IEEE Std 929-2000
(Revision of
IEEE Std 929-1988)

IEEE Recommended Practice for Utility Interface of Photovoltaic (PV) Systems

Sponsor

IEEE Standards Coordinating Committee 21
on Fuel Cells, Photovoltaics, Dispersed Generation, and Energy Storage

Approved 30 January 2000

IEEE-SA Standards Board

Abstract: This recommended practice contains guidance regarding equipment and functions necessary to ensure compatible operation of photovoltaic (PV) systems that are connected in parallel with the electric utility. This includes factors relating to personnel safety, equipment protection, power quality, and utility system operation. This recommended practice also contains information regarding islanding of PV systems when the utility is not connected to control voltage and frequency, as well as techniques to avoid islanding of distributed resources.
Keywords: islanding, nonislanding inverter, photovoltaic, utility interconnection

---

The Institute of Electrical and Electronics Engineers, Inc.
3 Park Avenue, New York, NY 10016-5997, USA

Copyright © 2000 by the Institute of Electrical and Electronics Engineers, Inc.
All rights reserved. Published 3 April 2000. Printed in the United States of America.

Print: ISBN 0-7381-1934-2 SH94811
PDF: ISBN 0-7381-1935-0 SS94811

No part of this publication may be reproduced in any form, in an electronic retrieval system or otherwise, without the prior written permission of the publisher.

Copyright The Institute of Electrical and Electronics Engineers, Inc.
Provided by IHS under license with IEEE
No reproduction or networking permitted without license from IHS
Not for Resale

IEEE Standards documents are developed within the IEEE Societies and the Standards Coordinating Committees of the IEEE Standards Association (IEEE-SA) Standards Board. Members of the committees serve voluntarily and without compensation. They are not necessarily members of the Institute. The standards developed within IEEE represent a consensus of the broad expertise on the subject within the Institute as well as those activities outside of IEEE that have expressed an interest in participating in the development of the standard.

Use of an IEEE Standard is wholly voluntary. The existence of an IEEE Standard does not imply that there are no other ways to produce, test, measure, purchase, market, or provide other goods and services related to the scope of the IEEE Standard. Furthermore, the viewpoint expressed at the time a standard is approved and issued is subject to change brought about through developments in the state of the art and comments received from users of the standard. Every IEEE Standard is subjected to review at least every five years for revision or reaffirmation. When a document is more than five years old and has not been reaffirmed, it is reasonable to conclude that its contents, although still of some value, do not wholly reflect the present state of the art. Users are cautioned to check to determine that they have the latest edition of any IEEE Standard.

Comments for revision of IEEE Standards are welcome from any interested party, regardless of membership affiliation with IEEE. Suggestions for changes in documents should be in the form of a proposed change of text, together with appropriate supporting comments.

Interpretations: Occasionally questions may arise regarding the meaning of portions of standards as they relate to specific applications. When the need for interpretations is brought to the attention of IEEE, the Institute will initiate action to prepare appropriate responses. Since IEEE Standards represent a consensus of all concerned interests, it is important to ensure that any interpretation has also received the concurrence of a balance of interests. For this reason, IEEE and the members of its societies and Standards Coordinating Committees are not able to provide an instant response to interpretation requests except in those cases where the matter has previously received formal consideration.

Comments on standards and requests for interpretations should be addressed to:

Secretary, IEEE-SA Standards Board
445 Hoes Lane
P.O. Box 1331
Piscataway, NJ 08855-1331
USA

Note: Attention is called to the possibility that implementation of this standard may require use of subject matter covered by patent rights. By publication of this standard, no position is taken with respect to the existence or validity of any patent rights in connection therewith. The IEEE shall not be responsible for identifying patents for which a license may be required by an IEEE standard or for conducting inquiries into the legal validity or scope of those patents that are brought to its attention.

Authorization to photocopy portions of any individual standard for internal or personal use is granted by the Institute of Electrical and Electronics Engineers, Inc., provided that the appropriate fee is paid to Copyright Clearance Center. To arrange for payment of licensing fee, please contact Copyright Clearance Center, Customer Service, 222 Rosewood Drive, Danvers, MA 01923 USA; (978) 750-8400. Permission to photocopy portions of any individual standard for educational classroom use can also be obtained through the Copyright Clearance Center.

--`,,`-`-`,,`,,`,`,,`---

Copyright The Institute of Electrical and Electronics Engineers, Inc.
Provided by IHS under license with IEEE
No reproduction or networking permitted without license from IHS Not for Resale

Introduction

[This introduction is not a part of IEEE Std 929-2000, IEEE Recommended Practice for Utility Interface of Photovoltaic (PV) Systems.]

This revision of IEEE Std 929 is in response to the maturation of the photovoltaic industry. That maturation has identified the critical need to have the interconnection of photovoltaic (PV) systems to the utility grid be covered under a comprehensive document that includes specific recommendations rather than general guidance. The intent of this document is to define the technical requirements of PV system interconnection in a manner that can be adopted as a PV system technical interconnection standard by individual utilities. This document also includes several annexes for tutorial and clarification purposes.

A significant effort has been made to coordinate this document with Underwriters Laboratories in the production of UL 1741, a test procedure that can be performed by an independent body to verify that an inverter intended for use with a utility-interconnected PV system meets the recommendations described in this recommended practice. The safety test procedure put forth by the Underwriters Laboratories will, among other things, test the inverter for proper response, as detailed in this recommended practice (including Annex A), to loss of utility or "out of bounds" utility conditions. One aspect of this testing is to ascertain that the inverter will not operate as a utility-independent island.

Participants

At the time this recommended practice was completed, Standards Coordinating Committee 21, on Fuel Cells, Photovoltaics, Dispersed Generation, and Energy Storage, had the following membership:

R. DeBlasio, *Chair*

S. Chalmers, *Vice Chair*

A. J. Anderson, *Secretary*

R. Addiss
G. Atmaram
M. Azzam
T. Basso
M. Behnke
R. Bonn
W. Bottenberg
W. Bower
B. Brooks
P. Butler
J. Bzura
J. Call
P. Capps
R. Cary
J. Chamberlin
J. Chau
D. Conover
G. Corey
R. D'Aiello
D. Dawson
J. Drizos
T. Duffy
J. Dunlop
J. Emming
B. Farmer
W. Feero
M. Flis
C. Freitas
D. Garrett
R. Gonsiorawski
R. Hammond
K. Hecht
S. Hester
R. Hoffman
J. Hoffner
S. Hogan
B. Hornberger
T. Hund
M. Jackson
T. Jester
S. Jochums
B. Jones
W. Kanzer
W. Kaszeta
G. Kelly
G. Kern
J. Koepfinger
B. Kroposki
S. Kurtz
L. Libby
D. Loweberg
S. Macera
K. MacKamul
N. Magnani
A. Mikonowicz
J. Moriarty
D. Myers
C. Napikoski
A. Nilsson
U. Ortabsi
C. Osterwald
P. Overholt
J. Posbic
R. Rider
T. Ruhlmann
M. Russell
P. Russell
K. Sanders
R. Schmit
J. Smyth
J. Stevens
C. Sun
J. Sutherland
M. Thomas
J. Turner
J. Tuttle
S. Vechy
J. Ventre
C. Whitaker
K. Whitfield
J. Wiles
R. Wills
J. Wohlgemuth
T. Zgonena

Copyright © 2000 IEEE. All rights reserved.

Copyright The Institute of Electrical and Electronics Engineers, Inc.
Provided by IHS under license with IEEE
No reproduction or networking permitted without license from IHS
Not for Resale

At the time this recommended practice was completed, the Utility Working Group of Standards Coordinating Committee 21, on Fuel Cells, Photovoltaics, Dispersed Generation, and Energy Storage, had the following membership who participated in the preparation of this recommended practice:

John Stevens, *Chair*

Miles Russell, *Secretary*

Michael Behnke
Bill Brooks
John Bzura
Steve Chalmers
Joe Chau
Doug Dawson
Richard DeBlasio
Tom Duffy
Chris Freitas
D. Lane Garrett
Steve Hester
John Hoffner
Barry Hornberger
Bob Jones
Greg Kern
Leslie Libby
Don Loweberg
Tron Melzl
John Moriarty
Chester Napikoski
Jean Posbic
Jodi Smyth
Chase Sun
Rick West
Chuck Whitaker
Robert Wills
Tim Zgonena

The following members of the balloting committee voted on this recommended practice:

Mike Behnke
John Bzura
Steve Chalmers
Jay Chamberlin
Doug Dawson
Richard DeBlasio
Tom Duffy
Bill Feero
D. Lane Garrett
Bob Hammond
John Hoffner
Stephen Hogan
Bob Jones
Greg Kern
Tron Melzl
John Moriarty
Miles Russell
John Stevens
Chase Sun
Chuck Whitaker
John Wiles
Robert Wills

When the IEEE-SA Standards Board approved this standard on 30 January 2000, it had the following membership:

Richard J. Holleman, *Chair*

Donald N. Heirman, *Vice Chair*

Judith Gorman, *Secretary*

Satish K. Aggarwal
Dennis Bodson
Mark D. Bowman
James T. Carlo
Gary R. Engmann
Harold E. Epstein
Jay Forster*
Ruben D. Garzon
James H. Gurney
Lowell G. Johnson
Robert J. Kennelly
E. G. “Al” Kiener
Joseph L. Koepfinger*
L. Bruce McClung
Daleep C. Mohla
Robert F. Munzner
Louis-François Pau
Ronald C. Petersen
Gerald H. Peterson
John B. Posey
Gary S. Robinson
Akio Tojo
Hans E. Weinrich
Donald W. Zipse

*Member Emeritus

Also included is the following nonvoting IEEE-SA Standards Board liaison:

Robert E. Hebner

Jennifer McClain Longman
IEEE Standards Project Editor

Copyright © 2000 IEEE. All rights reserved.
Copyright The Institute of Electrical and Electronics Engineers, Inc.
Provided by IHS under license with IEEE
No reproduction or networking permitted without license from IHS
Not for Resale

Contents

1. Overview 1

1.1 Scope 1
1.2 Purpose 2

2. References 2

3. Definitions 3

4. Power quality 4

4.1 Normal voltage operating range 5
4.2 Voltage flicker 5
4.3 Frequency 6
4.4 Waveform distortion 6
4.5 Power factor 6

5. Safety and protection functions 7

5.1 Response to abnormal utility conditions 7
5.2 Direct-current injection 9
5.3 Grounding 9
5.4 Utility-interface disconnect switch 9

Annex A (normative) Minimum test procedure for a nonislanding PV inverter 11

Annex B (informative) Bibliography 15

Annex C (informative) PV inverters and the utility interface 16

Annex D (informative) Disconnect switches and utility procedures 19

Annex E (informative) Islanding as it applies to PV systems 20

Annex F (informative) The PV inverter under utility fault conditions 22

Annex G (informative) Dedicated distributed transformer 25

--`,,`-`-`,,`,,`,`,,`---
Copyright © 2000 IEEE. All rights reserved.

