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IEEE Recommended Practice for Interconnecting Distributed Resources with Electric Power Systems Distribution Secondary Networks

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Abstract: Recommendations and guidance for distributed resources (DR) interconnected on the distribution secondary networks, including both spot networks and grid networks, are provided. This document gives an overview of distribution secondary network systems design, components, and operation; describes considerations for interconnecting DR with networks; and provides potential solutions for the interconnection of DR on network distribution systems. IEEE Std 1547.6-2011 is part of the IEEE 1547™ series of standards. IEEE Std 1547-2003 provides mandatory requirements for the interconnection of DR with EPSs and focuses primarily on radial distribution circuit interconnections. For DR interconnected on networks, all of IEEE Std 1547-2003 needs to be satisfied. IEEE Std 1547.6-2011 was specifically developed to provide additional information in regard to interconnecting DR with distribution secondary networks.
Keywords: distributed resources, distribution grid, distribution secondary networks, electric power systems, grid networks, IEEE 1547.6, interconnection, spot networks, utility grid

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Introduction

This introduction is not part of IEEE Std 1547.6-2011, IEEE Recommended Practice for Interconnecting Distributed Resources with Electric Power Systems Distribution Secondary Networks.

The IEEE 1547 series of standards was created to develop a national consensus on using distributed resources (DR) in electric power systems (EPSs). IEEE Std 1547-2003 provides mandatory requirements for the interconnection of DR with EPSs.[a] It focuses primarily on radial feeder interconnections. For DR interconnected on networks, all of IEEE Std 1547-2003 needs to be satisfied.

IEEE Std 1547.6-2011 is part of the IEEE 1547 series of standards. IEEE Std 1547.6 provides recommendations and guidance for DR interconnected on EPS distribution secondary networks, including both spot networks and grid networks. IEEE Std 1547.6 was specifically developed to provide additional information in regard to interconnecting DR with distribution secondary networks. This document contains several clauses that address various aspects of DR interconnection with distribution secondary networks. Clause 1 provides an overview including the scope, purpose, and limitations of the document. Clause 2 provides normative references that must be understood and used with IEEE Std 1547.6, and Clause 3 lists definitions, acronyms, and abbreviations used in the document. Clause 4 identifies that IEEE Std 1547-2003 provides mandatory requirements for the interconnection of DR with EPSs. Clause 5 gives an overview of distribution secondary network systems design, components, and operation. Clause 6 describes considerations for interconnecting DR with networks. And Clause 7 provides potential solutions for the interconnection of DR on network distribution systems.

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

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1. Overview

1.1 Scope

This standard builds upon IEEE Std 1547™-2003 for the interconnection of distributed resources (DR) to distribution secondary network systems.[1] This standard establishes recommended criteria, requirements, and tests, and provides guidance for interconnection of distribution secondary network system types of area electric power systems (area EPS) with DR providing electric power generation in local electric power systems (local EPS).

1.2 Purpose

This recommended practice focuses on the technical issues associated with the interconnection of area EPS distribution secondary networks with a local EPS having DR generation. The document provides

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

recommendations relevant to the performance, operation, testing, safety considerations, and maintenance of the interconnection. In this recommended practice consideration is given to the needs of the local EPS to be able to provide enhanced service to the DR owner loads as well as to other loads served by the network. Equally, the recommended practice addresses the technical concerns and issues of the area EPS. Further, this document identifies communication and control recommendations and provides guidance on considerations that will have to be addressed for such DR interconnections.

1.3 Limitations

The recommendations in this document are not mandatory requirements. Further, the recommendations are intended to be compatible with other IEEE-related guides and recommended practices to the extent possible. These recommended practices also may not cover all locations or all operating conditions. Therefore, following the recommended practices herein does not assure that any specific DR interconnection is feasible at any specific location.

