference [B5][B7][B13][B14]. System grounds, when used, generally provide the ground paths using the intended current-carrying conductors, whereas equipment grounds provide the ground paths for the metallic surfaces that may be unintentionally energised [B8]. Equipment grounds ensure that those surfaces remain at or near ground potential.

Systems are solidly grounded, when system grounds are used, with single-point grounds to limit the magnitude of the voltage to ground during normal operation and to reduce induced voltages due to lightning, switching transients, or line surges [B8]. Grounding of electrical systems can provide a stabilisation of the system voltage during switching and surges, and also provides the necessary path to trip protection devices if there is unintentional contact with higher voltage lines.

6.4 Theoretical results

This work in this task included a review of experience, of hardware, of standards, codes, guidelines and practices, and of available publications. Reviews and theoretical results from the various grounding methods will be presented. The data also includes the results of the survey of Task 5 experts on grounding and performance of PV systems in participating countries. The spreadsheet showing country responses to the survey may be found in Appendix 6.

The results of the survey completed by Task V experts and pertinent literature on grounding provided data and information on the following topics:

I. Inverters and Charge Controllers
   A. Grounding Provisions and Practices
   B. Neutral-and Grounding Provisions
   C. Bonding Provisions
   D. Conductive and Non-conductive Equipment Cabinets

II. Building Integrated PV Hardware
   A. Grounding Requirements
   B. Multiple Source Grounding and Bonding
   C. Structure Materials Compatibility to ensure grounding integrity

III. Array Disable Requirements
IV. DC and AC System Hardware Grounding Requirements
V. Transient and Surge Suppression Grounding Requirements

Terminology Used, Utility Concerns, a Glossary of Grounding Terms, and part of the Bibliography as reported in this chapter were also derived from the survey.

An important consideration for grounding PV systems is to determine the compatibility of the PV system ground with the interconnected utility. The utility grounds often dictate special requirements for the PV system. A good example of where grounding methods used by the utility present challenges for PV systems is the Protective Multiple Earthing (PME) used in the UK. There, the majority of new domestic electrical supplies provided by the Regional Electricity Companies are of the Protective Multiple Earthing or PME type. These supply cables have a Combined Neutral and Earth (CNE) metallic outer sheath which is known as the Protective Earth Neutral conductor or PEN conductor. This conductor or sheath is earthed at various or multiple points along the suppliers distribution network.

Separate earth and neutral terminals are provided by the electricity supplier within the customers premises. All incoming services and extraneous metalwork is bonded to the earth terminal to guard against differential potentials existing between exposed metallic parts during a fault. In this configuration the metalwork bond provides a low impedance path for faults between a live conductor and any apparatus framework ensuring rapid disconnection of the faulty equipment by the overcurrent protection.

Generally, the PME is not allowed to be used outside of the equipotential zone due the possibility that a fault could raise the potential of the earth or remote structure relative to the PME thus exposing a person to differential potentials within touch zones. Thus in the UK, exposed metalwork outside of the building's equipotential zone must be earthed separately using a local earth spike or rod and not be connected to the PME system.

Exceptions to this are where equipment such as PV modules and inverters are mounted directly on, or within touching distance of the existing buildings exposed metallic parts; then that equipment may well have to be connected to the buildings earth in order to limit touch potentials. Alternatively, some older premises may have a Separate Neutral Earth system or SNE connection from the electricity supplier, which requires conventional earthing arrangements. Building integrated PV is often mounted outside of or on the building's roof. PV shingles are part of the building but facades and awnings may be add-ons at a later time. Additionally AC PV modules may be building additions that may or may not be attached to the building but will be wire to the building ac power at the distribution panel.

6.4.1 The purpose of grounding

The general purpose of grounding is for grounding or "earthing" various metal parts and conductors of an electrical system is an approach to minimise electrical shock hazards, minimise fire hazards associated with faults, minimise damage to equipment from faults and induced surges, and reduce the incidence of electromagnetic interference. System grounds, when used, provide the grounding paths using the intended current-carrying conductors, whereas equipment grounds that are used in all countries provide the grounding paths for the metallic surfaces that may be unintentionally energised. Equipment grounds ensure that those surfaces remain at or near ground or earth potential.

Systems are solidly grounded with single-point grounds to limit the magnitude of the system voltage to ground during normal operation and to reduce induced voltages due to lightning, switching transients, or line surges. Grounding of electrical systems provides a stabilisation of the system voltage during surges, and also provides the needed path to trip protection devices if there is unintentional contact with higher voltage lines.

6.4.2 PV System considerations

Installed PV systems rarely perform exactly in the manner indicated by electrical schematics. Stray inductance, capacitance and resistance abound and are distributed throughout the system. Leakage currents associated with the array, wiring, surge protection and conduit often make ground-fault detection difficult. Improperly selected or improperly installed cables, diodes, PV modules, and other components have failed in PV systems. The leakage currents associated with all of the system elements pose unseen and unfamiliar hazards to personnel, and may contribute to fault currents.

PV systems are frequently connected to other sources of power or energy storage such as batteries, standby generators, hydro-generators and the utility grid. The grounding of the PV system must be consistent with the grounding used on the connected power system. Including a battery storage system in a PV application adds additional battery-related considerations including corrosion of connections, leakage paths caused by condensed acidic gasses, spillage of electrolyte and conduction along normally insulated surfaces, and very high dc fault currents from the batteries when the fault is low resistance.

The interface between the interconnected power systems often may allow unanticipated currents to flow in the PV system. These ground-fault conditions must be accounted for in all aspects of the design of the PV grounding system. Utility-interconnected PV systems are often installed in close proximity to utility power lines and accidental cross connection is a possibility that must be addressed especially when sizing grounding components.

There has been at least one documented electrical shock case related to PV systems in the USA, and there has been several fires associated with faults to grounding conductors resulting in substantial damage [B10]. Grounding practices were followed in all cases but the uniqueness of the PV energy source contributed to conditions that allowed personnel and fire dangers to exacerbated.

6.4.3 PV System grounding configurations

General: In this chapter, grounding is defined as connecting a conductor or equipment to earth or ground potential with a solid, low-resistance, and low impedance conductor. The grounding conductor must be sized to carry the same fault current that any other conductor in the system is sized to carry. System grounding with single-point grounding, and equipment grounding with solid, low impedance bonding of multiple grounds, provides an equipotential ground for surge protection and minimises circulating ground currents that can lead to corrosion and ground-fault detection problems. The grounding configurations for PV systems may differ significantly. Figure 1 shows a PV system with single-point system and equipment grounding.

Ungrounded: A floating (Ungrounded) or double-insulated grounding system (Class II insulation) has none of the current-carrying conductors grounded, and exposed metal conducting surfaces are effectively double-insulated from the current-carrying conductors. Exposed metal conducting surfaces are grounded using an equipment ground system.

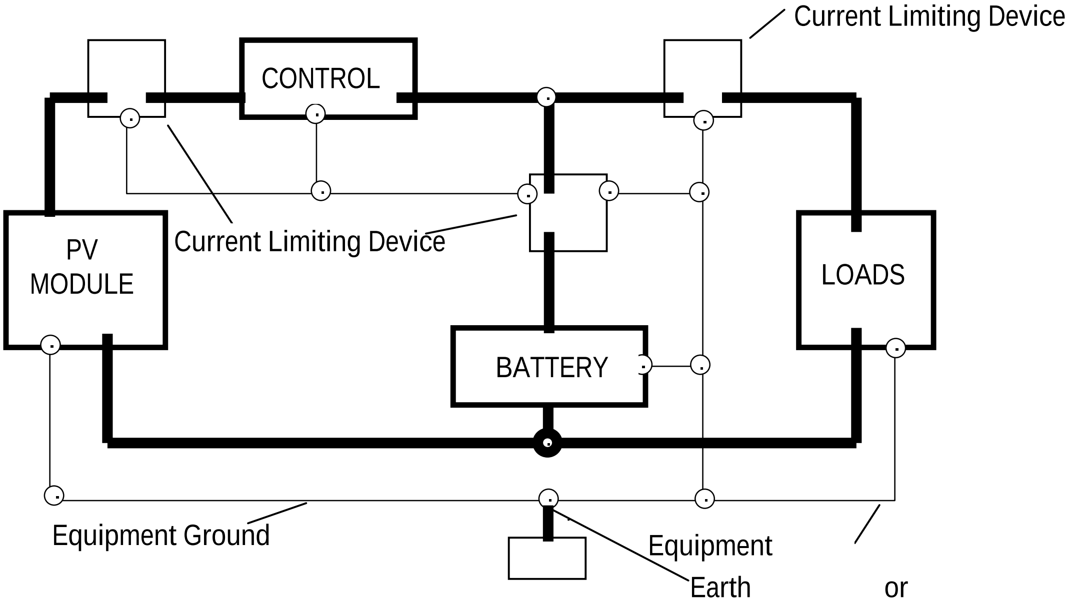

Figure 2. PV System with Equipment Grounding Only

Figure 2 shows a PV system that does not us a system ground. Exposed metal cases, conduit, frames, and battery structures , however are bonded and grounded in this type of system.

6.4.4 Ground faults in PV systems

General: Ground-fault currents are defined as currents flowing in other than the normally designated current-carrying conductors. The magnitude of ground-fault current depends on the impedance of the fault path and the potential difference across the fault. Ground faults are typically localised and not distributed since they are normally caused by damaged insulation, PV module breakage, localised corrosion or fallen objects that strike and damage insulation in the system. Ground fault currents may pose fire and electrical shock hazards. Leakage currents are fault currents that are small in magnitude, distributed throughout the PV array and system components, and are generally associated with high voltages (>100V). The leakage currents in an ungrounded PV system is generally due to a distributed high-resistance-ground connection, but can accumulate to allow sufficient ground-fault current to injure unsuspecting personnel (the second ground path) who treat the system as ungrounded.

PV modules can develop leakage currents as they age, especially in wet conditions. The leakage comes from internal module current paths to the outside frame or surface of the module through the edge seal or through other deteriorated insulating membranes. Ground faults can evolve from continuous leakage when carbon or metal is released or deposited by the leakage current. Module junction boxes can accumulate moisture, either from condensation or rain, and this water, coupled with airborne debris or corrosion products, creates leakage paths within a junction box. Leakage currents also occur as the insulation on conductors ages or becomes damaged due to abrasion [B12].

Insulation failures between current-carrying conductors of opposite polarity cause bolted (line-to-line) faults. The current flow into bolted faults can be from PV modules in the faulted circuit, from modules connected in parallel with the faulted circuit, or from external sources such as batteries or inverters. Blocking diodes have failed on many occasions in PV installations and have allowed multiple PV strings to contribute to ground fault currents. Some inverters, even under normal operating conditions, can feed ac utility currents into faults in the PV array wiring.

Insulation failures between current-carrying conductors and ground are known as ground faults. Ground faults can develop within the PV array, in circuits that have electrically combined the array or in switches and inverters. Ground-fault detectors must be used to sense ground faults in both grounded and ungrounded PV systems. The ground-fault detectors used in ungrounded systems should be more sensitive to protect personnel, than for grounded systems. The practical limit for ground-fault sensitivity is limited by wet-weather leakage currents. More than one ampere of leakage current has been measured in a 300-kW system in the USA. Single-point system grounds are used to minimise circulating ground currents that may interfere with sensing and operation of ground-fault detectors. Equipment grounds are used in ungrounded systems to protect personnel from coming in contact with unintentionally energised conducting surfaces. The equipment ground is an integral part of the PV system protection whether or not the electrical system is grounded.

Ungrounded: On ungrounded systems, a single ground fault will not cause fault currents, but a second ground fault in a conductor of a different voltage, will allow fault currents that circulate through circuits associated with the two faults. PV array modules and conductor capacitance to ground can contribute significant shock hazards in the form of a capacitive discharge on ungrounded systems. Resistance grounding can eliminate the charge on these distributed capacitances.

Grounded: On systems that are grounded (system and equipment), faults involving the ungrounded conductor generally do not trip overcurrent devices. The ground fault must be detected with a ground-fault detector that then also disables the PV array. Distributed capacitiances are a lesser problem because they are already ground referenced and act in parallel with the grounded current sources.

6.4.5 Personnel safety

General: The requirement for the safety of users and maintainers of electrical power systems has been a basic impetus for the study and application of grounding for electrical power systems. Much of the research on electrical shock has been derived from actual studies on human volunteers and animals [B6][B16].

Research has defined the term let-go current as the current level, either ac or dc, where the subject in contact with the electrical circuit experiences involuntary muscle contractions to the point where he or she in unable to disengage from the circuit. The effects of currents through the human body are a function of the applied voltage, the resistance of the body, and the path through the body. Although varying greatly, the average body resistance is assumed to be about 1000 ohms. Biological and situation variations can cause this value to vary over a ten-to-one range. While the let-go level may not be fatal, higher levels of current can cause the heart to go into a rapid, useless beating rate called ventricular fibrillation, which if not corrected, results in death [B6][B16]. It has been found recently that long-term effects of electrical shock can be life-threatening.

The values of let-go and ventricular fibrillation currents have been found to be higher for dc currents than for ac currents. Men are less susceptible to these currents than are women. DC let-go currents are in the range of 90 mA for men and 60 mA for women. Ventricular fibrillation currents are between 500 and 1300 mA for men and women [B16].

Ungrounded: It is commonly thought that a floated, ungrounded, electrical system is safer to work on and service than is a system where one of the current-carrying conductors is grounded [B3][B4]. With an ideal ungrounded system, contact between one of the current-conductors and ground cannot result in a current path. This is true only of theoretically ideal systems with no leakage and no capacitance to ground. However, the average PV system may have one of many leakage paths to ground and has distributed capacitance between modules, wiring, and ground.

With resistive leakage paths to ground, accidental contact with the conductors of the supposedly ungrounded system results in a closed circuit for shock currents. Even with no leakage to ground, the ungrounded system, with its distributed capacitance to ground, can impose a shock experience during the capacitive discharge that can cause involuntary muscle contractions that result in other injuries.

Leakage paths and capacitance in ungrounded systems results in a voltage reference to ground and leakage currents to ground. The Class II systems proposed in parts of Europe will minimise these factors by ensuring a more ideal ungrounded system. If the Class II guidelines and hardware are not used in ungrounded systems, both conductors can have voltages that are theoretically higher than the normal operating system voltage. For example, a 300-V system would typically have balanced line voltages that are approximately 150 volts to ground. If one conductor develops a leakage to ground, the second conductor may have 300-V to ground. Additionally, static charge may build up in an ungrounded system and the resulting conductor voltage to ground may be greater than the operating voltage of the system. Unintentional contact with high-voltage system conductors from other sources will result in system voltage levels much higher than the design values in the ungrounded system.

Grounded: In a grounded system, where one current-carrying conductor is grounded, or the system is centre-tap grounded, the system voltage is stable, and the highest voltage appearing on the ungrounded conductors, except when large surge currents are induced into the circuits, is the normal system operating voltage. During nearby lightning strikes, the conductor voltages may rise to a clamped voltage determined by the surge protection devices for a short time during the surge pulse.

With grounded systems using grounded equipment enclosures, there is a greater possibility of service personnel completing a fault path when working within the enclosure. The grounded system presents energised conductors in close proximity with substantial amounts of grounded, exposed metal in the enclosures. Non-conductive enclosures minimise this problem.

6.4.6 Fire safety

General: The fault currents supplied by a PV array are determined and limited by the array size, the incident irradiation and the circuit impedance. A properly designed system uses cables and overcurrent devices sized to carry the highest short-circuit current in each protected circuit. The current limited PV source normally will not supply enough current to open protection devices on ground faults. In cases where more current has been supplied from a second source or PV string, the blocking diodes had failed. Other sources of current that may cause the fuses or circuit breakers in PV circuits to open or trip include inverters connected to the utility grid or batteries [B10][B11][B12]. Even bolted faults (line-to-line) in PV array conductors may create arcs that will burn insulation at current levels that will not trip an overcurrent device. Multiple ground faults in grounded or ungrounded systems result in circulating currents that may not be detected, but can result in loss of power and create fire hazards.

Ungrounded: Ungrounded systems offer clear advantages for avoiding fire hazards. The ungrounded system must develop two ground faults before a ground-fault fire hazard exists. Ground-fault detectors are also easier to install on ungrounded systems. They can detect the first ground fault and disable the system before dangerous multiple ground faults develop. The ungrounded system may also continue operating with a single ground fault while a warning may alert operators that the ground fault exists and should be repaired as soon as possible. Disabling an ungrounded system can easily be achieved by short-circuiting or open-circuiting the array. Excessive leakage to ground may cause ground-fault detection sensitivity problems in the ungrounded system.

Grounded: A single ground fault to ground results in circulating ground current whenever the PV array is illuminated in a grounded system. This is a dc current and can result in corrosion of dissimilar metal connections, and if sufficiently high, can impose fire hazards. Grounded systems can be very difficult to disable because of the division of current. Short circuiting a faulted array will not guarantee the ground fault current will be eliminated or even reduced to safe levels.

Open-circuiting the PV array with a ground fault may increase the available energy to the fault. The disabling circuit for a PV array usually includes many meters of wire, various terminals, disconnect devices, fuses or circuit breakers, and blocking diodes between the ground fault and the disabling device. The current division between the ground fault resistance and the array disable circuit can approach a value that allows current to flow through the ground fault with enough power dissipated to cause a fire. The ground fault current, voltage, and power can actually increase unless the ground fault current is interrupted by ungrounding the system. If all of the conductors are open circuited, the ground fault path is opened when only one fault exists. The ungrounded array then can be disabled by short-circuiting or open-circuiting. New changes in the NEC in the US will allow ungrounding the PV source circuit so long as labelling and an indication of the ungrounding is used.

6.4.7 Surge suppression

Surge suppression devices may be added to any of the PV system grounding configurations. The application of these devices is, to some extent, separate from the grounding system. Suppression devices are used to control surges induced by nearby lightning strikes, or by other inductively or capacitively coupled surges that might be introduced to the system. Surge suppression devices on ungrounded systems are connected between each of the current-carrying conductors for line-to-line (differential mode) suppression. They are connected between each current-carrying conductor and earth for line-to-ground (common mode) suppression. In grounded systems, surge protection should be closely linked to the single point system ground. For ungrounded systems, a failed or shorted surge suppression device provides a possible path for unintended ground connections. Surge suppression methods used for PV systems connected to a PME grounding system in the UK must consider all possible points of differential potential and protect accordingly.

6.4.8 General guidelines for installing grounding

Properly designed and installed (system-grounded or ungrounded) PV systems can protect personnel from electrical shock hazards and minimise equipment damage caused by voltage transients. System-grounded installations provide for one or more of the following:

1. A potential reference for the PV electrical system.
2. AC Overcurrent protection device operation on ground faults.
3. Instrumentation or communication signal reference.
4. Ground-referenced surge protection.

There are several types of ground mechanisms that may be used with PV systems. They may be used for equipment grounds and for most system grounds and are:

1. A single vertical rod driven into the ground to a specified depth.
2. Buried horizontal rods or wire that may be used where bedrock is just below the surface.
3. Multiple ground rods bonded together in a straight or circular configuration.
4. Ground Mats typically used in utility substation design.
5. Ufer (Named after Mr. Ufer) grounds using imbedded conductors in the concrete footing or floor of a building. It should be noted that Ufer grounds have minimum requirements for placement and length of imbedded conductors. There have been cases where Ufer grounds have created enough heat from lightning induced currents to generate steam within the concrete and to cause the concrete to disintegrate near the conductors.
6. Conductive water pipes or well casings.

Table 1 Typical Resistivities of Soils

Type of Soil	Resistivity in Ohm-Meters
Loam and garden soils	5 - 50
Clay	25 - 70
Sandy Clay	40 - 300
Wet Concrete	50 - 100
Peat, Marsh or Cultivated	50 - 250
Sand	1000 - 3000
Glacier Rock	300 - 10,000
Dry Concrete	2000 - 10,000

Earthing or obtaining a good ground resistance for a PV system is difficult in some locations. Table 1 lists the typical resistance of earth materials. Each of these values are altered significantly by the amount of water present and the chemicals or salts that may be present. The ground resistance should be as low as possible (<5 ohms) with suggested maximum values below 5 ohms. One method to reduce ground resistance on mountain-top installations where granite or other rock is the only reference to ground is to sense an oncoming electrical storm and spray the rock with a water solution to help reduce the resistance during the storm.

Some important points to consider when establishing grounding designs are:

1. The grounding resistance will increase with age so start with low resistance.

2. Seasonal fluctuations occur due to ground water content and temperature and top soil may have a resistivity of $>10^7$ ohm-m with zero water content and 64 ohm-m with just 30% water content by weight.
3. Use compatible non-reactive materials and use the same material throughout. If the material cannot be the same throughout, use approved connecting devices for the materials being tied together.
4. Design the ground systems to use support structures but insure electrical continuity is maintained.
5. Inspect at regular intervals.

Other important considerations in the design of a ground for PV systems are to keep the ac and high frequency impedance of the ground system as low as possible. The low ac and high-frequency impedance allows the suppression devices to effectively protect the remainder of the circuit components by eliminating voltage drops between the source of the disturbance and the surge suppressing element. The rules for grounding for EMI or EMP protection are similar to the rules for surge suppression and have been confirmed through experiments. They are:

1. Reduce inductance by using flat conductors as the grounding conductors. Generally a flat conductor will use less copper and will have less inductance than an equivalent round conductor.
2. Reduce the number of bends in the conductor to a minimum the keep the radius of bends as large as possible.
3. Keep paths as short as possible
4. Keep loops between the grounding conductors and the ac and dc active circuits to a minimum. Run grounding conductors as close to the active conductors as possible.
5. Size the grounding conductor to carry worst-case currents.
6. Grounding conductors that must be routed through conduit must bond to the conduit where it enters and exits the conduit.
7. Grounding conductors must not penetrate any conductive material wall. The magnetic fields around the conductor carrying a large surge current will created eddy current in the wall which will increase the inductance of the conductor.
8. All metal connections should be made to bare, clean material with no water, grease, or oxidation on the surfaces.
9. Exothermic connections are always better than compression bonds.
10. Compression bonds should use a joint compound suitable for the metals being joined.
11. Bond all ground electrodes. This includes ac ground, dc ground, communication system, surge protection so that there is essentially one earth electrode.
12. If a Ufer ground is being used, it is generally not intended to be the only ground in the system and is intended to augment an in-the-ground system.
13. Power lines, telephone lines, coax lines, and external generator lines all must have protection devises for surge protection.
14. Once a ground system is installed, the earth resistance should be measured with an appropriate earth resistance meter. Remember these meters operate at low frequencies and do not measure the high-frequency impedance that determines the reaction of the system to surges and lightning induced pulses.

6.5 Experimental results

Although much of the information needed on grounding of PV systems is already available from systems experiences and from common engineering practices, additional information needs to be obtained to determine quantitative safety values for voltage, current and power levels that may occur in PV systems under various grounding or ungrounded configurations.

These values need to be determined to assure both personnel safety and to assure ground fault conditions are not capable of starting fires before ground faults are detected and the system disabled.

There are three ways to stop the power supplied by a PV array. They are to short-circuit the array, open circuit the array or block the source of light to the array. When the array is shorted, the voltage approaches zero hence the power delivered is near zero. When the array is open-circuited, the output current goes to zero, again resulting in no power produced.

Tests have been conducted to determine the results of simulated ground faults. Tests to show current division values between active circuit conductors or components and paths created by ground faults in grounded systems have shown that ground-fault currents continue to flow even when the PV array is crow-barred at the inverter. The value of the ground-fault current, at the fault, is a function to the ratio of the fault resistance and the combined resistance of the wiring, connections, switches, fuses and the crow bar. Keeping the system resistance as low as economically practical will assure the power dissipated in ground faults is minimised. As the system resistance increases, the power dissipated by the ground fault increases as the operating point on the PV array moves toward the maximum-power-point.

Open-circuiting a grounded array exacerbates the ground-fault power dissipation in a grounded system because voltage increases and the available current increases. The worst case situation is when the ground-fault resistance is the same as the array impedance at the maximum power point of the PV array.

When PV systems are ungrounded, the occurrence of a fault to ground does not result in ground-fault current. When a second ground fault occurs, however, there is no simple method to reduce the ground-fault current to zero just as in the grounded array situation.

Simulated electrical transients caused by lightning on ungrounded arrays have also been conducted by personnel at KEMA in the Netherlands and reported in papers [B5][B7].

6.5.1 Overview and comparison of grounded and ungrounded systems

The following table gives an overview and comparison of the relative performance, personnel safety and fire safety of properly grounded (system ground) and ungrounded PV systems.

	Solid Ground	Resistance Ground	Ungrounded
General			
System Ground	Use a single-point ground. The system ground is a path for the current from lightning strikes. The high currents result in potential difference along the grounded conductor.	Use a single-point ground. The system ground is a path for lightning strikes. The resulting potential difference is across the resistance but allows the grounded conductor potential to rise above ground potential.	No tie to equipment ground. Caution advised with potential ground caused by shorted or resistive surge protection tied to ground.

	Solid Ground	Resistance Ground	Ungrounded
System Performance	No effect on performance. Grounding and operational compatibility of components critical.	No effect on performance. Grounding and operational compatibility of components critical.	No effect on performance but system may operate with a single ground fault. Compatibility of components related only to voltages and current levels.
Surge Protection	Both common mode and differential mode easily implemented.	Both common mode and differential mode easily implemented.	Both common mode and differential mode easily implemented.
System Voltage	Most stable even in the event of surges and induced transients from nearby lightning.	Stable except in the event of surges and induced transients from nearby lightning.	Unstable with respect to ground. PV array leakage may result in imbalance of line voltage.
Battery Applications	Grounding of batteries in high voltage applications results in leakage currents to ground and possible high-current faults resulting in battery and/or system destruction.	Grounding of batteries in high voltage applications results in multiple paths and leakage currents to ground due to conductive acids and salts on surfaces.	Most compatible configuration for use with batteries.
EMI	Best Immunity to external EMI. Filtering relatively easy for emanated conduced EMI.	Somewhat Immune to external EMI.	Least immune to EMI and difficult to control common mode EMI.
Personnel Safety			
Shock Hazard from Unknown Conditions	Best, since system ground is established, generally low impedance and designed for the system.	Good, since system ground is established and known, but high resistance may allow high voltage on normally grounded conductors.	Good because there is no reference to ground in the ideal system. Problems arise when leakage paths develop and unexpected grounds are established. Class II systems proposed by Germany add another degree of safety.
Shock Hazard of Unfaulted system during normal operation.	Severe Hazard! Ungrounded lines have reference to ground. Equipment grounds on metal containers are a current path.	Moderate Hazard! Ungrounded lines have reference to ground but current is limited. Equipment grounds on metal containers are a current path.	Minimal! System conductors have no reference to ground. A ground fault may provide that reference and must be detected. Leakage may cause shock hazard.
Fire Safety			
Fire Hazard of Unfaulted system during normal operation	Minimal, however a single ground fault is difficult to stop without disconnecting the system ground.	Minimal, and a single ground fault is current limited. Disconnecting the system ground generally not necessary to control ground-fault currents.	Best system for fire safety. A single ground fault results in no current.

6.6 Conclusions

The grounding of systems is complicated by the introduction of current-limited PV systems interconnected with batteries and conventional voltage-source electromechanical generators. There still is no international agreement for grounding PV systems and there is little likelihood of agreement. The USA requires system grounding of all electrical systems with voltages greater than 50 volts. Many other countries allow ungrounded PV systems. Two universal rules for grounding are: a) most codes and standards generally require equipment grounds for all metal surfaces that might become energised, b) when system grounds are used, single-point grounds are required.

The ungrounded system provides the best fire hazard reduction because multiple ground faults are needed to create a fire hazard. The ungrounded system could also be the best protection for preventing human shock if the system were ideal, with **no** leakage. Ungrounded systems allow easy ground fault detection and simple array disable. The proposed Class II European systems operating at voltages below 120 volts will increase fire and personnel safety in PV systems.

The grounded PV system generally provides the best personnel protection from electrical shock because the voltages to ground are well defined. Since PV systems inherently have leakage to ground they are not solidly grounded or ungrounded. The system grounding ensures a solid or known PV array ground through properly sized conductors. The distributed capacitance to ground, of the PV modules and wiring, does not build static charges and the system voltage is stable and known in the grounded PV system. With proper design, both grounded and ungrounded PV systems can achieve personnel, fire and equipment safety.

Experience substantiation, hardware capabilities, standards appropriateness, listing guidelines and practices for PV system installations were analysed. The results of simulated ground faults, simulated transients and lightning, and measured performance for the selected grounding methods are reported.

6.7 Recommendations for future work

Future studies for grounding requirements for new concepts such as the AC PV module or new PV building integrated array systems will be required as building-integrated PV systems evolve.

6.8 Glossary

1. **Array Disable:** To reduce the output power of the PV array to zero. Technically always possible by blocking incoming light. Voltage and power may be reduced to near zero by short-circuiting the array. Conversely, the current and power may be reduced to near zero by open-circuiting the array.
2. **Bonded or Bonding** Permanently joining of metallic parts to form an electrically conductive path that will assure electrical continuity and the capacity to conduct safely any current likely to be imposed.
3. **Earthed** Connected to earth or to some conducting body that serves in place of earth. Also grounded.

4. Equipment Ground	The grounding circuit not intended to be part of the active circuits and associated with the metallic chassis, conduit, junction boxes, fixtures, apparatus, PV module frames or supporting structure and intended to keep those conductive components at ground potential.
5. Equipment Grounding Conductor	The conductor used to connect the noncurrent-carrying metal parts of equipment, raceways, and other enclosures to the system grounded conductor, the grounding electrode conductor, or both, at the service equipment or at the source of a separately derived system.
6. Fault	Unintentional connections within or between circuits. Faults may occur between active parts of the circuit or between the active circuit and ground. The connection may be relatively high impedance as with leakage currents or nearly a short as with insulation failures on conductors.
7. Ground Rod	A rod driven into the earth and intended to provide a low electrical impedance to earth. This rod is normally constructed of steel with a copper cladding of sufficient thickness to protect the steel. Note that ground rods may become sacrificial electrodes with dc currents if the wrong materials are used.
8. Grounded	Connected to earth or to some conducting body that serves in place of the earth.
9. Grounded Effectively	Intentionally connected to earth through a ground connection or connections of sufficiently low impedance and having sufficient current-carrying capacity to prevent the build-up of voltages that may result in undue hazards to connected equipment or to persons.
10. Grounded Conductor	A system or circuit conductor that is intentionally grounded.
11. Grounding Electrode	The electrode (ground rod, water pipe and the like) used to tie the grounding system to earth or effective earth.
12. Grounding Electrode Conductor	The conductor used to connect the grounding electrode to the equipment grounding conductor, to the grounded conductor, or to both, of the circuit at the service equipment or at the source of a separately derived system.
13. Grounding Electrode System	Two or more grounding electrodes that are effectively bonded together.
14. Grounding Conductor	A conductor used to connect equipment or the grounded circuit of a wiring system to a grounding electrode or electrodes.
15. Hard Ground	A ground connection intended to provide a low impedance to the tie to earth.
16. MOV	Metal Oxide Varistor device used for transient suppression either line to line or line to ground.
17. Neutral	The conductor or circuit generally associated with the grounded conductor when a system ground is used.

18. Resistance Ground	A grounding connection that intentionally uses a resistor in series with the grounded circuit.
19. Separately Derived System	A premises wiring system whose power is derived from a battery, a solar photovoltaic system, or from a generator, transformer, or converter windings, and that has no direct electrical connection, including a solidly connected grounded conductor to circuit conductors originating in another system.
20. Point of System Ground	Ideally a single point to which all system ground connections are tied.
21. Ungrounded System	Systems where no active circuit elements are tied to ground.
22. System Voltage	For grounded circuits, the maximum voltage between any two conductors. For a grounded system the maximum operating voltage. For ungrounded circuits, the greatest voltage between the given conductor and any other conductor of the circuit.

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7. GROUND-FAULT DETECTION AND ARRAY DISABLE FOR PV SYSTEMS

7.1 Summary

Installed PV systems rarely perform exactly in the manner indicated by electrical schematics. Accumulative leakage currents associated with the large PV array, long runs of wiring, surge protection, diodes, junction boxes that collect moisture, and conduit often make actual ground-fault detection difficult. Leakage currents in early PV systems were often sufficient to cause false indications of ground faults and contributed to many hours of system down time. The leakage currents associated with all of the distributed PV source components and wiring also pose unseen and unfamiliar hazards to personnel, or may contribute to ground faults that increase fire danger and personnel hazards.

Fault currents may occur between active conductors in the circuit called line-to-line or bolted faults, and active circuit conductors-to-ground called ground faults. Utility-interconnected PV systems are often installed in close proximity to utility power lines and accidental cross connection is a possibility that must be addressed. Unintentional connections or faults may result in insulation failures and line-to-line (bolted) faults or line-to-ground (ground) faults. The ground-fault protection of the PV system must be consistent with the ground-fault protection used on the connected AC power system. The AC circuit ground-fault protection requirements are generally part of electrical system installation codes for the application.