Copyright The Institute of Electrical and Electronics Engineers, Inc.
Provided by IHS under license with IEEE
No reproduction or networking permitted without license from IHS
Not for Resale

Copyright © 2000 IEEE. All rights reserved.

Copyright The Institute of Electrical and Electronics Engineers, Inc.
Provided by IHS under license with IEEE
No reproduction or networking permitted without license from IHS
Not for Resale

IEEE Recommended Practice for Utility Interface of Photovoltaic (PV) Systems

1. Overview

This recommended practice contains guidance regarding equipment and functions necessary to ensure compatible operation of photovoltaic (PV) systems that are connected in parallel with the electric utility. This guidance includes factors relating to personnel safety, equipment protection, power quality, and utility system operation.

The document also includes seven annexes

— Annex A, Minimum test procedure for a nonislanding PV inverter
— Annex B, PV inverters and the utility interface
— Annex C, Disconnect switches and utility procedures
— Annex D, Islanding as it applies to PV systems
— Annex E, The PV inverter under utility fault conditions
— Annex F, Dedicated distribution transformers
— Annex G, Bibliography

1.1 Scope

This recommended practice applies to utility-interconnected PV power systems operating in parallel with the utility and utilizing static (solid-state) inverters for the conversion of direct current (dc) to alternating current (ac). (This recommended practice does not apply to systems utilizing rotating inverters.)

This recommended practice describes specific recommendations for “small” systems, rated at 10 kW or less, such as may be utilized on individual residences. These recommendations will provide greater standardization for these smaller systems, thereby reducing the engineering and design burden on both the PV system installer and the interconnecting utility.

“Intermediate” applications, ranging from over 10 kW up to 500 kW, follow the same general guidelines as small systems. Options to have adjustable setpoints or other custom features may be required by the inter-

--`,,`-`-`,,`,,`,`,,`---
Copyright © 2000 IEEE. All rights reserved.

Copyright The Institute of Electrical and Electronics Engineers, Inc.
Provided by IHS under license with IEEE
No reproduction or networking permitted without license from IHS
Not for Resale

connecting utility, depending on the impact of the PV system on the portion of the utility system to which it is interconnected.

"Large" systems, greater than 500 kW, may combine various standardized features as well as custom requirements, depending on the impact of the PV system on the portion of the utility system to which it is interconnected. A greater degree of custom engineering of the utility interface is to be expected as the size of the PV system grows in relation to utility system capacity.

1.2 Purpose

This recommended practice will provide value to a wide spectrum of personnel involved with utility-interconnected PV systems, including utility engineers, PV system designers and installers, and PV system owners. The standardized interconnection recommendations included in this recommended practice will minimize custom engineering of many aspects of the interconnection. This document is focused on providing recommended practice for utility interconnection of PV systems in a manner that will allow the PV systems to perform as expected and be installed at a reasonable cost while not compromising safety or operational issues.

Small utility-interconnected PV systems should use standardized, listed inverters (listed to test standards, such as UL 1741-1999[1], which include the testing requirements described in Annex A). The listing process assures that the inverter incorporates fixed voltage and frequency trip settings and incorporates an integral anti-islanding scheme. It is the intent of this recommended practice that small systems designed and installed in accordance with this document and other applicable standards, such as the National Electrical Code® (NEC®) (NFPA 70-1999), will require no additional protection equipment.

2. References

This recommended practice shall be used in conjunction with the following publications. When the following standards are superseded by an approved revision, the revision shall apply.

Accredited Standards Committee C2-1997, National Electrical Safety Code® (NESC®).[2]

ANSI C84.1-1995, American National Standard for Electric Power Systems and Equipment—Voltage Ratings (60 Hertz).[3]

IEEE Std 519-1992, IEEE Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems.

NFPA 70-1999, National Electrical Code® (NEC®).[4]

UL 1741–1999, Standard for Static Inverters and Charge Controllers for Use in Photovoltaic Power Systems.[5]

---

[1]Information on references can be found in Clause 2.

[2]The NESC is available from the Institute of Electrical and Electronics Engineers, 445 Hoes Lane, P.O. Box 1331, Piscataway, NJ 08855-1331, USA (http://standards.ieee.org/).

[3]ANSI publications are available from the Sales Department, American National Standards Institute, 11 West 42nd Street, 13th Floor, New York, NY 10036, USA (http://www.ansi.org/).

[4]NFPA publications are available from Publications Sales, National Fire Protection Association, 1 Batterymarch Park, P.O. Box 9101, Quincy, MA 02269-9101, USA.

[5]UL standards are available from Global Engineering Documents, 15 Inverness Way East, Englewood, Colorado 80112, USA (http://global.ihs.com/).

Copyright © 2000 IEEE. All rights reserved.
Copyright The Institute of Electrical and Electronics Engineers, Inc.
Provided by IHS under license with IEEE
No reproduction or networking permitted without license from IHS
Not for Resale

3. Definitions

For purposes of this recommended practice, the following terms and definitions apply. IEEE 100-1996 [B7],[6] The IEEE Dictionary of Electrical and Electronics Terms, should be referenced for terms not defined in this clause.

3.1 inverter: Equipment that converts direct current (dc) to alternating current (ac). Any static power converter (SPC) with control, protection, and filtering functions used to interface an electric energy source with an electric utility system. *Syn*: **static power converter (SPC)**, **power conditioning subsystems, power conversion systems, solid-state converters, or power conditioning units**.

NOTES

1—The term "inverter" is popularly used for the converter that serves as the interface device between the PV system dc output and the utility system. However, the definition for SPC more accurately describes this interface device. Because of popular usage, the term "inverter" is used throughout this recommended practice. It should be born in mind that this inverter includes the control, protection, and filtering functions as described in the definition for SPC.

2—Because of its integrated nature, the inverter is only required to be totally disconnected from the utility for service or maintenance. At all other times, whether the inverter is transferring PV energy to the utility or not, the control circuits remain connected to the utility to monitor utility conditions. The phrase "cease to energize the utility line" is used throughout this document to acknowledge that the inverter does not become totally disconnected from the utility when a trip function occurs, such as an overvoltage trip. The inverter can be completely disconnected from the utility for inverter maintenance by opening the ac-disconnect switch required by the NEC®.

3.2 nonislanding inverter: An inverter that will cease to energize the utility line in ten cycles or less when subjected to a typical islanded load in which either of the following is true:

a) There is at least a 50% mismatch in real power load to inverter output (that is, real power load is < 50% or > 150% of inverter power output).

b) The islanded-load power factor is < 0.95 (lead or lag).

If the real-power-generation-to-load match is within 50% and the islanded-load power factor is > 0.95, then a nonislanding inverter will cease to energize the utility line within 2 s whenever the connected line has a quality factor of 2.5 or less.

NOTE—See Annex A for a test procedure that identifies an inverter as a nonislanding inverter.

3.3 islanding: A condition in which a portion of the utility system that contains both load and distributed resources remains energized while isolated from the remainder of the utility system.

3.4 distributed resource islanding: An islanding condition in which the distributed resource(s) supplying the loads within the island are not within the direct control of the power system operator.

3.5 point of common coupling (PCC): The point at which the electric utility and the customer interface occurs. Typically, this point is the customer side of the utility revenue meter.

NOTE—In practice, for building-mounted photovoltaic (PV) systems (such as residential PV systems) the customer distribution panel may be considered the PCC for convenience in making measurements and performing testing.

3.6 quality factor: Two pi times the ratio of the maximum stored energy to the energy dissipated per cycle at a given frequency.

NOTE—In a parallel resonant circuit, such as a load on a power system

[6]The numbers in brackets correspond to those of the bibliography in Annex G.

Copyright © 2000 IEEE. All rights reserved.

Copyright The Institute of Electrical and Electronics Engineers, Inc.
Provided by IHS under license with IEEE
No reproduction or networking permitted without license from IHS Not for Resale

$$Q = R\sqrt{\frac{C}{L}}$$

where

Q is quality factor
R is effective load resistance
C is effective load capacitance (including shunt capacitors)
L is effective load inductance

Or, on a power system, where real power, P, and reactive powers, $P_{qL,}$ for inductive load, and P_{qC} for capacitive load, are known as

$$Q = (1/P)\sqrt{P_{qL} \times P_{qC}}$$

where

Q is quality factor
P is real power
P_{qL} is inductive load
P_{qC} is capacitive load

3.7 resonant frequency: The frequency, f, at which a parallel resonant resistive-inductive-capacitive (RLC) load has unity power factor

$$f = 1/(2\pi\sqrt{C \times L})$$

where

f is the resonant frequency
C is effective load capacitance (including shunt capacitors)
L is effective load inductance

Also, the frequency at which the reactive powers P_{qL} and P_{qC} are equal, and hence the parallel RLC load appears equivalent to the load resistance only.