- This document applies to the interconnection of DR with an area EPS secondary network on the load side of the network protector (NP). This recommended practice presents interconnection concepts that are not binding to any area EPS operator to accept or implement.
- This recommended practice does not presume that an area EPS operator will permit DR interconnection on the local EPS side of the point of common coupling (PCC).
- This recommended practice does not presume that an area EPS operator will make any adjustments to the operation of its NPs to facilitate the operation of DR within the network.
- This recommended practice does not address protection of the customer’s interconnected DR.
- A delta-wye network transformer is the basis for this document. Some of the statements may not be suitable for a wye-wye transformation.
- This recommended practice applies to distribution secondary network systems with operating voltage 1000 V and less, between any two conductors, or between a conductor and ground.
- The topics not specifically covered in this issue of the recommended practice are deferred for discussion and development in future revisions of this document.

2. Normative references

The following referenced documents are indispensable for the application of this document (i.e., they must be understood and used, so each referenced document is cited in text and its relationship to this document is explained). For dated references, only the edition cited applies. For undated references, the latest edition of the referenced document (including any amendments or corrigenda) applies.

IEEE Std 1547™-2003 (Reaff 2008), IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems.[2, 3]

IEEE Std 1547.1™-2005, IEEE Standard Conformance Test Procedures for Equipment Interconnecting Distributed Resources with Electric Power Systems.

IEEE Std 1547.2™-2008, IEEE Application Guide for IEEE Std 1547™, IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems.

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IEEE Std 1547.4™-2011, IEEE Guide for Design, Operation, and Integration of Distributed Resource Island Systems with Electric Power Systems.

IEEE Std C37.108™-2002, IEEE Guide for the Protection of Network Transformers.

IEEE Std C57.12.44™-1994, IEEE Standard Requirements for Secondary Network Protectors.

IEEE Std C57.12.44™-2005, IEEE Standard Requirements for Secondary Network Protectors.

3. Definitions, acronyms, and abbreviations

3.1 Definitions

For the purposes of this document, the following terms and definitions apply. *The IEEE Standards Dictionary: Glossary of Terms & Definitions* should be consulted for terms not defined in this clause.[4]

cable limiter: *See:* **network limiter.**

contingency (contingencies): The number of coincidental distribution system equipment outages (e.g., feeders) that can be tolerated without adversely affecting the character of customer service. Distribution systems can be categorized with respect to the allowable contingencies accommodated while still supplying customer load reliably. For instance, a radial distribution system is identified as a zero-contingency design because the loss of the primary feeder would result in a customer outage and thus seriously affect associated customers. Some area networks are designed and operated to a second-contingency criteria, and in these distribution systems, two primary feeders can be out of service without affecting customer service.

cycling: Undesirable repetitive tripping and closing of a network protector (NP) because of variations in loading and other conditions.

distribution secondary network: An ac distribution system where the secondaries of the distribution transformers are connected to a common network for supplying electricity directly to consumers. There are two types of secondary networks: grid networks (also referred to as *area networks* or *street networks*) and spot networks. *Syn:* **secondary network.**

dynamically controlled inverter (DCI): An inverter with the capability to govern its power output based on an input control signal.

grid network: A secondary network system with geographically separated network units (NUs) and the network-side terminals of the network protectors (NPs) interconnected by low-voltage cables that span the distance between sites. The low-voltage cable circuits of the grid networks are typically supplied by numerous NUs. A grid network is also referred to as an *area network* or a *street network.*

interconnection study: A study to ascertain the effect of parallel operation of a distributed resources (DR) on the distribution network system. It may be used to determine the scope and cost of the modifications needed to accommodate parallel DR operations.

network limiter: An enclosed fuse for disconnecting a faulted cable from a low-voltage network distribution system and for protecting the unfaulted portions of that cable against serious thermal damage. *Syn:* **cable limiter.**

[4] *The IEEE Standards Dictionary: Glossary of Terms & Definitions* is available at http://shop.ieee.org/.