A review of PV system experiences and requirements related to ground faults for grid-tied applications was included as part of a survey of participating IEA countries. The survey included hardware compatibility reviews and ground-fault detection requirements as well as detection methods and disable methods. New developments such as the rapidly evolving AC PV module will not require the use of ground-fault detection on the PV-side DC circuits, since the DC voltage is self-contained within the module and inverter, and there is no external access to the DC circuits. Additionally, the tests associated with listing or certifying the self-contained AC PV modules will assure both fire and personnel safety. . It is very unlikely that any conditions will require DC ground-fault detection in AC PV module applications.

The evolution of building-integrated PV systems using DC wiring circuits, PV source circuit combiners and inverters will require ground-fault detection and PV array disable devices for fire and personnel safety. Issues such as backfeeding that may result from inadvertent four-quadrant operation of an inverter, transformer insulation breakdowns or internal circuit failures must be addressed for building-integrated systems

Comparisons of the fire and personnel safety of the grounded and ungrounded PV systems along with considerable research, showed the advantages and disadvantages of each with respect to ground-fault detection. Users and operators must be aware of the grounding methods used and the ground-fault detection and array disable methods. The work included comparisons of PV array ground-fault detection requirements and array disable experience, along with hardware, standards, listing guidelines and practices used for PV system installations. The results of simulated ground faults, simulated transients and lightning, and measured performance for the selected grounding methods are reported and referenced.

7.2 Introduction

Installed PV systems rarely perform exactly in the manner indicated by electrical schematics. Stray inductance, capacitance and resistance abound and are distributed throughout the PV system. Accumulative leakage currents associated with the extensive PV array, long runs of wiring, surge protection, diodes, junction boxes that collect moisture, and conduit often make ground-fault detection difficult. Leakage currents in early PV systems were sufficient to cause false indications of ground faults and contributed to many hours of system down time. The leakage currents associated with all of the distributed PV source components and wiring also pose unseen and unfamiliar hazards to personnel, or may contribute to ground faults that increase fire danger and personnel hazards.

The interface between interconnected power systems may allow unanticipated currents to flow in the PV system. These fault conditions must be accounted for in the design of the PV grounding system. Fault currents may occur between active conductors in the circuit called line-to-line or bolted faults, and active circuit conductors-to-ground called ground faults. Utility-interconnected PV systems are often installed in close proximity to utility power lines and accidental cross connection is a possibility that must be addressed. Unintentional connections or faults may result in insulation failures and line-to-line (bolted) faults or line-to-ground (ground) faults. Equipment and system grounding generally helps protect end-users and service personnel who may be exposed to unexpected shock and fire hazards.

Grid-interactive PV systems are often connected to other sources of power and sometimes to energy storage. Other devices and generators commonly connected to PV systems include batteries, standby generators, and the utility grid. The ground-fault protection of the PV system must be consistent with the ground-fault protection used on the connected power system. The ac circuit ground-fault protection requirements are generally part of electrical system installation codes for the application. This chapter will focus on the dc ground-fault detection and array disable methods associated with PV systems. The unique current source characteristics of the PV source will be addressed.

Subtask 20 of the International Energy Agency Implementing Agreement for a Co-operative Programme on Photovoltaic Power Systems (PVPS) has embarked on a project to identify topics and issues associated with PV systems for further research. Ground-fault detection in PV systems was considered a Priority 2 topic. This chapter parallels Chapter 6 that addresses “Grounding of Equipment.”

7.3 Scope of work

This chapter will provide examples ground faults and help the reader to determine and define reasons for using a ground-fault detector and array-disable methods in PV systems. The need for ground-fault detectors on dwellings to reduce fire danger is discussed. The relaxed requirements for ground-fault detection for AC PV modules will also be addressed.

There is no attempt to provide specific ground-fault detection levels because of the wide range of system ratings, different methods for grounding, applications of ungrounded PV arrays, requirements that vary with roof mounted-systems on dwellings and ground-mounted systems that are only accessible to qualified personnel. Local codes, standards and requirements must be considered when designing a PV system installation.

7.4 Theoretical results

7.4.1 General

This chapter includes a review of standards, codes, guidelines and practices, and a review of available publications for ground-fault detection. Limited tests were conducted to determine relative magnitudes of the currents associated with simulated ground faults with varying impedances in PV systems. The effectiveness of selected PV array disable methods was also studied.

A review of PV system experience and requirements related to ground faults for grid-tied applications are included as part of the survey results attached to this report as part of Chapter 6. The survey review included a hardware compatibility review and ground-fault detection requirements as well as detection methods and disable methods.

New developments such as the rapidly evolving AC PV module will not require the use of ground-fault detection on the PV-side dc circuits since the dc voltage is self-contained within the module and inverter and there is no external access to the dc circuits. Backfeed from other energy sources into a dc-side ground fault of AC PV module is eliminated with proper circuit design and internal protection. Additionally, the tests associated with listing or certifying a self-contained AC PV modules will assure both fire and personnel safety.

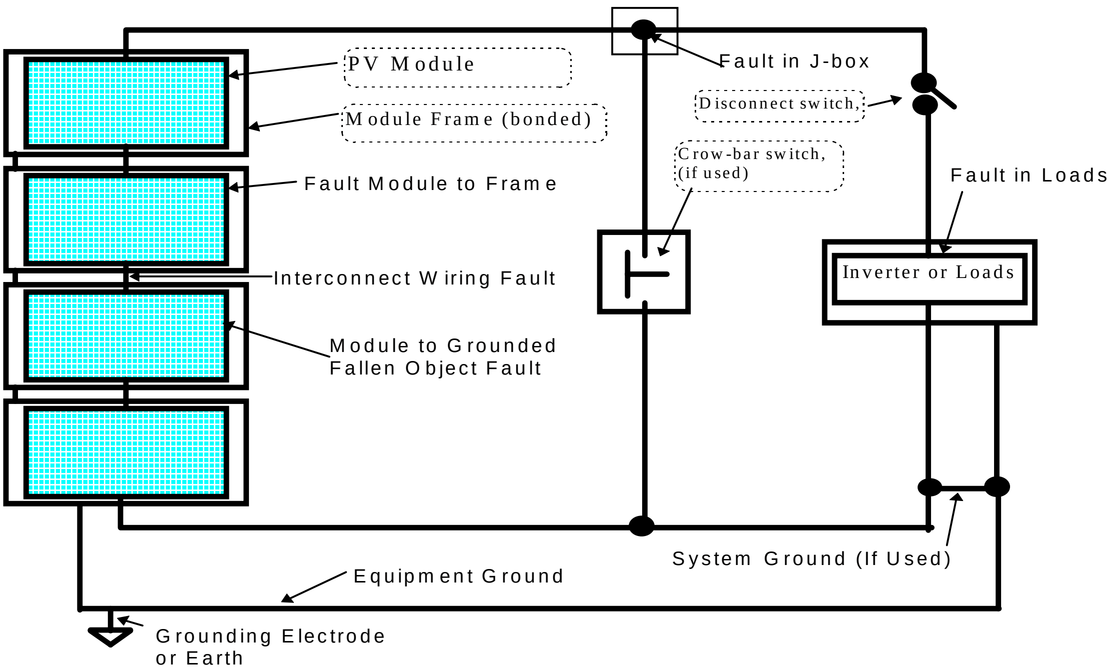

Figure 1 Typical PV system showing locations of possible ground faults.

The evolution of building-integrated PV systems using dc wiring circuits, PV source circuit combiners and inverters will certainly require ground-fault detection and PV circuit disable devices for fire and personnel safety. Issues such as backfeeding that may result from inadvertent four-quadrant operation of an inverter, transformer insulation breakdowns or internal circuit failures must be addressed for building-integrated systems. The probability of backfeed conditions coinciding with ground faults in PV modules must be addressed for conventional systems where conductors and circuits associated with the dc PV array are exposed and are susceptible to unexpected failures. It is very unlikely that any conditions will require dc ground-fault detection in AC PV module applications. Figure 1 shows a typical PV system showing possible locations of dc ground faults in a conventional PV system with dc loads or with an inverter tied to loads or to a utility grid

7.4.2 The purpose of ground-fault detection

Ground-fault detection in PV systems must be considered for both the dc PV array side of the system and the ac or dc load side of the system. Since the PV array is located on the surface of a building or outside of a building, it should be considered a wet location and ground-fault detection and circuit interruption is generally required. Ground-fault detection on the dc side of very small, stand-alone lighting or low voltage dc system is generally not necessary. Once the size of the PV array becomes large enough to cause a fire, or if there are other energy sources or storage connected, then the need for ground-fault detection becomes apparent. Ground-fault protection applies to fire prevention and safety of personnel. All PV systems with voltages greater than 50 V should be considered for ground-fault protection. If either the dc or ac voltage rises above 100 V, ground-fault detection becomes a necessity for personnel protection in wet locations. If the PV system is larger than 50 W and is placed on a dwelling, ground-fault detection on the PV circuits is necessary as a fire prevention measure.

7.4.3 Ground faults in PV systems

General: Ground-fault currents are defined as currents flowing in other than the normally designated current-carrying conductors. The magnitude of ground-fault currents depends on the impedance of the fault path and the potential difference across the fault. Ground faults are typically localised and not distributed since they are normally caused by damaged insulation, PV module breakage, localised corrosion or fallen objects that strike and damage the system. Ground-fault currents may pose fire and electrical shock hazards. Leakage currents are fault currents that are small in magnitude, distributed throughout the PV array and system components, and are generally, but not always associated with high voltages (>100V). The leakage currents in an ungrounded PV system are generally due to a distributed high-resistance-ground connection, but can accumulate to allow sufficient ground-fault current to injure unsuspecting personnel (the second ground path) who treat the system as ungrounded or to allow sufficient ground fault current to be a fire danger.

Most PV modules can develop leakage currents as they age, or are damaged, especially in wet conditions. The leakage comes from internal module current paths to the outside frame or surface of the module through the edge seal or through other deteriorated insulating membranes. Ground faults can evolve from continuous leakage when carbon or metal is released or deposited by the leakage current. Module junction boxes can and have been found to accumulate moisture, either from condensation or rain. This moisture, coupled with airborne debris or corrosion products, creates leakage paths within a junction box. Leakage currents also occur as the insulation on conductors ages or becomes damaged due to abrasion [6].

Insulation failures between current-carrying conductors of opposite polarity cause bolted (line-to-line) faults. The current flow into bolted faults can be from PV modules in the faulted circuit, from modules connected in parallel with the faulted circuit or from external sources such as batteries or inverters. Ground faults within the PV array field may be exacerbated when blocking diodes are absent or shorted. Blocking diodes have failed on many occasions in PV installations and those failures have allowed multiple PV strings to contribute to ground-fault currents. Some inverters, even under normal operating conditions, can feed ac utility currents into ground faults in the PV array wiring.

Insulation failures between current-carrying conductors and ground are known as ground faults. Ground faults can develop within the PV array, in circuits that have electrically combined the array or in switches and inverters as shown in Figure 1. Ground-fault detectors must be used to sense ground faults in both grounded and ungrounded PV systems. The ground-fault detectors for ungrounded systems should be more sensitive to protect personnel, than for grounded systems. The practical limit for ground-fault sensitivity is limited by wet-weather leakage currents. More than one ampere of leakage current has been measured in a 300-kW system in the USA. Single-point system grounds are used to minimise circulating ground currents that may interfere with sensing and operation of ground-fault detectors. Equipment grounds are used in ungrounded systems to protect personnel from coming in contact with unintentionally energised conducting surfaces. The equipment ground is an integral part of the PV system protection whether or not the electrical system is grounded.

Ungrounded: On ungrounded systems, a single ground fault will not cause fault currents, but a second ground fault in a conductor of a different voltage will allow fault currents that circulate through circuits associated with the two ground faults. Leakage paths to ground in the ungrounded system also allow limited ground-fault current to flow when a single ground fault occurs. PV array modules and conductor capacitance to ground can contribute significant shock hazards in the form of a capacitive discharge on ungrounded systems. Resistance grounding can eliminate the charge on these distributed capacitances.

Grounded: On systems that are grounded (system and equipment), ground faults involving the ungrounded conductor generally do not trip overcurrent devices but may be responsible for fires. The ground fault must be detected with a ground-fault detector that then also disables the PV array. Distributed capacitiances are a lesser problem in these systems because they are already ground referenced and act in parallel with the grounded current sources.

7.4.4 Ground-fault detection for personnel safety

General: The requirement for the safety of users and maintainers of electrical power systems has been a basic impetus for the study and application of grounding for electrical power systems. Much of the research on electrical shock has been derived from actual studies on human volunteers and animals [4][6].

Research has defined the term let-go current as the current level, either ac or dc, where the subject in contact with the electrical circuit experiences involuntary muscle contractions to the point where he or she in unable to disengage from the circuit. The effects of currents through the human body are a function of the applied voltage, the resistance of the body, and the path through the body. Although varying greatly, the average body resistance is assumed to be about 1000 ohms. Biological and situation variations can cause this value to vary over a ten-to-one range. While the let-go level may not be fatal, higher levels of current can cause the heart to go into a rapid, useless beating rate called ventricular fibrillation, which if not corrected, results in death [4][7]. It has been found recently that long-term effects of electrical shock also can be life-threatening.

The values of let-go and ventricular fibrillation currents have been found to be higher for dc currents than for ac currents. Men are usually less susceptible to these currents than are women. DC let-go currents are typically in the range of 90 mA for men and 60 mA for women. Ventricular fibrillation currents are between 500 and 1300 mA for both men and women [7].

Ungrounded: It is commonly thought that a floated, ungrounded, electrical system is safer to work on and service than is a system where one of the current-carrying conductors is grounded [2][3]. The ideal ungrounded system is safest for personnel since contact between one of the current-conductors and ground cannot result in a current path. This is only true of ideal systems with no leakage and no capacitance to ground! However, the average PV system may have one or many leakage paths to ground and also has distributed capacitance between modules, wiring, and ground.

With resistive leakage paths to ground, accidental contact with the conductors of the supposedly ungrounded system results in a closed circuit for shock currents. Even with no leakage to ground, the ungrounded system, with its distributed capacitance to ground, can impose a shock experience during the capacitive discharge that can cause involuntary muscle contractions that result in other injuries.

Leakage paths and capacitance in ungrounded systems results in a voltage reference to ground and leakage currents to ground. The Class II systems proposed in parts of Europe will minimise these factors by ensuring a more ideal ungrounded system. If the Class II guidelines and hardware are not used in ungrounded systems, both conductors can have voltages that are theoretically higher than the normal operating system voltage. For example, a 300-V system would typically have balanced line voltages that are approximately 150 volts to ground. If one conductor develops a leakage to ground, the second conductor may have 300-V to ground. Additionally, static charge may build up in an ungrounded system and the resulting conductor voltage to ground may be greater than the operating voltage of the system. Unintentional contact with high-voltage system conductors from other power sources will result in system voltage levels much higher than the design values in the ungrounded system.

Grounded: Ground-fault detectors in grounded systems will protect a person that has contacted the hot line and has completed a ground-fault current circuit. In a grounded system, where one current-carrying conductor is grounded, or the system is centre-tap grounded, the system voltage is stable, and the highest voltage appearing on the ungrounded conductors, except when large surge currents are induced into the circuits, is the normal system operating voltage. During nearby lightning strikes, the conductor voltages may rise to a clamped voltage determined by the surge protection devices for a short time during the surge pulse. Operation of surge suppression devices may trip ground-fault detection devices as well.

Since grounded systems using grounded equipment enclosures poses greater possibilities of service personnel completing a ground-fault path when working within the enclosure, ground-fault protection must be located to protect personnel under any circumstances. Non-conductive enclosures minimise this problem.

7.4.5 Ground-fault detection for fire safety

General: In review, the fault currents supplied by a PV array are determined and limited by the array size, the incident irradiance, and the ground-fault impedance. A properly designed system uses cables and overcurrent devices sized to carry the highest short-circuit current in each protected circuit. The current-limited PV source normally will not supply enough current to open protection devices on ground faults. In cases where more current has been supplied from a second source or PV string, the blocking diodes had failed. Other sources of current that may cause the fuses or circuit breakers in PV circuits to open or trip include inverters connected to the utility grid or batteries [6]. Even bolted faults (line-to-line) in PV array conductors may create arcs that will burn insulation at levels of current that will not trip an overcurrent device. Multiple ground faults in grounded or ungrounded systems result in circulating currents that may not be detected, but can result in loss of power and create fire hazards.

Ungrounded: Ungrounded systems offer clear advantages for avoiding fire hazards. The ungrounded system must develop two ground faults or have sufficient leakage paths before a ground-fault fire hazard exists. Ground-fault detectors are also easier to install on ungrounded systems. They can detect the first ground fault and disable the system before dangerous multiple ground faults develop. The ungrounded system may also continue operating with a single ground fault while a warning may alert operators that the fault exists and should be repaired as soon as possible. Disabling an ungrounded system can easily be achieved by short-circuiting or open-circuiting the array. Excessive leakage to ground may cause ground-fault detection sensitivity problems in the ungrounded system.

Grounded: A single ground fault results in circulating ground current whenever the PV array is illuminated in a grounded system. This is a dc current and can result in corrosion of dissimilar metal connections, and if sufficiently high, can impose fire hazards. Grounded systems can be very difficult to disable because of the division of current. Short-circuiting a faulted array will not guarantee the ground-fault current will be eliminated or even reduced to safe levels.

Open-circuiting the PV array with a ground fault may actually increase the available energy to the fault. The disabling circuit for a PV array usually includes many meters of wire, various terminals, disconnect devices, fuses or circuit breakers, and blocking diodes between the ground fault and the disabling device. The current division between the ground-fault resistance and the array disable circuit can approach a value that allows current to flow through the fault with enough power dissipated to cause a fire. The fault current, voltage, and power can actually increase unless the fault current is interrupted by ungrounding the system. If all of the conductors are open-circuited, the fault path is opened when only one ground fault exists. The ungrounded array then can be disabled by short-circuiting or open-circuiting. New changes in the NEC in the US will allow temporary ungrounding the PV source circuit so long as labelling and an indication of the ungrounding is used.

7.5 Experimental results

References to results of tests conducted to determine the results of simulated ground faults, simulated ground-fault detection, and measured performance for the selected ground detection and disable methods are listed in the bibliography of this chapter. New developments such as the AC PV module will allow the elimination of ground-fault detection on the PV circuits since the dc voltage is contained within the module and inverter with no external access. Issues such as backfeeding that may result from inadvertent four quadrant operation of an inverter, transformer insulation breakdown or internal circuit failures must be addressed.

7.5.1 Overview and comparison of grounded and ungrounded systems

The following table gives an overview and comparison of grounded (system ground) and ungrounded PV systems that have developed ground faults. This table does not address line-to-line faults.

	Solid Ground	Resistance Ground	Ungrounded
General Performance			
Array Fault to Ground	Fault must be detected and array disabled immediately. Fault may be isolated and remainder of array may operate. New codes should allow disconnection of the system ground to disable array.	Fault must be detected. Fault current may be limited by the resistance element that must be properly sized.	Fault detection is necessary but system may continue operating with a notice to repair fault as soon as possible before a second fault occurs.
Fault between array and Inverter or Loads	Fault must be detected and system disabled immediately. Fault may be isolated and the remainder of system may operate. New codes should allow the disconnection of system ground to disable array.	Fault must be detected. Fault current may be limited by resistance element that must be properly rated.	Fault detection is necessary but system may continue operating with a notice to repair fault as soon as possible.
Fault at Inverter	Fault must be detected and the system disabled immediately. New codes should allow disconnection of system ground to disable array.	Fault must be detected. Fault current may be limited by the resistance element that must be properly rated. Use caution since the resistance ground may be bypassed.	Fault must be detected and indicated. Fault current may provide a path between the grounded ac part of the inverter and the ungrounded dc part. Use caution since the ungrounded dc may become grounded.
Personnel Safety			
Fault at Array	Safest system. Fault currents flow in a ground loop, but system is still properly grounded as expected. Fault currents to personnel will trip ground-fault equipment.	Safe system. Fault currents flow in a current-limited ground loop, but system is still grounded as expected. The potential of the grounded conductors will rise above ground potential. Fault currents to personnel will trip ground-fault equipment.	Least safe system. Suddenly there is an unexpected system ground. Unsuspecting personnel can receive electrical shocks. Fault currents to personnel will trip ground-fault equipment.
Fire Safety			
Ground Fault in Array	Least safe system, The fault must be detected and array disabled immediately. Fault may be isolated and remainder of array may operate. New codes should allow disconnection of system ground to disable array. Note that if the faulted section of the array remains grounded, fault current continues to flow raising fire danger.	Fault must be detected. Fault current may be limited by resistance element that must be properly sized.	Minimal! Single ground fault does not result in fault current. It takes excessive leakage current paths or two ground faults to become a fire hazard

7.6 Conclusions

Comparisons of the fire and personnel safety of the grounded and ungrounded PV systems showed both had advantages and disadvantages and that users and operators must be aware of the grounding methods and the ground-fault detection and array disable methods. This chapter included PV array ground-fault detection and array ground-fault disable experience, hardware capabilities, standards appropriateness, listing guidelines and practices for PV system installations. The results of simulated ground faults, simulated transients and lightning, and measured performance for the selected grounding methods are reported and referenced.

7.7 Recommendations for future work

Future work will follow up on ground-fault detection and interruption requirements for new concepts such as the AC PV module or new building-integrated PV applications.

7.8 Glossary

1. Ground Fault	An unintentional conductive path to ground or earth. May occur in PV installations between module and frame, module wiring and frame, system wiring to elements associated with equipment ground, within inverters and charge controllers, at surge protection devices, or at blocking diodes.
2. Ground-fault Detector	A component or circuit designed to detect ground-fault currents.
3. Ground-fault Circuit Interrupter	A device intended for the protection of personnel that functions to de-energise a circuit, or portion thereof, within an established period of time when a current to ground exceeds some predetermined value that is less than that required to operate the overcurrent protective device of the supply circuit.

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8. OVERVOLTAGE PROTECTION

8.1 Summary

PV systems are installed on roof tops, facades of buildings, special construction like sound barriers on motor ways. PV-system have, by definition, a large exposure to the open sky and are therefore subjected to atmospheric influences. A lightning strike is one of the most severe atmospheric influences. To protect a PV-system for a direct lightning stroke is very difficult due to the very high energy content of the lightning stroke. However, a PV system must and can be designed to withstand the effects of indirect lightning strike.

Another source of transient overvoltages in PV systems is the AC-network. These overvoltages originate from switching phenomena, fault clearance in the power network, and/or lightning induced voltages in overhead lines of the utility. These transient overvoltages are not special for PV systems and are applicable for all types of equipment connect to the distribution network.

Overvoltages due to indirect lightning strokes can be controlled with a proper design of the grounding structure of the PV-system. The main objective is to reduce loops between the DC and AC wiring and the ground structure. This can be solved to have a grounding wire running down from the metal support structure of the array, DC wiring, inverter, AC wiring to the ground structure at the main fuse box. If an external lightning protection system is available this should be connected to the metal support structure of the array. This deliberately formed ground loop allows currents to flow, but reduces the presence of overvoltages to a minimum. Since these currents flow in a well defined path, no hazards are present.

A simple and cost effective grounding structure is defined for PV-systems. This reduces all possible overvoltages to very acceptable and controllable levels.

8.2 Introduction

PV systems have a large exposure to the open sky and are subjected to atmospheric influences. A lightning strike is one of the most severe atmospheric influences. PV systems must be designed to withstand the effects of lightning strikes. However, a distinction must be made between a direct strike and an indirect strike.

To protect a PV system for a direct lightning strike is very difficult, if not impossible. The energy in a direct lightning strike is extremely high. This will simply destroy materials by thermal overloading, damage to the insulation and/or deform materials due to the pressure of expanding air. Adequate protection of PV systems for direct lightning strikes can only be established by using arrestor poles and/or a grid of grounded wires above the modules.

The average risk that a house will be hit by a direct lightning strike is approximately once every 800 years. The presence of a PV system (with electrical wiring and other conductive parts) on top of the roof has a negligible effect on this risk. The risk of a direct lightning strike is sufficiently low and an additional lightning protection installation is in general not required. However, the risk may be higher in some countries or parts of countries and lightning protection may be required. Exhibits are found in the mountain regions for example in Switzerland and Germany.

An indirect lightning strike can only induce transient overvoltages in a PV system. These overvoltages may cause defects in sensitive equipment like the power inverter. High transient voltages can easily be induced as a result of the large surface of a PV system. Adequate and very simple protection against the effects of an indirect lightning strike is possible.

Transient overvoltages may also come from the AC power network. These overvoltages originate by switching actions, fault clearance, and/or lightning strikes. These kinds of transient overvoltages are not special for PV systems. All appliances connected to the low voltage network have to able to withstand these transient voltages.

8.3 Scope of work

This chapter illustrates the characteristics of lightning induced voltages in PV systems. The results measurements carried out at the high power laboratory of KEMA will be discussed.

Some theoretical background is also given to illustrate the mechanism between an indirect lightning strike and the overvoltage induced in a PV system. This theory is discussed very briefly as the calculation of induced voltages in a PV system is virtually impossible due to the complexity of the system.

Some discussion will be given on how to protect PV systems and how to control lightning currents The discussion is based on the theory of the Electromagnetic Grounding Structures (modern high frequency grounding techniques). Finally, a recommendation is given on how to construct an efficient and cost effective grounding system for PV systems.

8.4 Theoretical results

8.4.1 Indirect lightning strikes

A lightning strike is an atmospheric phenomenon. It is a discharge of the electrostatic energy between the earth and clouds or between individual clouds. The discharge is a very abrupt phenomenon. Although people only see and hear the lightning strike, Kirchhoff’s current law is applicable. When a lightning strike hits the ground another current (equal in value) flows back to the clouds. This is illustrated in figure 1.

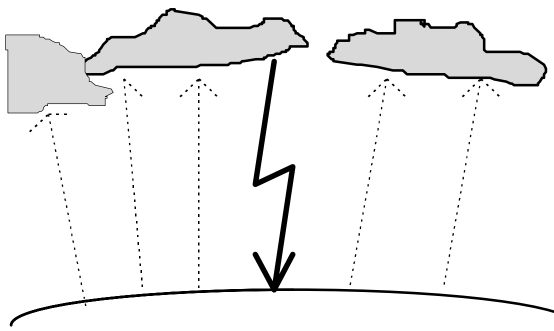

Figure 1 Illustration of a lightning strike and displacement currents

The bold line is the lightning current. The dotted lines are the displacement currents forming the return path for the current according to Kirchhoff's current law. The actual lighting can be seen by people, the displacement current normally not.

A lightning current (surge) is a fast phenomenon and can be characterised by following values:

- Peak current: The maximum (absolute) current of the lightning current.
- Front time: The time needed for the current to grow from 10% to 90% of the peak current.
- Tail time: The time needed for the current to decline to 50% of the peak current.

An illustration of a typical lightning current is given in figure 2. The lightning current has a front time of 1.2 μs, a peak current of approximately 30 kA and a tail time of 50 μs. The maximum di/dt is approximately 25 kA/μs.

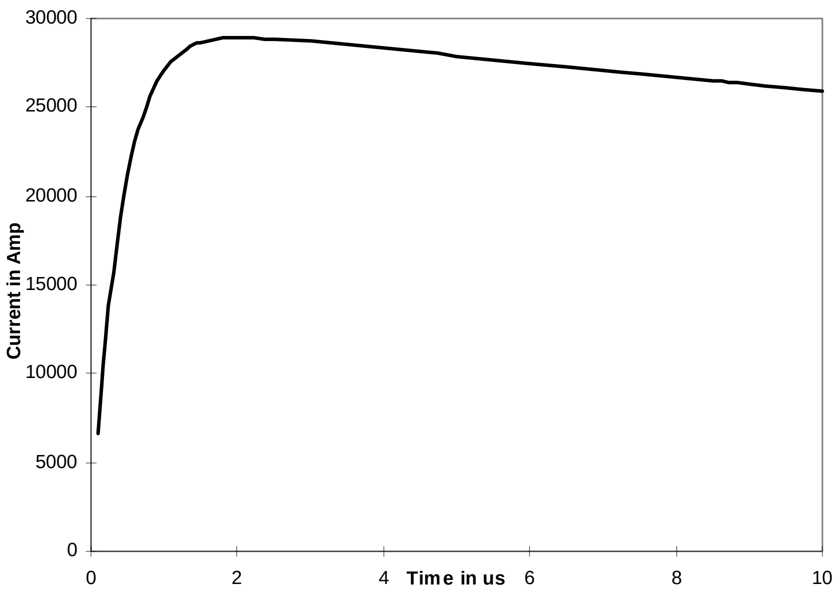

Figure 2 Typical lightning current

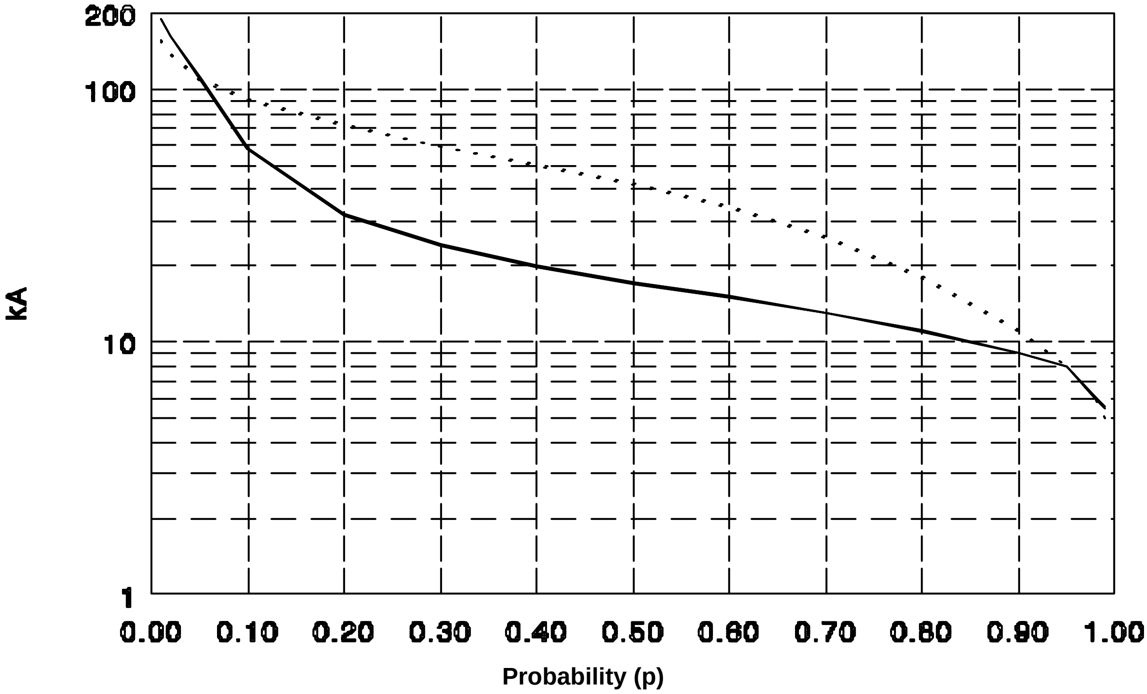

Figure 3 Probability of the peak value of a lightning strike

The straight line in figure 3 represents the positive lightning current, the dotted line the negative. The data in this figure reflect a measuring period from 1992 till 1995 and includes 45.810 positive and 349.040 negative measurements. The figure clearly shows that lightning strikes with extreme peak values of 100 kA to 200 kA very seldom appear (less then 5%).

The absolute peak value of the lightning strike is not important when talking about induced voltages. The rate of change of the current is far more important. Figure 4 shows the di/dt as a function of the probability.

The information acquired with the lightning measuring systems leads to the following conclusions:

- The average lighting density in the Netherlands is in the range of 1.5 - 2 strikes per km^2 per year. Comparison with data from other European countries showed that this value is also applicable for the northern part of Europe.
- The standard lighting strike has a peak value of 30 kA, a front time of 1.2 μs and tail time of 50 μs
- The standard di/dt is approximately 25 to 30 kA/μs.