3.8 utility-interface disconnect switch: A switch that may be required at the interface between the photovoltaic (PV) system and the utility system. This terminology is used to distinguish this switch from others that may be installed for other reasons, such as to satisfy requirements of the National Electrical Code®.

4. Power quality

The quality of power provided by the PV system for the on-site ac loads and for delivery to the interconnected utility is governed by practices and standards addressing voltage, flicker, frequency, and distortion. Deviation from these standards represents out-of-bounds conditions and may require that the inverter cease to energize the utility line. For intermediate and large systems, the interconnected utility may prefer to have the PV remain connected during some voltage or frequency excursions to assist in riding through disturbances. Abnormal conditions are discussed in Clause 5.

All power quality parameters (that is, voltage, flicker, frequency, distortion) are specified at the point of common coupling (PCC) unless otherwise stated in this recommended practice.

-`-`-`,,`,,`-`-`,,`,,`,`,,`---

Copyright © 2000 IEEE. All rights reserved.
Copyright The Institute of Electrical and Electronics Engineers, Inc.
Provided by IHS under license with IEEE
No reproduction or networking permitted without license from IHS
Not for Resale

Underwriters Laboratories has prepared UL 1741-1999 specifically for PV inverters and PV charge controllers. The utility interconnection testing in UL 1741-1999 contains tests to confirm that an inverter meets the power quality recommendations of Clause 4 of this recommended practice.

4.1 Normal voltage operating range

Utility-interconnected PV systems do not regulate voltage, they inject current into the utility. Therefore, the voltage operating range for PV inverters is selected as a protection function that responds to abnormal utility conditions, not as a voltage regulation function.

Clearly, a large quantity of this current injection has the potential for impacting utility voltage. As long as the magnitude of PV current injection on a utility line remains less than the load on that line, the utility's voltage regulation devices will continue to operate normally. If the PV current injection on a utility line exceeds the load on that line, then corrective action is required, as the voltage regulation devices do not normally have directional current sensing capability.

See 5.1.1 for recommended device response when voltage at the PCC lies outside the specified operating range.

4.1.1 Small systems (≤ 10 kW)

Small PV systems should be capable of operating within the limits normally experienced on utility distribution lines. It is in the best interest of both the interconnected utility and the PV system owner that the operating window be selected in a manner that minimizes nuisance tripping. The operating window for these small PV systems is 106–132 V on a 120 V base, that is, 88–110% of nominal voltage. This range results in trip points at 105 V and at 133 V.

In actual practice, the 133 V trip point is related to the PCC voltage, which is not necessarily the inverter terminal voltage. If the inverter installation is electrically near enough to the PCC to allow negligible voltage difference between the inverter and the PCC, then the 133 V trip point will apply to the inverter terminals as well as the PCC. However, some systems may have installation restrictions that do not allow negligible voltage difference between the inverter and the PCC. In such cases, the techniques described in B.9 may be useful in allowing for this voltage difference.

The recommendation of this clause is that the inverter cease to energize the utility lines whenever the voltage at the PCC deviates from the allowable voltage operating range of 106–132 V.

4.1.2 Intermediate and large systems

Utilities may have specific operating voltage ranges for intermediate and large PV systems and may require adjustable operating voltage settings for these larger systems. In the absence of such requirements, the principles of operating between 88% and 110% of the appropriate interconnection voltage (see 4.1.1) should be followed.

4.2 Voltage flicker

Whether a particular amount and frequency of voltage flicker are problems is highly subjective. The topic has been documented in several studies in the past, including one by the New England Electric Power Service Co. [B10], and is discussed in 10.5 of IEEE Std 519-1992, particularly Figure 10.3. Any voltage flicker resulting from the connection of the inverter to the utility system at the PCC should not exceed the limits defined by the maximum borderline of irritation curve identified in IEEE Std 519-1992. This requirement is necessary to minimize the adverse voltage effects to other customers on the utility system.

--`,,`,,`-`-`,,`,,`,`,,`---
Copyright © 2000 IEEE. All rights reserved.

Copyright The Institute of Electrical and Electronics Engineers, Inc.
Provided by IHS under license with IEEE
No reproduction or networking permitted without license from IHS
Not for Resale

4.3 Frequency

The utility controls system frequency, and the PV system shall operate in synchronism with the utility. Small PV systems installed in North America should have a fixed operating frequency range of 59.3–60.5 Hz. Systems installed in another country should follow the frequency operating window standards of that country. Small isolated utility systems, as are often encountered on islands and in remote areas, may require larger frequency windows for small systems because of prevalent frequency deviations outside the above-specified window. Utilities may require adjustable operating frequency settings for intermediate and large systems.

See 5.1.2 for action recommended when frequency at the PCC lies outside the specified operating range.

4.4 Waveform distortion

The PV system output should have low current-distortion levels to ensure that no adverse effects are caused to other equipment connected to the utility system. The PV system electrical output at the PCC should comply with Clause 10 of IEEE Std 519-1992 and should be used to define the acceptable distortion levels for PV systems connected to a utility. The key requirements of this clause are summarized in the following:

— Total harmonic current distortion shall be less than 5% of the fundamental frequency current at rated inverter output.

— Each individual harmonic shall be limited to the percentages listed in Table 1. The limits in Table 1 are a percentage of the fundamental frequency current at full system output. Even harmonics in these ranges shall be <25% of the odd harmonic limits listed.

Table 1—Distortion limits as recommended in IEEE Std 519-1992 for six-pulse converters

Odd harmonics	Distortion limit
3rd–9th	< 4.0%
11th –15th	< 2.0%
17th– 21st	< 1.5%
23rd–33rd	< 0.6%
Above the 33rd	< 0.3%

These requirements are for six-pulse converters and general distortion situations. IEEE Std 519-1992 gives a conversion formula for converters with pulse numbers greater than six.

4.5 Power factor

The PV system should operate at a power factor > 0.85 (lagging or leading) when output is > 10% of rating. Most PV inverters designed for utility-interconnected service operate close to unity power factor. Specially designed systems that provide reactive power compensation may operate outside of this limit with utility approval.

Copyright © 2000 IEEE. All rights reserved.
Copyright The Institute of Electrical and Electronics Engineers, Inc.
Provided by IHS under license with IEEE
No reproduction or networking permitted without license from IHS
Not for Resale

5. Safety and protection functions

This clause describes recommendations addressing the proper and safe operation of the PV system. Recommendations include equipment protective functions as well as hardware recommendations to address personnel safety. This clause also includes specifications regarding the response to electrical disturbances. Annex B discusses the capabilities of inverters and their response to electrical disturbances.

UL 1741-1999 contains safety tests, as described in the minimum inverter test procedure discussed in Annex A, which confirm the existence of trip settings that adhere to the recommendations in this clause, including testing for the existence of an anti-islanding scheme.

5.1 Response to abnormal utility conditions

Abnormal conditions can arise on the utility system that require a response from the connected PV system. This response is to ensure the safety of utility maintenance personnel and the general public, as well as to avoid damage to connected equipment, including the PV system. The abnormal utility conditions of concern are voltage and frequency excursions above or below the values stated in 4.1 and in 4.3 and the complete disconnect of the utility, presenting the potential for a distributed resource island. (See 3.4 for a definition of distributed resource islanding, and see 5.1.3 and Annex D for a discussion of islanding as it applies to PV systems.)

A PV system should sense utility conditions and cease to energize the utility line when the sensed voltage or frequency lies outside the values stated in 4.1 and 4.3, when the potential for a distributed resource island exists, or when excess dc current injection is sensed.

5.1.1 Voltage disturbances

All discussions regarding system voltage assume a nominal 120 V base. To help in translating these guidelines to voltage bases other than 120 V, the limits will also be provided as approximate percentages.

The inverter should sense abnormal voltage and respond. The conditions in Table 2 should be met, with voltages in root-mean-square (rms) values and measured at the PCC.

Table 2—Response to abnormal voltages

Voltage (at PCC)	Maximum trip time[1]
V < 60 (V < 50%)	6 cycles
60 ≤ V < 106 (50% ≤ V< 88%)	120 cycles
106 ≤ V≤ 132 (88% ≤V≤ 110%)	Normal operation
132 < V < 165 (110% < V < 137%)	120 cycles
165 ≤ V (137% ≤ V)	2 cycles

[1]"Trip time" refers to the time between the abnormal condition being applied and the inverter ceasing to energize the utility line. The inverter will actually remain connected to the utility to allow the inverter to sense utility electrical conditions for the "reconnect" feature.

The purpose of the allowed time delay is to ride through short-term disturbances to avoid excessive nuisance tripping.

Copyright © 2000 IEEE. All rights reserved.

Copyright The Institute of Electrical and Electronics Engineers, Inc.
Provided by IHS under license with IEEE
No reproduction or networking permitted without license from IHS
Not for Resale

For small systems, the above setpoints should be nonuser-adjustable.

For intermediate and large PV systems, the voltage setpoints may be field adjustable if approved by the interconnecting utility. For intermediate and large PV systems being fed from medium-voltage switchgear, consideration should be given to monitoring voltage for the recommendations of this subclause at the PCC in order to avoid problems with voltage drop in various transformers, wiring, or feeder circuits.