network master relay: A relay that functions as a protective relay by opening a network protector (NP) when power is back-fed into the supply system and as a programming relay by closing the protector in conjunction with the network phasing relay when polyphase voltage phasors are within prescribed limits.

network protector (NP): An assembly composed of a circuit breaker and its complete control equipment for automatically disconnecting a transformer from a secondary network in response to predetermined electrical conditions on the primary feeder or transformer and for connecting a transformer to a secondary network through manual or automatic control responsive to predetermined electrical conditions on the feeder and the secondary network. The NP is usually arranged to automatically connect its associated transformer to the network when conditions are such that the transformer, when connected, will supply power to the network and to automatically disconnect the transformer from the network when power flows from the network to the transformer.

network system: A collection of spot networks, secondary grid networks, or combinations of such networks and the primary feeders that supply them.

network system reliability: A measure of the degree of certainty that the network system will perform its required functions under stated conditions for a stated time. Typical indices used to measure the reliability of a network system include the number of service interruptions (i.e., a complete loss of voltage), the frequency of service interruptions, and the duration of interruptions.

network transformer: A transformer designed for use in a vault, or other location, to feed a variable capacity system of interconnected secondaries. It usually, but not always, has a provision for attaching a network protector (NP). It can also have provisions for primary grounding or disconnection.

network unit (NU): This unit consists of a primary disconnect and/or grounding switch, a network transformer, and a network protector (NP) with its controls, protection, and communications.

phasing voltage (of a network protector): The voltage across the open contacts of a selected phase.

NOTE—This voltage is equal to the phasor difference between the transformer voltage and the corresponding network voltage.[5]

primary network feeder: A feeder that supplies energy to a network system or the combination of a network system and other radial loads. Dedicated primary network feeders are feeders that supply only network transformers for the grid network, the spot network, or both. Non-dedicated primary network feeders, sometimes called *combination feeders,* are feeders that supply both network transformers and non-network load.

solid-state or microprocessor network relay: A relay with few or no mechanical parts, using solid-state components, that performs the combined functions of the master and phasing relays, and that may include a time delay function.

spot network: A small network, usually at one location, consisting of two or more primary feeders, with network units (NUs) and one or more load service connections.

3.2 Acronyms and abbreviations

ac	alternating current
area EPS	area electric power system
AMI	advanced metering infrastructure

[5] Notes in text, tables, and figures of a standard are given for information only and do not contain requirements needed to implement this standard.

DCI	dynamically controlled inverter
DR	distributed resource
EPS	electric power system
local EPS	local electric power system
MV	medium voltage
NP	network protector
NPM	network protector monitor
NU	network unit
PCC	point of common coupling
PPE	personal protective equipment
PV	photovoltaic
SCADA	supervisory control and data acquisition

4. Existing requirements for the interconnection of distributed resources with networks

IEEE Std 1547-2003 provides mandatory requirements for the interconnection of DR with EPSs. It focuses primarily on radial feeder interconnections. For DR interconnected on networks, all of IEEE 1547 requirements need to be satisfied. In addition, IEEE Std 1547.6-2011 provides recommendations and guidance for DR interconnected on networks.

5. Overview of distribution secondary network systems: design, components, and operation

5.1 Background

Secondary-voltage ac networks (secondary networks) were first developed in the 1920s to provide highly reliable electric service to concentrated load centers—primarily in the downtown areas of major cities. There are two types of secondary networks: spot networks and grid networks (also referred to as *area networks* and *street networks*). A minimum of two primary feeders is required to supply a network. The number of feeders supplying a network depends on the design parameters such as level of reliability and the load requirement of the grid network or the spot network.

An area EPS may have multiple grid networks operated independently from one another within a city. Customers in a secondary network area typically take service from the network at the secondary network voltage level, with no interposing transformer. Grid networks serve many customers over a dispersed area. A spot network serves one or a limited number of customers at one location. In either case, network service increases reliability compared to other forms of service. The higher level of reliability is a result of system design that allows one or more primary feeders to be out of service without affecting customer service. A faulted primary feeder or transformer connection to the secondary network is isolated within a few cycles and the load continues to see service without any interruption.