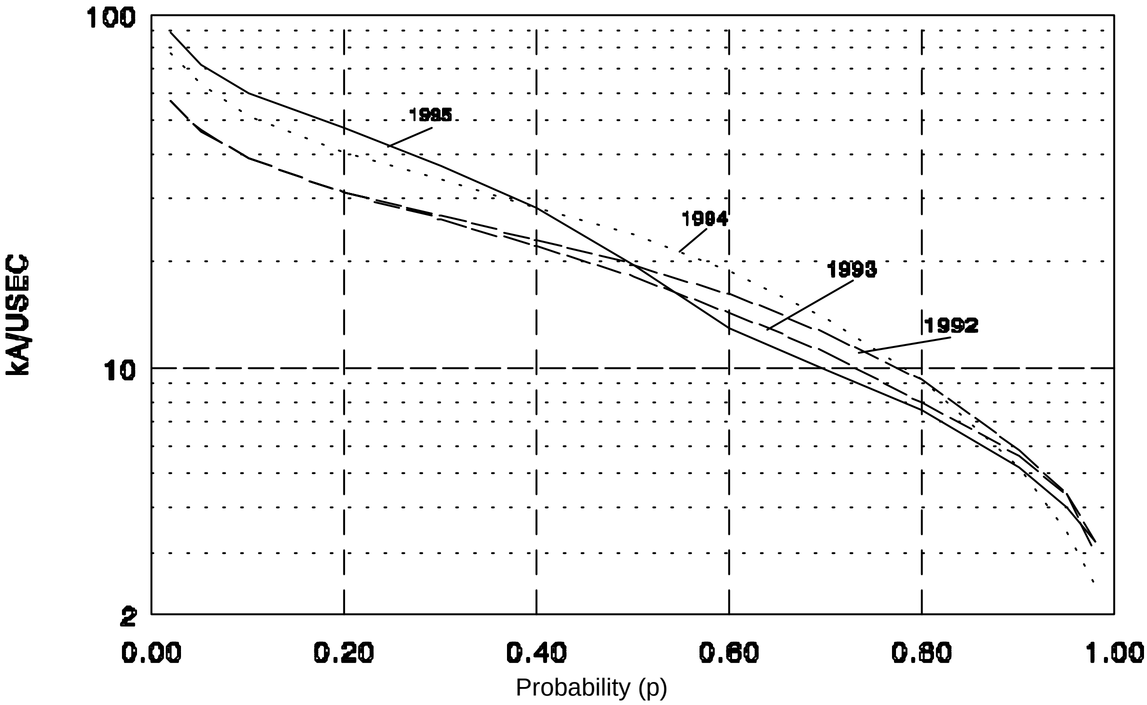

Figure 4 Probability of the di/dt of lightning current

8.4.2 Lightning induced voltages

The voltage induced in a PV module depends on the magnetic coupling (M) between a lightning strike and the module, and the rate of change of the lightning current. When assuming a maximum coupling between surface of the PV module and the magnetic field, the voltage can be calculated with:

$$U_{induced} = A\ dB/dt = M\ di/dt$$

Where A is the surface, dB/dt the rate of change of the magnetic field, M the mutual coupling between the magnetic field and the PV module and di/dt the rate of change of the current. Figure 5 shows the peak value of the induced voltage in loop of 1 m^2 as a function of the distance between the loop and the lightning current (di/dt is 25 kA/μs).

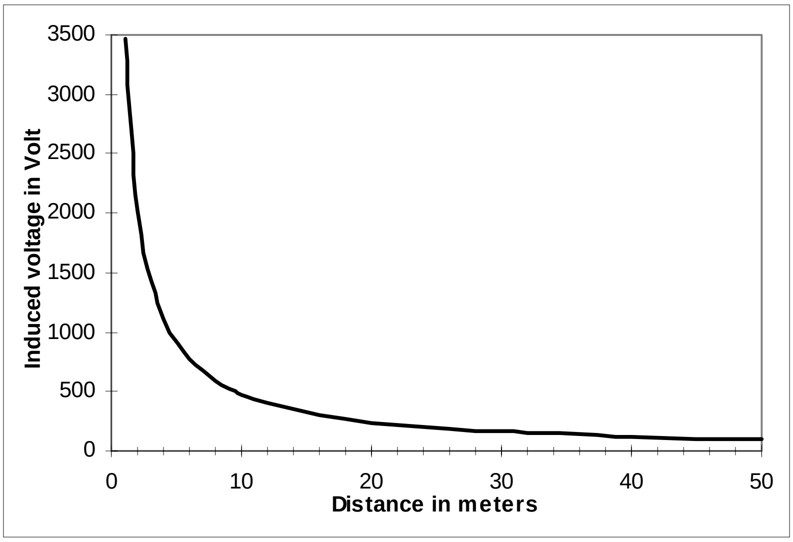

Figure 5 Induced voltage in a loop of 1 m^2 versus the distance between the loop and the lightning current

Similar calculation can be made for a combination of several modules. For a series connection of 12 modules the peak value of the induced voltage is given in table 1. For this exhibit the modules are connected in series using a normal wiring configuration. The induced voltage is calculated for 4 different values of the di/dt.

Table 1 Induced voltage in an array with PV modules as a function of the distance and di/dt

Distance in [m]	2 kA/µs	8 kA/µs	25 kA/µs	50 kA/µs
30	24	95	300	600
2	310	1200	3800	7700

8.4.3 Overvoltage from the power network

Transient overvoltages in power networks originate from switching actions and fault clearance. Lighting strikes may also cause overvoltages in countries with low (and medium) voltage overhead lines. The power network is designed to withstand these voltages and to suppress these voltages to an acceptable level.

These kind of transient overvoltages are not special for PV systems. All appliances (e.g. computers and television sets) connected to the network have to be able to withstand these transient voltages. All appliances connected to the low voltage network have be able to withstand these transient voltages. In Europe the EN 61000-4-4 and the EN 61000-4-5 define fast transients and surges that need to be applied to these appliances, and hence also to PV-inverters. In other parts of the World other but comparable standards are in place.

Information of relevant standards and/or appropriate levels can be obtained from the utility or national standardisation bodies.

Additional information can also be found in chapter 10 of this report.

8.5 Experimental results

8.5.1 Experiments on modules

In high power laboratories of KEMA tests have been carried out to determine the induced voltage in a PV module. The experimental set-up is shown in the figure 6. The lightning current was generated using high voltage surge generator. The peak amplitude of current was approximately 4 kA and had a maximum front time of 2 μs.

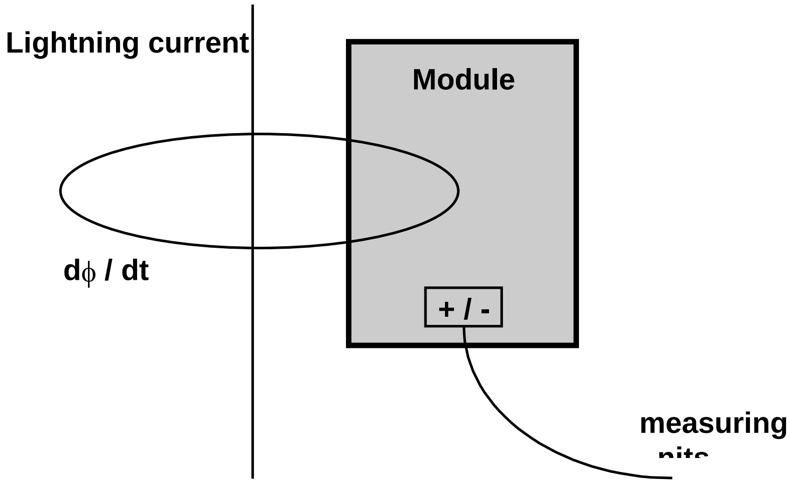

Figure 6 Schematic overview of measuring of the induced voltage in a PV module

The distance between the conductor carrying the surge current and the module (36 solar cells) was 1,5 meters. The induced voltage between the positive and negative terminals of the module was measured. The measurements indicated an induced voltage (differential mode) in the range of 10 to 60 Volts for a di/dt of 2 kA/μs. Similar tests have been carried out for the following types of solar modules:

- Glas-Glas module
- Glas-Tedlar module with aluminium foil
- Glas-Tedlar module with aluminium foil and metal frame

Table 2 Relative induced voltage in three different type of PV modules

Module	Induced voltage
Glas-Glas module	100%
Glas-Glas module and free standing aluminium plate at 30 cm distance from the module	60%
Glas-Tedlar module with aluminium foil	30%
Glas-Tedlar module with aluminium foil and metal frame	20%

The number of solar cells and the routing of the interconnections between solar cells are equal for all four types of modules. The differences between the induced voltage depends on the type of encapsulation. The result of the test is given in table 2. The table clearly shows the significant reduction of the induced voltage between the four different types of modules.

A metal frame has little influence on the reduction of the induced voltage. More detailed information is given in (Verhoeven, 1994)

8.5.2 Experiments on array level

Special measurement have been conducted to determine the induced (differential mode) voltage in an array with solar modules. An array with two strings of each 18 modules was placed under a grid with copper rods, as illustrated in figure 7. The modules used are identical to the Glas-Tedlar modules as described in the previous paragraph.

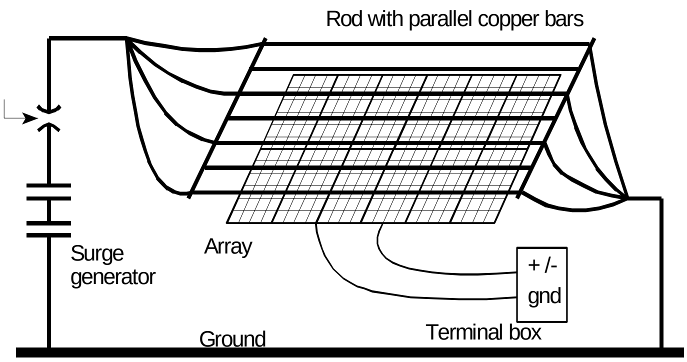

Figure 7 Schematic overview of test set-up for lightning induced voltage in an array of PV modules. Two strings with each 18 modules connected in series.

With a special surge generator a current was generated with a peak-amplitude of approximately 75 kA. The grid with copper rods was fitted at a distance of 80 cm distance above the modules. The result of the induced (differential mode) voltage is given in the figure 8. The simulated lightning current is oscillating with a frequency of 6,3 kHz. The maximum di/dt of the current is therefore 2,9 kA/µs which is still a relatively low value

The DC voltage of the array was approximately 210 V. This relatively low value is due to the low level of illumination. The normal Voc is in approximately 380 V. Figure 8 shows the induced voltage as a oscillating voltage superimposed on the DC voltage.

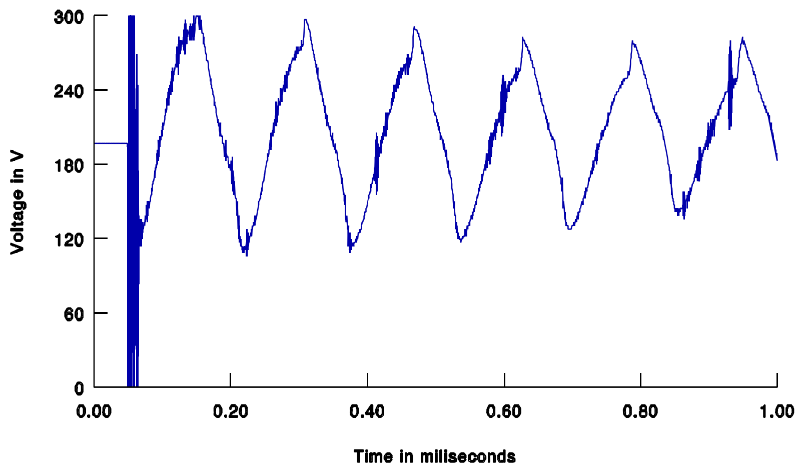

Figure 8 Result of lightning induced voltage in an array

The surge generator is triggered at t = 5 ms. Between t = 0 ms and t = 5 ms the voltage has a value of 210 Volt. Just after the triggering of the surge generator a high frequency distortion is measured. This voltage distortion is not an induced voltage in the array but a distortion in the measurement due to the spark gap of the surge generator. Additional information on these measurements can be found in (Verhoeven, 1995).

A very important result of this measurement is that the induced voltage does not cross the zero-line. If a surge arrestor like a spark gap is used to suppress the peak voltage, this spark gap would never stop conducting. When using surge arrestors in PV systems, the inception and inclination voltage must be well above the maximum open DC voltage level of the array.

8.6 Conclusions

8.6.1 Grounding structure

To protect a PV system for indirect lightning strikes, it is advised to connect all metal enclosures and/or support structures to a ground wire. This ground wire must be connected to the earth-terminal or bar of the main-service panel of the low voltage installation. This ground wire must be bundled together with the wiring in the DC and AC section over its etire length. With this bundling the surface area between the DC and AC wiring and the ground wire is kept as low as possible.

If the DC-wiring has several branches to other parts of an array or to other arrays it is strongly advised to also branch off the ground wire and bundle the ground wire with all DC wiring.

Only for small PV systems this ground wire can be omitted.

If a building has an external lightning protecting systems it is required that the support structure of the array is connected with the external lightning protection installation. This introduces a ground-loop between the external lightning protection installation and the ground wire bundled together with the DC and AC wiring. This loop should not be interrupted at any point and should not included spark gaps or other kinds of surge arrestors.

8.6.2 Surge arrestors

Surge arrestors may be used to limit the level of induced voltage at the DC side of PV systems. Metal oxide or comparable surge arrestors may only be used. The use of spark gap’s or comparable arrestor is prohibited as these devices will never stop conducting (inclination level is nearly zero).

To eliminate any free floating of the non-grounded DC voltage the surge arrestors it is preferable to connect the surge arrestor as illustrated in figure 9.

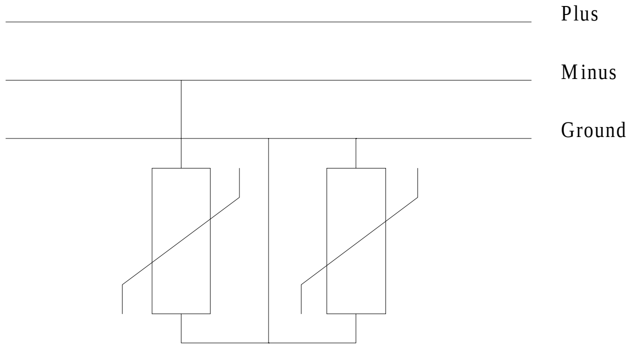

Figure 9 Connection of surge arrestors

The inception and inclination voltage must be well above the maximum open DC voltage level of the array. An acceptable level is 120% of the maximum open circuit voltage under standard test conditions. Metal oxide surge arrestors are normally used in PV systems. This kind of surge arrestor is widely available, has a wide range in surge voltages, is very robust and is very reliable.

Surge arrestors are not required for all PV systems. The use of surge arrestors for small system is not very effective since the induced differential mode voltage will never reach a value above the inception voltage of the surge arrestor.

Surge arrestors are not required at the AC-side if the inverter, nor at the main terminal box.

8.7 Recommendation for future work

Future studies for overvoltage protection in PV-systems are in principle not required, unless field experience shows otherwise.

8.8 References

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9. ISLANDING

9.1 Summary

Islanding is the continued operation of a grid-coupled inverter (or generator in general) in cases where the utility grid has been switched off, cut off or the distribution lines have been damaged so that no electric energy is delivered from the utility side. In such a situation the safety of persons and/or the safety of equipment might no longer be guaranteed.

Many anti-islanding methods have been identified in the literature and have been tested in practice. They can be divided into 2 groups:

- Passive methods:

a detection circuit monitors grid parameters (e.g. voltage, frequency, voltage phase jumps, voltage harmonics); these methods do not have any influence on grid quality

- Active methods:

a detection circuit deliberately introduces disturbances (e.g. active or reactive power variation, frequency shift) and deduces from the reaction to these disturbances if the grid is still present. The grid quality is somehow affected; however, ordinary devices like TV sets have a much bigger (negative) effect.

There are hardly two countries with identical legislation as far as islanding is concerned, but there is some common ground: in all countries a PV inverter (or some external protective device) is required to monitor voltage and frequency. However, the set-points for shutdown and disconnection from the grid are not generally agreed upon.

Islanding seems to be the most controversial topic with grid-coupled PV systems. However, theoretical studies show that islanding can only happen under very special and unlikely circumstances if basic safety methods are implemented. These basic methods are

- monitoring of grid voltage
- monitoring of grid frequency

As these parameters can be monitored very easily it is recommended to include the sensing circuits in the inverter electronics to reduce system costs. Some countries like The Netherlands, Germany, Switzerland and Austria have tried this approach and have made very good experiences.

It is further recommended to perform a scientific risk analysis based on real load patterns in real distribution systems to determine the probability of islanding. Such an analysis could form the common ground from where generally accepted anti-islanding methods could be derived. At present the dangers of islanding seem to be over-estimated; in some countries this has led to legislation demanding very costly or too sensitive anti-islanding methods.

From the technical point of view it seems to be possible to include effective and reliable anti-islanding methods in the inverter electronics which would make PV systems more simple to install and bring costs down.

9.2 Introduction

Islanding is a potentially dangerous mode of operation of grid-connected inverters. Generally "islanding" of an inverter can be defined as follows:

> Islanding is the continued operation of a grid-coupled inverter (or generator in general) in cases where the utility grid has been switched off, cut off or the distribution lines have been damaged so that no electric energy is delivered from the utility side

Early on it was recognised that such a condition is extremely dangerous because two important conditions cannot longer be guaranteed:

Safety of persons
If the grid is supposed to be "dead" because it has been switched off (e.g. for maintenance work) workmen might forget about the usual safety measures. An inverter which keeps the voltage on the line can therefore have fatal consequences either directly (electrical shock) or indirectly (e.g. workman falling from a working platform after touching a live wire)

Safety of equipment
As the inverter voltage might be unstable without support from the grid the voltage fluctuations could damage or destroy sensitive equipment (not only in the owner´s house but also in neighbouring houses).

Fortunately it is not difficult to detect islanding conditions except for very special (and highly unlikely) cases. Monitoring a few grid parameters is enough to reduce the possibility of islanding almost completely. However, because of the grave consequences that could follow if islanding happened different methods to prevent islanding have been developed and tested.

Before common international guidelines addressing the problems of islanding can be implemented a consensus on the following questions has to be found:

- Which measures lead to an acceptable degree of security?
- What is the maximum allowable time an inverter may continue to work after the grid has been switched off?
- Which test method should be employed to guarantee a common safety standard?

9.3 SCOPE OF WORK

The scope of Task V is limited to small grid-connected inverters. However, the problem of islanding does not stop here but affects all independent power producers of any size. The subject has been analysed both theoretically and experimentally; especially in Germany and Japan a great deal of work has been done.

The results presented here will be valid for all kinds of grids and for all sizes of generators (inverters). It will become clear, however, that the problem of islanding detection will become more and more difficult if the number of inverters connected to the same branch of the grid increases.

In this report a short overview of islanding prevention methods will be given. The theoretical background will be briefly reviewed and the advantages and disadvantages are summarised.

9.4 Theoretical results

9.4.1 Background

It is known that three conditions have to be met for islanding of an inverter [1]:

- Interruption of the grid without earthing of the lines
- Production of active power by the generator (=inverter) must be (almost) exactly balanced by consumption of active power by loads
- Production of reactive power by the generator (=inverter) must be (almost) exactly balanced by consumption of reactive power by loads

In all practical situations it is possible to substitute a number of loads connected to the grid by an equivalent ohmic resistance in parallel to an inductor and a capacitor. Furthermore it is assumed that the inverter will always try to inject only active power into the grid and to the loads. The latter assumption is valid for all modern inverters using PWM. All such inverters have two control loops which can stabilise islanding:

- The voltage control loop will keep the input voltage at such a level that the maximum possible energy is taken from the solar modules. If irradiation is constant the output voltage will also be constant, thus leading to a stable operating point. If we have load matching this output voltage will be within the tolerance band of the grid voltage.

In case of islanding the active power consumed by the load is only a function of the voltage:

$$P = \frac{U^2}{R_L}$$

- Phase synchronisation will always try to keep current and voltage in phase. If mainly capacitive loads (current leading with reference to voltage) are present, the inverter will raise its frequency until the reactive power consumed by the load will be zero. The opposite will happen for inductive loads. In case of islanding the reactive power consumed by the load is a function of voltage and frequency:

$$Q = \frac{U^2}{\omega L}\left(1-\left(\omega / \omega_R\right)^2\right)$$

where $\omega_R = \frac{1}{\sqrt{LC}}$

This behaviour leads to the conclusion that it is easily possible to eliminate almost all cases of islanding just by limiting the allowable voltage and frequency band (i.e. specify upper and lower limits and require immediate shutdown if one of these parameters is outside of these limits). Depending on how narrow these limits are defined only very special arrangements of loads could theoretically lead to islanding conditions. It should be noted that these conditions will hardly occur in "real life" as active AND reactive power matching plus stable irradiation and load conditions at the same time are very improbable.

However, the situation can be quite complicated if a large number of inverters are connected to the same branch of the grid. Usually there is one transformer feeding into this branch, and if this transformer is switched off while load-matching conditions exist it is very difficult for a single inverter to notice that anything happened at all.

This means that other measures have to be taken if the probability of islanding is to be further reduced.

9.4.2 Overview of methods to detect islanding

9.4.2.1 Passive methods

Passive methods basically monitor certain electrical parameters and shut down the inverter operation if changes in these parameters could be a result of the transition from normal operation to islanding.

- Monitoring of the grid voltage
- Monitoring of the grid frequency

The theoretical results presented above show that these two methods form a very effective first barrier against islanding behaviour. All that has to be done is to define voltage and frequency bands outside which no operation is allowed. These parameters are easy to measure, so the technical solution can be integrated into the inverter.

- Monitoring of all phases of the grid voltage

The effectiveness of voltage monitoring can be further enhanced if in case of a single-phase inverter (in a 3-phase grid) all phase voltages are monitored. In such a situation even load matching in one phase cannot keep the voltage in the other two phases within limits [2],[3].

- Monitoring of voltage phase jumps

At the time of transition from normal operation to islanding usually a rapid change in the voltage phase takes place. This is due to the imbalance of output power and the load connected to the inverter. A special detection circuit looks for such phase jumps and stops inverter operation. This method, however, will not detect islanding in case of an almost perfect balance between production and consumption.

- Monitoring of sudden changes in the voltage harmonic content

Usually the amplitude of higher harmonics of the grid voltage changes significantly if the grid is disconnected. Monitoring the harmonic content is therefore one possible way to detect islanding. This method will usually work in case of matched production and consumption in case of current-controlled inverters. It may fail, however, with voltage-controlled inverters.

9.4.2.2 Active methods

Active methods introduce a deliberate disturbance to the connected circuit and, depending on the response to these disturbances, deduce if the utility grid is still connected.

- Active frequency shift

The inverter constantly tries to change its working frequency; if the grid is still present, then the inverter frequency is "reset" to the correct value by the grid zero crossing. If the grid is off the frequency will slowly drift out of the allowed tolerance band which leads to shutdown.
If this method is applied it is important that all inverters connected to the same branch shift their frequency in the same direction.

- Impedance measurement

Measuring the impedance of the grid is a very effetive method to determine if the connection to the local MV/LV transformer is interrupted [1]. As the idea behind impedance measurements is not directly obvious it will be explained in more detail.

It can be shown both theoretically and experimentally that the MV/LV transformer feeding electricity to the LV grid can be regarded as a voltage source with a very low impedance (in the order of a few milliohms). At a given point of the distribution line one or more inverters may be connected. The inverter(s) are connected to the transformer via cables, switches, electricity meters and fuses; these act as impedances in series to the transformer impedance.

All loads connected to the grid are in parallel to the transformer. From the point of view of the PV inverter the grid looks like a parallel connection of various loads; the transformer as an almost ideal voltage source can act as a load, too (in case of reverse power flow). (see Figure 1)

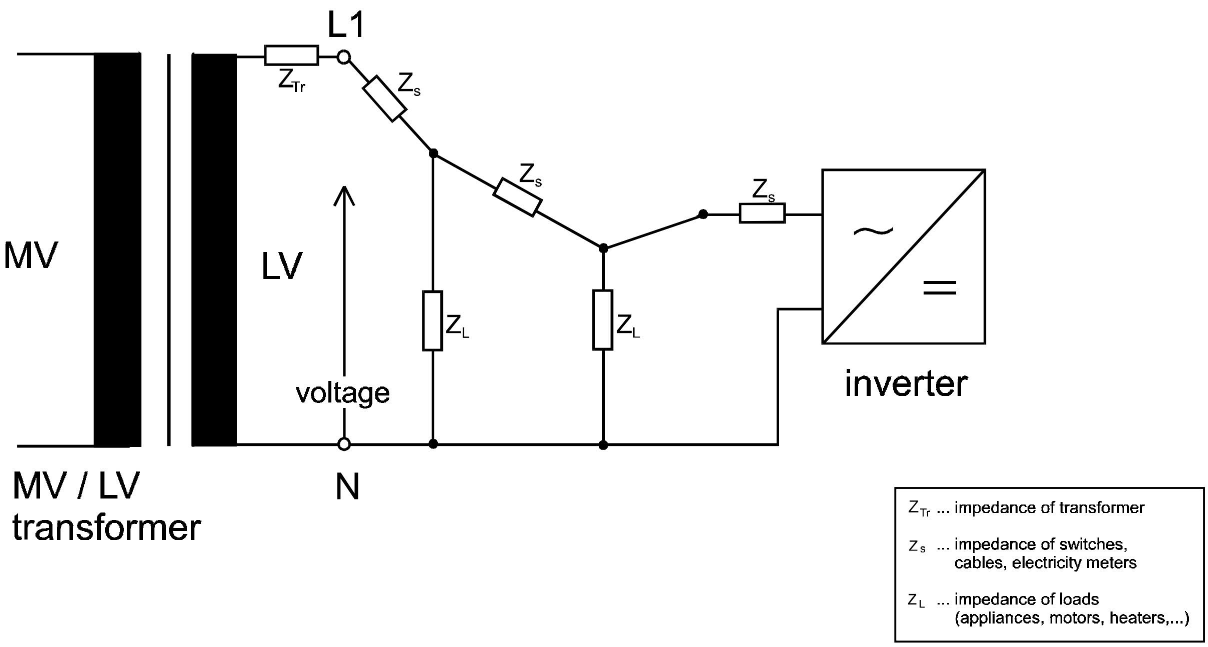

Figure 1 Typical situation in a low-voltage distribution line with one independent power producer.

For the sake of simplicity of figure 1 just one phase and two connected loads (e.g. appliances, motor, heaters) having an impedance Z_L are shown. The vertical distance of any connection point from the baseline (=neutral conductor) represents the AC-voltage at that point. This represents the fact that power will always run "downstream", i.e. a power flow to a load requires a voltage difference because of parasitic impedances. All parasitic impedances (cables, fuses, switches, electricity meters etc.) are combined into equivalent impedances Z_S; the small impedance of the transformer is shown as Z_T.

If the connection between a given point of the grid and the local transformer is disrupted (e.g. by accident, due to maintenance works etc.), the total impedance seen by the inverter suddenly increases as the very small impedance of the transformer is suddenly removed. This sudden change can be detected even if a number of other independent generators were to keep grid voltage and frequency within tolerable limits. The parameter evaluated in this method is a *sudden change in impedance.*

This method has been adopted as an absolutely reliable way to determine islanding conditions in Germany [7] and Austria. However, as the critical value for impedance change has been set to a very low level (0.5 Ohms) this method can lead to troubles (i.e. frequent unnecessary shutdown of inverters) in "weak" grids.

- Variation of active power [5], [8]
- Variation of reactive power [5], [8]

The inverter deliberately introduces periodic variations in its power output and monitors the response of the parameters voltage, current and frequency. If the grid is stable the parameters will hardly change at all while in an islanding situation the effects of power variation can be clearly detected. This method works very well for a single inverter; as the number of independent power producers in the grid increases, the reliability of islanding detection decreases. This is because the independent generators usually do not communicate; while one inverter is in its power variation phase all the others might stabilize voltage and frequency so that no change can be detected. A coordinated timing (i.e. all inverters vary their power output at the same time in the same manner) might eliminate this problem.

9.5 Experimental results

In [4] Prof. Häberlin of Switzerland could show already in 1991 that in principle inverters can operate in the absence of the grid. He found that at load matching conditions several inverters did not shut down for prolonged periods of time. His test was only performed with a single inverter and therefore small modifications by the manufacturers were sufficient to eliminate islanding in his test set-up.

Tests on multiple inverter configurations have been performed mostly in Japan [5]. There it was shown that large numbers of inverters can operate in islanding mode for longer periods of time (> 30 seconds) if no sophisticated islanding detection methods are employed and load matching conditions exist.

9.6 Conclusions

From theoretical considerations it is clear that the vast majority of islanding situations can be prevented by specifying voltage and frequency bands outside which no inverter may operate. It is therefore necessary to establish guidelines which define these limits as an effective first barrier against islanding.

Theoretical and experimental results show that with sophisticated methods it is possible to reduce the danger of islanding to practically zero; however, at present there is no common opinion on the degree of safety that has to be achieved. Bringing down the risk is connected with narrowing tolerance bands of parameters like voltage, frequency or allowable changes in grid impedance which means increasing sophistication of monitoring devices. It has to be noted that active methods for islanding detection introduce disturbances to the grid which have negative consequences on the quality of the grid.

Within the next few years it should be a goal to define internationally accepted safety standards which allow a faster growth of the PV market as the present situation is not very encouraging with very different guidelines in different countries.

As an example of current standards the present guidelines in some countries are presented:

9.6.1 Netherlands

The Netherlands take a very liberal approach [6] and allow any single phase inverter below 5 kVA to be connected to the grid if it monitors grid voltage and frequency and shuts down if certain tolerance bands are left. It is not even mandatory to install a disconnection relay but blocking of semiconductor switches is sufficient.

At present there is a recommendation that as an additional measure an active frequency shift towards lower frequencies should be employed; this is not mandatory, however.

9.6.2 Germany and Austria

In Germany and Austria the concept of the "ENS" is used as an anti-islanding method. The ENS is basically an electro-mechanical device which has to meet certain criteria. In Germany these criteria have even been written down as pre-standard VDE 0126 [7].
The basic concept of the ENS relies on REDUNDANCY.

Two independent switching devices must be connected in series; at least one of these must be able to physically disconnect the inverter from the grid (e.g. a relay). The second one may consist of an electronic switching device which can be disabled by electrical signals (e.g. transistors, MOSFETs, IGBTs, GTO-thyristors).

The ENS must be built in such a way that any fault within the ENS itself leads to permanent disconnection of the inverter until the fault is removed by repair. The ENS must monitor the following parameters and allows current flow into the grid only within the following tolerance bands:

Grid parameter	**Nominal value**	**Tolerance**	**In case of abnormal value disconnect within:**
voltage	230V	+10% -15%	0.2 sec
frequency	50 Hz	$\pm$ 0.2 Hz	0.2 sec
fault current on DC side (*)	-	30 mA eff	0.2 sec
grid impedance before connecting the inverter to the grid	-	$Z_N \leq 1.25\Omega$	-
grid impedance during operation of inverter		$Z_N \leq 1.75\Omega$	5 sec
dynamic changes of grid impedance during operation of inverter		$\Delta Z_N \leq 0.5\Omega$	5 sec

(*) monitoring only required for transformerless inverters

The ENS is approved on the basis of a TYPE APPROVAL. In this test, performed by independent test houses, the compliance with above-stated requirements is verified. The test focuses mainly on the recognition of dynamic changes in the grid impedance (obviously the parameter most difficult to measure). A very sophisticated test set-up is used, but in principle this test is equivalent to inserting an impedance of 0.5 Ω into the current path during operation of the inverter. Once the ENS of a given manufacturer passes this type approval it may be used in PV inverters; however, each ENS device must be checked individually by the manufacturer before it is shipped out.

Advantages of the ENS:
- Once it is installed, no regular checks have to be made in the future.
- The concept of impedance checking is certainly on the safe side and will stop inverter operation rather too often than not.

Disadvantages of the ENS:
- As the safety limits in its present form are very tough, several cases have been reported where an ENS blocked the operation of an inverter because of a "weak" but otherwise normal grid. Especially in rural areas with some distance to the distribution transformer problems will occur.
- It must be noted that the ENS begins to fail exactly where it is needed most: if the density of PV systems in a given distribution area is too high, the individual impedance measurements tend to influence each other, leading to a very unstable operation. At a 1 MW installation in Germany with 600 inverters the individual ENS were disabled because a trouble-free operation could not be guaranteed
- Due to the measurement principle the ENS decreases grid quality by introducing periodic disturbances

9.6.3 Switzerland

In Switzerland it is de facto necessary to have an inverter tested by Prof. Häberling of the Ingenieurschule Burgdorf. There it is subjected to an islanding test where load-matching conditions are established before the grid is removed. If the inverter shuts off within a few seconds it is considered safe and may be used on the Swiss market.

9.6.4 Japan

In Japan the use of an Over/Undervoltage and Over/Underfrequency Relay is mandatory. Apart from that the "Technical Recommendations for the Grid Connection of Dispersed Power Generators" [8] require the installation of an Islanding detection device which uses at least one active and one additional passive detection method. Japan has established its own testing procedure and the islanding detection device is tested at a certified Laboratory (in Japan the "Japan Electrical Safety and Environment Technology Laboratory" [JET]). The wording of the test procedure is given in Annex C.

9.6.5 United States of America

The US is currently working to establish guidelines and standards for islanding protection. Utilities will use document IEEE929 once it has been balloted and approved. The committee is still working on set points and requirements for islanding. Only inverters of less than 10-kw size will be required to meet IEEE929.
The following requirements for inverters are presently foreseen:

- Disconnect instantaneously when the utility frequency remains outside the window of 59.5 to 60.5 Hz. (Instantaneously is defined in the IEEE dictionary as "as fast as practical or as fast as the equipment can". (Note that "disconnect" is defined as disabling the ac output of the inverter, while leaving the sensing circuitry connected to allow monitoring of the utility so that automatic reconnect can be accomplished when the utility has returned to normal operating conditions.)
- Inverter shall disconnect within 6 cycles when the terminal voltage is less than 50% of the nominal voltage.
- Inverter shall disconnect within 2 seconds when the terminal voltage is between 50% of nominal and 92% of nominal.
- Inverter shall disconnect within 2 seconds when the terminal voltage is greater than 110% but less than 150% of nominal.
- Inverter shall disconnect within 2 cycles when the terminal voltage is greater than 150% of nominal.