5.1.2 Frequency disturbances

As discussed in 4.3, small PV systems should have a fixed frequency operating range of 59.3–60.5 Hz. The test points for determining proper operation of the frequency trip function should be 59.2 Hz and 60.6 Hz. For intermediate and large systems, utilities may require the ability to adjust the operating frequency range for special circumstances.

When the utility frequency is outside the range of 59.3–60.5 Hz, the inverter should cease to energize the utility line within six cycles. The purpose of the allowed time delay is to ride through short-term disturbances to avoid excessive nuisance tripping.

5.1.3 Islanding protection

This subclause addresses anti-islanding features required of the PV inverter to ensure that the inverter ceases to energize the utility line when the inverter is subjected to islanding conditions. For a discussion of islanding as it applies to PV systems, see Kern et al. [B4]; Stevens et al. [B12]; Begovic et al. [B1]; and Annex D.

PV systems are protected against the vast majority of potential islanding situations by voltage and frequency detection schemes as discussed in 5.1.1 and 5.1.2. However, it is possible that circumstances may exist on a line section that has been isolated from the utility and contains a balance of load and PV generation that would allow continued operation of PV systems (see Begovic et al. [B1] and Annex E). Such circumstances would require a load-to-generation balance so that both frequency and voltage remain inside the trip limits described in 5.1.1 and 5.1.2. Although such a load balance is perceived as a low-probability event, the potential impact of such an occurrence is great enough that this distributed resource islanding has been the subject of numerous studies and much research (Kern [B3]; New England Electric Power Service Co. [B10]; Stevens [B11]; Kern et al. [B4]; Stevens et al. [B12]; and Begovich et al. [B1]). This work has resulted in development of active control techniques that have proven to be reliable in detecting potential distributed resource islands, as well as a method to determine whether an adequate anti-islanding scheme is operational in an inverter. (See Annex A and Annex D.)

A utility wishing to ensure against establishment of a PV-supported distributed resource island should require the use of a nonislanding inverter. See 3.2 for the definition of a nonislanding inverter.

Another factor that works in favor of nonsupport of a distributed resource island by PV systems is the inability of most PV inverters designed for utility interconnection to supply the demand distortion or nonunity power factor associated with nonlinear loads. An instructive example is presented in Stevens et al. [B12] and briefly described in Annex D.

5.1.4 Reconnect after a utility disturbance

Following an out-of-bounds utility event that has caused the PV system to cease to energize the utility line, line energization should remain disabled until continuous normal voltage and frequency (that is, voltage and frequency within the limits described in 4.1 and 4.3) have been maintained by the utility for a minimum of 5 min, at which time the inverter is allowed to automatically reconnect the PV system to the utility.

Copyright © 2000 IEEE. All rights reserved.
Copyright The Institute of Electrical and Electronics Engineers, Inc.
Provided by IHS under license with IEEE
No reproduction or networking permitted without license from IHS
Not for Resale

5.2 Direct-current injection

The PV system should not inject dc current > 0.5% of rated inverter output current into the ac interface under either normal or abnormal operating conditions. See Annex B for further discussion of dc injection prevention with commercial inverters.

5.3 Grounding

The PV system and interface equipment should be grounded in accordance with applicable codes. A discussion of grounding is outside the scope of this document. Information relating to grounding of PV systems as required by the NEC can be found in Wiles [B13].

5.4 Utility-interface disconnect switch

The term “utility-interface disconnect switch” is used to identify a switch that may be included in a PV system for the express purpose of disconnecting the PV system output from the interconnected utility. This switch may be in addition to other disconnect switches, such as those required by the NEC.

A utility-interface disconnect switch is a manual, lockable, load-break disconnect switch that provides clear indication of the switch position and is both visible and accessible to utility workers. The switch should provide a visual verification of the switch contact position when the switch is in the open position. Many low-voltage safety switches have a cover that cannot be opened when the switch is in the “closed” position, but can be opened when the switch is in the “open” position, providing visual verification that the contacts are open. Such a switch meets the requirements of this clause.

When a utility-interface disconnect switch is required, it is to allow utility workers to disconnect the PV system from the utility electrical system when it is necessary for safe utility line work. Two situations exist where utilities may choose not to require a utility-interface disconnect switch

— If a utility has operating procedures that do not require such a switch for PV systems.
— When certified nonislanding inverters are used.

There may be other nontechnical or business-related reasons to install a utility-interface disconnect switch. For example, a utility might have contract requirements that specify a lockable, outdoor-accessible, load-break disconnect switch to allow the PV system to be locked out of service in the case of default on contract requirements. Also, agreements with labor unions may require the installation of this utility-interface disconnect switch. See Annex C for further discussion of disconnect switches and utility procedures.

Compliance with the requirement for a utility-interface disconnect switch is further described in 5.4.1 and 5.4.2 for PV systems that are not associated with a building and for PV systems that are on buildings (including residences, apartments, and commercial and industrial buildings).

5.4.1 Nonbuilding-associated PV systems

All PV systems include disconnect switches for a variety of reasons. For example, the ac and dc switches required by the NEC to electrically to isolate an inverter to allow service or removal of the inverter. Another switch is required to electrically isolate a distribution transformer associated with the PV system. In most nonbuilding-associated PV systems (for example, a ground-mounted PV system), these switches can perform the function of the utility-interface disconnect switch described in 5.4 and may be accepted by the local utility for that purpose. In such cases, an additional switch is not recommended.

Copyright © 2000 IEEE. All rights reserved.

Copyright The Institute of Electrical and Electronics Engineers, Inc.
Provided by IHS under license with IEEE
No reproduction or networking permitted without license from IHS
Not for Resale

5.4.2 PV systems on buildings

The switches noted in 5.4.1 may also serve as the utility-interface disconnect switch for PV systems on buildings, depending on the location of the switch. For example, if an inverter is mounted on the exterior of the building in a location readily accessible to the utility worker, then the ac disconnect required by the NEC for that inverter can also serve as the utility-interface disconnect switch if it fulfills the other requirements described in 5.4. If no disconnect switch has been installed as a normal part of the PV installation that will meet the requirements of a utility-interface disconnect switch, then such a switch should be provided (unless the interconnecting utility does not require the switch) as discussed in the first paragraph of 5.4.

Copyright © 2000 IEEE. All rights reserved.
Copyright The Institute of Electrical and Electronics Engineers, Inc.
Provided by IHS under license with IEEE
No reproduction or networking permitted without license from IHS
Not for Resale

Annex A

(normative)

Minimum test procedure for a nonislanding PV inverter

A.1 Introduction

Nonislanding PV inverters are designed for connection as a parallel source to a utility service. In addition to fixed overfrequency, underfrequency, overvoltage, and undervoltage trips described in Clause 5, this type of inverter includes a means to shut down when the utility source is not present (the nonislanding feature). Testing inverters at rated output for interactive operation with a utility requires special test equipment. Thus, full capacity tests are usually reserved for certified design type testing. Anytime a circuit or software is changed in the inverter, the design type testing should be repeated.

Measurement error for all parameters, except frequency, in the following test procedures shall be < 2%. Measurement error for frequency shall be ≤ 0.1 Hz.

A.2 Test procedure to verify frequency and voltage limits

a) Connect the output of the inverter to a simulated utility source that is capable of absorbing the energy to be delivered by the inverter. It is not necessary to run the inverter at full output to verify the fixed frequency and voltage set points.

b) Adjust the simulated utility source to nominal frequency and voltage and verify the inverter is delivering power.

c) Verify the voltage trip points and time to trip as specified in Clause 5 by raising and lowering the voltage to values outside the normal operating windows.

d) Verify the frequency trip points and time to trip by varying the frequency at a rate no faster than 0.5 Hz/s to the trip points specified in Clause 5.

e) Following disconnection from the simulated utility source, restore the voltage and frequency to the nominal output values of the inverter and verify that

   1) An inverter that is provided with manual reset remains disconnected from the simulated utility source.

   2) An inverter with automatic reset does not reconnect to the simulated utility source until the utility voltage and frequency are restored for the period specified in Clause 5.

Each of the above tests shall be repeated 10 times. The actual tripping time shall be recorded in each test. A single failure of any of these tests is considered a failure of the entire test sequence.

A.3 Test procedure to verify nonislanding

Once the fixed frequency and voltage limits have been verified, test to determine that the inverter cannot maintain stable operation without the presence of a utility source. A utility source means any source capable of maintaining an island within the recommended voltage and frequency windows. An engine generator with voltage and frequency control and with no anti-islanding protection is considered a utility source for the purpose of this test. However, because of the uncertainty associated with the need to sink both real and reactive power from the inverter, this test may be performed most conveniently with a utility connection, rather than a simulated utility. This test is best conducted with voltage and frequency near the middle of their operating

--`,,`-`-`,,`,,`,`,,`---

Copyright © 2000 IEEE. All rights reserved.

Copyright The Institute of Electrical and Electronics Engineers, Inc.
Provided by IHS under license with IEEE
No reproduction or networking permitted without license from IHS
Not for Resale

ranges. Voltage should be at least 3% inside the most restrictive voltage trip limits. Frequency should be at least 0.25 Hz inside the most restrictive frequency trip limits. (Frequency and voltage variation is not required for this testing.)