Network transformers and protectors may be located in a separate vault below the sidewalk or street, on pole-supported structures above the street, or dispersed throughout high-rise buildings. For vault-located NPs, the parallel connections on the low-voltage side may be made in a separate room. For underground vaults, the equipment may be in a harsh environment (e.g., they are frequently submersed), complicating the interfacing with other control equipment. Network engineers often refer to a network unit (NU), which typically consists of the network transformer, low-voltage air circuit breaker, fuse, reverse power relay function, and phasing relay function. Figure 1 shows the components within a NU in detail.

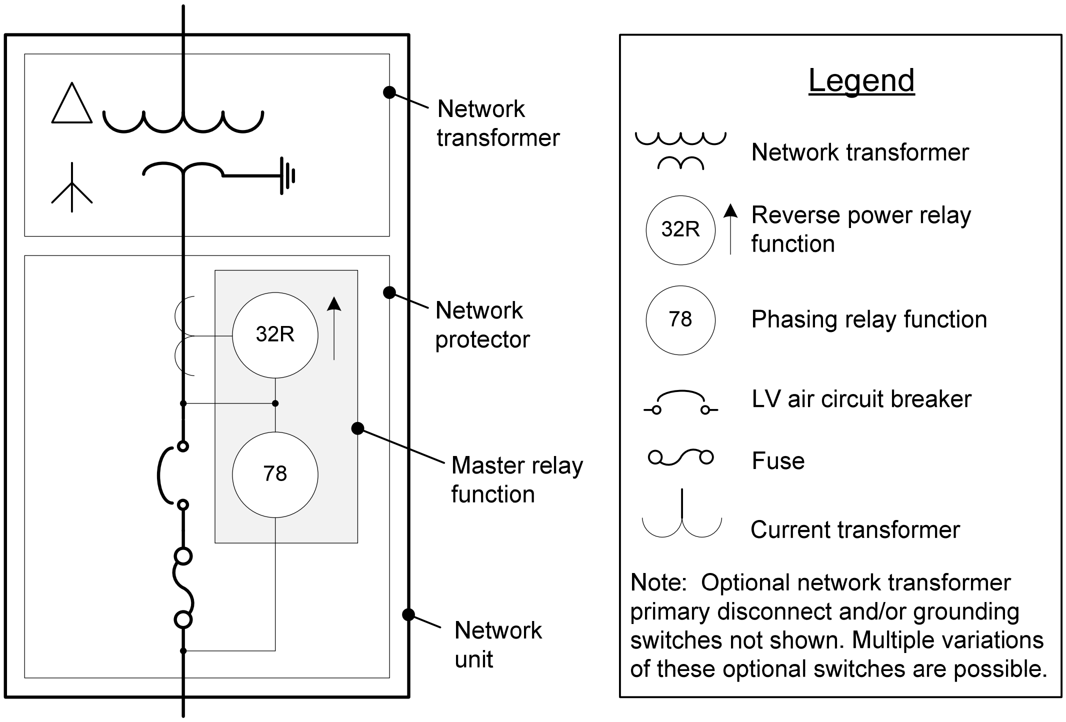

Figure 1—Illustrative example of network unit components

5.2 Network transformers

Network transformers are typically liquid-filled and air-cooled, although some dry-type network transformers are used. The network transformer may have a manually operated primary oil switch located directly on the transformer, which can be in the closed, opened, or grounded position. The network transformer is equipped with an NP mounted directly on the transformer or within close proximity of the transformer. In the latter case, it is cable-connected to the transformer. Typical network transformer secondary nominal voltages are 208Y/120 V, 216Y/125 V, and 480Y/277 V. The primary of the network transformer may be connected either in delta or grounded wye. The secondary of the network transformer is usually connected grounded wye to supply voltage to the grid network or the spot network customer.