Another document that will be used for listing hardware is the draft Standard UL1741 now named UL Standard for Static Inverters and Charge Controllers for Use in Photovoltaic Power Systems. That standard will require setpoint testing and anti-island testing. Anti-islanding testing basically requires a matched resistive load and only one inverter will be tested at a time. UL will coordinate with IEEE969 on set points and run-on times.

9.7 Recommendations for further work

As islanding is still a very controversial topic there are many open questions. To reach an international consensus the following aspects have to be clarified:

- Definition of voltage and frequency limits for the operation of inverters
- Definition of the allowable duration of islanding
- Definition of a standard test method for islanding-prevention devices

A valuable basis for further work and guidelines would be a probability analysis. Starting from real load patterns at low voltage distribution lines an investigation could determine the theoretical probability of islanding and the possible duration of such a condition. Such a study could act as a sound basis from which anti-islanding guidelines reflecting the real dangers could be derived.

As the technical problem is absolutely identical everywhere in the world there should be no obstacle to a common approach. However, some pragmatism will be necessary to overcome the different safety philosophy which dictate widely different solutions at this moment.

9.8 References

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[2] Richtlinie für den Parallelbetrieb von Eigenerzeugungsanlagen mit dem Niederspannungsnetz des Elektrizitätsversorgungsunternehmens (EVU); Vereinigung Deutscher Elektrizitätswerke VDEW-e.V. 3.Auflage 1991 (German guideline for grid-connected PV inverters; in German)

[3] ÖVE/ÖNORM 2750 (Austrian guideline for grid-connected PV inverters) (in German)

[4] H.Häberlin et al: PV Inverters for Grid-Connection: Results of Extended Tests, Proceedings of the 11th PV Solar Energy Conference in Montreux, p. 1585ff (1992)

[5] A. Kitamura: Islanding prevention measures for PV systems, Proceedings of the IEA PVPS Task V Workshop, p. 173ff, Zurich (1997)

[6] S.A.M Verhoeven: New Dutch Guidelines for Dispersed Power Generators, Proceedings of the IEA PVPS Task V Workshop, p. 35ff, Zurich (1997)

[7] U. Lappe: German prestandard DIN VDE 0126, Proceedings of the IEA PVPS Task V Workshop, p. 167ff, Zurich (1997)

[8] Technical Recommendations for the Grid Connection of Dispersed Power Generators, issued by the New Energy and Industrial Technology Development Organisation (NEDO) and the Central Research Institute of Electric Power Industry (CRIEPI)

10. ELECTRO-MAGNETIC COMPATIBILITY (EMC) OF INVERTER

10.1 Summary

Electro-magnetic compatibility is the ability of an electric or electronic device or system to operate according to its purpose in its electromagnetic environment without negatively influencing other equipment by conducted or radiated electromagnetic emissions.

Therefore a manufacturer of PV inverters has to make sure that his device has a certain immunity against external electromagnetic phenomena. At the same time it must not produce emissions disturbing other electronic devices.

All industrialised nations have some form of legislation that sets limits to the maximum allowable level of electromagnetic emissions. These limits are usually a result of long discussions and are well-proven in practice. The compliance with these limits is tested in well-defined test set-ups with standardised test instruments. The relevant standards for Australia, Europe, Japan and the US have been compiled and referenced. Where possible, the relevant immunity standards (if such exist) have also been cited.

The problem of EMC is not a PV-specific topic. Therefore it does not make sense to create new standards for PV equipment like inverters as the existing standards are generally valid. The only remaining topic: the test set-up for measurements of emissions on the DC lines has to be defined more clearly as conventional devices usually do not have DC connections.

10.2 Introduction

Electro-magnetic compatibility is the ability of an electric or electronic device or system to operate according to its purpose in its electromagnetic environment without negatively influencing other equipment by conducted or radiated electromagnetic emissions.

As our daily life is more and more governed by electronic systems and devices, the interaction of equipment often cannot be neglected. The breakdown of data processing systems in banks or insurance companies would cause enormous damage; the same would be true if automatic manufacturing equipment in factories was paralysed by electronic interference.

Modern aircraft are completely controlled by electronics; here the results of disturbance could be catastrophic. Therefore many countries have enacted legislation that limits the emissions of electronic devices and requires a minimum level of immunity against electro-magnetic immissions.

10.3 Scope of work

As the basic problem of EMC is already well known a lot of measures have been implemented to limit the negative impact of electronic noise. In most cases governments have introduced standards which limit the allowable level of electro-magnetic emissions produced by electronic devices. The scope of this chapter is to give an overview of the different approaches which have been taken by countries to deal with EMC. As the inverter is the main source of emissions, the information will focus on this device. It is, however, very difficult to describe the system "Inverter and PV array" as far as radiated emissions are concerned. This is because the emissions depend very strongly on factors as:

- the length of DC cabling
- the way of wiring of the PV modules
- the influence of module frames in contrast to frame-less modules
- the way the modules are mounted (roof-mounted, ground-mounted)

Here a lot of basic research has to be done to better understand the possible effects and give recommendations for optimum results. Some investigations suggest that radiated emissions can be filtered relatively easily [1].

10.4 Theoretical results

Electro-magnetic phenomena can be subdivided into 4 groups:

Emissions from the inverter (can disturb other equipment)	**Immunity against external phenomena** (inverter can be influenced in its operation)
1) Radiated emission	3) Susceptibility against radiated phenomena
2) Conducted emission	4) Susceptibility against conducted phenomena

Of course all equipment should ideally produce no unwanted emissions at all while at the same time operate normally under the influence of disturbances from the outside. This is not possible in reality so certain standards have been created in different parts of the world to ensure a trouble-free operation of electronic devices while keeping the costs of filtering at affordable levels.

10.4.1 Europe

In Europe there is a general tendency to harmonise the national standards in order to simplify the free trade of products between individual countries. All members of the EU and EFTA are members of CENELEC (Comité Européen de Normalisation Electrotechnique) and are obliged to convert harmonized standards into national law.

> As of Jan. 1st 1996 all electronic devices must be marked with the "CE" sign which requires that these devices comply with the relevant EMC standards.

The European standards are classified into three different groups.

10.4.1.1 Basic standards

Basic stadards define the measurement methods for EMC measurements (i.e. physical test set-up, equipment to be used, measurement environment). Currently the following standards are to be applied in Europe:

Emission (examples)
- CISPR 16-1 (deals with radio disturbance and immunity measuring apparatus)
- EN 61000-3-2 (deals with measurement of current harmonics)
- EN 61000-3-3 (deals with measurement of flicker)

Susceptibility (examples)
- EN 61000-4-2
- EN 61000-4-4
- EN 61000-4-5
- EN 61000-4-8
- EN 61000-4-11

(Deals with measurements of susceptibility against static discharges, burst [transient phenomena], voltage spikes, voltage drops and voltage variations). IEC 1000-4-3 (deals with immunity against radiated electromagnetic fields). IEC 801-3 (deals with immunity against radiated electromagnetic fields)

10.4.1.2 Generic standards

Generic standards define limits for the emission and susceptibility of electronic devices if no specific product standard is available for a certain device. Currently the following generic standards exist:

EN 50081-1 Electromagnetic Compatibility - Generic emission standard Part 1: Residential, Commercial and light industry" (Emission limits for equipment used mainly in domestic environment) As an example the following table gives details of all the tests that are required by EN 50081-1. The measurements are generally described in basic standards.

Phenomenon	Frequency range	Basic standard applicable	Remark
radiated emissions	30 ... 1000 MHz	EN 50022 class B	
conducted emissions	0 ... 2 kHz	EN 60555-2 EN 61000-3-2	harmonics
conducted emissions	0 ... 2 kHz	EN 60555-3 EN 61000-3-3	flicker
conducted emissions	0.15 ... 30 MHz	EN 55022 class B	continuous
conducted emissions	0.15 ... 30 MHz	EN 55022 class B	discontinuous (clicks)

EN 50081-2
Emission limits for equipment used mainly in industrial environment. Classification similar to table above. Some limits allow a higher level of emissions due to the heavy machinery used in such an environment.

EN 50082-1 Electromagnetic Compatibility - Generic immunity standard Part 1: Residential, Commercial and light industry (Standard for susceptibility of equipment used mainly in domestic environment). As an example the following table gives details of all the tests that are required by EN 50082-1. The measurements are generally described in basic standards.

Test performed on:	Test of immunity against:	Basic standard applicable:
Chassis	electrostatic discharge (8 kV air discharge to chassis)	IEC 801-2
Chassis	RF field 27 . 500 MHz field strength 3V/m CW	IEC 801-3
Signal- and communication lines	Burst 0.5kV	IEC 801-4
DC terminals	Burst 0.5kV	IEC 801-4
AC terminals	Burst 1 kV	IEC 801-4

EN 50082-2
Standard for susceptibility of equipment used mainly in industrial environment. There is a similar table as above, but a higher level of immunity is required.

10.4.1.3 Product standards

Product standards define limits for the emission and susceptibility of specific product groups that are manufactured in large quantities (e.g. radio and TV equipment, household appliances, Computer). These standards may even define measurement methods different to those defined in the basic standards. An example is the product standard for household appliances, which is divided into

EN 55014 deals with electro-magnetic interference (=emissions)
EN 55104 deals with electro-magnetic susceptibility (= immunity)

Here some confusion arises as to which group an inverter belongs. Many tests were performed regarding the inverter as a household appliance, but more recently it seems that there is a consensus to treat an inverter differently and apply the generic standards. However, the applicable limits are hardly any different so this question is not of great importance.

10.4.2 Japan

At present there is no general standard regulating the EMC of electronic devices in Japan. There is also no requirement regarding EMC in the "Grid-interconnection Guideline for Low Voltage Distribution Line". At present the Japanese manufacturers of PV inverters have self-imposed a voluntary standard concerning EMC called VCCI (Voluntary Control Council for Interference). The limits therein correspond to CISPR pub. 22. [2]

10.4.3 United states

High frequency electromagnetic interference is regulated by the Federal Communications Commission (FCC). The FCC Rules & Regulations, 47DFR, Ch I, Chapter 15, 1992 Edition, Subpart B for Unintentional Radiators are applicable for conducted and radiated emissions.

Basically, conducted radiation is limited to 250 microvolts within 450 kHz through 30 MHz. The radiated emissions are measured at 3 meters from the device. They shall not exceed:

100 microvolts/meter	for	30-88 MHz
150 microvolts/meter	for	88-216 MHz
200 microvolts/meter	for	216-960 MHz
500 microvolts/meter	for	Above 960 MHz

Inverters must also be immune to FCC approved levels of disturbances

10.4.4 Australia

Australia has adopted guidelines very similar to those in Europe. The last remaining question is if an inverter for PV systems should be treated like a household device or not. The current Australian guidelines refer to AS 1044 “Limits and methods of measurement of radio disturbance characteristics of electrical motor operated and thermal appliances for house hold and similar purposes electric tools and similar electric apparatus”, which is technically very similar to EN 55014.

However, the new AS 4251.1 “Electromagnetic Compatibility - Generic emission standard Part 1: Residential, Commercial and light industry” and AS 4252.1 “Electromagnetic Compatibility - Generic immunity standard Part 1: Residential, Commercial and light industry” seem to be more appropriate standards. These standards are technically equivalent to CENELEC/EN 50081-1 and 50082-1, respectively.

10.5 Experimental results

A few tests of PV inverters have already to be performed in independent test houses or research institutes [4], [5]. A few years ago most inverters did not comply with the limits on emissions, but the situation has changed with the introduction of the CE sign. As new devices may enter the market only after they have passed the EMC tests the negative consequences of the past (bad quality of radio and TV signals due to interference by the inverter) have vanished. A modern inverter does not produce more interference than other commercially available devices.

10.6 Conclusions

In most industrialised countries of the world there are firm rules for the EMC of devices. As a lot of experience and work has been involved in setting up the present standards, it does not make sense to look for different standards for inverters. Measurements of conducted emissions on the AC-side and on the DC side are well defined and do not need any changes. Measurements of radiated emissions need a standardised test set-up as differences in the wiring of the modules, the length of the DC cables, the impedance of the DC source and the way of grounding of the modules prevents reproducible results.

10.7 Recommendations for future work

As the effects of EMC are well defined and covered by national and international standards it is simply recommended to collect all necessary information and keep track of any changes that might be made in the future. It is necessary, however, to define clearly which standards have to be applied for inverters used in PV systems.

10.8 References

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3. Grid-connected photovoltaic power systems: Status of existing guidelines and regulations in selected IEA member countries, Report IEA-PVPS V-1-01 (July 1996)
4. H.Häberlin et al: PV Inverters for Grid-Connection: Results of Extended Tests, Proceedings of the 11th PV Solar Energy Conference in Montreux, p. 1585ff (1992)
5. Wildenbeest et al.: Comparison of six inverters, ECN test report ECN-C-94-050 (June 1994)

11. EXTERNAL DISCONNECT

11.1 Summary

This topic examined the necessity for PV systems to have an external manual ac disconnect switch to allow the Utility to disconnect the PV system in the case of maintenance on the ac network or fire hazard etc., to comply with Health and Safety Regulations

Nearly all countries required a means of physically disconnecting the PV generator from the mains for maintenance of the inverter and the ac network to which it is connected. The traditional means to achieve this was a mechanical switch mounted in an external position such that the Utility could operate it before carrying out maintenance on the ac network. This had evolved for a situation of a relatively small number of large generators.

It was generally agreed that as small generators became more common, the task of isolating every unit at an external switch would become impossible to implement reliably, and moreover it did not take into account units that were illegally connected, and thus not registered with the Utility. For this reason, and the relatively high installation costs for such a switch, it was proposed to investigate other solutions.

Some countries, such as Germany the Netherlands and Austria, were coming to the view that in certain circumstances protection relays and operational procedures could be relied upon. This was backed up by a risk assessment study in Germany by the Employer's Liability Insurance Association to IEC guidelines.

It was generally agreed that if anti-islanding devices were used for the external disconnect function, they would have to be relay devices with a physical opening of contacts rather than an electronic semiconductor switch.

For PV it is anticipated that the situation evolving in Germany and the Netherlands will become more widely adopted, where the external switch is not mandatory, and the Utility relies on the relay 'islanding' protection and their practices for checking and grounding the conductors, assuming that they are live, before carrying out maintenance. This relies on the involvement of the Utilities.

It is important to recognise that the problem is not specific to PV but also applies to other embedded generators, and so it is sensible to harmonise with other work being carried out in this area.

When more information is available from the anti-islanding work, then these devices should be assessed for their suitability to provide the function of the external disconnect also.

11.2 Introduction

This chapter discusses the necessity for PV systems to have an external ac disconnect switch to allow the Utility to disconnect the PV system to comply with Health and Safety Regulations, in the case of maintenance on the ac network or fire hazard, etc.

Nearly all countries require a means of physically disconnecting the PV generator from the mains for maintenance of the inverter and the ac network to which it is connected. The traditional means to achieve this is a mechanical switch mounted in an external position such that the Utility can operate it before carrying out maintenance on the ac network.

Some countries, such as Germany the Netherlands and Austria, are coming to the view that in certain circumstances protection relays and operational procedures can be relied upon.

11.3 Scope of work

It is generally agreed that as small generators become more common, the task of isolating every unit at an external switch will become impossible to implement reliably, moreover it does not take into account units that are illegally connected, that is not authorised by the Utility. For this reason, and the high installation costs for such a unit, it is proposed to set out the requirements for a system and look at alternatives that might be considered by the Utilities.

11.4 Theoretical results

Three methods of disconnect are used at present. These are illustrated in Figure 11.1.

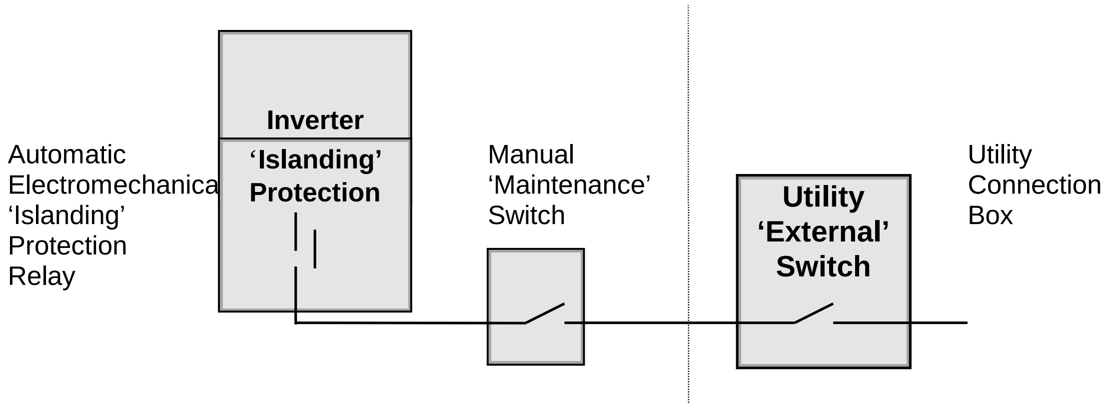


Figure 11.1 External Disconnect Methods

External switch Mounted outside the building and accessible to the Utility at any time. Typically a mechanical switch with a mechanical lock-off facility. Operated before carrying out maintenance work on the ac network.

Maintenance switch Mounted inside the building, typically near to the output from the inverter, without permanent access to the Utility. This would be used by the PV system owner to isolate the inverter from the mains when carrying out maintenance on it.

Electromechanical protection This is automatic protection in the form of a relay operated automatically when the Utility mains is sensed to have exceeded a range of pre-set limits. It is the protection provided against 'islanding', and is covered in more detail in Chapter 9.

The main trade-offs are summarised in the table 11.1.

Table 11.1 Trade-offs

Type of switching and position		Comments
External Disconnect Switch	Mechanical, typically with mechanical lock-off. External to building permanently accessible to Utility	Expensive to install Unlikely to be operated if many systems No protection for illegal connections At the moment an explicit requirement for many Utilities Designed for larger centralised generators
Mainten-ance Switch	Mechanical, typically internal to building without permanent access to Utility	Would probably be installed anyway to allow maintenance of inverter Relatively cheap as standard switch mounted close to inverter Not permanently accessible to Utility as typically inside building
Automatic Electromec hanical Protection	Automatic islanding protection from electromechanical switch triggered by mains power being sensed to be outside pre-set parameters	Not as certain an isolation as a mechanical switch; no guarantee that would not reconnect if faulty (no manual reset) Would need to be combined with operational procedure to check for residual generation and ground conductors using earth sticks or similar

11.5 Experimental work

11.5.1 External Switch

The table 11.2 summarises current Country policies. Testing of external switches is not considered necessary as they are conventional isolator switch units.

Table 11.2. Experiences of External Disconnect Switches

Country	Necessity of external disconnect switch	Location of disconnection	Comments	Regula-tions/ stan-dards
Austria	Generally required; can be omitted in case of single phase inverter feeding into three phase grid if three phase over/undervoltage relay is installed	AC-side; not specified, but explicitly stated that it may be inside the inverter	Only mandatory on 3 phase inverters	3.3.5
Germany	Generally required; not necessary if a single phase inverter feeds into a three phase grid via a three phase undervoltage relay New alternative: 'MSD' (see Para 11.4.3) redundant isla-nding detection circuitry may replace external switch. MSD has to be approved in a defined test	To be accessible to Utility people at any time	‘Automatic Isolating Facility for house-load generators, e.g. photovoltaic installations, with a rated output ≤ 4.6 kVA with a single phase parallel feed by means of an inverter into the public low voltage mains’	VDEW Guidelin es /1/

Country	Necessity of external disconnect switch	Location of disconnection	Comments	Regula-tions/ stan-dards
Italy	Mandatory	Access by the Utility required	Italian standards impose the external disconnector because of the present procedures regarding safety during maintenance	
Japan	Disconnection from the system should be carried out by two mechanical switches or by one mechanical switch and power inverter gate block, etc. When the passive system of the islanding detecting function is operating, however, the power generating facilities can be disconnected only by the power inverter gate block to prevent unnecessary operation. For self-contained operation, disconnection should be carried out by two mechanical switches or by one mechanical switch and one manual switch.	Each mechanical switch for disconnection should be located at one of the following devices where the power generating facilities can be disconnected from the system: 1 Receiving breaker 2 Power inverter output port breaker 3 Power inverter link breaker.	Each mechanical switch for disconnection should be installed in such a manner that prevents, for assuring safety, the switch from being turned on during service interruption of the system and in a certain time after system recovery so that the power generating facilities cannot be interconnected with the system in those durations	Guideline for Technical Requirements for Interconnection with System (updated October 1995)
Ne-therlands	No	N/A	Not necessary. Philosophy is that good earthing is better than to rely on administration of dispersed generators. With maintenance on a feeder, special grounding precautions are always taken. Illegal power generation units cannot lead to dangerous situations	
Switzerland	Generally required	AC-side; permanently accessible to the power utility at any time. (household: external to the building, industrial: close to the main grid connection)	Depending on the power utility if mandatory or being omitted in the case of single phase inverter. For three phase inverter it is mandatory.	Guidelines STI No233.0690d VSE 2.8d-97
UK	A lockable means of isolation accessible to the REC is required to allow disconnection from the system	To be accessible to REC staff at all times without undue delay	UK Engineering Recommendation G59/1 states that an external disconnector is mandatory, but this is primarily intended for large single site rotating generators. It is anticipated that the Utilities may relax the rules for PV connections provided that reliable isolation can be built into the inverter	Engineering Recommendation G.59/1 & E.113

Country	Necessity of external disconnect switch	Location of disconnection	Comments	Regula-tions/ stan-dards
USA	The National Electrical Code requires that the inverter have a means to disconnect the equipment from all ungrounded conductors of all sources. Generally this is interpreted as meaning external dis-connects so the inverter can be totally de-energised	Disconnects are required to be grouped and in close proximity by the NECode. Disconnects may not be higher than 6.5 feet above the walking surface	External disconnects are required for PV systems in the USA. Disconnects that provide positive, visible breaks are required by the National Electrical Code. Disconnects and circuit breakers that are internal to the power con-ditioner may provide the necessary breaks for oper-ation, but do not provide means to connect and dis-connect the power conditioner hardware from the Utility	NECode ANSI/NFPA7-011.4.2

11.5.2 Anti-islanding Methods

It is generally agreed that if anti-islanding devices were used for the external disconnect function, they would have to be relay devices with a physical opening of contacts rather than an electronic semiconductor switch. The comments from the countries are summarised in the table 11.3. Anti 'islanding' devices will be tested under a separate work package.

Table 11.3 Experiences of Anti-islanding Switches at April 1995

Country	Mechanical or electronic switching?
Germany	Electromechanical relay contact in islanding prevention scheme is required, tested with approx. 4000Vac for 'safe separation'
Japan	When the passive system of the islanding detecting function is operating, however, the power generating facilities can be disconnected only by the power inverter gate block to prevent unnecessary operation.
Italy	The anti-islanding device consists of two parts: a protective relay based on voltage and frequency detection, and a mechanical device (contactor or circuit breaker) on which the protective relays operate to physically disconnect the inverter from the grid. The anti-islanding device must be approved by means of type tests.
Netherlands	Yes, for maintenance a disconnection of physical contacts is necessary
Switzerland	The anti-islanding device consists of two parts: a protective relay based on voltage and frequency detection, and a mechanical device (contactor or circuit breaker) on which the protective relays operate to physically disconnect the inverter from the grid (all phases). The anti-islanding device must be approved by means of type tests.
UK	A static isolation switch is required by Engineering Recommendation G.59/1 Para 6.2.5 as follows: '6.2.5 Points of Interconnection and Means of Isolation Every installation or network which includes an embedded generating plant, operating in parallel with the REC's supply, must include a means of isolation, (suitably labelled) capable of disconnecting the whole of the embedded generating plant infeed from the REC's network. This means of isolation must be lockable, in the open position only, by a separate padlock. Access to the points of isolation should be kept clear and unobstructed. The embedded generator must grant the REC rights of access to the means of isolation without undue delay and the REC must have the right to isolate the embedded generator's infeed at any time as network conditions dictate. The means of isolation should normally be installed close to the metering point, but may be positioned elsewhere with the REC's agreement. It is assumed that this will also be required for small PV systems

Country	Mechanical or electronic switching?
USA	Some power conditioners contain circuit breakers but external disconnects are needed to safely connect and disconnect wires to the hardware. Other power conditioners contain relays to provide operating disconnects for overvoltage, and other out-of-spec Utility conditions or when PV input falls below operating levels

11.5.3 The German MSD philosophy

In Germany the Employer's Liability Insurance Association has examined the risks associated with excluding the External Disconnect switch in a formalised risk assessment to European Specifications, and have concluded that this is acceptable provided that the automatic relay replacement is approved in a Type Approval test overseen by themselves.

At present the requirements and tests are specified in 'Automatic Isolating Facility for house-load generators, e.g. photovoltaic installations, with a rated output ≤ 4.6 kVA with a single phase parallel feed by means of an inverter into the public low voltage mains'.

This requires that there are two independent monitoring devices each connected to independent switching devices in the ac output (MSDs). One of these devices must be an electromechanical device with the features of a mains load-cut-off relay, although the second may be the power stage of the inverter.

The following is taken from a paper that appeared in the magazine of the Employer's Liability Insurance Association 'Information for the Safety Expert':

The corresponding safety integrity level and the technical measures adequate for this level were determined based on the risk analysis and the cited safety-relevant standards. The standards and pre-standards for functional safety up to the committee drafts for voting (CDV) IEC 65 A/179-185/1995/96 which are applied pre-standards of the future IEC 1508 'Functional Safety - Safety Related Systems' with pilot function, have consistent requirements so that a clear unambiguous requirement basis for automatic isolating facilities exists.

This procedure which is particularly established in the area of machine safety and protective circuits here has been extended to a new area of electrical engineering.

DIN V 19250 'Measurement and Control; Fundamental Safety Aspects to be Considered for Measurement and Control Equipment' comprises the risk graph of Damage Consequence, Exposure Time, Hazard Avoidance and Probability of Unwanted Occurrence. Applied to the automatic isolating facility the most probable damage consequence would be S2 'Serious Permanent Injury to one or more Persons or Death of a Person'. The exposure time is the time required for work at the supposed isolated mains to all sides i.e. A2 'More Frequent to Permanent'. For the avoidance of hazard G2 'Almost Impossible' from the grid which is also applicable to the area of mechanical engineering is relevant, since the electrical expert touching the live, supposedly isolated network has no further chance of avoiding the danger. If however, the electrical expert observes the five safety rules, i.e. 'Isolation, Safeguard to Prevent Unintentional Restarting, Verify Safe Isolation from Supply, Earthing and Short-circuiting as well as Covering and Fencing Adjacent Live Parts', the group W1 'Very Slight' up to W2 'Slight' results for the probability of the unwanted occurrence. The measure Single Fault Safety with Fault Detection and Subsequent Operation Blockage which is technically realisable by the co-operation of e.g. diversity, self monitoring, fail-safe principles, etc. corresponds in accordance with DIN 19251 'Control Technology, MC Protection Equipment, Requirements and Measures for Safeguarded Function' to the safety integrity level 3/4 obtained in this way.

The better known EN 954-1 'Safety of Machinery - Safety Related Parts of Control Systems - Part 1: General Principles for Design' as well as the committee drafts IEC 65A(Sec)123 'Functional Safety of Electrical/Electronic/Programmable Electronic Systems - Generic Aspects - Part 1: General Requirements' and DIN IEC 65A(Sec)122 'Software for Computers in the Application of Industrial Safety-Related Systems' with their successor papers IEC 65 A/179-185/CDV - all very detailed and competent. The last-mentioned standards lead to a deep understanding of the risk-related functional safety and give information on special problems, but regarding application they led to the same requirement with the same technical realisation possibilities of the automatic isolating facility.

The result of the work of the committee 'Safety Aspects and Islanding' [the Employer's Liability Insurance Association together with inverter manufacturers and representatives of the power supply companies] is that all new inverters which will get on the market must be subjected to a type test for isolation under islanding conditions and for the design of the isolating facility in accordance with the requirements of the safeguarded function of M/C protection equipment.

This type testing will be effected in accredited test bodies, at present in the Test and Certification body of the technical committee 'Electrical Engineering' under the overall control of the Employer's Liability Insurance Association for the Precision Mechanics and Electrical Engineering Industry.

11.6 Conclusions

Some means of external disconnection is a necessary requirement from all Utilities in all countries. At present individual Utilities require solutions that are based on their current operational practices. As distributed generators become more common it is expected that Utilities will be guided by developments and change their approach as they react to the new situation.

For PV it is hoped that the situation evolving in Germany and the Netherlands can become the norm, where the external switch is not mandatory, and the Utility relies on the relay 'islanding' protection and their practices for checking and grounding the conductors before carrying out maintenance.

11.7 Recommendation for future work

It is important to recognise that the problem is not specific to PV but also applies to other embedded generators, and so it is sensible to harmonise with other IEC work being carried out in this area.

When more information is available from the anti-islanding work, then these devices should be tested as part of Subtask 30 to assess their suitability to provide the function of the external disconnect also, and a recommendation be made

12. RE-CLOSING

12.1 Summary

By re-closing, it is meant the automatic procedure used by the distributor to reduce the duration of the power supply interruption to the users caused by network faults. Therefore, no procedures relevant to the manual re-closing operations carried out by the personnel is considered in this chapter.

Re-closing is utilised by the distributor on the MV network but, as MV networks are usually operated in an open-ring scheme, it has consequences on the downstream LV network where PV systems are connected.

In fact, the re-closing procedure may lead to out-of-phase parallel conditions with consequent potentially dangerous stress for the inverters, for the loads, for the line-breakers and for the transformers installed on the utility network.

The chapter illustrates the re-closing principle of operation, the effects of the automatic re-closing and gives an indication of the counter-measures that can be adopted in order to overcome the above mentioned problems.

12.2 Introduction

The analysis of the technical aspects regarding the connection of the PV systems to the LV network, leads to the need to deal with the re-closing.

By re-closing, it is meant the automatic procedure used by the distributor to reduce the duration of the power supply interruption to the users caused by network faults. Thus, no procedures relevant to the manual re-closing operations carried out by the personnel shall be considered in the next sections.

In general, all distributed generating systems, and PV systems too, that operate in parallel to the LV distribution networks, may be affected by the automatic re-closing used by the distributor.

In fact, the re-closing procedure may lead to out-of-phase parallel conditions with consequent potentially dangerous stress for the inverters, for the loads, for the line-breakers and for the transformers installed on the utility network.

In the following, the principle of operation and the effects of the automatic re-closing will be illustrated as well as some counter-measures that can be adopted.

12.3 Scope of work

The scope of this section is to shortly illustrate the re-closing procedures and to provide inverter manufacturers with technical information about the electrical phenomena relevant to the re-closing procedures.

12.4 Theoretical results

12.4.1 Motivation of automatic re-closing

The service quality of the electrical networks is characterised by several parameters, one of which is the continuity of the electricity supplied, which can be interrupted as a consequence of fault.

As regards the overhead lines, it has been noticed that many faults are temporary. In fact, the search for the fault often leads to negative results and, on the following re-closing of the line-breaker, the service is regularly resumed.

For example, with reference to the Italian MV distribution network where the automatic procedure is adopted, the percentages of the faults recorded in 1988 indicate that 90% of faults occurring on the MV overhead lines can be eliminated by the automatic re-closing.

It is worth noting that the percentage corresponds to the national distribution network average, of course the number of events mainly depends on the line features (line length, number of arresters,...) and the environmental conditions (mountain installation, pollution,...).

As regards the cable distribution networks, the situation is completely different. In fact, the available data of the Italian MV cable distribution network show that faults are approximately 5/year per 100 Km, practically all of them of the permanent type.

Therefore, the automatic re-closing is usually operated on overhead distribution networks only.

12.4.2 Principle of operation of automatic re-closing

As IEA - Task V is interested in PV generating systems mainly connected to the LV networks, the illustration of the phenomena relevant to the automatic re-closing will be limited to the LV and MV networks. In fact, also MV networks must be considered because they are usually operated in an open-ring scheme, so that re-closing carried out on the MV network has consequences on the LV network downstream and therefore on the PV generating systems connected.

The automatic re-closing is usually a device that automatically activates after the line-breaker opens because of fault and that, after a defined waiting time (dead time), operates the re-closing of the line-breaker itself. The use of the automatic re-closing is thus possible only with protections that automatically can be resetted when causes that have caused their intervention, and with line-breakers that can be operated by a remote control, therefore is generally possible/available on the MV network only as confirmed by information contained in the document “Information on electrical distribution systems in IEA related Countries” prepared by IEA PVPS Task V - Subtask 10.

Although the automatic re-closing, as previously illustrated, can eliminate a large number of the temporary faults that occur in the MV overhead lines, it causes an interruption in the electrical power supply, whose duration is determined by the dead time preceding the re-closing of the line-breaker. Such a period must be sufficiently long to guarantee the fault self-extinction, but the shortest possible to minimise the interruption for the users.