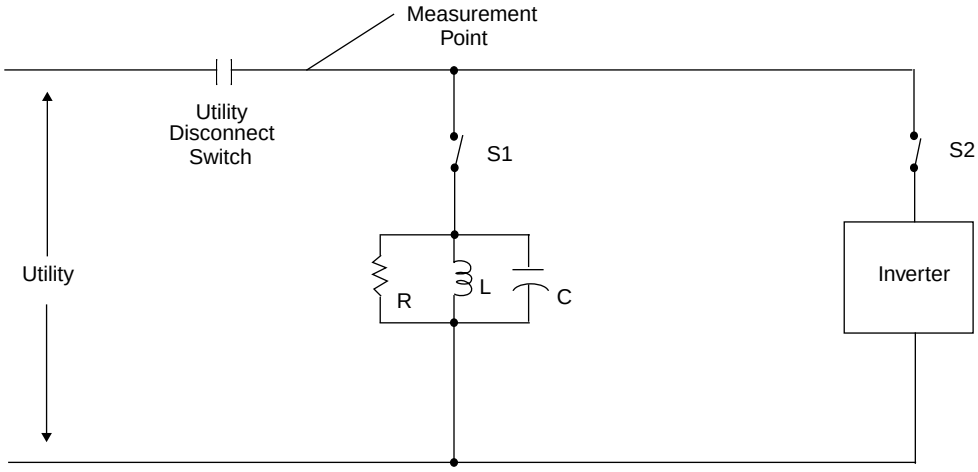

Figure A.1—Nonislanding inverter test circuit

This test procedure is based on having the quality factor Q of the islanded circuit (including load and generator) set equal to 2.5. The definitions in 3.6 and 3.7 imply how this should be done. Note from 3.6 that

$$Q = (1/P)\sqrt{P_{qL} \times P_{qC}}$$

Note also that, in the resonant case

$$P_{qL} = P_{qC} = P_q$$

Therefore, in the resonant case,

$$Q = P_q/P.$$

These formulas apply to the unity-power-factor inverter.

A.3.1 Test procedure background

This test procedure is designed to be universally applicable to both unity-power-factor inverters and nonunity-power-factor inverters. With unity-power-factor inverters, the second step, where $P_{q\text{-}inverter}$ is measured, will result in a value of $P_{q\text{-}inverter}$ that is zero, simplifying the remainder of the procedure. For inverters where $P_{q\text{-}inverter}$ is not zero, the test is complicated by the presence of reactive power in the inverter.

Harmonic currents that flow between the utility, the capacitor, and the inverter, further complicates the situation by making it appear that current is flowing when the 60 Hz component of current has been zeroed. Thus, it is important, when adjusting inductive and capacitive reactance, to use instruments that can distinguish the 60 Hz component of current and power from other frequencies.

The sequence of the steps below is recommended for several reasons. The inductance is measured first because that measurement is low in harmonics. The capacitance is added second so that the voltage is stable when the resistance is added. The resistive parallel load is then added and adjusted. This resistance will be in addition to the resistance that will be part of the inductive load.

Copyright © 2000 IEEE. All rights reserved.
Copyright The Institute of Electrical and Electronics Engineers, Inc.
Provided by IHS under license with IEEE
No reproduction or networking permitted without license from IHS
Not for Resale

This test procedure assumes that a nonunity-power-factor inverter will be sourcing, not sinking, reactive power. The procedure refers to a circuit that is configured as shown in Figure A.1. Details of this circuit may be changed to suit the specific hardware available to the tester. For example, it may be convenient to replace switch S1 with individual switches on each leg of the RLC load. For each inverter/load power combination the following procedure is suggested to achieve the proper generation-to-load complex power balance.

A.3.2 Nonislanding inverter test procedure

a) Determine inverter test output power P_{inv} that will be used.

b) Operate the inverter at P_{inv} and measure inverter reactive power output $P_{q\text{-}inverter}$.

NOTE—The utility disconnect switch should be closed. With no local load connected (that is, S1 is open so that the RLC load is not connected at this time) and the inverter connected to the utility (S2 is closed), turn the inverter on and operate it at the output determined in step a). Measure real and reactive power flow at the measurement point. The real power should equal P_{inv}. The reactive power measured in this step is designated $P_{q\text{-}inverter}$.

c) Turn off the inverter and open S2.

d) Adjust the RLC circuit to have Q = 2.5. This step is accomplished by

1) Determining the amount of inductive reactance required in the resonant RLC circuit using the relation $P_{qL} = 2.5\ P_{inv}$

2) Connecting an inductor as the first element of the RLC circuit and adjusting the inductance to P_{qL}

3) Connecting a capacitor in parallel with the inductor and adjusting the capacitive reactance so that $P_{qL} - P_{q\ inverter} = P_{qC}$

4) Connecting a resistor that results in the power consumed by the RLC circuit equaling P_{inv}

e) Connect the RLC load configured in step d) to the inverter by closing S1. Close S2 and turn the inverter on, making certain that the power output is as determined in step a).

NOTE—The purpose of the procedure up to this point is to zero out the 60 Hz components of real and reactive power, or to zero out the 60 Hz component of current flow, at the utility disconnect switch. System resonances will typically generate harmonic currents in the test circuit. These harmonic currents will typically make it impossible to zero out an RMS measurement of power or current flow at the disconnect switch. Because of test equipment measurement error and some impact from harmonic currents, it is necessary to make small adjustments in the test circuit to achieve worst case islanding behavior. Step g) is performed to make these small adjustments.

f) Open the utility-disconnect switch to initiate the test.

g) After each successful test, one parameter is adjusted by approximately 1.0% per test, within a total range of ±5% of the operating point determined in step d). The parameter that is adjusted may be load inductance L or load capacitance C. After each adjustment, an island test is run and time to trip is recorded. If any of these tests results in islanding for longer than the time specified in 3.2, the unit fails the test and the test sequence is considered complete.

This test should be performed with the ratios, shown in Table A. 1, of real load to inverter output, where both values are given as a percent of inverter full output rating

The actual tripping time for each test shall be recorded. A single failure of any of these tests is considered a failure of the entire test sequence.

Copyright © 2000 IEEE. All rights reserved.

Copyright The Institute of Electrical and Electronics Engineers, Inc.
Provided by IHS under license with IEEE
No reproduction or networking permitted without license from IHS
Not for Resale

Table A.1—Ratios of real load to inverter output

Real load	Inverter output
25%	25%
50%	50%
100%	100%
125%	100%

Copyright © 2000 IEEE. All rights reserved.
Copyright The Institute of Electrical and Electronics Engineers, Inc.
Provided by IHS under license with IEEE
No reproduction or networking permitted without license from IHS
Not for Resale

Annex B

(informative)

PV inverters and the utility interface

B.1 Introduction

Most single-phase PV inverters available at the time of this recommended practice was written are high-frequency switching, self-commutated designs. (The term “high-frequency” is used loosely to mean the switching frequencies are significantly above utility line frequency, ranging from about 1 kHz to tens of kHz, making response times of a fraction of a 60 Hz cycle possible.) These high-frequency switching inverters are the result of a natural evolution in design to allow control of harmonic current output, control of power factor, and a myriad of other control features that are most readily addressed with digital technology and the rapid response possible with high-frequency switching.

Solid-state inverters do not behave like rotating generators. Solid-state inverters have no “inertia” in their output and can respond immediately to changes in the ac power system, such as a frequency shift. These inverters generally sense a short circuit by an associated voltage drop, rather than by actually sensing short-circuit current, as discussed in Annex E. Thus, the voltage trip recommendations of 5.1.1 are really the equivalent of short-circuit protection. Most PV inverters operate at unity power factor (or near-unity power factor, as discussed later in this annex), making them incapable of supporting most ac loads as an island.

B.2 Line-commutated inverters

Line-commutated inverters (that is, an inverter that derives its switching signal directly from the line current) were once popular in utility-interconnected PV applications, but are no longer generally used with single-phase PV systems. An important reason behind this change is that the low switching frequency (120 Hz) does not allow wave-shaping other than with the addition of filtering elements. These filtering elements (inductors and capacitors) are bulky and expensive. Therefore, a low current-distortion line-commutated, single-phase inverter typically does not provide an economically practical design.

However, a three-phase line-commutated inverter system using a multi-phase isolation transformer at the utility interface to combine the outputs of individual inverters can cancel the unwanted harmonics without the addition of filtering elements or energy-storing components as discussed in Bingley [B2].

Testing of single-phase inverters has shown that one of the assumed advantages of line-commutated inverters, an inherent inability to operate as the source for an island, does not actually exist. The specific loads attached to the inverter can be varied (capacitance is a key factor) so that, under certain load-to-output relations, indefinite run-on after utility disconnect can be achieved in an island that includes multiple inverters as discussed in Stevens [B11]. This limitation has been overcome in modern line-commutated inverters by simply adding control and sensing circuits that detect utility voltage and frequency as is mentioned in B.3 for self-commutated inverters. The isolation transformer included in the three-phase inverter system referenced in this clause provides an additional measure of protection. (See Bingley [B2].)

B.3 Self-commutated inverters

A common misconception is that a self-commutated inverter inherently has the ability to run on after the utility has disconnected, thus supporting an island. This misconception is apparently supported by the fact

Copyright © 2000 IEEE. All rights reserved.

Copyright The Institute of Electrical and Electronics Engineers, Inc.
Provided by IHS under license with IEEE
No reproduction or networking permitted without license from IHS
Not for Resale

that all stand-alone inverters (that is, those used in nonutility-interconnected systems) are self-commutated and, by definition, can operate without the utility connected. This case is not necessarily true with self-commutated utility-interconnected inverters. Utility-interconnected inverters have a variety of parameters, such as operating voltage and frequency, that are dependent on interaction with the utility in order to be able to operate and, thus, are dependent on the utility as a parallel source for operation.

Self-commutated inverters can be designed as either voltage or current sources. Most utility-interconnected self-commutated inverters are designed to be current sources. The inverter uses the utility voltage as a reference and provides the current available from the PV array at whatever voltage and frequency the utility has presented to it. If the utility signal is not there for comparison, the unit is designed to cease to energize the utility line.