5.3 Spot networks

A spot network consists of two or more network transformers connected to a common bus on the low-voltage side at a single site. In normal operation, all the spot network transformers are electrically paralleled on the secondary side via their associated NPs and share the load. Spot networks are typically installed with secondary voltages of 208Y/120 V and 480Y/277 V. Figure 2 depicts an example of a spot network configuration.

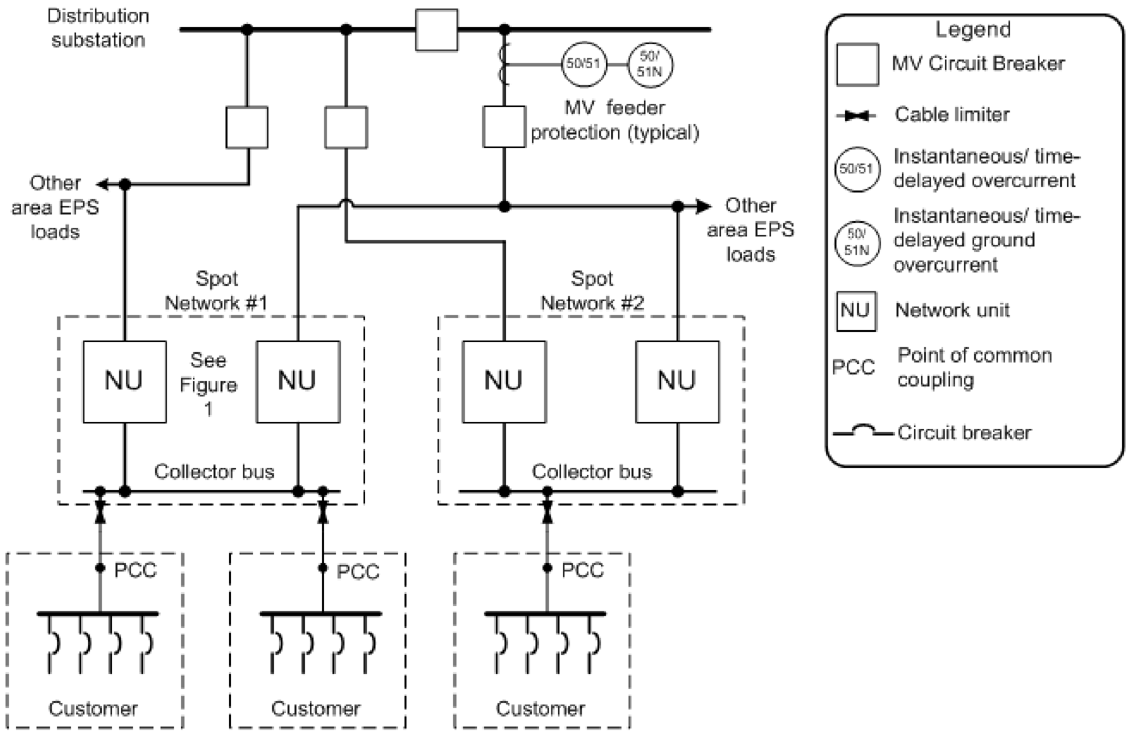

Figure 2—Illustrative example of a spot network configuration

Each network transformer is equipped with an NP containing a low-voltage circuit breaker and a protective package so that the spot network can continue to operate if a primary feeder becomes faulted. The protective package includes an NP master relay that is sensitive to directional real and reactive power flow. The protective package may consist of discrete electromechanical, analog solid-state, or numeric (microprocessor) relays.

Under normal operation, the spot network is designed such that all the NPs are closed, thereby paralleling the associated network transformers to the collector bus, and each network transformer supplies a share of the customer load. If one NP should open, the load will still be supplied without interruption from the remaining network transformers and NPs that have remained closed.