From the information supplied by the participating countries, and reported in the document "Information on electrical distribution systems in IEA related Countries" prepared by IEA PVPS Task V - Subtask 10, it can be deduced that the operation principle adopted is generally the following:

- detection of single-phase or multiphase fault by means of protections,
- opening of the line-breaker,
- waiting for a "sufficient" time for the fault self-extinction (< a few seconds),
- fast re-closing of the line-breaker,
- possible new opening in case of the fault's permanence,
- waiting for a sufficiently long time for the fault self-extinction (about a few minutes),
- slow re-closing of the line-breaker.

From the above, it can be stated that in the MV overhead lines two automatic re-closings are used, a fast and a slow one.

As slow automatic re-closing takes an estimated time of around some minutes, the relevant problems seem to be much closer to those of the islanding phenomenon than to those of the properly called automatic re-closing. Therefore the followings the attention will be focused on the fast re-closing and the effects that it can have on the PV distributed generating system.

12.4.3 Potentially dangerous effects of the automatic re-closing

The automatic re-closing is usually operated on the MV overhead networks only, but it have repercussions on the network downstream (usually the MV network has a tree or open ring structure) and therefore on the LV network where small-size PV systems are connected.

The potentially dangerous effects of the re-closing operation can be divided between:

- aspects concerning the distribution network, and
- aspects relevant to the PV distributed generating systems connected to the distribution networks.

The main aspects concerning the distribution network are:

- the stress on the line-breakers that must withstand two heavy close operation in case of permanent fault,
- the "inrush" current that may raise when a re-closing operation is carried out and that may affect transformers, protections, circuit breakers, feeders,
- the possibility that the distributed generating systems continue to supply the fault during the dead time before the fast re-closing, not allowing the fault to self-extinguish and thus making the following re-closing to fail.

On the other hand, as regards the aspects relevant to the PV distributed generating systems connected to the LV distribution network, the effects basically concern the possibility of a parallel operation between the network and the PV system, with such a phase difference to cause dangerous stresses for the PV system itself.

In particular, the possibility of out-of-phase parallel operations can be illustrated with reference to figure 1.

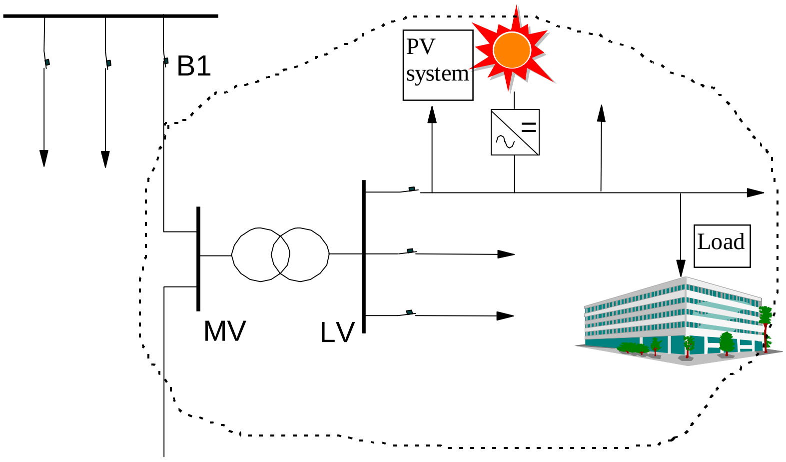


Figure 1 MV network re-closing affecting PV system connected to the LV network

- In case of (single-phase or poli-phase) fault, the MV line-breaker B1 is opened.
- During the dead time (a few seconds) before fast re-closing is operated, an electrical island may be formed by the PV generating system (including all the other distributed generating systems installed) feeding part of the distribution network (dashed area in figure 1). Under these circumstances, the distribution network and the PV-system supplying the islanded network will not usually have the same voltage and, above all, the same frequency. In fact, while the distribution network frequency remains supposedly almost steady, the frequency of the PV system supplying the islanded network may shift. Consequently, the phase difference between the two voltages (distribution network and electrical island) increases. The amount of that phase difference basically depends on the active and reactive power exchange. (In principle, if the power exchange was perfectly balanced, that is the PV system (including all the other distributed generating systems installed) was able to supply all the active and reactive power required by the load, the frequency of the islanded system, would remain steady, and would prevent possible frequency protections from intervening)
- On the following fast re-closing, a sudden out-of-phase parallel would occur between the two systems, that could cause dangerous stresses on the PV system, and, in particular, a considerable increase of the inverter current.

However, it must be pointed out that the possibility for the above described phenomenon to happen are very low, because:
- the active and the reactive power supplied by the distributed generating systems is usually much lower than that required by the load,
- the distributed generating systems are usually interfaced to the distribution network by means of inverters equipped with frequency and voltage protections that intervene if the frequency and voltage values should exceed the nominal field (due to the unbalance mentioned in the preceding point).

The effects of the fast re-closing on the PV systems have been documented through various lab tests and/or field recordings. Some of them are reported in the “Experimental results” chapter.

12.4.4 Counter-measures to avoid the fast re-closing effects.

In order to overcome the problems that have been pointed out previously, since we cannot imagine that the utility gives up the automatic re-closing, the distributed generating systems must be equipped with suitable protections that are able to disconnect those systems from the network before the line-breaker re-closes. For example, the inverter manufacturer should provide for a frequency protection whose setting (fn±Δf),will depend on:

- The allowed phase difference (φlim) between the network voltage and that of the distributed generating system, compatible with a safe parallel operation.
- The dead time usually used before fast re-closing operates (Δt), according to the following expression:

$$\Delta f = \pm \frac{\varphi_{\lim}}{\Delta t} \quad (1)$$

An appropriate frequency protection setting seems to be in the range of ±1 Hz. Moreover, expression (1) allows to evaluate the maximum phase difference that the distributed generating system will have to withstand during the re-closing procedures

12.5 Experimental results

This chapter reports some tests carried out at the CESI laboratory (Italy) by ENEL S.p.A. (Italy) and at the Rokko Test Center for Advanced Energy Systems in Kobe (Japan), with the aim to investigate the behaviour of inverters in the event of loss of the network, followed by islanded operation and fast re-closing. Both the tests were planned to verify the inverters behaviour in case of re-closing operation by measuring the currents flowing through the inverters themselves. Furthermore, the current flowing through the circuit-breaker installed in the distribution network was recorded, to check the stress that had to be withstanded.

12.5.1 ENEL tests

The ENEL tests were carried out on the following inverters:
- Siemens line-commutated, 5kW,
- Sun-Power self-commutated, 5 kW, current control,
- Invertomatic self-commutated, 20 kW, current control,
- Omnion self-commutated, 20 kW, current control.

and are described in the ENEL internal report “Laboratory and field tests on generating PV systems equipped with line or self commutated dc/ac converters” - November 1994.

Fig. 2 shows the test circuit that was so arranged in order to check the re-closing procedure effects by opening the circuit breaker SW, waiting for 300 ms. (i.e. the dead time usually used in the Italian distribution network), and finally re-closing SW.

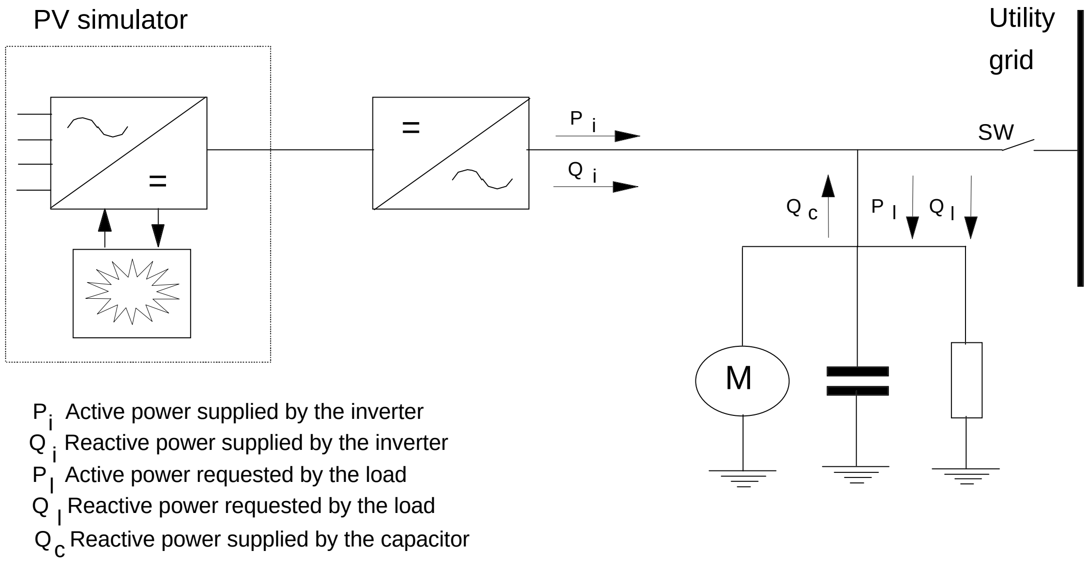


Fig. 2 ENEL test circuit

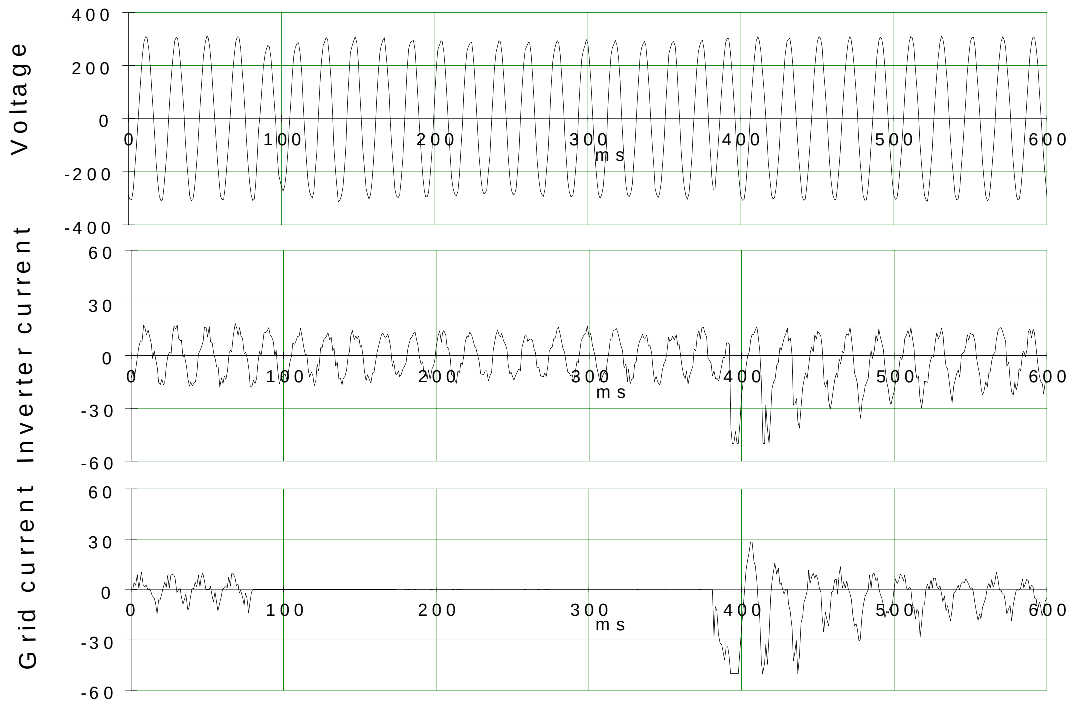


Fig. 3 Re-closing test

Fig. 3 shows an example of quantities recorded during a re-closing test.

12.5.2 Rokko Island tests

Further tests on the effects that re-closing can have on PV-systems were carried out at the Rokko Island Test Center and are reported in the paper “Demonstration Test on PV-grid Interconnection at Rokko Test Center (Re-closing of distribution circuits during islanding)” - A.Kitamura, K.Nakaji, ...issued at the Technical Digest of the International PVSEC-7, Nagoya, Japan, 1993.

The main results of these tests can be summarised as follows:

- measurements showed that the transient overcurrent flowing through the PV inverters were two times the rated current for the current-controlled inverters, whereas it reached five times their rated current in the case of voltage-controlled inverters. In all cases the duration of the transient current was about one cycle;
- the highest transient overcurrent measured at the substation line-breaker was about ten times its rated current and the duration of the transient was as short as about one cycle.

12.6 Conclusions

The analysis of the technical aspects regarding the fast re-closing effects shows that fast re-closing operation may cause large amounts of transient overcurrents flowing through both inverters connecting PV systems to the distribution network and the distribution network itself.

In fact, the fast re-closing procedure may lead to out-of-phase parallel conditions with consequent potentially dangerous stress for the inverters, for the loads, for the line-breakers and for the transformers installed on the utility network.

In order to overcome the above mentioned problems, inverters connecting PV systems to the distribution should have a capability of withstanding the disturbances due to the automatic re-closing.

Some example of experimental results have been illustrated showing the re-closing effects on inverter connecting PV systems to the utility network, as well as on the transformer and on the line-breaker of the utility network.

13. ISOLATION TRANSFORMER AND DC INJECTION

13.1 Summary

Transformerless inverters gain increasing importance for grid-connected PV systems due to technical and economical advantages. Contrary to current technology, which mostly relies on transformers built into the inverter, transformerless inverters offer no inherent protection against a dc component fed into the utility's network.

A dc current fed from the customer's side into the grid can disturb the regular operation of the upstream distribution transformer. It can shift the transformers operating point and cause saturation. This would result in high primary current peaks, which might trip the input fuse and thus cause a power outage to that specific section of the grid. It would furthermore cause increased harmonics.

An overview is given how the participating countries view the requirement for an isolation transformer. The possible impact of a dc current on the operation of a distribution transformer was assessed using literature review and laboratory experiments.

Findings:
- From the references it can be concluded that dc components from a transformerless inverter may cause saturation effects in the local distribution transformer. However, a disruption of the utility service is to be unlikely.
- The experiments showed that primary currents from secondary ac and pulsed dc components linearly superimpose.
- Under high dc components high primary current peaks occur. Also, a high level of harmonics is generated.
- The pulsed dc component may reach levels around 10 % of rated current without jeopardising the proper operation of the transformer.

The hazard of dc currents from small PV systems for the local distribution transformer seems to be negligible. A general requirement for isolation transformers for PV inverters is not justified. The very unlikely case of equal dc currents to each winding of a 3-phase transformer could not fully be resolved

13.2 Introduction

A dc current fed from the customer's side into the grid may disturb the regular operation of the grid. It can shift the operating point of the local distribution transformer and lead to transformer saturation. This would cause high primary current peaks, which might trip the input fuse and thus cause a power outage to that specific section of the grid. It would furthermore cause increased harmonics.

Many inverter designs employ transformers. These suppress any dc component by design. However, transformerless inverters gain increasing importance due to technical and economical advantages. Thus, the possible impact of this concept on the operation of the grid has to be assessed. This chapter addresses the effects of dc components fed into the grid and assesses the possible consequences for the utility's service.

13.2.1 Transformerless Inverters

To exclude any hazard by dc injection, regulation bodies in some countries, respectively some utilities, require an isolation transformer between a PV system and the public grid. However, a quest for cheaper inverters and higher efficiency calls for transformerless inverters. Omitting the transformer means:
- reduced no-load losses
- lower weight
- lower volume
- lower costs
- inherent chance of feeding a dc current into the grid.

13.3 Scope of work

This chapter gives an overview on the relevant regulations in the participating countries and it discusses requirements for transformers. It gives information on what happens, when the transformer is exposed to a dc component. Last not least, it addresses the potential risk for a utility company to deteriorate the quality of its service to the customers.

The method of investigation is literature research and laboratory experiments. Both will be reported in the following sections. It must be emphasised that this report focuses on grid-connected PV systems employing inverters with a current source characteristic. The situation in stand-alone systems with voltage-source inverters needs different considerations.

13.4 Theoretical results

This section summarises the requirements for isolation transformers in the participating countries. It furthermore outlines the existing knowledge on dc components into the public grid.

13.4.1 Isolation Transformer

Using a transformer to electrically separate a PV system from the public grid involves several technical issues:
- voltage step-up
- grounding scheme
- transient suppression
- safety requirements
- dc injection.

A transformer offers the advantages of an arbitrary operating voltage of the PV system. It allows a free grounding scheme to be selected and it provides a certain degree of transient voltage suppression from the grid. A transformer definitely suppresses any dc injection into the grid. The main reason to integrate a transformer into an inverter is based on personal safety measures: if Class III, i. e. safety low voltage according to IEC 364, is selected as a protective measure for personal protection, then the open circuit voltage of the array is limited to 120 V /1/.

The need for an isolation transformer is viewed differently in different countries as indicated in table I.

Table 1 Isolation transformer requirement in different countries

Not required	It depends	Required
Germany	Australia	Italy
The Netherlands	Austria	
Portugal	Japan	
Switzerland	Great Britain	
	USA	

In some countries the requirement for an isolation transformer depends on technical features of the inverter. If the inverter employs a dc monitoring scheme, then the requirement of an isolation transformer is waived. Some countries leave it to the utilities whether to require an isolation transformer or not /2/, /3/.

13.4.2 DC Injection into the grid

There are very few regulations concerning dc injection. The standard IEC 1003-2 (limits for harmonic current emissions) allows half-wave rectifiers up to 50 W /4/. This corresponds to approximately 0.22 A. Only in one country, Australia, has a standard explicitly limits dc components into the grid. This Australian standard AS 3300 /5/ allows a daily total of 120 mAh. 120 mAh means 5 mA for continuous load and up to 1.44 A for an operation time of 5 minutes. An exception is made for half-wave rectifying equipment: up to 100 W power is permitted. This corresponds to a current of approximately 450 mA.

Anecdotal evidence suggests that the AS 3300 limits were derived, to prevent corrosion of the installation's earth-electrode, to prevent poor rectification stages being used in appliances (which in number will affect grid quality) and nuisance tripping of earth leakage circuit breakers /12/.

In Japan a dc component of less than 1 % of nominal inverted power is required for transformerless inverters /6/.

In Germany appliances like hair blowers regularly employ half-wave rectifiers to reduce power. This causes dc power of approximately 400 W and pulsed dc currents of about 5 A peak value. The German "Association of Electric Utility companies" (VdEW) is not aware of any problems caused by dc injection /11/.

Wills /7/ discussed the problem rather generally for a north-american grid structure. He doubts that a dc component from a smaller PV system can indeed affect the power supply to other customers on the same transformer. He sees no need for an isolating transformer, and believes that electronic protection circuitry in transformerless inverters adequately solves the problem.

Klein and others /8/, perform a theoretical analysis to determine the time elapsing between a dc injection fault and transformer saturation. They assume a constant dc current fed into the transformer, again for the US grid. This leads to some 1 to 5 seconds for a counteraction before the transformer saturates.

This paper considers a crude approximation, a truly constant current, which does not represent the real effects. The grid voltage will always ensure that the transformer core is reset in consecutive cycles. The reported conclusions are thus too pessimistic.

From the above references it can be concluded that dc components from a transformerless inverter may cause saturation effects in the local distribution transformer. However, a disruption of the utility service caused by this seems to be unlikely.

13.5 Experimental results

13.5.1 Field experiments

There are two reports on experiments with dc injection into the public grid. Kitamura /9/ reports on experiments in a simulated Japanese grid where a PV generator is connected to the transformer via a resistor. No inverter is employed. No further load was connected. Transformer saturation was observed with primary current during saturation peaking at about 130 % of the nominal value. Apparently, transformer operation was not interrupted.

Germany's biggest utility, RWE, runs a field experiment with 25 PV systems, 2 kWp each, in a dense urban settlement. All systems use the same type of line commutated, transformerless inverter. All system feed the same phase. Hotopp and others /10/ report that they found a typical dc component between 0 % and 5 % of the fundamental current for a single inverter and a maximum dc component of about 4 A for all 25 inverters. During one year of testing, these dc components did not cause any disturbance of the grid.

13.5.2 Laboratory experiments

To gain an understanding of the effects of dc injection into a transformer, we conducted tests simulating a defective PV inverter. We wanted to answer three questions:

- How does a secondary dc component influence the primary current?
- Does the effect of a given dc current level on the primary current depend on the ac load of the transformer?

Assuming an ac load of the transformer of about 80 % of its rating (which is a reasonable value for distribution transformers), how much dc could be tolerated without excessive primary current peaks?

13.5.3 Assumptions

We assumed that the hazard of dc injection mainly stems from two mechanisms. One is a soft control error, which creates a dc component by a slight asymmetry between positive and negative half-waves. The other is a failure of a power switch in an inverter output bridge into permanently "off" state. This leads to a signal like a half-wave rectified current. The corresponding wave shapes are depicted in figure 1 for a 50 Hz grid. Power stage failures resulting in a short circuit of a power semiconductor are not considered. They will most likely blow the mandatory branch fuse.

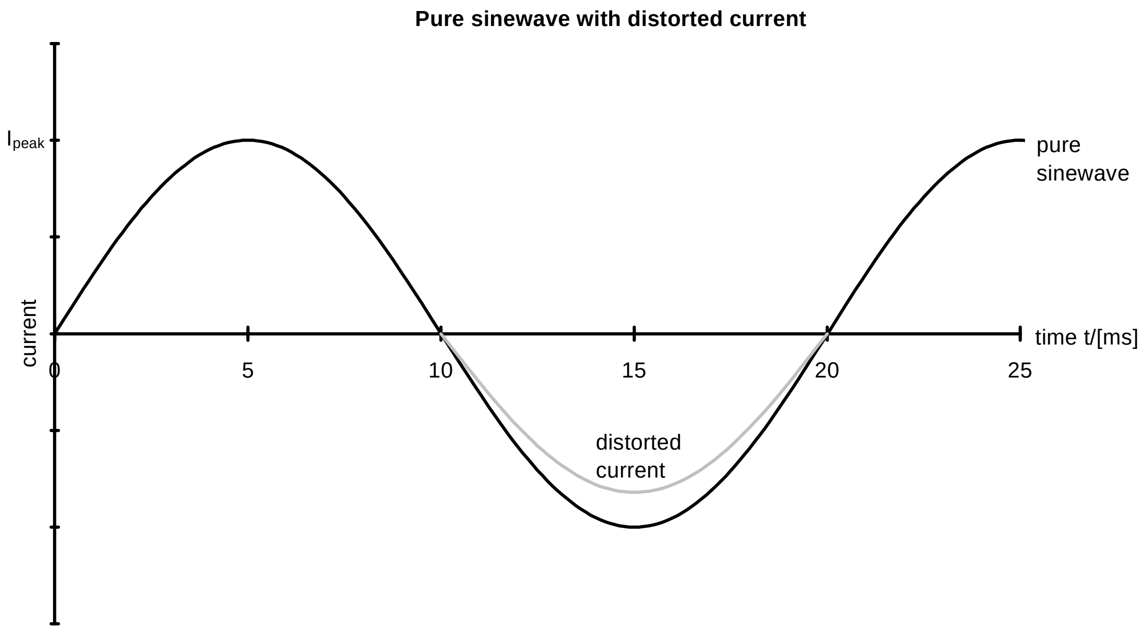


Figure 1 Current with an asymmetrical wave shape.

13.5.4 Experimental arrangement

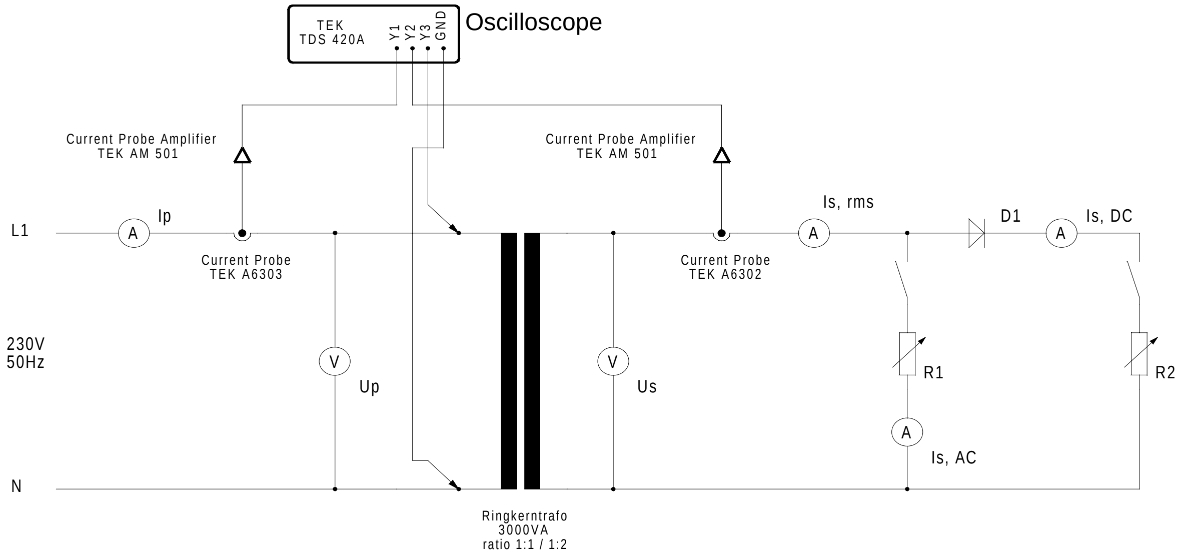
Based on these assumptions we built a test set-up as shown in figure 2 using a toroid transformer of 3 kVA as a model. The relative short circuit voltage Vsc is 4%. This corresponds well with a LV distribution transformer. Table 2 gives the technical data of the transformer.

Table 2 Technical data of the model transformer

Vn	230 V
In	13.6 A (rms)
Vsc	4 %

The transformer was connected to the 230 V grid at the primary side. The nominal input current of the transformer was 13.6 A (rms) corresponding to a peak current of approximately 20 A for a sine-wave shaped current. At the secondary side a variable resistive load, R1, was connected to produce the ac load.

Parallel to the ac load a second load was connected consisting of another variable resistor, R2, in-series connected with a power diode, D1. This branch produced a pulsed dc current of variable amplitude. We could change the ac load between zero and more than nominal rating and we could vary the dc component between zero and half the nominal current.



Symbols used			
Up	Primary voltage (line voltage)	Ip,rms	Primary current, rms value
Ir	Rated current (primary)	Is	Secondary current
Ip	Primary current	Is,peak	Secondary peak current
Ip,peak	Primary peak current	Is,rms	Secondary current, rms value

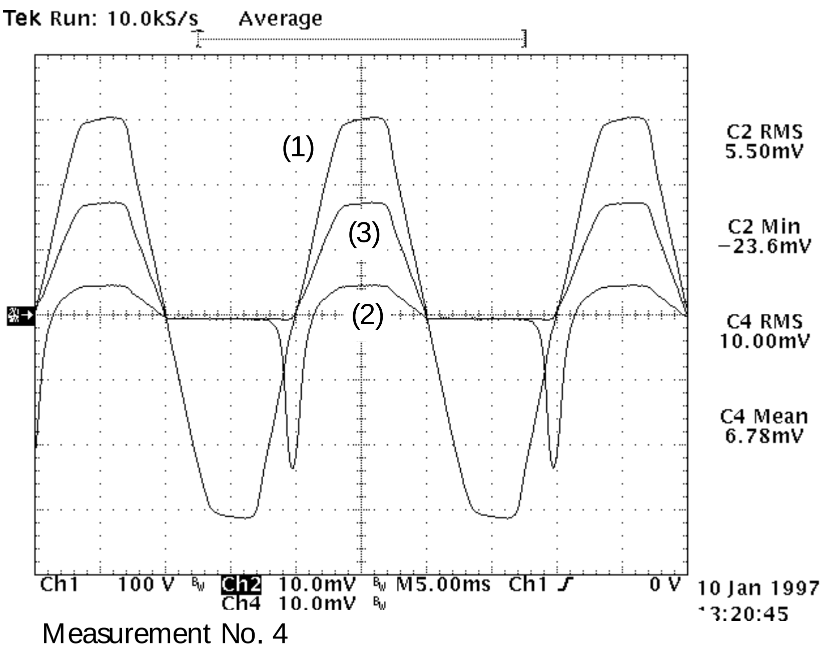
Figure 2 Experimental arrangement for dc injection.

Primary current Ip, secondary current Is and line voltage Up were recorded with a Digital Storage Oscilloscope (Tektronix TDS 420 A). All currents were measured using "true rms" current meters. According to the initial questions we performed three sets of experiments:

- varied pulsed dc currents - no ac load
- constant pulsed dc load - variable ac load
- high, constant ac load - variable pulsed dc load

13.5.5 Pulsed dc currents without ac load

First the transformer was subjected to pulsed dc current only. The dc current was increased from 0.5 Arms to 7.5 Arms, which is about half the transformers rated current. Figure 3 shows the relevant electrical signals of one test record.



Is,rms = 5 A
Ip, rms = 11 A
Ip, peak = 47 A

Measurement No. 4
(1) Up: 100V/div (2) I_p: 20A/div (3) I_s: 5A/div

Figure3 Line voltage Up, (1), primary current Ip, (2), and secondary current, Is, (3) for a pulsed dc load.

The dc component causes a sharp peak in the primary current, when the transformer approaches saturation. This peak reaches 47 A for a dc component of 7.5 Arms compared to a rated peak current of 20 A. Despite the high peak current, the corresponding rms value is only 11 A. This is below the rated transformer current of 13.6 A. Thus, the high peak currents cannot cause an immediate action of a primary fuse, because the rms value is too low. There would be no hazard of a local black-out, even under the presence of a significant dc component. The situation can be different, if electromagnetic or electronic overcurrent devices are used for the distribution transformer output.

The results of this test run are summarised in figure 4. Peak value and rms value of primary current are plotted against the secondary dc current rms value. Figure 4 shows that the primary current increases almost linearly with dc current. Primary peak current is nearly 4 times higher than its rms value. It needs about 6 A of dc until the primary current exceeds the rated value.

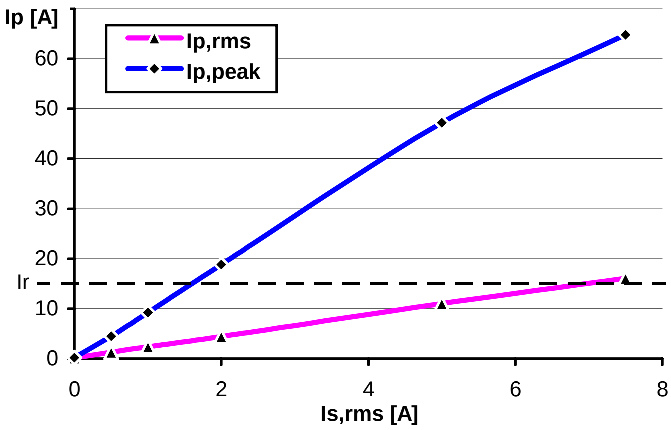
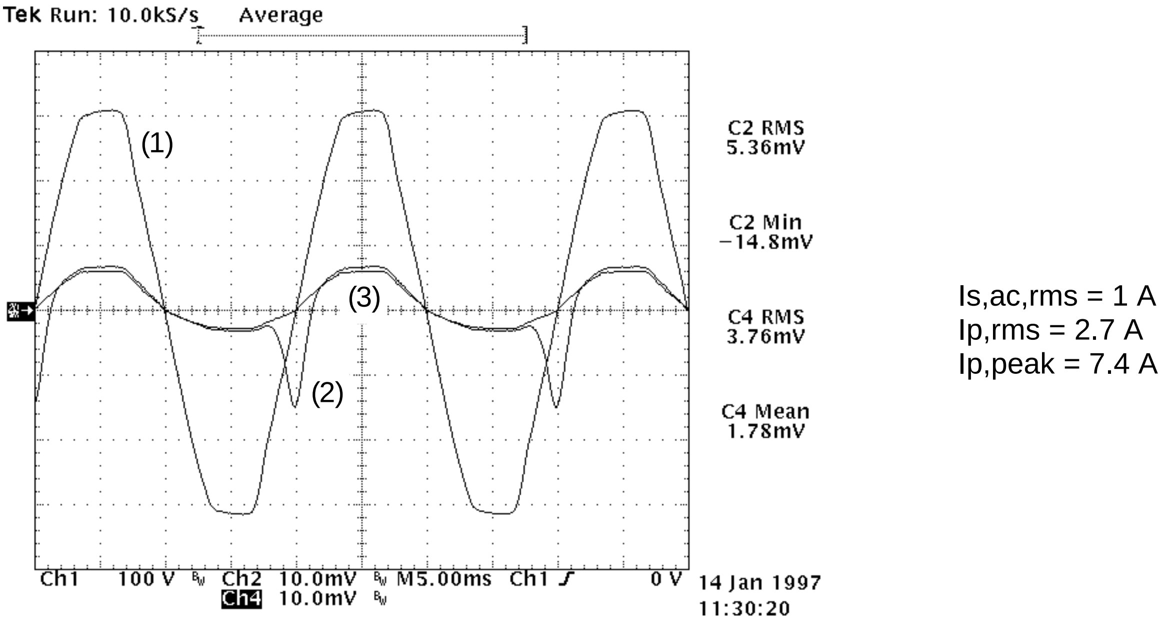


Figure 4 Primary current versus secondary dc current; no ac load. Ir indicates the rated primary current. It needs a high dc component to exceed the rated current Ir.