Generally speaking, these high-frequency switching inverters sample critical parameters at high frequency, which allows response to changes to occur in fractions of a cycle. The issues are then to determine what to monitor and within what limits to allow continued operation versus shut down. As pointed out elsewhere in this recommended practice (Clause 4 and Clause 5), voltage and frequency are two of the more useful parameters to monitor.

The high-frequency switching and digital control also allow manufacturers to employ a variety of schemes to avoid islanding. One of these techniques, recently developed by a consortium of PV inverter manufacturers in the U.S. and Sandia National Laboratories, and discussed in Stevens et al. [B12], uses positive feedback from voltage and frequency to accelerate the drift of voltage or frequency outside of the normal trip limits when the utility is not available to control these parameters.

B.4 Inverter shutdown

When a utility-interconnected inverter “shuts down” or “trips,” what actually happens is the inverter ceases to energize the utility line. The inverter does not completely disconnect from the utility, nor does it completely “turn off.” The inverter controls remain active and a connection to the utility is maintained so that the inverter may continue sensing utility conditions. The power-producing wires may or may not be disconnected, but there is always some connection maintained (perhaps by separate sensing wires, depending on inverter design) to allow the inverter to monitor utility conditions for the reconnect feature. The maintained connection and continued sensing of the utility are necessary to allow the inverter to return to normal operation once the utility service has been restored to normal operating conditions for a minimum of 5 min.

B.5 The PV inverter as an uninterruptible power supply (UPS)

Some inverters are designed to provide uninterruptible power to critical loads, in a UPS-like function. With these inverters, the critical loads may be connected to a second distribution panel to which power is maintained when the connection to the utility is severed. Such inverters are employed in systems that also have energy storage. This storage, in addition to the PV source, serves as a dc energy input for the inverter. With this design, when the inverter ceases to energize the utility line because of abnormal voltage or frequency, the inverter continues to power the loads connected to the second distribution panel in a nonutility-connected mode.

B.6 Power factor

Current-regulated, self-commutated inverters are inherently capable of regulating the phase angle of the output current with respect to the line voltage. In most cases, this phase angle is regulated to produce a power

Copyright © 2000 IEEE. All rights reserved.
Copyright The Institute of Electrical and Electronics Engineers, Inc.
Provided by IHS under license with IEEE
No reproduction or networking permitted without license from IHS
Not for Resale

factor that is very near unity. Some inverter manufacturers provide optional power factor control capability that allows the user to set either a constant power factor or constant reactive power delivery by the inverter.

At very low power levels (< 10% of inverter rated capacity), inverters designed to operate at unity power factor at full load may operate at a nonunity power factor due to inverter components (e.g., output filters, transformers) that appear as small, fixed reactive loads. Even though the power factor may drop below unity at these low power levels, however, the reactive demand on the utility is no greater than it is at full inverter output.

B.7 DC injection

Inverter manufacturers generally use one of two methods to prevent the injection of dc current into the utility interface. One method is to incorporate an ac output isolation transformer in the inverter. The other method, which uses a shunt or dc-current sensor, initiates inverter shutdown when the dc component of the current exceeds the specified threshold.

B.8 Soft starting

Modern PV inverters with peak-power-tracking capability often employ soft starting. Upon restoration of the utility voltage and the appropriate time delay of 5 min, the peak-power-tracking algorithm in the inverter will ramp the output current over time to bring the array from open-circuit voltage (that is, zero current) to its peak power-point voltage.

B.9 Line-drop voltage offset

Service voltage of the PV system is discussed in 4.1. On PV systems where the inverter is mounted remotely from the PCC, as rooftop PV systems often are, it is possible that a voltage difference will exist between the inverter terminals and the PCC. Since the voltage at the PCC is the parameter that should be maintained within specified limits, the inverter may have some means of compensating for this voltage difference. Inverter manufacturers may take any of several approaches, including switches in the inverter (either hardware or software) that add amounts of voltage to the trip setting, as determined by the maximum voltage drop possible with the particular installation. For example, if it is calculated that a 2 V difference will exist in the wiring between the inverter and the PCC at maximum PV output, then the switch is set at +2 V. Another approach is to have the inverter calculate the voltage difference, then add it to the trip setting. In keeping with the practices required in the NEC, the installation should be designed in a manner that the voltage difference between the inverter and the PCC does not exceed 3% for branch circuits and 5% for feeder circuits.

B.10 Controls integrated into the inverter

The integration of protection and controls into the inverter itself, as opposed to utilizing separate, discrete protective devices, is being pursued as both a cost-reduction measure and as a means of increasing the reliability of the protection system. With this integration, any failures of protection or control features will result in an inoperative inverter, rather than an inverter that continues to operate without protection.

Copyright © 2000 IEEE. All rights reserved.

Copyright The Institute of Electrical and Electronics Engineers, Inc.
Provided by IHS under license with IEEE
No reproduction or networking permitted without license from IHS Not for Resale

Annex C

(informative)

Disconnect switches and utility procedures

Strategically located disconnect switches are an integral part of any electrical power system. These switches provide isolation points commonly required by safe work practices. The NEC dictates the requirements for disconnect devices that allow for safe operation and maintenance of the electrical power systems within public or private buildings and structures. This annex deals specifically with disconnect switches required to ensure safe work practices for the portion of the electrical power system associated with the electric utility to which the PV system is interconnected, which is not addressed in the NEC.

Similar to the NEC, all electric utilities have established practices and procedures that ensure safe operation of the electrical power system under both normal and abnormal conditions. Several of these procedures identify methods that ensure that the electrical system has been properly configured to provide safe working conditions for utility line and service personnel. Although these procedures may vary somewhat between utilities, the underlying intent of the procedures is to establish “safe work area clearances” to allow utility line and service personnel to operate safely in proximity to the electrical power system. To achieve this goal, electric utilities have developed procedures that require controlled visible isolation, protective grounding, and jurisdictional tagging of the portion of the electrical power system where clearance is to be gained. (Jurisdictional tags specify the individual person who can authorize operation of a particular device, such as a disconnect switch.) These procedures, in unison with other safety procedures and sound judgment based upon knowledge and experience, have resulted in a safe work environment for utility personnel.

To facilitate the utility safety procedures described in this annex, it is a general practice that a lockable visible-break isolating device be provided for each source of electrical energy that is electrically connected to the utility electrical system. These isolation devices, typically electrical disconnect switches, are used to provide visible isolation of the electrical power source from the utility’s electrical system when clearance is to be gained. Following the isolation of all electrical power sources, protective safety grounds are attached to the high voltage phase conductors; and jurisdictional tags and locks are placed to further safeguard utility personnel. These procedures ensure that safe work area clearances are established and maintained. Following the necessary maintenance work, the jurisdictional tags and the protective grounds are removed and the disconnect switches are closed to allow for re-energization of the electrical power system.

As described, these safety practices are presently uniformly applied to all utility electrical power systems. For this reason, an electrical disconnect switch that can provide visible isolation of the PV system from the utility system is currently required by many, but not all, utilities.

Much work has been, and continues to be, done to develop inverters that can ensure that the PV system will not be able to generate electrical energy in the absence of the utility electrical source (that is, the nonislanding inverter discussed throughout this recommended practice, including Annex D). Utilities may choose to relax their requirement for a utility-interface disconnect switch when a PV system employs a nonislanding inverter, as demonstrated by the inverter’s ability to pass testing such as described in Annex A.

There may be other nontechnical reasons to install a PV system disconnect switch. For example, a utility might have contract requirements with the PV system owner, such as annual testing that requires a lockable, outdoor-accessible load-break PV disconnect switch.

Copyright © 2000 IEEE. All rights reserved.
Copyright The Institute of Electrical and Electronics Engineers, Inc.
Provided by IHS under license with IEEE
No reproduction or networking permitted without license from IHS
Not for Resale

Annex D

(informative)

Islanding as it applies to PV systems

D.1 Introduction

Islanding is a condition in which a portion of the utility system that contains both load and generation is isolated from the remainder of the utility system. This recommended practice does not address islands that contain utility-controlled generation. This recommended practice is concerned only with a subset of general islanding that is referred to as “distributed resource islanding.”

In distributed resource islanding, one or more nonutility generation sources (more specifically, sources over which the utility has no direct control) and a portion of the utility system operate while isolated from the remainder of the utility system.

A significant amount of effort has gone into developing the nonislanding inverter (as described in 3.2) for the specific purpose of providing a PV system that will not support a distributed resource island. A complete discussion of this development program and the testing that has been performed on this concept is contained in Stevens et al. [B12].

D.2 The distributed resource island

If a segment of a utility system is established as a distributed resource island, then, as defined in 3.4, there is no utility control over the operating parameters of that island. Distributed resource islanding may occur under the following conditions:

— As a result of a fault that is detected by the utility and results in opening a disconnecting device, but is not detected by the distributed resource.
— As a result of an accidental opening of the normal utility supply by an equipment failure.
— As a result of utility’s switching of the distribution system and loads.
— As a result of human error or malicious mischief.
— As an act of nature.

Utilities feel that distributed resource islanding should be avoided for the following reasons:

— Because the utility cannot control voltage and frequency in the island, there is the possibility of damage to customer equipment in a situation over which the utility has no control. Utilities, along with the distributed resource owner, can be found liable for electrical damage to customer equipment connected to their lines that is the result of voltage or frequency excursions outside of the acceptable ranges.
— Islanding may interfere with the restoration of normal service by the utility.
— Islanding may create a hazard for utility line-workers by causing a line to remain energized when it is assumed to be disconnected from all energy sources.
— Reclosing into an island may result in re-tripping the line or damaging the distributed resource equipment, or other connected equipment, because of out-of-phase closure.