The protective package senses the reverse flow through the transformer for feeder faults or flow because of the feeder charging current or transformer magnetizing current. This protective package operates to cause the network breaker to open and isolate the initiating condition. The network relay is a very sensitive reverse-power relay, with a pickup level on the order of 1 kW to 2 kW. It is the mission of the reverse power relay to be capable of sensing reverse power flow with no other feeder loads than the core losses of its own network transformer. For delta primary network transformers, little to no reverse current will flow for a primary phase-to-ground fault, hence, reverse power relay will not operate. It will, however, operate once the feeder breaker at the substation detects the fault and trips the feeder.

NPs by themselves do not contain any forward-looking overcurrent protection. In many cases, fuses are installed in series with the NP. These fuses are sized well above the capability of one transformer and will have limited capability to operate for arcing-type faults that are the most common in the network vault. The fuses will operate for bolted faults within the vault.

The main purpose of the NP fuses is to act as a backup to the NP for a fault on the primary feeder in the event the NP fails to open for a fault on the primary feeder. This failure to open could be because of a network relay or NP malfunction. Further, under this fault condition, the fuses provide through-fault protection to the affected network transformer. However, in the case of a network transformer with a primary connected in delta, there is no backup protection provided by these fuses.

Multiple sets of secondary cables are installed between the NP and the collector bus. These may be protected with inline fuses, called *cable limiters,* on each end, such that cable faults are isolated by the limiters. Limiters may also be installed on the service cables going to the customer's switchgear. The primary purpose of a limiter is to protect the insulation of the conductors from excessive thermal damage.

In addition to tripping for faults or reverse flow, the NP master relay has another function, which is to supervise the closing of the NP. The relay measures the voltage on both sides of the protector. When the transformer-side voltage is higher than the bus side (by perhaps 1 V) and the phase relationship defined by the relay settings is satisfied, NP closing is initiated.

A spot network is supplied by two or more primary distribution circuits, typically from a single substation and single bus section or multiple bus sections with closed bus ties. Occasionally, feeders from separate bus sections or substations are used, but the flow of circulating currents between substations or transformers can result in excessive protector operations, especially at light load. Primary feeders at the substation typically are protected by time-overcurrent phase and ground protection to see faults on the circuit. They may have an instantaneous ground element set to see faults on the primary side of the network transformer. Delta-wye connection of the network transformers limits the reach of the ground relays on one primary network feeder from seeing ground faults on the primary of another primary network feeder and over-tripping. Typical substation relaying for the primary cables will not see faults on the secondary side of the network transformer; damage has occurred in vaults before any of the protection operates for sustained faults in 480 V NPs. However, implementation of time-delay overcurrent protection, coordinated with NP fusing, may provide a proper response to secondary faults. For further discussion, see the IEEE Std C37.108-2002, which goes into more sophisticated schemes of protection. Such schemes are beyond the scope of this short discussion on networks.

5.4 Secondary grid networks

As defined in 3.1 and shown in Figure 3, a secondary grid network is a network system with geographically separated NUs and the network-side terminals of the NPs interconnected by low-voltage cables that span the distance between sites. The low-voltage cable circuits of the grid networks are supplied by numerous NUs. The low-voltage cables may have customer service cables connected in manholes between the network transformer vaults.

Network transformers are located at various locations throughout the grid to supply power and support the grid voltage as required per studies. The same transformers and NPs are used here as with spot networks. Secondary grid networks are typically 208Y/120 V, although some 480Y/277 V systems were developed. Secondary grids typically have multiple sets of secondary cables per phase running between network transformers. These cables can have inline fuses (cable limiters) installed at each end to isolate a faulted cable and provide for high-current faults and thermal overload protection for the cables without interrupting service to customers or the grid. If limiters are not present or the limiters do not function as designed, the fault is isolated by the cable burning such that a gap is created at the fault site. This opening of the cable conductor and insulation is a sufficient distance to create a gap that is adequate to withstand the arc recovery voltage at the faulted location in 208Y/120 V secondary network systems. The number of primary feeders, transformer units, and sets of low-voltage cables installed is determined by performing power-flow studies both under normal and contingency conditions to avoid circuit overloading.