13.5.6 Constant dc load - variable ac load

For this set of measurements a constant dc load of 1 A (rms) was set. The ac load was varied between 1 A (rms) and 12 A (rms). Figure 5 shows the signals for an example shot with an ac load of 1 A.



Measurement No. 2
(1) Up: 100V/div (2) I_p: 5A/div (3) I_s: 5A/div

Figure 5 Line voltage Up, (1), primary current Ip, (2), and secondary current, Is, (3) for a dc current of 1 A and an ac load of 1 A.

Primary currents due to dc load and ac loads appear to be linearly superimposed. The peak in Ip of 7.4 A resulting from the dc component is constant and it stays visible up to full ac load. However, at high ac loads it appears as a minor distortion of the waveshape. Please, refer also to figure 7. Figure 6 summarises this test run. Peak and rms values of primary current are plotted against the secondary rms value of the current. Ir indicates the rated current (rms) of the transformer.

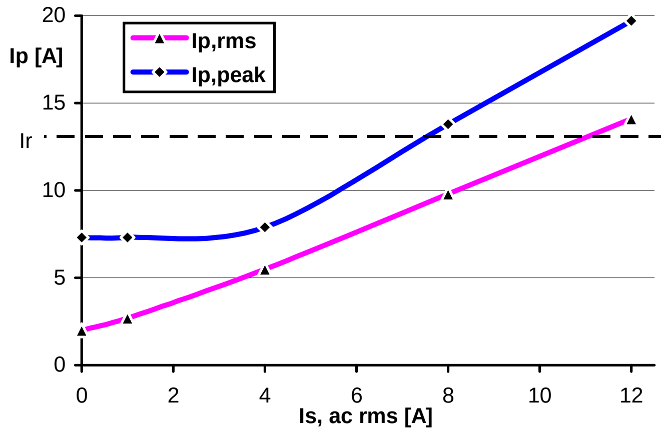
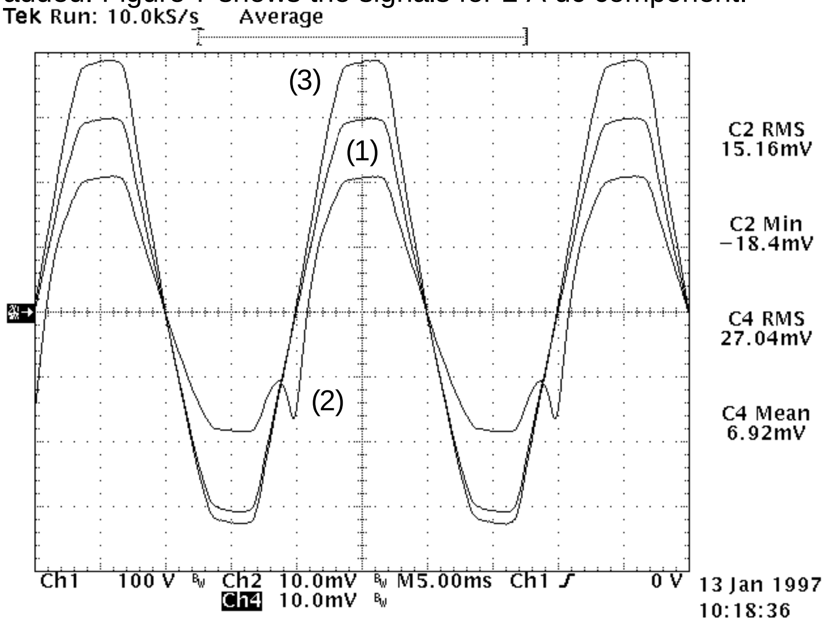


Figure 6 Primary current versus ac load; fixed dc component of 1 A.

The dc component introduces a kind of offset in the peak primary current, but there is no dangerous increase in the primary current. It is obvious that this load combination does not pose any problem.

13.5.7 High, constant ac load - variable dc load

This test run reflects the operating conditions of an utility transformer. To a base load of approximately 85 % of nominal rating, 12 A in this case, a variable dc component of 1-2 A is added. Figure 7 shows the signals for 2 A dc component.



Is,dc,rms = 2 A
Ip,rms = 15.2 A
Ip, peak = 21 A

Measurement No. 3
(1) Up: 100V/div (2) I_p: 10A/div (3) I_s: 5A/div

Figure 7 Line voltage Up, (1), primary current Ip, (2), and secondary current, Is, (3) for an ac load of 12 A and 2 A dc load. The current peak from saturation is below the regular peak load current.

Figure 7 shows qualitatively the same signals as before. The dc component causes a distortion of the primary current, however, up to 2 A (corresponding to some 13 % of the nominal current) this poses no hazard at all. Figure 8 summarizes this test run.

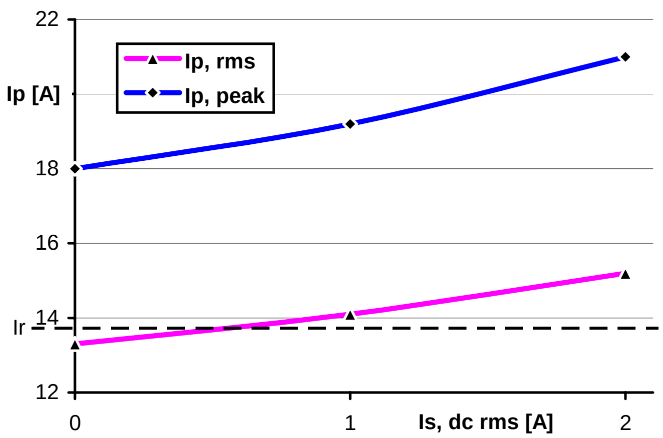


Figure 8 Primary current versus secondary dc component; constant ac load of 12 A

To illustrate the effect of voltage step-up the last experiment was repeated using a transformation ratio of 2:1. The curves look exactly the same, the only difference is the calibration factor for the primary current Ip; Ip is reduced by the transformation ratio.

13.6 Summary

The experiments showed that primary currents from ac and pulsed dc components linearly superimpose.

- The pulsed dc component may reach significant levels without jeopardising the proper operation of the transformer.
- Under high dc components high primary current peaks occur. Also, a high level of harmonics is generated.

13.7 Conclusion

The hazard of dc currents from small PV systems for the local distribution transformer seems to be negligible. A general requirement for isolation transformers for PV inverters is not justified.

13.8 Recommendations for future work

Some uncertainties remain, whether the different distribution transformers used in the participating countries show a different susceptibility to effects of dc injection. Transformers used vary from single phase, pole-mounted, 30 kVA transformers to three phase, 630 kVA units. Furthermore the question was raised, if a zero-sequence flux component resulting from balanced dc injection into 3 phases of a typical european urban transformer can have worse effects than those reported in the previous sections.

13.9 Literature

1. Laukamp, H.; "The Basic German Electric Safety Standard and its Application to PV Systems", Proceedings 12th PVSEC, Amsterdam 1994
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14. CONCLUSIONS AND RECOMMENDATIONS

The conclusions and recommendations of the individual subjects are given at the end of each chapter.

Table 1 shows an overview of the subjects that can be categorised as “solved”. For these subjects the number of remaining technical questions is (nearly) zero. Some of the subjects grouped in the column “solved” may however still be under discussion in some countries. For those situations the information provided in this report may be used as an international reference.

Table 1 Overview of the technical status of the subject described in this report

“Solved”	**Need for further research**
• Harmonics for single inverter • AC Modules • Grounding and ground fault detection of PV-systems • Lightning induced overvoltages • EMI of inverters • Reclosing • External disconnect • Isolation transformer and DC-injection	• Harmonics with multiple inverters • Effects on power network with multiple inverters • Islanding of inverters in a part of the network

From the table it must be concluded that the issue of multiple PV-inverters is the main unresolved subject. It is advised to continue to study the behaviour of multiple inverters and the effects of high penetration levels of PV-systems in a relatively small electrical network, for example a residential area. The need for this research is clearly identified in almost all Task V participating countries. Examples can be found in the Olympic village in Australia, the village S• ringen in Denmark and a residential area with 1 MW in the Netherlands.

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16. ANNEX A INVESTIGATION GRID IMPACT FROM PV-SYSTEMS

ELSAMPROJEKT

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Summary

This report describes the impact on the voltage quality exerted by 60 identical photovoltaic (PV) installations in the private single house neighbourhood known as “Søringen” in Brædstrup, Denmark. The systems are divided onto 29 single houses, equalling 80% of the houses of the neighbourhood. The composite capacity of the photovoltaic system is 60 kWpeak.

The impact from the PV system on the voltage quality has been examined by measurements and subsequent analysis of the voltage distortion over a period of time from November 1996 to September 1997. The measurements have been conducted before, during and after the photovoltaic installations were put into service.

According to the results of the study, the photovoltaic system at “Søringen” seems to have no detectable impact on the local voltage distortion. Furthermore, comparisons of the voltage distortion, harmonics and grid impedances suggest that most of the local voltage distortion by far is caused by non-local sources. The most important internal contribution to the voltage distortion found in “Søringen” comes from TV-sets, and only to a limited extent from the photovoltaic system itself

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INTRODUCTION

In the autumn of 1996 / spring of 1997 the power distribution company VOK installed photovoltaic (PV) systems at 29 existing private single houses in the neighbourhood known as “Søringen” in Brædstrup, Denmark. The installations are divided onto 29 single houses, equalling 80% of the houses of the neighbourhood. The project has received funding from the Danish Energy Agency, ELFOR and ELSAM.

The composite capacity of the PV installations in the neighbourhood totals 60 kWpeak divided onto 60 identical installations of 1 kWp each and each with a 1-phase grid connection via a Sunny Boy SWR 850 inverter.

The primary objectives of the project have been to study the following:

- The system's impact on the grid, in particular the significance of the installations on the voltage quality.
- The consumer conduct when posing as producers of their own electricity.
- Architectural and structural aspects of integrating PV installations into building structures.
- Tariff questions.

This report solely describes the impact of the installations on the grid with particular focus on the significance of the installations on the voltage quality. The possible impact from PV cells on voltage quality has been examined by measurements and subsequent analysis of the current and voltage distortion before, during and after the PV installations were put into service.

OBJECTIVES OF THE STUDY

The overall objective of the study has been to evaluate the significance of a relatively high concentration of PV cells on the voltage quality. The composite capacity of the PV installations at the neighbourhood totals 60 kWpeak which is 30% of the feeding transformer's rated capacity. The neighbourhood is fed from a 200 kVA 10/0.4 kV transformer via two of its five feeders. It follows from this that the neighbourhood is expected to become a net producer to the grid during low load periods with solar radiation. Likewise the power direction through the transformer will become positive from the low voltage side towards the 10 kV side.

One of the concrete objectives has been to assess the overall impact of the PV cells on the voltage quality via the harmonics produced by the inverters and transmitted through the transformer. Normally harmonics in the grid will result in an increase of the voltage distortion (= a reduction in the voltage quality) according to the grid impedance to harmonics.

Another objective has been to evaluate voltage distortions stemming from individual systems further out in the low voltage grid (further away from the transformer) where the grid impedance is increased due to the longer distance between cables and overhead lines. Voltage distortions from this type of "extreme points" will primarily have a negative impact on the "polluter" himself, besides consumers connected to the same radial in the polluter's immediate vicinity.

OUTLINE OF PROBLEM

Voltage quality and voltage distortion

Voltage distortion is a common designation indicating a series of limits to:

- The RMS-value of the voltage.
- Flicker (voltage fluctuations).
- Voltage asymmetry.

- Grid frequency.
- Harmonics (voltage distortion).
- Transients.
- Etc.

The requirements to the voltage quality of the low and medium voltage grid are laid down in recommendations nos. R16 and R21 issued by the Research Association of the Danish Electricity Utilities.

In particular rectifiers and inverters from eg. PVs systems have a significant impact on the voltage distortion, which is an expression of voltage harmonics. By saying that the voltage is distorted it is implied that voltages with higher frequencies (harmonics) are found in addition to the fundamental 50 Hz frequency of the voltage. These higher frequencies can be expressed as n × 50 Hz, where n denotes the order of the harmonic (3rd, 5th, 7th order harmonics).

A voltage distortion which is too high may have an unwanted impact on eg. protective relays and electronic measuring equipment which is supposed to be activated by zero crossings or predefined voltage levels. Harmonics also result in increased losses in cables, capacitors, transformers and rotating machines.

Methods used when diagnosing voltage distortion

Non-linear components, such as rectifiers and inverters, give off harmonic currents the size of which is related to the mode of operation of the inverter and the presence of built-in harmonic filters. Just like voltage harmonics, harmonic currents have higher frequencies, which can be expressed as whole figures n times the 50 Hz fundamental of the current. The harmonic currents give rise to the voltage harmonics and the voltage distortion via the grid impedances which the harmonic currents feed into.

The impact of the grid impedance on the voltage distortion is illustrated in Figure 1. Harmonic currents, In, feed into an impedance which is equal to the short-circuit impedance, ZK, of the grid parallel to the load impedance ZL. Normally it will suffice to allow for only ZK, because ZL will normally be much higher than ZK. It follows that the harmonic voltage, Un, which a harmonic current, In, gives rise to can be derived as follows: Un = ZK × In.

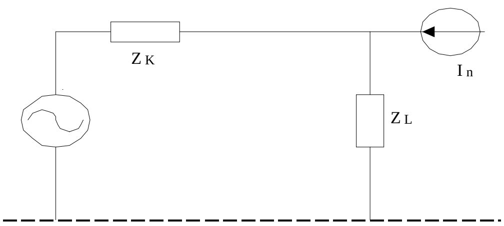


Figure 1 Illustration to calculate the harmonic voltage distortion

Calculating the grid Impedances of the higher frequencies is considerably more complex than calculating the grid impedances at 50 Hz. One of the reasons for this is that the stray capacitance of transformers becomes important to the impedance and that the lines must be divided into several p-led at the higher frequencies to allow calculation.

In practice measurements will have to be conducted to be able to assess the voltage distortion from a large number of PV installations, as the complexity of the relationship increases when a high number of sources distributed across a large interconnected grid feed harmonics into the grid at the same time. The impedances will vary according to where it is measured, and the harmonic currents will have a wide variety of phase angles. At the same time the background distortion, which comes from higher external system voltages, must be allowed for.

METHODOLOGY

Measurements realised

Measurements have been realised before, during and after the PV installations were put into service. The measurements were conducted both at the output of transformer 281, which supplies the entire neighbourhood, and at individual consumers with PV installations “further out” in the low voltage grid. All the measuring campaigns comprise:

- Current, voltage and power of all three phases;
- Total harmonic distortion (UTHD) of the voltage in all three phases;
- The size of individual voltage harmonics in all three phases;
- The size of individual current harmonics in all three phases and the neutral conductor.

The measuring campaigns are based on 24-hour measurements with mean values stored every two minutes. At the same time short 10-min. campaigns have been realised with values stored every second to record any short disturbances.

The measurements were conducted over the following periods:

- November 1996, when only a single 1 kW PV installation was put into service (it produced no electricity due to cloudy weather and a low sun);
- February 1997, when about 30% of all the systems were connected;
- April 1997, when about 90% of the systems were connected;
- June 1997, when all the systems (60 kW) were connected;
- September 1997.

The measuring campaigns in February and April 1997 took place on days when the weather ranged from overcast to sunny. The measuring campaigns in June 1997 took place on days with varying solar radiation and days with full solar radiation. In September 1997 only fast 10-min. campaigns have been realised under varying solar radiation conditions.

Processing of the measuring results

All measuring results have been transferred to Lotus 1-2-3 spreadsheets for processing. The most important questions during the processing have been:

- Do the measured voltage distortions exceed the limits laid down in the recommendations issued by the Danish Association of Electricity Utilities ?
- In respect to the measured voltage distortion, what is the relationship between the internal distortion, which is caused by local harmonic currents and the background distortion, which is caused by external sources.

The measured voltage distortion has been consistently compared with the generated harmonic currents, which feed into the grid. The voltage distortion has been compared with the voltage distortion (the internal distortion) to be expected by multiplying the harmonic currents with the grid impedances (cf. subsection 3.2). Finally the voltage distortion before and after the PV installations were put into service has been compared.

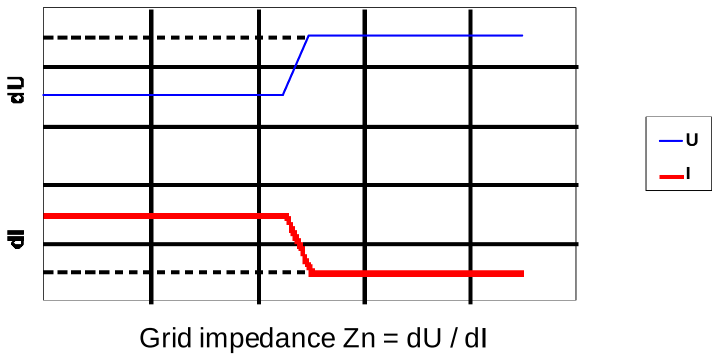


Figure 2 Grid impedance calculation by current and voltage jumps

The grid impedances have been determined on the basis of the related values of the current and voltage jumps (cf. Figure 2). It is essential only to look at the voltage jumps which are clearly related to simultaneous current jumps in the low voltage grid concerned because most voltage changes are due to external sources.

MAIN RESULTS OF THE STUDY

Power load and power production

Enclosure 3 shows the net power measured which was supplied from the grid to the consumers supplied by transformer 281 supplying the neighbourhood. The power is shown for four different 24-hour periods at different times of the year, installed PV capacity and with different solar radiation. The curves show 10-min. mean values.

Practically all the PV installations had been installed when the measurements where realised in April and June 1997. As a result the power direction was negative for both curves at some points in time (ie. the transformer was delivering power to the 10 kV side).

Of course the presence of the PV installations can be most clearly seen from the June curve, partly because the solar radiation is highest in June, because the solar radiation differed quite a lot over the 24 hours in April, and partly because the consumption was lower in June. The main reason for the variable solar radiation seen on April 15, 1997 was the many fast moving clouds causing the frequent changes in radiation ranging from full solar radiation to practically zero radiation. These fast changes can be seen from the upper curve in enclosure 4. The curve shows the power, measured as 2-min. mean values.

The variation in power is particularly pronounced around 16.30 on April 15, 1997. At this time the weather cleared up, as can be seen from the associated curve of the solar radiation (enclosure 5). The variation in power was considerably lower the following morning on the 16th, which can be seen both from the power curve in enclosure 4 and the solar radiation curve in enclosure 6. The majority of the PV installations seems to the connected to phase S. Enclosure 7 shows the distribution of the power onto the three phases during the June measurements when the net supply to the grid is highest in the S phase. A similar distribution was found for the April measurements.

Of course the asymmetric distribution can be caused by the load in the S phase being lower than in the other phases, but the fact that the load is highest in the evening and night hours of the S phase contradicts this. However, it is a fact that the PV system production is most clearly seen in the S phase, and hence special attention will be given to the S phase in the subsequent analyses of the voltage distortion.

Voltage distortion

Enclosure 8 shows the Total Harmonic Distortion (THD) of the voltage in the S phase for the same four 24-hour measurements as approached above. The most conspicuous feature is that there are no noteworthy differences in the voltage distortion detected over the four 24-hour measurements between about 8.00 and 16.00 - exactly when the PV installations should have the most significant impact on the distortion.

According to all the curves the voltage distortion increases after 18.00. The primary reason for this increase must be that TVs are switched on around that time. Conversely, the distortion caused by the TVs is expected to decrease between 22.00 and midnight, which is in fact the case for November 1996, but the other curves show a somewhat different pattern.

Although the curves for the other months also show a drop in the distortion between 22.00 and midnight, the level is surprisingly high throughout the hours of the evening and the night until after 6 in the morning. One possible explanation could be that the local cogeneration plants are not in service in the hours of the evening and the night outside the winter. As a result the grid will have less short-circuit power (= higher impedance) so that harmonic currents will cause more pronounced voltage distortion.

Another explanation to the high level of voltage distortion found during the night could be that industries with non-linear loads have had a higher level of nightly operations during the spring and the summer, but it has not been possible to verify this hypothesis.

However, much of the credit for the voltage distortion generated during the day should be given to an industrial enterprise, as can be seen from enclosure 9, which presents curves from one of the short time series, where values are recorded every second. The pronounced increase of the voltage distortion almost every three minutes is a result of the company starting a frequency controlled fan motor at these times with the motor slowly decreasing before the next start-up. The same pattern has been measured in all the short time series. The level is even higher in the spring and summer, which again can be explained by the grid having less short-circuit power during these periods because of the non-operating decentralised plants.

The conclusion seems to be that the PV system in the neighbourhood have no detectable impact on the voltage distortion.

Generation of harmonic currents

Enclosure 10 presents the sum of the harmonic currents passing through the low voltage side of the transformer in the S phase. Again the curves apply to the same four 24-hour measurements as the ones discussed in a previous subsection. The curves show the weighted RMS value of the harmonic currents because this value together with the reactive impedances of the grid decide the size of the contribution to the voltage distortion. (For the weighted RMS-value the size of the individual harmonics is weighted with the order of the harmonics, squared and summed, and the square root of the sum is used in the curves).

The largest generation of current harmonics is found during the TV-hours between 18.00 and 23.00, even after all the PV installations have been put into service. However, the generation of current harmonics was elevated for the daytime in April, when the PV power production was even higher ! (The reason for this may be that the solar radiation in April changed quite a lot due to many fast-moving clouds).

The current harmonics, In, produced in this local system due to the PV installations, etc. will give rise to current harmonics, Un = ZK $\times$ In, where ZK is the grid's short circuit impedance as seen from the harmonics source (cf. Figure 1), assuming that the short circuit impedance, ZK, is much smaller than the load impedance, ZL, so that ZL can be dispensed with.

Please note that the applied impedances correspond to the harmonics frequencies concerned. At higher frequencies the stray capacitance of the transformers will become important, and long cables and lines can be divided into several π-sections. However, for this study, it should suffice only to look at the values for resistance and reactance as only the order of magnitude of the distortion is to be assessed.

The grid impedance, ZK, (the 50 Hz short circuit impedance) seen from the 0.4 kV side of transformer 281 is determined on the basis of the correlating values of current and voltage jumps, as illustrated in Figure 2. Using this method ZK will be set at a value which at 50 Hz will be between 30 and 40 mΩ, based on the measured current and voltage values shown in enclosure 11. Only the changes in voltage which clearly correlate with a simultaneous change in current have been considered. Eg. the times 10:20:21, 10:20:37, 10:21:00 and 10:21:19 (The clear voltage drop at 10:20:55 is caused by start-up of the frequency controlled fan motor!).

The value of 30-40 mΩ for ZK must be compared with the load impedance, ZL, at the low voltage side of the transformer. At no point in the project has the value of ZL been below 1.5Ω in the measurements. Hence the incorrectness arising from not including ZL is negligible.

Alternatively ZK can be determined by applying the fact that ZK is almost equal to the short circuit impedance of the transformer, which can be reached as follows:

$| Z_k| = e_k \cdot U^2/S = 0.04 \cdot 0.4^2/0.2 = 32$ milliohm

Where:

- ek = the short circuit voltage of the transformer (4%),
- U = the rated voltage (0.4 kV),
- S = the rated power (0.2 MVA).

The impedance of the 10 kV grid behind the transformer is not included in the formula, but then the transformer impedance will typically make up the largest part of the short circuit impedance by far.

The relationship between resistance and reactance (the R/X ratio) will typically be 0.4 for distribution transformers of the size concerned. Hence the following would be a likely ZK value:

$Z_K = R_K + j @ X_K = (12 + j @ 30)$ mΩ.

This value applies to the 50 Hz fundamental. For harmonics the reactance XK will make up the most important part of the impedance because the reactance is proportional to the frequency. A good approximation of the correlation between voltage and current harmonics can be expressed as follows:

$U_n = n @ X_K @ I_n$

It can be demonstrated that the correlation between the total voltage distortion, U_{THD}, and the weighted sum of harmonic currents, $I_{THD,W}$, can be expressed as follows with the same approximation:

$U_{THD} = X_K @ I_{THD,W}$

The weighted sum of harmonic currents measured at the low voltage side of transformer 281 is in the range of 20-50 A (enclosure 10). The expected contribution to the voltage distortion from the neighbourhood should be in the range between (30 mΩ x 20 A) = 0.6 V and (30 mΩ x 50 A) = 1.5 V, ie. in the range of 0.25-0.65%. However, the voltage distortion measured for the neighbourhood is 1-3%.

Hence it must be concluded that the most important part of the voltage distortion in the neighbourhood comes from external sources. At the same time the most significant part of the current harmonics produced in the neighbourhood is caused by TV sets and only to a limited extent by the PV installations. This conclusion is also confirmed by measurements realised at individual consumers with PV installations where there have been detected *no* differences in the voltage distortion of phases with and without energy produced by the installations.

CONCLUSION

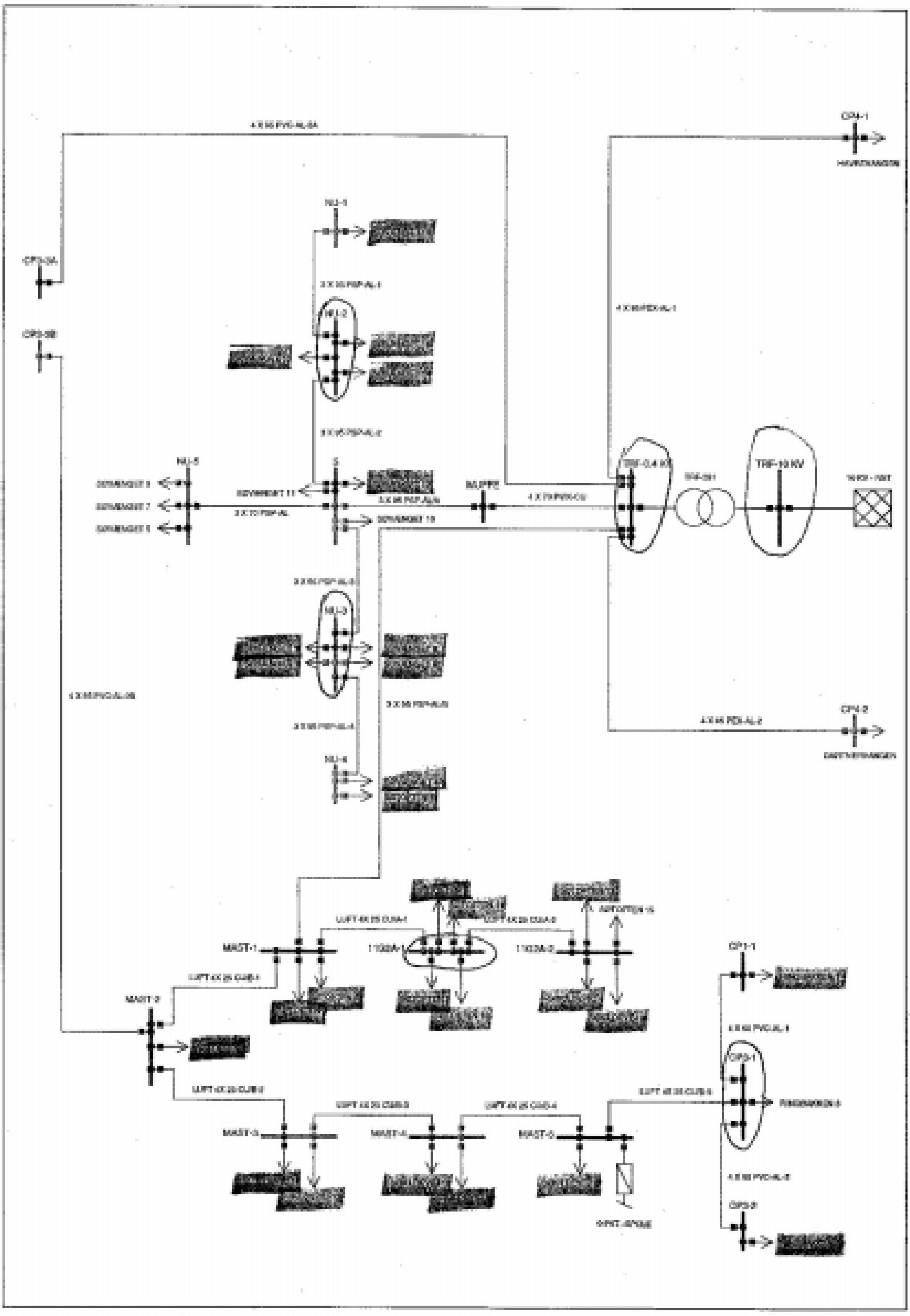
According to the measurements realised in the neighbourhood from • S• ringen" November 1996 to September 1997 there seems to be no detectable impact from the PV installations inside the neighbourhood on the local voltage distortion. Furthermore, all the voltage distortions measured lie significantly below the upper limits as recommended by recommendation R16 issued by the Research Association of the Danish Electricity Utilities.

On the basis of a comparison of the voltage distortion, current harmonics and grid impedances it is found that most of the local voltage distortion by far is caused by external sources. It has even been possible to identify one of the external sources by means of fast measurement campaigns. Finally, the measurement of harmonic currents has demonstrated that the most significant share of the local contribution to the voltage distortion is caused by TV sets, and only to a limited extent by the PV installations.

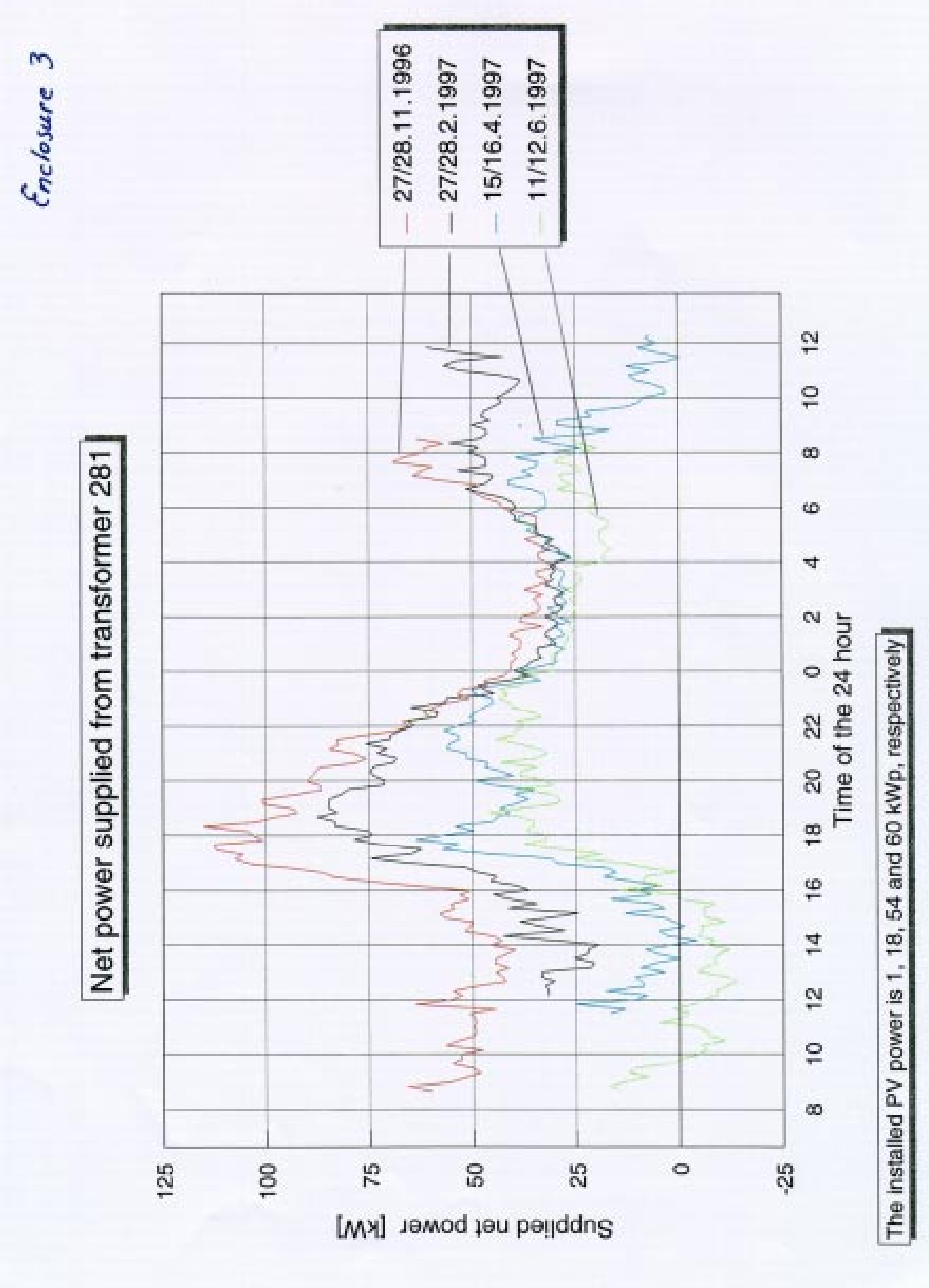
The concentration of PV installations found in "Søringen" must be considered to be as close to the maximum to be realised within a geographically limited residential area. The risk that a similar concentration of photovoltaic cells in other confined areas would give an unwanted impact on the voltage quality cannot be excluded, if the grid in that area had a significantly lower short-circuit power than is the case for "Søringen".