Copyright © 2000 IEEE. All rights reserved.

Copyright The Institute of Electrical and Electronics Engineers, Inc.
Provided by IHS under license with IEEE
No reproduction or networking permitted without license from IHS
Not for Resale

Most islands can be easily avoided by monitoring voltage and frequency and only allowing inverter operation when these parameters are within acceptable limits. It is possible, however, that the power supplied by a dispersed generator matches the load so closely that voltage and frequency limits would not be exceeded if the system were islanded, as discussed in Begovic et al. [B1]. In this case, unless other means are incorporated into the controls, a system could operate as long as the generation and load remain matched. Although this situation is extremely unlikely with PV systems, it remains a concern. There is, therefore, a need for additional controls to detect this distributed resource islanding condition and remove the PV generator from the circuit until the utility system is restored to normal service.

Tightening voltage and frequency windows for distributed resource has been suggested as a means to eliminate this problem, but this approach only reduces the probability of an island occurring, rather than eliminating the possibility. Tightening operating windows also increases the occurrence of nuisance tripping.

A more satisfactory solution to the problem of detecting a balanced distributed resource island is the use of an inverter that incorporates a task-specific anti-islanding scheme, such as that described in Kern et al. [B4] and Stevens et al. [B12]. These documents describe an anti-islanding scheme that involves accelerated frequency drift and accelerated voltage drift, both utilizing positive feedback. The essence of the scheme is to accelerate the drift in voltage and/or frequency to the respective trip points when the utility is not connected to maintain these values in their normal ranges. Extensive test results have shown this particular anti-islanding task-specific scheme to be effective, as documented in Stevens et al. [B12].

D.3 Testing for a nonislanding inverter

There is also a need for an accepted testing procedure by which PV generator controls can be verified to be incapable of maintaining a distributed resource islanding condition. An effective test (also discussed in Kern et al. [B4] and Stevens et al. [B12]) is to attempt to island the inverter under test with a RLC load that has been tuned to the local utility operating frequency—60 Hz in North America. This load should have a real power match as close as reasonable (see Annex A for test procedures) to the PV system output and a quality factor $Q \leq 2.5$, where $Q = R\sqrt{C/L}$ (see 3.6). Because the test conditions include a worst-case assumption that reactive supply from capacitors exactly matches reactive load, Q can be mathematically associated with the power factor of an uncorrected line. In other words, even though the line may have capacitors connected to improve power factor, the following calculation is performed using the power factor of the line as it would be without the capacitors connected:

Q = tan(arccosine[pf])

Thus, the selected Q of 2.5 equates to a power factor of 0.37. As power factor increases, Q decreases. Thus, the test requirement that $Q \leq 2.5$ equates to lines with uncorrected power factors from 0.37 to unity and appears to cover all reasonable distribution line configurations.

This islanding detection test with a tuned RLC load is included in the minimum test procedure for a nonislanding PV inverter described in Annex A and is included in UL 1741-1999 for inverters of < 10 kW capacity.

D.4 Impact of distortion on islanding

The islanded load total demand distortion (TDD)[7] has an impact on the probability of establishing a distributed resource island. Increased distortion can have several results that impact the ability of an inverter to operate. These include additional voltage zero crossings and reduced total power factor. An inverter that has

[7]Total demand distortion is defined in IEEE 519-1992 as the total root-sum-square harmonic distortion, in percent of the maximum demand total load current (15 min or 30 min demand).

Copyright © 2000 IEEE. All rights reserved.
Copyright The Institute of Electrical and Electronics Engineers, Inc.
Provided by IHS under license with IEEE
No reproduction or networking permitted without license from IHS
Not for Resale

been designed to operate at unity power factor and low distortion will not continue operating with high load distortion. An instructive example is presented in Stevens et al. [B12].

Copyright © 2000 IEEE. All rights reserved.

Copyright The Institute of Electrical and Electronics Engineers, Inc.
Provided by IHS under license with IEEE
No reproduction or networking permitted without license from IHS Not for Resale

Annex E

(informative)

The PV inverter under utility fault conditions

E.1 Introduction

The response of a PV inverter and its controls to fault conditions on the system of the interconnected utility depends on what the inverter "sees" as terminal voltage and apparent load impedance during the fault. The voltage and apparent impedance, in turn, depend on the type of fault and which phases are involved. The voltage and impedance "seen" may change drastically when the utility's substation breaker or feeder recloser opens to clear the faulted line. The purpose of this annex is to give a qualitative explanation of the various voltage and load impedance conditions that a PV inverter may experience for a fault on the serving utility's primary feeder system.

Small PV inverter systems are typically single-phase whereas utility distribution feeders are almost always three-phase with single-, two-, or three-phase branches taken off from the main feeder. Single-phase services from the three-phase feeders are usually provided by phase-to-neutral connected transformers, but systems with phase-to-phase connected single-phase transformers are also used. Thus a fault (three-phase, double-phase, or single-phase to ground) on the utility feeder may or may not involve the same phase(s) to which the inverter is connected. Faults involving the same primary phase(s) that supply the inverter are the easiest to visualize and will be discussed first.

E.2 Inverter primary supply phases faulted

When the fault initially occurs, the voltage of the faulted phase(s) drops to a low value at the location of the fault. The utility substation delivers high-level fault current down the feeder to the fault. Any current contribution to the fault by the inverter is negligible compared to the utility short-circuit current.

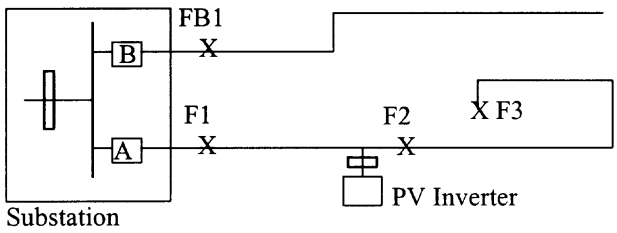

Figure F.1—Fault location determines voltage deviation at PV inverter

At this instant in time, the voltage seen by the inverter may be anything from zero to almost normal, depending on the fault location. For example, faults at F1 or F2 on feeder A, in Figure F.1, will give nearly zero voltage at the PV inverter. For a fault at F3, the inverter voltage may be much higher, possibly near normal if the feeder is long, the inverter is near the substation, and the substation is a strong source of short-circuit current. Also, a fault at FB1 on an adjacent feeder may result in nearly zero voltage at the inverter whereas the remote fault at FB2 may not significantly drop the voltage at the PV installation.

Copyright © 2000 IEEE. All rights reserved.
Copyright The Institute of Electrical and Electronics Engineers, Inc.
Provided by IHS under license with IEEE
No reproduction or networking permitted without license from IHS
Not for Resale

These conditions exist only while the utility substation breaker is closed and delivering fault current to the fault. If the PV inverter has not disconnected during this period then, when the substation breaker opens to disconnect the fault, the voltage collapses to near zero at all locations on the line. This happens because the impedances of the fault, the lines, and the distribution transformer serving the PV site are very small (viewed through the ratio of the distribution transformer) in comparison to the rated load impedance of the PV inverter. Because PV inverters cannot supply currents much in excess of rated load current, the PV cannot support the voltage and will rapidly trip.

From the above, it is apparent that detection of utility faults by the PV system, when those faults involve the phase(s) serving the PV, is largely a matter of the PV system's control response to undervoltage conditions. Depending on the time and/or undervoltage characteristics of the PV controls, the unit will disconnect either before or shortly after the utility substation breaker opens. Some unwanted tripping will occur for faults (such as FB1) on other feeders, but this problem is less serious for PV than for some other generation technologies because PV can restart as soon as the fault on the other feeder is cleared and voltage conditions at the inverter return to normal. Unwanted undervoltage tripping can be reduced by incorporating some time delay when the voltage is only slightly out of tolerance.

E.3 Faults involving other phases

Figure F.2 shows a simplified three-phase line that serves three single-phase loads. Phase C also has a PV inverter connected. The loads are shown lumped at one location, but would actually be distributed along the length of the line. For simplicity, no phase-to-phase or three-phase loads are shown. The distribution transformers that serve the loads and the inverter are also omitted for simplicity.

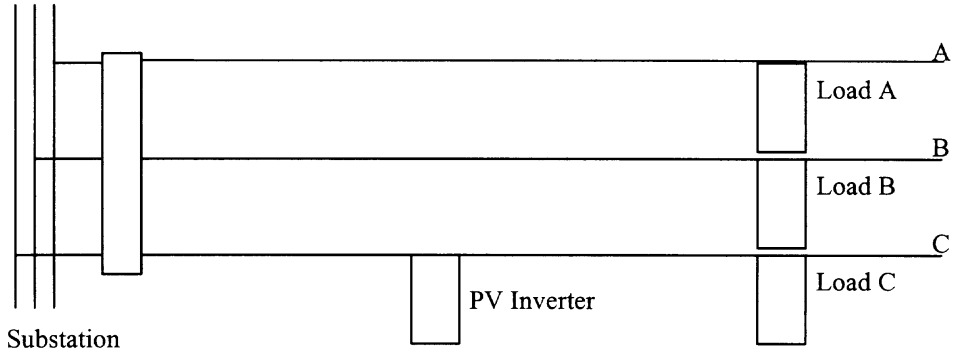

Figure F.2—Single-phase inverter on a three-phase line

For a phase-to-phase fault between A and B phases, at any location along the line, there is essentially no disturbance to the C phase-to-ground voltage to which the inverter is connected. Although there is mutual inductance coupling from Phases A and B to Phase C, the fault currents for an A-B fault are equal in magnitude and opposite in direction so their effects on C cancel out.