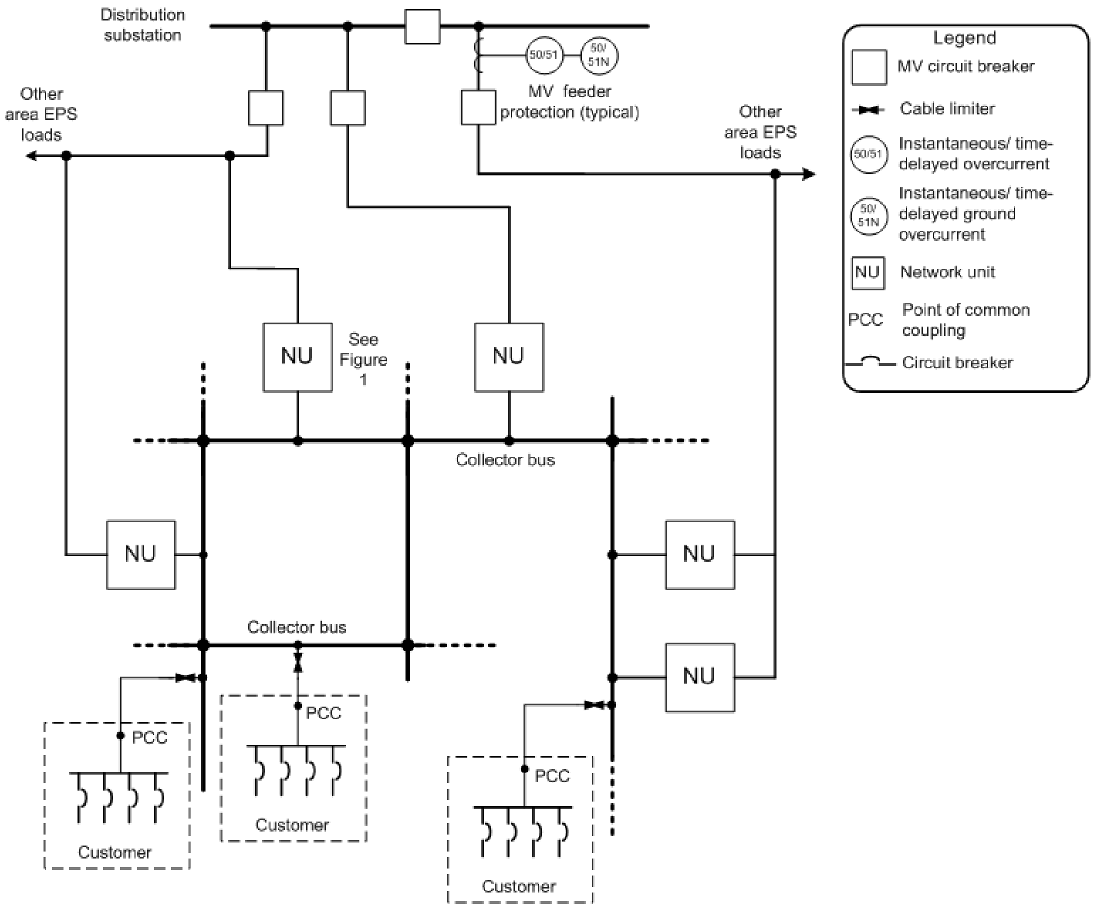

Figure 3—Illustrative example of a grid network

Different planning strategies may exist for a secondary grid network, but a typical scenario allows for one primary circuit to be out of service (faulted) at peak load times and two primary circuits to be out of service (one for maintenance with a subsequent fault occurring on another) at non-peak times. Power flow studies need to be run for all these scenarios to determine whether or not customers receive adequate voltage and no equipment is overloaded.