ENCLOSURE 1

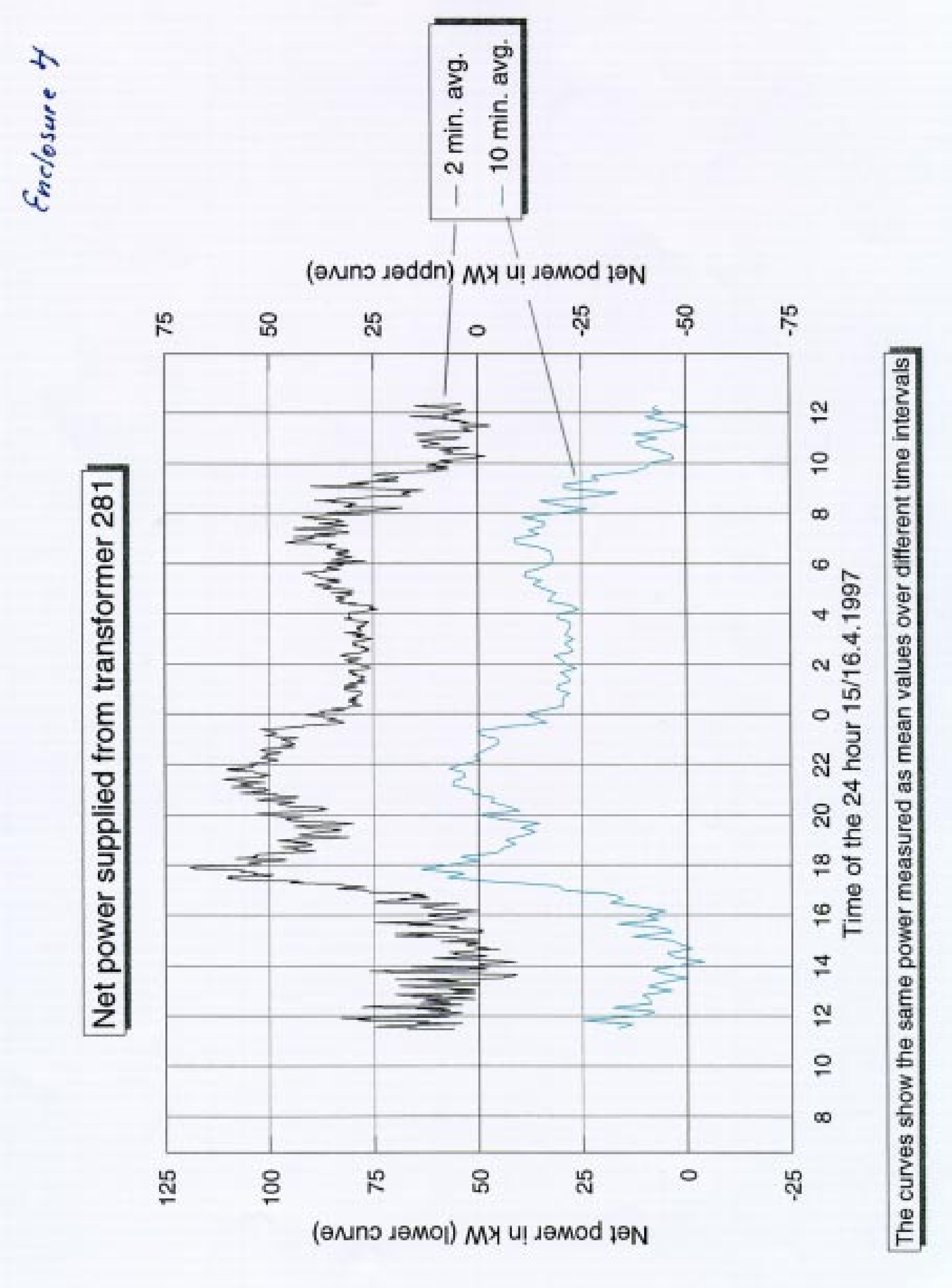
ENCLOSURE 2



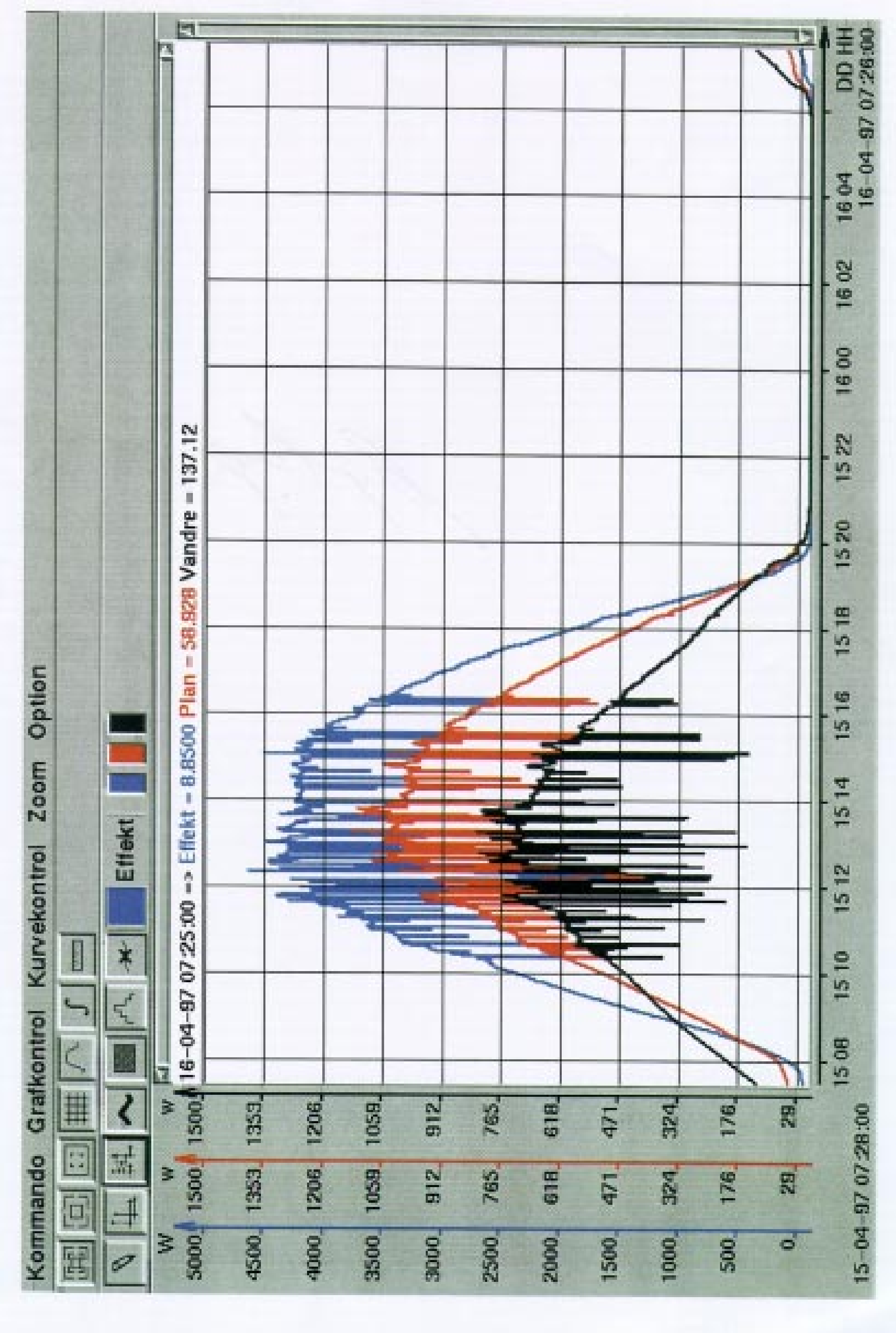
ENCLOSURE 3


Enclosure 3
Net power supplied from transformer 281
27/28.11.1996
27/28.2.1997
15/16.4.1997
11/12.6.1997
Supplied net power [kW]
125
100
75
50
25
0
-25
8
10
12
14
16
18
20
22
0
2
4
6
8
10
12
Time of the 24 hour
The installed PV power is 1, 18, 54 and 60 kWp, respectively

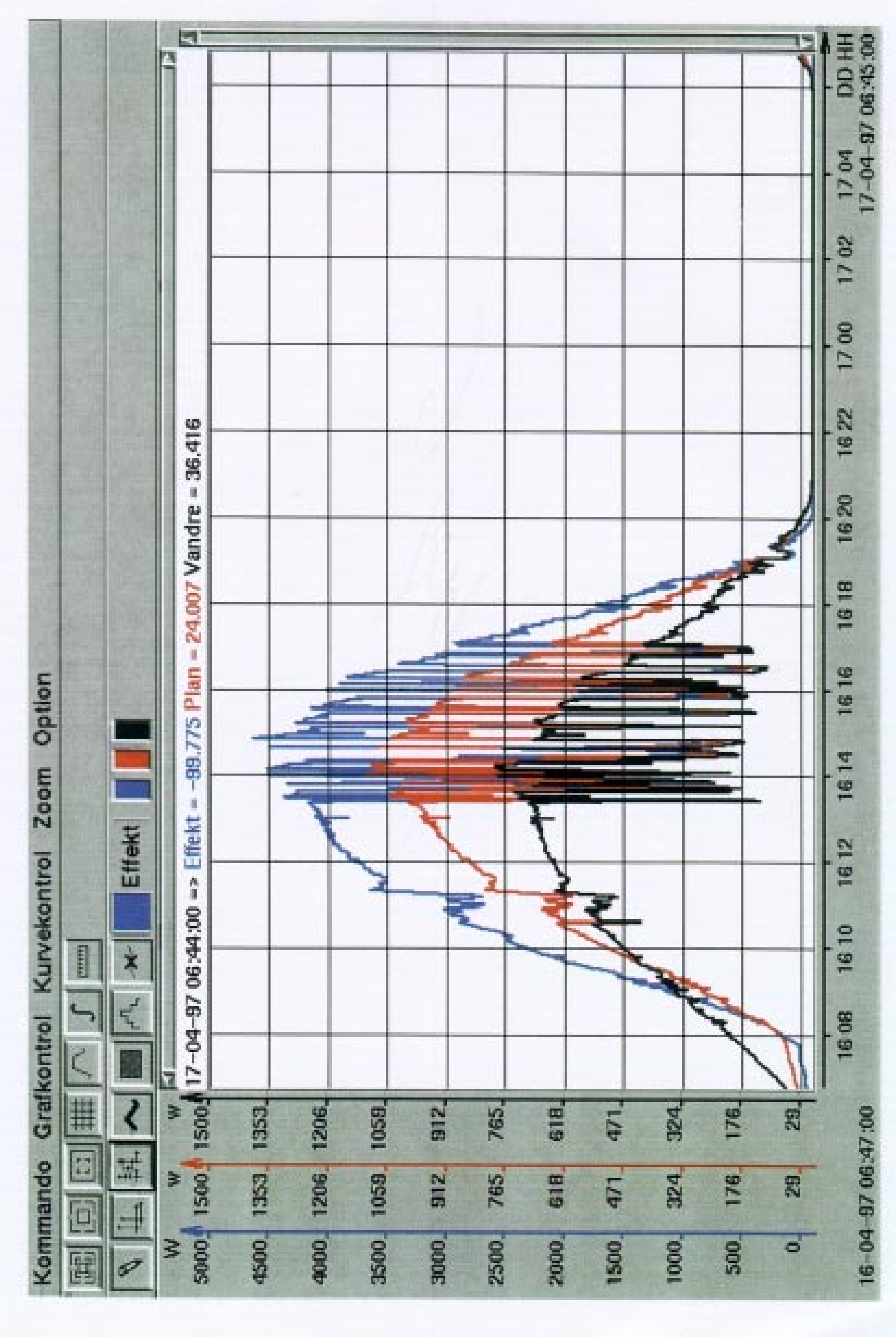
ENCLOSURE 4


Enclosure 4
Net power supplied from transformer 281
2 min. avg.
10 min. avg.
Net power in kW (upper curve)
Net power in kW (lower curve)
Time of the 24 hour 15/16.4.1997
The curves show the same power measured as mean values over different time intervals

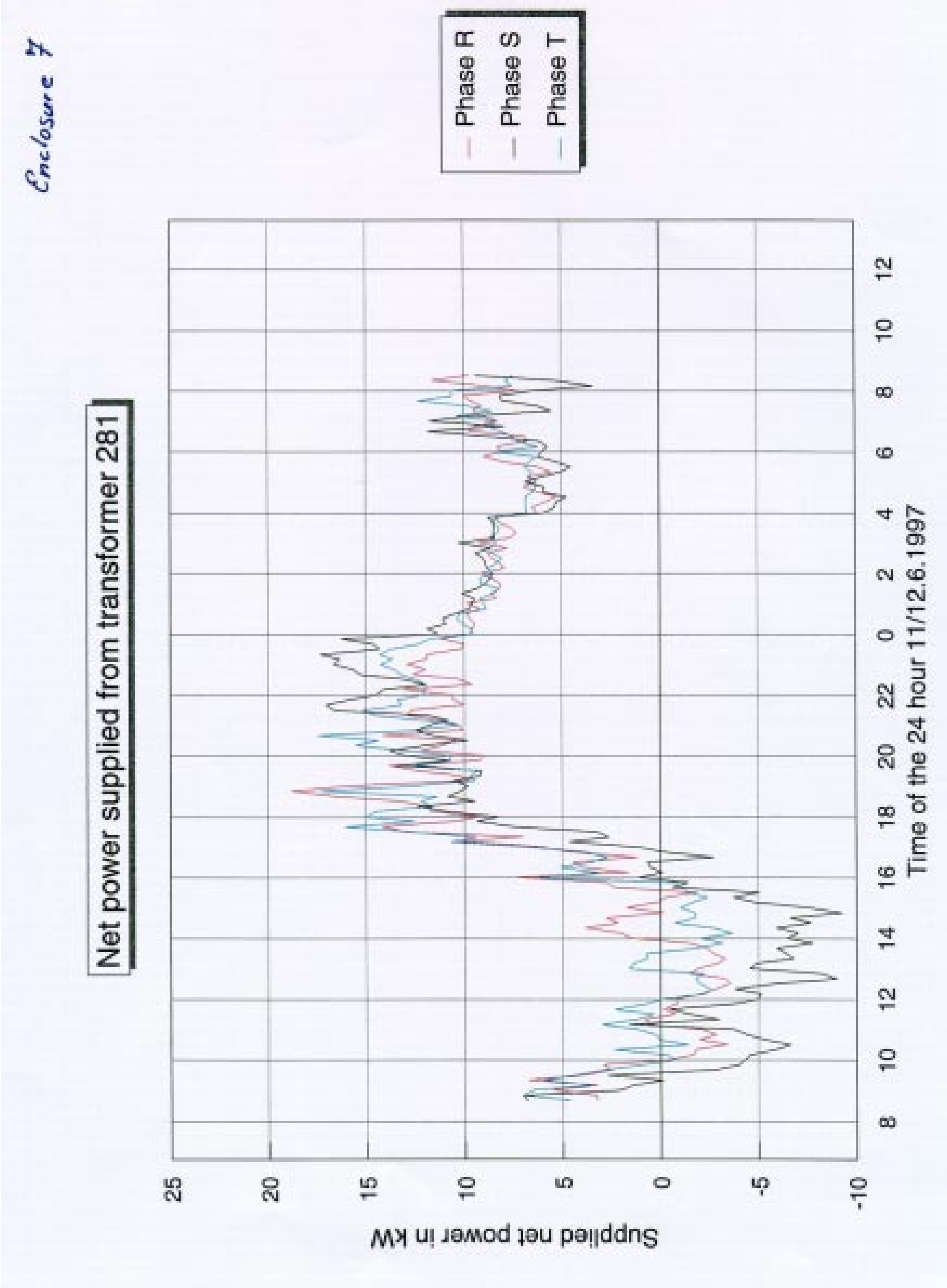
ENCLOSURE 5


Kommando Grafkontrol Kurvekontrol Zoom Option
Effekt
16-04-97 07:25:00 => Effekt = 8.8500 Plan = 58.928 Vandre = 137.12
15-04-97 07:28:00
16-04-97 07:28:00
DD HH

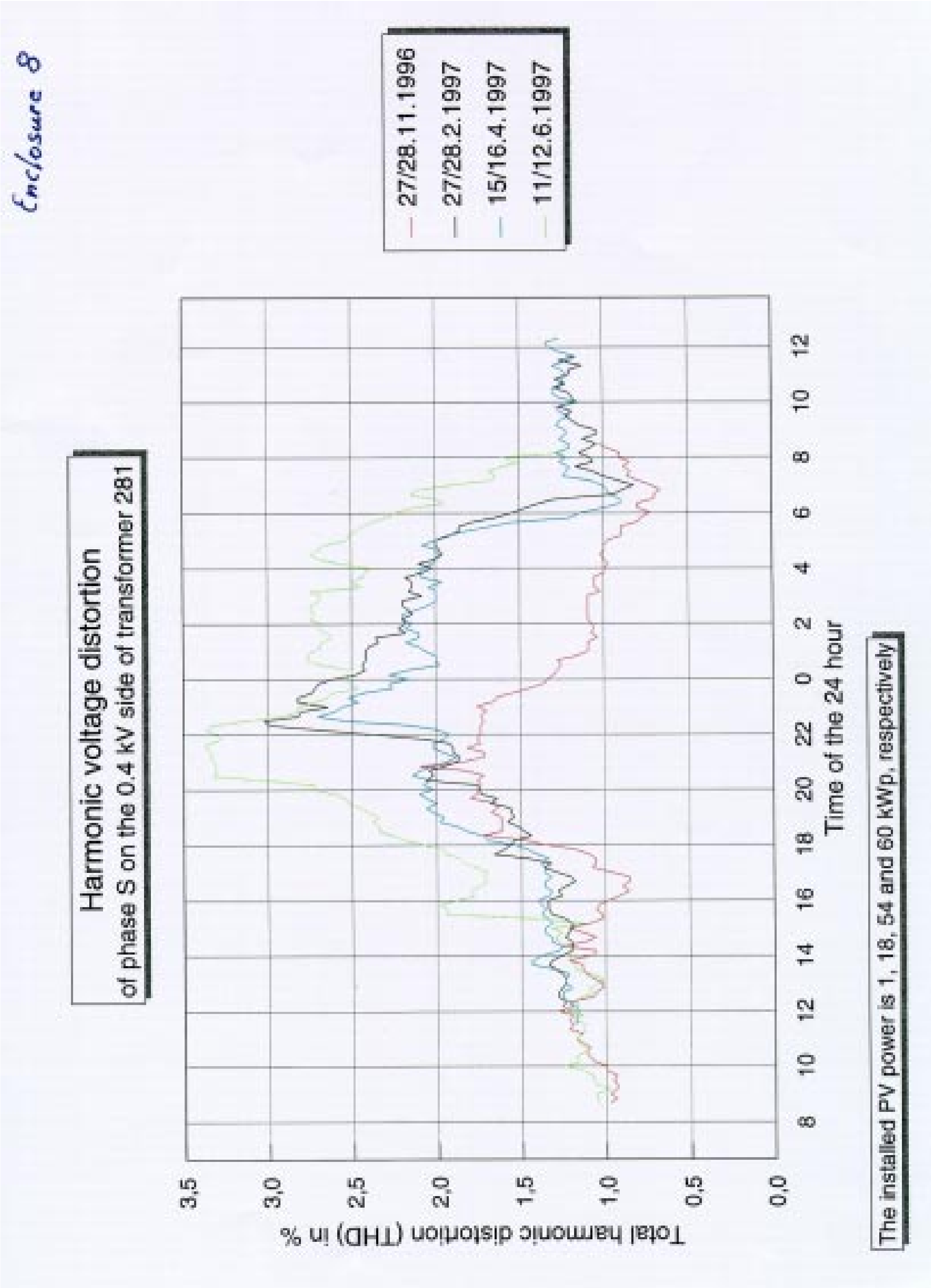
ENCLOSURE 6


Kommando Grafkontrol Kurvekontrol Zoom Option
Effekt
17-04-97 06:44:00 => Effekt = -99.775 Plan = 24.007 Vandre = 36.416
W
5000
4500
4000
3500
3000
2500
2000
1500
1000
500
0
W
1500
1353
1206
1059
912
765
618
471
324
176
29
16-04-97 06:47:00
16 08
16 10
16 12
16 14
16 16
16 18
16 20
16 22
17 00
17 02
17 04
DD HH
17-04-97 06:45:00

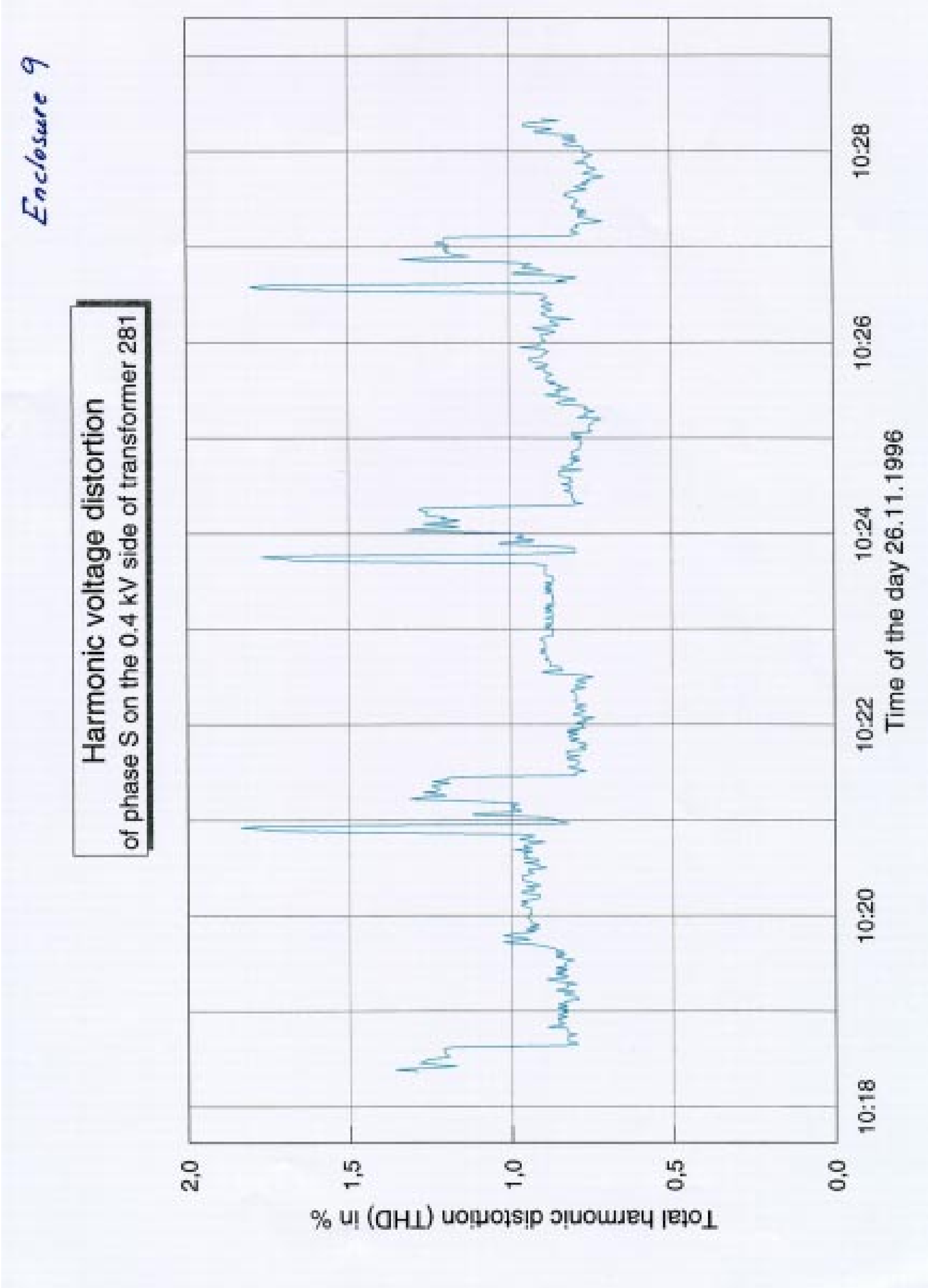
ENCLOSURE 7


Enclosure 7
Net power supplied from transformer 281
Phase R
Phase S
Phase T
Supplied net power in kW
25
20
15
10
5
0
-5
-10
8
10
12
14
16
18
20
22
0
2
4
6
8
10
12
Time of the 24 hour 11/12.6.1997

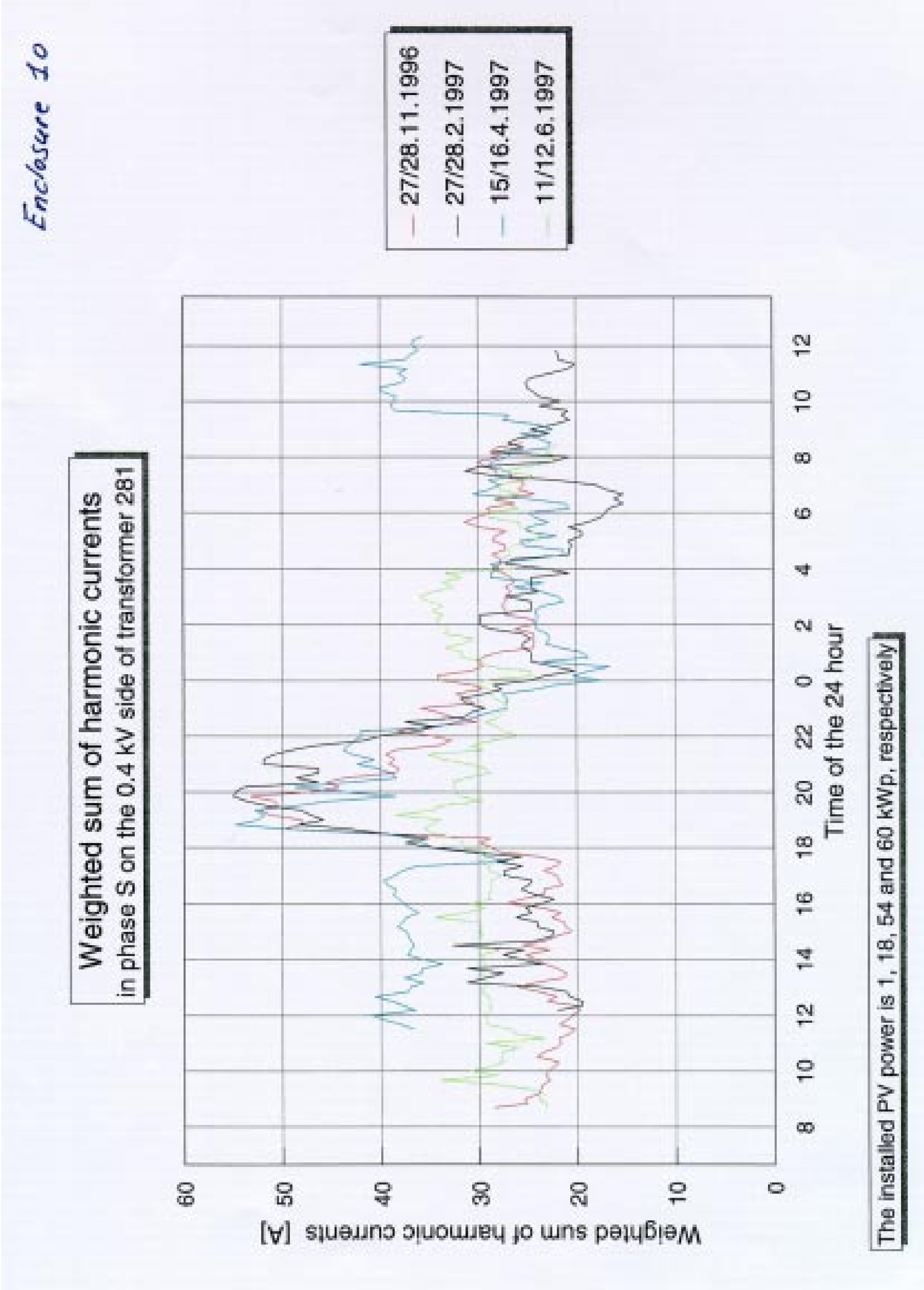
ENCLOSURE 8


Enclosure 8
Harmonic voltage distortion
of phase S on the 0.4 kV side of transformer 281
27/28.11.1996
27/28.2.1997
15/16.4.1997
11/12.6.1997
Total harmonic distortion (THD) in %
3,5
3,0
2,5
2,0
1,5
1,0
0,5
0,0
8
10
12
14
16
18
20
22
0
2
4
6
8
10
12
Time of the 24 hour
The installed PV power is 1, 18, 54 and 60 kWp, respectively

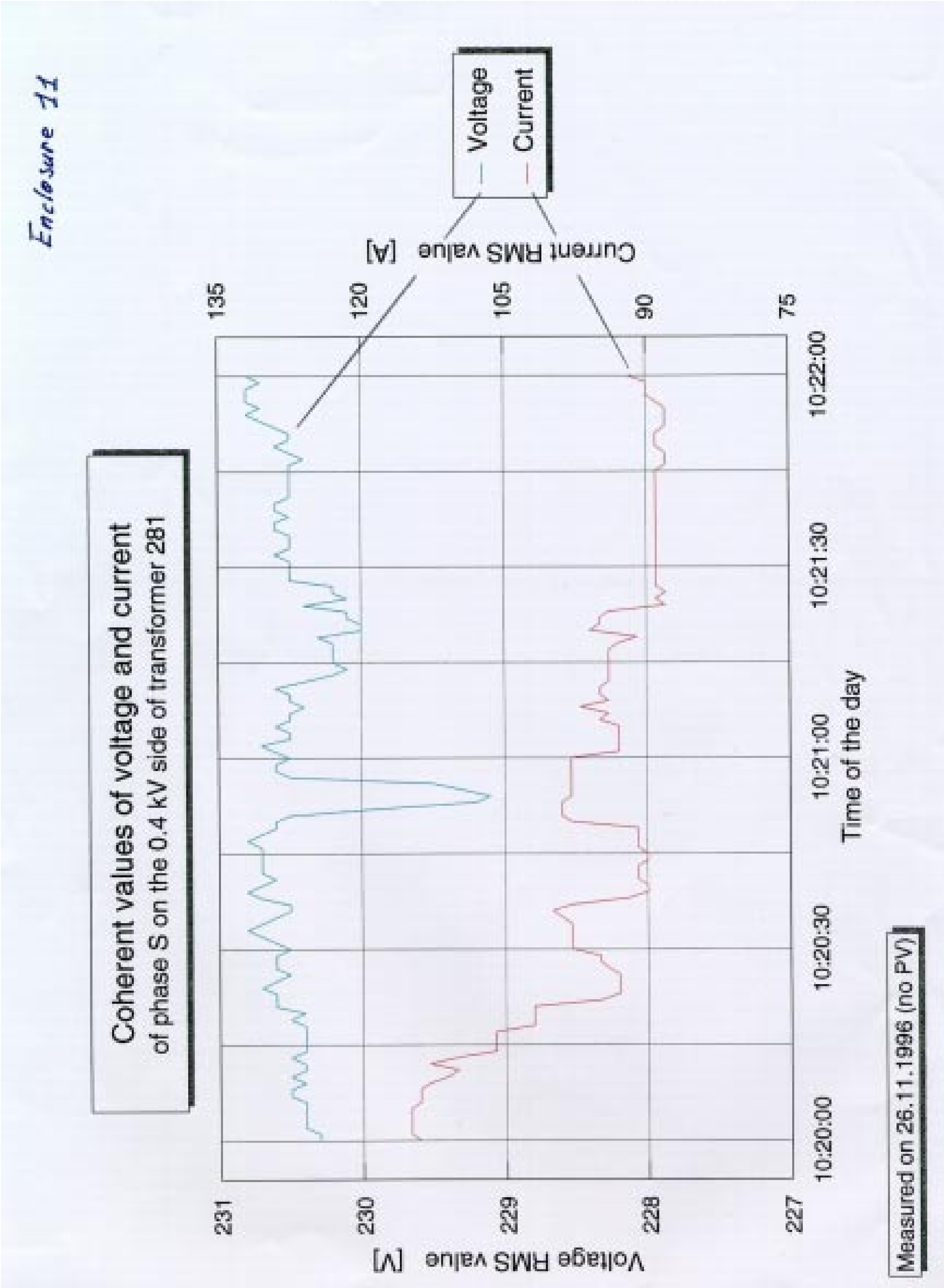
ENCLOSURE 9


Enclosure 9
Harmonic voltage distortion
of phase S on the 0.4 kV side of transformer 281
Total harmonic distortion (THD) in %
2,0
1,5
1,0
0,5
0,0
10:18
10:20
10:22
10:24
10:26
10:28
Time of the day 26.11.1996

ENCLOSURE 10



ENCLOSURE 11



17. ANNEX B SYSTEM GROUNDING SUMMARY

The requirements for grounding of PV system components and PV systems are often the least understood design parameter in the system. PV Systems may be required to be grounded, double insulated, or may not require a system ground. The rules for grounding may depend on system size or categories of installations, such as low voltage, self contained, or utility-tied. The following lists the requirements for grounding of PV systems in eight participating IEA countries.