Because the voltage at the inverter does not change, the PV inverter cannot sense the fault until the substation breaker is opened and all three phases are disconnected. Once the breaker is open, the inverter and Load C are an islanded system with no fault present. If the Load C and the inverter output are nearly equal, the inverter islanding detection system is the only means to disconnect the inverter.

For a phase-to-ground fault on Phase A or B, inductive coupling from the faulted phase into Phase C tends to raise the C phase voltage. However, there is a counteracting tendency of the substation transformer to drop

--`,,`-`-`,,`,,`,`,,`---
Copyright © 2000 IEEE. All rights reserved.

Copyright The Institute of Electrical and Electronics Engineers, Inc.
Provided by IHS under license with IEEE
No reproduction or networking permitted without license from IHS Not for Resale

the C phase voltage. Thus the inverter voltage may increase or decrease or stay about the same. If the voltage changes significantly, the inverter may be able to detect the fault; otherwise, like the phase-to-phase fault case, it becomes islanded when the substation breaker opens.

A phase-to-phase fault between Phase C and Phase A or B causes a definite drop in the C phase-to-ground voltage, but not to zero. The lowest C phase voltage for this condition is 50% (for fault locations like F1 or F2 in Figure F.1). The C phase voltage is more nearly normal for remote faults like F3. The response of the inverter depends on its timing for moderate undervoltage conditions. If it is fast, it may disconnect before the substation breaker opens; if it is delayed, then it may become islanded when the substation breaker opens.

E.4 Arcing fault suppression

When the utility breaker opens for the A-C or B-C fault discussed in F.3, the fault itself becomes a path through which the inverter on Phase C might energize the load on the other faulted phase, as shown in Figure F.3. Although it is highly unlikely that the match of load and PV generation would be such that a stable island is possible, utilities that employ high-speed reclosing may be concerned about any tendency of a PV system to maintain a fault arc and interfere with successful arc suppression while the utility breaker is open. In an actual system where three-phase, and possibly single-phase, loads are connected between phases, there are additional paths through which an inverter might theoretically support a fault arc. To minimize the chances of a PV inverter supporting a fault arc, it is important that the inverter islanding detection operate as rapidly as practical, particularly for mismatched load and generation because that mismatch will be present in the great majority of incidents.

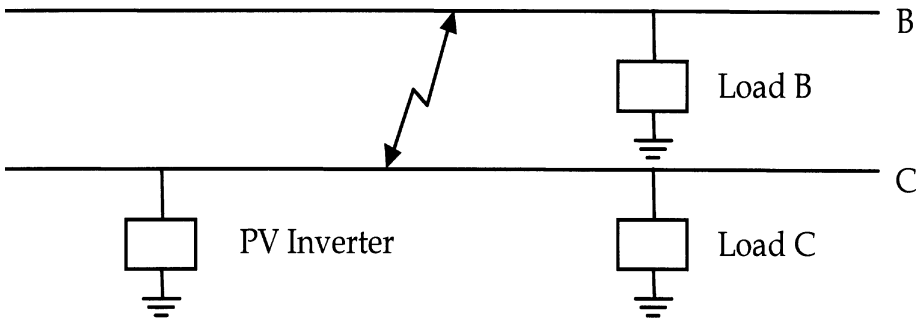

Figure F.3—PV inverter without islanding protection can maintain a fault while the utility attempts to clear the fault with reclosing

E.5 Three-phase inverters

In general, it is easier to detect primary system faults with a three-phase inverter than with single-phase types because the voltage of all three phases can be measured and all phases of the inverter shut down for a drop in any measured voltage.

The most difficult faults to detect from the secondary side with three-phase inverters are primary single-phase-to-ground faults when the distribution transformer serving the inverter is not a wye-ground/wye-ground connection. However, detection of these faults is more positive than detection of faults on the noninvolved phases by single-phase inverters because there is some voltage drop for any faulted primary phase. For any ground fault that cannot be detected by undervoltage or overvoltage protection, reliance is placed on the inverter anti-islanding scheme to prevent formation of a stable island.

Copyright © 2000 IEEE. All rights reserved.
Copyright The Institute of Electrical and Electronics Engineers, Inc.
Provided by IHS under license with IEEE
No reproduction or networking permitted without license from IHS
Not for Resale

Annex F

(informative)

Dedicated distribution transformer

This recommended practice has no requirement for a dedicated distribution transformer. As used here, the term “dedicated distribution transformer” refers to a distribution transformer serving the PV facility, but serving no other utility customers. This transformer may serve loads within the PV operator’s own premises. The reasons behind the lack of a requirement for a dedicated distribution transformer are summarized in this annex.

In a rural area, each house or farm may be served by a dedicated transformer. In an urban or suburban area, however, it is typical to serve five to ten homes from a single transformer. Apartment buildings with dozens of different utility customers are often served from a single, large distribution transformer.

Utilities may specify dedicated distribution transformers for one or more of the following reasons:

— To reduce the potential for islanding of the PV system with other utility customers on the same secondary system. With a shared distribution transformer, there is the possibility of an island with other customers whenever a distribution transformer fuse blows. When a dedicated transformer is used, the island contains only the PV owner and any consequences are regarded as the PV owner’s problem.

— To reduce the impact of harmonics and voltage fluctuations (flicker) from the PV system on other customers. The dedicated transformer requirement accomplishes this goal by changing the PCC from the secondary to the primary of the distribution transformer. On the primary side, the impedance of the system is much lower, and deviations in the current have much less impact on the voltage.

— To confine the triplen harmonics (that is, harmonic frequencies that are odd multiples of 180 Hz in three-phase systems) by the use of delta connections on the dedicated transformer.

— To avoid ferroresonant overvoltages.

— To avoid dc injection.

The problems that the dedicated distribution transformer requirement is meant to eliminate can be solved as follows by proper design of the PV system:

— Islanding can be prevented by having an adequate islanding protection scheme built into the inverter.

— Flicker is unlikely to be a serious problem with PV since the output changes gradually. Furthermore, flicker is a problem with all types of loads, and utilities have extensive experience in dealing with it. A dedicated transformer for the flicker-producing customer is usually the last resort.

— Harmonics can be controlled to acceptable levels by inverter design or by filtering.

— Testing has shown that ferroresonant overvoltages are not a problem with static inverters that have passed the test regime (including anti-islanding) in Annex A.

— DC injection can be controlled by proper inverter design.

The design and testing recommendations of this recommended practice are intended to ensure that the problems discussed in this annex are addressed by inverter design so that a dedicated transformer may be deemed unnecessary.

Copyright © 2000 IEEE. All rights reserved.

Copyright The Institute of Electrical and Electronics Engineers, Inc.
Provided by IHS under license with IEEE
No reproduction or networking permitted without license from IHS
Not for Resale

Annex G

(informative)

Bibliography

[B1] Begovic, M., Ropp, M., Rohatgi, A., Pregelj, A., "Determining the Sufficiency of Standard Protective Relaying for Islanding Prevention in Grid-Connected PV Systems," *Proceedings of the 2nd World Conference and Exhibition on Photovoltaic Solar Energy Conversion*, Vienna, Austria, July 1998.

[B2] Bingley, D. W., *Power Conditioning System for a Four Quadrant Photovoltaic Array,* Patent Number: 5,677,833, Oct. 14, 1997.

[B3] Kern, G. A., "Sunsine 300, Utility Interactive AC Module Anti-Islanding Test Results," *Proceedings of the 26th IEEE PVSC*, Anaheim, CA, 1997.

[B4] Kern, G., Bonn, R., Ginn, J., Gonzalez, S., "Results of SNL Grid-Tied Inverter Testing," *Proceedings of the 2nd World Conference and Exhibition on Photovoltaic Solar Energy Conversion*, Vienna, Austria, July 1998.

[B5] EPRI Report TR-111489, *Integration of Distributed Resources in Electric Utility Systems: Current Interconnection Practice and a Unified Approach*, Power Technologies, Inc.

[B6] EPRI GS-7227, July 1991, *Experiences and Lessons Learned With Residential Photovoltaic Systems*, Ascension Technology, Inc.

[B7] IEEE 100-1996, The IEEE Standard Dictionary of Electrical and Electronics Terms, Sixth Edition.

[B8] IEEE Special Publication 93THO 597-5 PWR, *Static Power Converters of 500kW or Less Serving as the Relay Interface Package for Non-Conventional Generators*, 1993.

[B9] Mohan, Underland, and Robbins, *Power Electronics, Converter, Applications and Design*, 2nd Ed., New York: Wiley & Sons, 1995.

[B10] New England Electric Power Service Co., *Photovoltaic Generation Effects on Distribution Feeders—Description of the Gardner, Massachusetts, Twenty-First-Century PV Community and Research Program*, EPRI EL-6754-L, Jan. 1992.

[B11] Stevens, J., "Utility Intertied Photovoltaic System Islanding Experiments," *Proceedings of the 19th IEEE PVSC*, New Orleans, La., 1987.

[B12] Stevens, J., et al., *Development and Testing of an Approach to Anti-Islanding in Utility-Interconnected Photovoltaic Systems*, SAND98-1684, Sandia National Laboratories, 1999.

[B13] Wiles, J., *Photovoltaic Power Systems and the National Electrical Code: Suggested Practices*, SAND96-2797, Sandia National Laboratories, 1996.

[B14] Wills, R., *The Interconnection Issues of Photovoltaic Power Systems with the Utility Grid: An Overview for Utility Engineers*, SAND94-1057, Sandia National Laboratories, 1994.

Copyright © 2000 IEEE. All rights reserved.

Copyright The Institute of Electrical and Electronics Engineers, Inc.
Provided by IHS under license with IEEE
No reproduction or networking permitted without license from IHS Not for Resale