Topic	Requirement or Comment By Country								
	Australia	Austria	Germany	Italy	Japan	Netherlands	Switzerland	United Kingdom	United States
PV Array Grounding Requirements (Conductive Frame)	Equipment Ground Required	Recommended for lightning, Prohibited for certain protection classes	Recommended for Lightning. Prohibited for Certain protection classes DE- VDE0100 Part 712 Draft	Equipment Ground Required CEI-ETD	Equipment Ground Required	Equipment Ground Required	Equipment Ground Required	Required (IEE Regulations BS7430) Note: PME Earth Should not be taken outside of Building	Equipment Ground Required NEC
PV Source Circuit Grounding Requirements	Ground Not Required	Depends on earthing and isolation transformer	Depends on earthing and isolation transformer	No Requirement for Grounding	No Grounding Requirement	Not required, normal practice is to have floating DC circuit	Grounding Not Specified	Grounding Not Specified	Grounding Required for >50V
Batteries Associated with PV Array Grounding Requirements	No Grounding requirements if fuse in both + and earth connections	None	Grounding Not Required	None	No Grounding Requirements	Grounding Not Required	Grounding Not Specified	Grounding Not Specified	Grounding is Required where non-qualified personnel have access for >50V.
Conductive Battery Support Structure Ground Requirements	None	Required	Grounding Required	Grounding Required	None	Grounding Required	Grounding Required	Grounding Required	Grounding Required
Inverter with Conductive case, Grounding Requirement	Case Grounding Required)	Depends on protection class	Depends on protection class	Case Grounding Required	Case Grounding - Required	Metal case must be grounded.	Grounding Required	Grounding Required	Case Grounding - Required
Inverter Active Circuit Conductors	Neutral Grounded (MEN System	Depends on system configuration	Depends on earthing & isolation transformer	Active Circuit - No Requirement	Active Circuit No Grounding Required	Not required, normal practice is floating DC	Grounding Not Specified	Grounding Not Specified	Active circuit Grounding Required for >50V
Are Center-Tapped DC Systems Allowed	Yes	Not discussed	Yes	Yes	Not Decided	Yes	Yes	Yes	Yes
Are High Resistance Grounds Allowed	Not Generally	No	No, (Not mentioned)	Yes	No (In Principle)	No	Yes	Yes, Earth leakage detection required	Yes

System Grounding Summary (Continued)

Topic	Requirement or Comment By Country								
	Australia	Austria	Germany	Italy	Japan	Netherlands	Switzerland	United Kingdom	United States
DC/AC Ground Intertie (Bond) Grounding Requirements	Not Specified	Yes	Depends on earthing system but varies from isolation to bond.		Not Decided	Not specified	Not Specified	Not Specified	Required
Are Ground Fault Detectors Required on DC Circuits	No, but generally used on large systems		No	No, but generally used on MV systems	Yes	Yes, for DC-voltage > 120	No	Not Specified	Yes, for systems mounted on dwellings
Are Ground Fault Detectors Required on AC Circuits	Yes	No	No	Yes	Yes	No	Not Mandatory	Yes, Requirement is for Disconnection Times to be Met	Yes
Are DC-Side Transient Suppressers Required	Not Specified	Yes, Class C	No, but recommended	No, but used by ENEL	Yes	Recommended	Yes	Not Specified General Practice to Include	No, but generally used
Are AC -Side Transient Suppressers Required	No	No	No	Yes	Yes	No	Yes	Not Specified	No, but usually used
Is Charge Controller/System Controller Grounding Required	Not Mentioned	Depends on system. Usually No	Not Mentioned		Required	Not mentioned	Not Specified	Not Specified	Required with exceptions for current limited systems and for systems >50V.
Comments									

Charge Controllers for Batteries in PV System

Charge controllers are used in PV Systems to regulate the charge supplied to a battery in a PV system. Some PV modules are sold as self regulating modules when used with lead acid batteries. Some PV systems use Nickel-Cadmium batteries for storage because the Ni-Cad batteries are more tolerant to overcharging. The design of some charge controllers is sometimes incompatible with some grounding methods. The following addresses charge controller-specific topics.

Topic	Requirement or Comment By Country								
	Australia	Austria	Germany	Italy	Japan	Netherlands	Switzerland	United Kingdom	United States
If a Charge Controller is Used, Is System Grounding Required	No	No	No	No, but conductive cases must be grounded	No	No	No		Case must be grounded and active circuit is grounded.
Are PV Systems with Batteries and No Charge Controllers Allowed	Yes, Not regulated		Yes, Not Regulated	Yes, Common Practice	Yes	Yes	Yes		Yes, Code requires regulation or current limited system
If So, Under What Conditions	Not Regulated	No	Not Regulated	Not Specified	Batteries are disconnected if over/under-charged	Not Regulated	Not Specified		Code requires regulation, .but doesn't specify charge controller
Are There Restrictions on Where a Charge Controller is Physically Located	No, but good practice not to have it in the same box	No	No	No	No	No	No		Yes, If sparks are possible with relay etc, then not allowed in vicinity of battery gasses.
Are charge controllers required to be certified	No	No	No	Yes	No	No	No		Yes
Comments			Very few high-voltage stand-alone systems have been install until now therefore no interest in standardization	ENEL generally bypasses PV modules to assure batteries are not overcharged					New Standards are being approved

Cables for External and Internal Applications

Cables for PV systems must withstand environments not typically seen in electrical applications. Sunlight resistance is needed for exposed conductor insulation for interconnecting a PV array. The use of solid conductors may be disallowed because of extreme and frequent temperature variations. The use of multiple conductor cables require flexibility for tracking arrays. The use of system diagnostics and instrumentation requires instrumentation cables to be routed to the array. Cable issues are numerous.

Topic	Requirement or Comment By Country							
	Australia	Austria	Germany	Italy	Japan	Netherlands	Switzerland	United Kingdom	United States
Are insulation types restricted for PV interconnects	Not Specifically, but cables must withstand expected ambient conditions and voltage levels	Double insulation is used.	Not Specifically, but cables must withstand expected ambient conditions	Double Insulation for over 50V	Yes	Yes, cable have to be certified	Yes Must meet temperature, humidity and ultraviolet requirements		Yes Must meet temperature, humidity and ultraviolet requirements
What types of insulation are allowed	As above	Must withstand expected conditions	Not Specifically, but cables must withstand expected ambient conditions	Certified types	IV (Poly-vinyl) CT (Rubber) CV-CE (Polyethylene)	Several	Not Specifically, but cables must withstand expected ambient conditions		Generally cross-linked thermoplastics or rubber rated by UL as applicable
Are Solid Conductors allowed for dc side cables	Not Specified. Multi-strand generally used		Not for Residences		Not Decided	Not decided, flexible wires are normally used	Yes		No.
What are conductor sizing requirements	Recommended minimum voltage drop	Referring to EN1	No specific requirements except where cable size is used for short-circuit protection	1 A/mm2 for ENEL Applications.	2 mm2 Minimum	Depends on current rating of string and/or array. Sizing according to IEC 364	According to IEC364		dc side ampacities at 125% of array SC current. (UL) plus 125% for continuous (NEC) derating
Is routing of data cables with power cables allowed	No	Yes	Yes, but not recommended	Yes, With Appropriate	Not Decided	Yes, recommended together with ground cable	Yes		Routing is OK but not recommended. J-Box must have compartment
What Color Codes are allowed for dc side	+ Red - Black Earth- Green/Yellow	(+ Red, - Blue) Not strictly regulated, Usually black cables are used.	+ Red - Blue and Black Not Strictly Regulated	No Restriction	+ Red - Blue	(+ Red /- Blue) In PV applications black is used for + and -	+ Red - Blue and Black Not Strictly Regulated		+ Black White Ground bare or green

Cables for External and Internal Applications (Continued)

Topic	Requirement or Comment By Country								
	Australia	Austria	Germany	Italy	Japan	Netherlands	Switzerland	United Kingdom	United States
What color codes are allowed for ac side	Single Phase- Red - Active Brown -Active Blue or Black - Neutral Green/Yellow- Earth 3-Phase Red - A White -B Blue - C Black - Neutral Green/Yellow- Earth Generally not regulated.	PE must be yellow/green. Brown, black or other - Active Light Blue - Neutral	Line 1 to Line n is Brown or Black with Numbers N Light Blue PE is Yellow/Green	Lines are Blue and Brown. Grounding is Yellow/Green	3-Phase U -Red V - White W - Blue N - Black 1-Phase 3-Wire U - Red V - Blue N - Black 1-Phase, 2-Wire red (blue) N - Black	Line 1 to Line n is Brown or Black with Numbers N Light Blue PE is Yellow/Green	Line 1 to Line n is Brown or Black with Numbers N Light Blue PE is Yellow/Green	3-Phase- 1st Red, 2nd Yellow, 3rd Blue. Earth green/Yellow 1-Phase Fixed Live Red, Neutral Black 1-Phase to Appliance Live Brown, Neutral Blue, Earth G/Y	3 Phase Red, Black Blue with cable markings. One-phase, 3 wire Hot .Black or Red Neutral White Ground Green or Bare wire
Are cable markings required for PV systems	Yes	No	Yes	Yes	Yes	Yes		Yes	Yes
How is grounding conductor for dc side sized	Conductor reared for fault load. Minimum size applies.	Same size as L+ and L- until 60mm2	Same Size as L+ and L-		PV Cable <500W >2mm2 500-2kW >3.5 > 2kW >5.5	10 or 16 mm2	10 mm2 or 25 mm2 if combined with lightning protection	Yes As IEE Regulations	Largest Conductor for rated PV output or largest conductor if backfeed from other sources is possible.
Comments									Color codes

PV Array

PV Arrays may be ground-mounted, roof-mounted or become part of a building as a facade or awning. This table addresses the wiring and grounding requirements for the PV array installation.

Topic	Requirement or Comment By Country								
	Australia	Austria	Germany	Italy	Japan	Netherlands	Switzerland	United Kingdom	United States
PV Source Circuit Grounding Requirements	No grounding requirements	Depends on earthing system	Depends on Earthing System	No grounding requirements	No grounding requirements	No grounding requirements	No grounding requirements		Grounding Required Grounding may be a resistance ground
Metal Frame Grounding/Bonding	Yes	Grounding generally recommended. Prohibited with certain protection	Grounding generally recommended. Prohibited with certain protection	Yes, Using standardized components	Required	Yes	Yes		Required
Frameless or Non-conductor frame Module Requirements	Not Regulated	Not regulated. Class II suggested	Not Regulated. Class II suggested	None	Not Mentioned	Not regulated	None		Metal structure must be grounded.
Blocking Diode Requirements	None	Required. May be omitted with Class II modules	Required. May be Omitted with Class II modules.	None, but practiced by ENEL	Required (Possible to Remove)	None	None		Not Required.
Bypass Diode Requirements	General Practice	According to Manufacturer specifications.	According to Manufacturer Specs	General Practice	Required (Possible to Remove)	None	General Practice. (Module supplier requirement)		Not Required
Allowable Open Circuit Voltage for Array	Not Specified	Not discussed. Depends on Module Specification (usually 600V)	1500V. 120 V for Class III Systems.(Vdc 0-100)	600V for LV 50V for passive safety	750 V (JIS deals only with under 750V dc Voltage)	Max 1500 Vdc according to IEC 364	Depends on Product Specification		600 Volts for One and Two-family dwellings. other systems limited to 1000V listing limit.
Wire Insulation Types Allowed	Must pass compliance tests for UV, heat etc.	Not Specified, but cables must withstand expected ambient and outdoor conditions	Not Specified, but cables must withstand expected ambient conditions	Certified	IV (Poly-vinyl) CT (Rubber) CV-CE (Polyethylene)	Cables must be suitable for application. Double insulation	Not Specifically, but cables must withstand expected ambient conditions		Types USE, UF, SE permitted. Where exposed to sunlight, USE, UF, or others listed & marked sunlight resistant

PV Array (Continued)

Topic	Requirement or Comment By Country								
	Australia	Austria	Germany	Italy	Japan	Netherlands	Switzerland	United Kingdom	United States
Wiring Types Allowed (Stranded/Solid Conductor) (Copper/ Aluminum	No Restrictions	No Restrictions. Usually stranded wire.	Stranded Wire	No Restrictions	Not Mentioned	Stranded copper wires are preferred	No Restrictions		Stranded Wire
Rules for Protecting Wiring Insulation. Is Conduit Required? Are PV Array Raceways Allowed? Sunlight Resistant Insulation Required?	Conduits not mandatory, however mechanical protection is preferred. Sunlight Resistant required		Not Strictly Regulated	Prevention of Electrical Shock	Not Mentioned Yes, sunlight resistant required		Not Strictly Regulated		Flexible Cords and Cables allowed on PV array where water and sunlight resistant.
Color Codes Allowed on PV array Interconnect Wiring.	+ Red - Black Preferred but other colors permitted	+ Red - Blue Not strictly regulated.	+ Red - Blue			Normally black	+ Red - Blue		+ Red - Black Ground Green or Bare Wire
Junction Boxes and Module Interconnect Requirements	None	J-boxes according to IEC	J-boxes According to IEC 439-1	Standard per IEC1245	Water Proof	according to IP-classification	J Boxes According to IEC 439-1		NEMA rated for appropriate locations
What are the Fusing Requirements for the PV array	Not required but currently under review	Usually string fuses used.		None	Not Required	String fusing required when more than 2 strings are paralleled	Individual array strings must be fused.		Individual array strings must be fused.
Visible Disconnect Requirements	None	Required between the array and inverter	Required between the array and inverter	None, but this is ENEL's practice	Not Required	Required between array and inverter	Visible disconnect required with lockout capability when not collocated with PV		Visible disconnect required with lockout capability when not collocated with PV
Lightning Protection Requirements	Not required, but generally used.	Not mandatory. If used, there are guidelines.	Not Mandatory. If used, there are guidelines	None, but ENEL's protections	Required	Advised for larger systems at DC side	Not Required but normally used.		Not Required but normally used.

Batteries in PV Systems

Batteries are used primarily in stand-alone PV systems but may be used in grid-connected PV systems where load leveling using battery storage is part of the design. Grounding of batteries is a controversial subject and opinions on grounding of battery banks vary widely. Disconnect requirements and fusing of battery circuits are often subject to debated because of the expense associated with high dc current disconnect hardware. This table lists the requirements for using batteries in PV systems.

Topic	Requirement or Comment By Country								
	Australia	Austria	Germany	Italy	Japan	Netherlands	Switzerland	United Kingdom	United States
Are batteries required to be located in protected rooms	Yes	Yes, in professional systems	Yes, in professional systems	Yes	Yes	Yes	In large systems		Yes in commercial systems
Are batteries grounded	Yes (If not then + and - fuses)	No	May be but not required.	No	No	No	Sometimes		For less than 50V not required.
Is there a limit to parallel batteries	Not Suggested	No	Unknown	Not Suggested	No	Unknown	No		No.
Is there a maximum voltage for battery banks	No	Unknown	No	600 Vdc for LV 50 Vdc for passive safety.	No	No	No		600 Volts for Residential. 50 V for ungrounded systems
Are batteries required to have terminal protectors	Yes	if V > 48V	if V > 48V	No	Not Required but usually used.		Yes		No but usually used
Are batteries required to be temperature regulated	No	No	No	No	Not required but batteries are usually controlled.	No	No		No but good engineering practice. When not regulated, a temperature compensation recommended for charging.
Are special fuses required for battery banks	Yes, Must have dc rating	Per IEC and CENELEC	No	No	Not Required but usually used.	Yes	Yes		Fuses rated to break short circuit current available from the battery
Is venting required for battery rooms	Yes	Depends on type of battery and room.	Yes	Yes	Not Required but ventilated in many cases	Yes	In Large systems (Uses building code and electrical code)		Depends on size. Good engineering practice for large battery banks.

Stand-alone Inverters in PV Systems

Stand-alone inverters differ from utility-interactive inverters but some inverters provide both functions. Stand-alone inverters are used in conjunction with battery storage and typically are low voltage/high current inputs. The inverter output supplies ac loads directly and must provide the surge currents for starting motors or other non-linear loads. The following table discusses requirements for stand-alone inverters as indicated below.

Topic	Requirement or Comment By Country								
	Australia	Austria	Germany	Italy	Japan	Netherlands	Switzerland	United Kingdom	United States
Are metal housings of stand-alone inverters required to be grounded	Yes	Yes if the I is not Class II. Must not if SELV, PELV or electrical separation is used on the dc side	Yes if the I is not Class II. Must not if SELV, PELV or electrical separation is used on the dc side	Yes	Yes	Yes	Yes		Yes
Are low volts connections allowed to be exposed	Yes, up to 12V	Yes, Up to 48 Volts	Yes, Up to 48 Volts	Yes, Under 50V dc/ac	??	Yes	Yes		No (in principle)
Are inverter power quality requirements imposed for stand-alone applications	No	Not Regulated	Not Regulated	Yes		Yes, standard EMC-CE	EMI, Yes		No, but customers are requiring high quality power more today
What are the power quality requirements	50 Hz, 240 V	Not Regulated, but in discussion	Not Regulated	50 Hz, 230 V THD<8%		Yes, standard EMC-CE	Not regulated		None for stand-alone but typically frequency is + 1 Hz and Voltage is +10%
Are dc operating voltage windows required to protect batteries	Not Regulated	Not Regulated	Not Regulated	1.8 to 2.6 Vdc for lead-acid cells		Not regulated	Not regulated		Not Required but generally 1.75 to 2.7 Vdc per cell (temperature compensated) for lead-acid cells
Must stand-alone inverters be certified	No, but advised	Yes, when installed in residences	Not Regulated	Yes	No	No, but advised	No		Yes when installed in a residence
Is Fusing for the Inverter Input Required	No	All wires have to be protected	All wires have to be protected	No		Yes	No		Yes

Stand-alone Inverters in PV Systems (Continued)

Topic	Requirement or Comment By Country							
	Australia	Austria	Germany	Italy	Japan	Netherlands	Switzerland	United Kingdom	United States
Can grounded PV systems be tied to the case ground	Yes	Yes. Generally there is a central grounding to which all grounding wires connect.	Yes. Generally there is a central grounding to which all grounding wires connect.	Yes.		Yes	Yes		Yes
Must the ac output system be grounded & how.	Yes, Neutral Ground and earth electrode	Depends on the system	Not Regulated	Yes, Neutral grounded		No	Not Regulated		Yes, Just as in all ac distribution systems
What are Operating frequency requirements	50 Hz +/- 2 Hz	Not Regulated	Not Regulated			not regulated	None		Not regulated but +1 Hz is generally practiced
Are ac voltage regulation requirements imposed	Yes, From +/- 6%	Not Regulated	Not Regulated	Yes, Vnom + 10%; + 1% Hz		not regulated	No		Not regulated except listing agency has requirements.
Are isolation transformers required	No. Device to prevent dc current component on ac side is required	The Market for stand-alone inverters is very small. No regulation in place yet/	The Market for stand-alone inverters is very small. No regulation in place yet/	No. Device to prevent dc current component on ac side is required.		No	No		No, but generally used.
Is Transient protection required		No		Yes		No	No		No, but normally used
Comments									

Utility-Interactive (U-I) Inverters in PV Systems

Topic	Requirement or Comment By Country								
	Australia	Austria	Germany	Italy	Japan	Netherlands	Switzerland	United Kingdom	United States
Are U-I Inverters categorized	Yes	No	No	Line Commutated	Yes	No	No	Yes, Distinction between Line Commutated and Line Synchronized in G5911	Self Commutated Line Commutated Transformerless. Inverters must be identified for use in PV systems
Must U-I inverters be certified	Yes, but no certification . Must conform to individual standards.	No	No	Yes	Yes	No, but advised AC-Modules must	Soon	No Overall Certification but must conform to individual standards	Yes. Listed is the general certification.
Must U-I inverters be protected against transients	Yes	Usually yes	Yes	Yes	Yes	Yes, according to standard EMC-CE	Yes	Yes, EMC Rules	Yes
Are dc voltages limited	Limited to associated equipment insulation class	Battery voltage <120V (series connection of cells)	To 1500 V; Lower values for class III (120 V)	NO	Yes (Based on insulation requirements	max. 1500Vdc = IEC 364.	No	Yes, ICE Regulations. 120V dc for SELV 1500V dc for Low Voltage	Yes (600 V for inverters used in residential applications. System Voltage is used as the limit.
Is dc transient protection required	No, but recommended	No, but recommended	No, but recommended	No. This is ENEL's practice	Yes	No, recommended	Yes	No, But Recommended	No
Must dc circuit be grounded	No, but depends on protection and earthing	No, Depends on protection measured and earthing	No, Depends on protection measured and earthing	No	No	No	No	No	Yes
Must ac circuit be grounded	Yes	Depends on local premise wiring	Depends on local premise wiring	Yes	No	No	Yes	Yes (PME Neutral and Earthed)	Yes

Utility-Interactive Inverters in PV Systems (Continued)

Topic	Requirement or Comment By Country								
	Australia	Austria	Germany	Italy	Japan	Netherlands	Switzerland	United Kingdom	United States
How is dc/ac ground handled	If DC system is floating, only PV frame bonded. If DC earthed, bond between ac and dc required.	If grounding exists, both shall be bonded	If grounding exists, both shall be bonded	DC system floating; SC support structure and ac grounded		Bounded to ground	If grounding exists, both shall be bonded	Bonded	Bonded to neutral when available. Bonded to ground where no neutral
List Required Set points and Thresholds for dc	120 Vdc	No requirements specified	No Requirements. Only 120V limit for Class III	Maximum allowed by inverters or appliances	Depends on Measuring System	120 Vdc according to IEC 364	No Requirements. Only 120V limit for Class III	120Vdc limit for SELV	
List Required Set points and Thresholds for ac	240V +/- 6%	No requirements specified	No Requirements Specified	Vnom + 10%	5 ~ 30 ma (0.1 ~ 2 sec) 50 ~ 100 ma (0.1 sec)	230 -10% +6%	230/400 +6, -10%	+10%, -6% on 230V +1, -1 frequency operating envelope	Nominal + 10% and +6,-13% are used.
Are isolation transformers required	No, but dc injection shall not occur	Generally No. Only for certain protection measures.	Generally No. Only for certain protection measures.	Only for single-phase connect	Yes (In Principle)	No	No	No, but dc injection shall not occur	No, but dc injection shall not occur
Are internal over/under voltage/frequency features allowed	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes, (Preferably sealed)	Yes
Are external over/under volt/frequency relays required	Yes, Unless inverter is tested and complies with guidelines	No or for example “ENS”	No	Yes	Yes	No	Yes	Yes, Electricity companies discretion if can be combined	No except some utilities may impose such a requirement
Comments									

Disconnects in PV Systems

Topic	Requirement or Comment By Country								
	Australia	Austria	Germany	Italy	Japan	Netherlands	Switzerland	United Kingdom	United States
Where in the PV system are visible disconnects required	Not Specified on dc. AC must have labeled disconnection point.	Between the Array and the Inverter	Between the Array and the Inverter	At the dc/ac switch	Visible Disconnects Not Required but disconnectors are required for ac and dc terminals	Between array and inverter and Inverter and array (different for AC Modules)	Dc to Inverter Inverter to AC	Not Specified, but good practice	Readily accessible. Visible disconnects must be grouped and identified when more than one source is available.
Is Neutral disconnected with center tapped systems	No center-tapped systems	No	No	N/A	No Center Tapped Systems	No	No	Not Specified	No
Are disconnects required on all conductors in ungrounded systems	Not specified	Yes	Yes		Yes	Yes, in nearly all	Yes	Not Specified	Yes
What disconnects are required in ground fault circuits	DC not mentioned. AC (RCD)	Load Break Capabilities	Load Break Capabilities		ac side, (ELB) Not Mentioned (dc side)		Not Specified	Not Specified	Under consideration. Normally the array is opened or short-circuited.
Must dc disconnect be rated to break under load	Yes	Yes	Yes	Yes	Not mentioned but usually rated to break load	Yes	Yes	Not Specified	No. When the disconnect cannot be operated under load.
Are solid-state disconnects allowed	No	No	No	No	No (ac side) Not Mentioned (dc side)	No	No	No, (AC side)	No
Are array disable switches or relays required for fire safety	No	Yes	No	Yes	Not Mentioned	No	No	Not Specified, but good practice	No, but good engineering practice.

Thresholds, Protective Devices and Circuits Required in PV Systems

Topic	Requirement or Comment By Country								
	Australia	Austria	Germany	Italy	Japan	Netherlands	Switzerland	United Kingdom	United States
DC GFI Requirements	Not Specified		Not Regulated	Any Requirements			Not Regulated	Not Specified	30 ma
AC GFI Requirements	30 ma		Not Regulated	Yes			Not Regulated	30 ma domestic	5 ma
Max DC Voltage	120V, 1500V		120V, 1500V	LV limit of 600 Vdc	750V for low voltage class	120,1500 Vdc	120V, 1500V	120V, 1500V	600 for residential
Max AC Voltage	415 V, 3-Phase	Not Regulated	Not Regulated	LV limit of 1000 Vdc	600 V for low voltage class	230/415	Open	415 V, 3-Phase	600 for residential
Max Ground Resistance Requirements	Not Specified	Not Regulated	Not Regulated	Any	100 ohms (in case of installing ELB, 500 ohms	No regulated	According to IEC1216	Designed to meet ICE disconnection times	Variable, but often less than 3 ohms.
Islanding Detect Requirements	Yes, Passive and Active Detect	Required	Can Replace external disconnect		Required	Yes,	Not Required	Required by 9591	Under discussion. Generally required by utilities
Passive Allowed or Required	U/O Voltage U/O Frequency			Min/Max Voltage and frequency	Required	Only voltage and frequency window Negative frequency shift is advised	Required	Min/Max Voltage and Frequency	Voltage and/or frequency
Active Allowed or Required	At least two active methods required. Method not specified.	3-phase UV relay or ENS	3-phase UV relay or ENS		Required	No	Not Required	Loss of Mains EG ROCOF	Non at this time

List of Standards Used for Grounding and Ground-fault Protection in Each Country

United Kingdom

UK Utility Standards	Topic or Name	Number and Issue
UK Utility Standard	ET 113	G 59/1
UK Earthing Standards	Code of Practice for Earthing	BS7430
	ICE Wiring Regulations	BS7671
	C.O.P. Protection of Structures Against Lightning	BS6651

PV Standards that May be Adopted as Best Practice	Topic or Name	Number and Issue
International Electrotechnical Commission	Safety Regulations for PV	IEC TC-82
	Overvoltage Protection for PV	IEC TC-1163

United States of America

Standards, Codes, Requirements for Grounding and Ground Fault Protection	Topic or Name	Number and Issue
National Fire Protection Association National Electrical Code	NEC-1996	ANSI/NFPA 70-1996
Underwriters Laboratories Standard	UL Draft Standard for Inverters, Charge Controllers, and AC Modules for use in Photovoltaic Power Systems	UL 1741 Standard Tentative Dated To be Published December 1997.
Underwriters Laboratories Standard	UL Standard for Flat-Plate Photovoltaic Modules and Panels	UL 1703 Standard
Institute of Electrical and Electronic Engineers Standard	IEEE Recommended Practice for Installation and Maintenance of Lead-Acid Batteries for Photovoltaic Systems	IEEE 1146
Institute of Electrical and Electronic Engineers Standard	IEEE Recommended Practice for Installation and Maintenance of Lead-Acid Batteries for Photovoltaic Systems	IEEE 937
Institute of Electrical and Electronic Engineers Standard	IEEE Recommended Practice: Test Procedure for Utility-Interconnected Static Power Converters	IEEE 1035
Institute of Electrical and Electronic Engineers Standard	IEEE Guide for Terrestrial Photovoltaic Power System Safety	IEEE 1374 In Committee- Tentative publish Dec. 1997.
	IEEE Recommended Practice on Surge Voltages in Low-Voltage AC power Circuits	C62.41
Institute of Electrical and Electronic Engineers Standard	IEEE Recommended Practice for Installation and Maintenance of Nickel-Cadmium Batteries for Photovoltaic Systems	IEEE 1145

18. ANNEX C INVERTER TEST CIRCUIT (JAPANESE EXHIBIT)

Japanese Certification Test Procedure of Islanding Prevention Measures for Grid Connected Photovoltaic Power Generation Systems
March 4th, 1998

1. Introduction

If grid connected PV system is in islanding in the event of utility grid outage, it may cause problems in aspects of safety and reliability of the utility grid. Many types of islanding prevention measure have been developed and recommended in current Japanese guideline for grid interconnection of dispersed power generators including PV system. The purpose of this certification test is to certify adaptation of the performance of islanding prevention measures to the guideline.

2. Scope

This document describes certification test for testing the performance of islanding prevention measures installed in power conditioner of grid connected PV system which connects to single or three phase utility grid.

3. Definitions

- PV array simulator
- etc.

4. Testing Circuit

Testing circuit shown in Fig.1 shall be employed. Similar circuits shall be used for three phase output.

5. Testing Equipment

5.1 Measuring instruments

Either analog or digital instrument may be used for measurement.

5.2 DC and AC power supply

Either PV array or PV array simulator shall be utilized. If tested power conditioner is the type that storage battery is also connected as a DC power source, the constant voltage power supply including storage battery shall be capable. The AC power source shall be capable of simulating the utility grid power supply.

5.3 AC loads condition

On AC side of the tested power conditioner, variable resistance, capacitance, and inductance shall be connected in parallel as loads between the power conditioner and AC power supply. A rotating load, such as inductive motor, shall be also connected as a load.

6. Test Procedures

(1) Test under balanced condition of generation power and load

(a) Conditions of AC and DC power supplies

AC voltage and frequency of AC power supply shall be adjusted to the rated values. DC power shall be adjusted so that the power conditioner operates under the rated output.

(b) Load conditions

Rotating load shall be operated with no load. Real power and reactive power flowing at SW_{CB} shown in Fig.1 shall be set 0 kW and 0 kVar respectively by means of adjusting resistance for real power and inductance and /or capacitance for reactive power. In the condition, SW_{CB} shall be disconnected and the time until the power conditioner output current supplied to loads is equal to zero shall be measured.

(2) Test under imbalance condition of generation power and load

(a) Conditions of AC and DC power supplies

Same conditions as (1)-(b) shall be applied.

(b) Load condition

Rotating load shall be operated with no load. Real power and reactive power flowing at SW_{CB} shown in Fig.1 shall be set +/-20%,+/-15%, +/-10%, and +/-5% of real output power of the power conditioner respectively by means of adjusting resistance, inductance, and/or capacitance. In each condition, SW_{CB} shall be disconnected and the time until the power conditioner output current supplied to loads is equal to zero shall be measured.

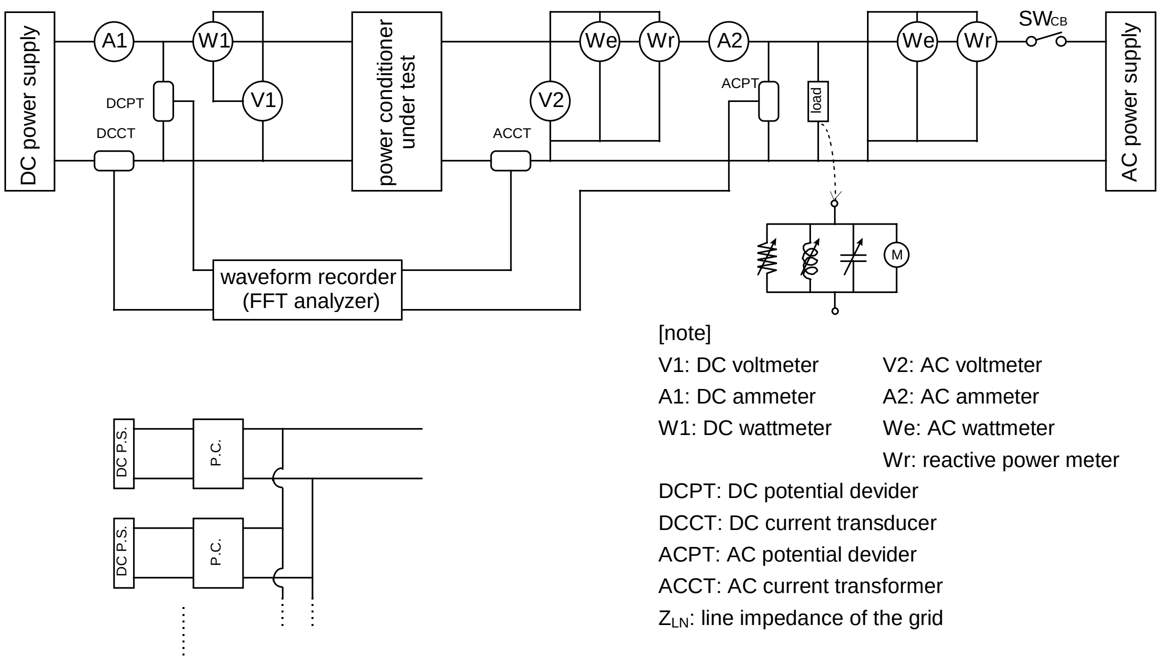


Figure 1 Test circuit for utility connected power conditioners