Power flow studies are also presently performed to determine whether or not the secondary grid network can supply the load. The base case varies depending on the utility's design and operating criteria, but it usually addresses the peak period with the design basis contingency conditions. If, for example, the design basis included the need to supply the customer load for a peak period with a second contingency in effect, power flows would have to be performed for all combinations of second contingencies. The results of these studies are examined to determine whether or not the customer load is supplied without equipment overload and electric service to the customer is within normal voltage range.

Regarding power flow studies, the utility typically has access only to peak loads that occurred at the NP without any time stamp and customer peak demands, with or without time of day depending on the metering employed. Periodic voltage measurements are made on the grid, but they may not correspond to when specific load data were extracted. Most utilities do not monitor voltage and current on the secondary network. The utility also has substation load data for the primary feeders that are part of the grid. This information, limited in kind and detail, is commonly the only source of information available to utility engineers asked to run power flow studies and plan secondary network grid upgrades.

Furthermore, there are many uncertainties associated with network power flow studies. In the majority of grid network installations, there is a lack of real-time information on the distribution of the currents flowing in the grid conductors. Estimates of this data (currents) are available only from power flow studies, which are a snapshot of a static set of network parameters that are assumed to represent worst-case conditions. They may or may not represent real-world operating conditions, such as the loss of one or more conductors of the multiple conductors that make up one phase of a current path. The current paths in the grid consist of multiple cables connected in parallel per phase that may or may not be sharing the load current equally. It has also been noted that the failure of one or more parallel conductor(s) could go undetected for an extended period of time, resulting in a reduction of the current-carrying capacity of that current path.

Finally, within a given facility served by a network, the issue of whether the customer or customers served at the site decide to install and operate DR adds the same degree of uncertainty as that posed by tenants moving in or out and customers adding load when business is growing or cutting back energy usage in a recession. At least when a DR installation is planned, the utility needs to be notified; this can provide information about the new minimum load at the site. In contrast, customers rarely notify the utility when they are cutting back operations significantly, which also results in a drop in the minimum load (all other things equal). When a customer proposes to install a significant level (in kilowatts) of DR, it presents the opportunity for utility personnel to obtain new and useful information for conducting power flow studies with and without DR operation.

5.5 Operation

In normal operation of the grid, all primary feeder circuit breakers and NPs are closed and all secondary cables are in service at both peak and light load times. Although this is the preferred method of operation, secondary cable faults, which will be cleared by limiters or burn clear, can occur at any time. These faulted cables will not be detected until a physical inspection of the grid is performed, unless the loss results in a low-voltage complaint or overloading of in-service cables with resultant smoke, fire, or other noticeable activity. NPs can be out of service for maintenance, a primary feeder fault, or a failure of the protector to close (typically a burned-out close motor). Unsupervised protectors that fail in the open position will not be detected until a physical inspection is performed. A primary feeder can trip open because of a fault, and this will cause all the protectors connected to that feeder to open. If supervisory control and data acquisition (SCADA) is present at the substation, this would be detected, but if SCADA is not present and the feeder serves only network load, this would not be detected until a physical inspection of the substation is performed.

Network feeders are radial feeders that normally do not have ties on the primary to other feeders. Typically, there are no sectionalizing switches installed on the network feeders supplying network transformers except for the disconnect switch on the primary of the network transformer. If a fault occurs on a network feeder, the feeder will be out of service until the fault is located and repaired. Prior to repair, the protectors would be verified open, and if the transformer primary switches are available, they would be put into the grounded position.

If loss of service occurs on the entire grid network, it can be a lengthy process to get it restored. Typically, there are no switches on the secondary cables in the grid. It may be necessary to make secondary cable cuts or unbolt secondary cables from buses to start picking up the grid in pieces. In some cases, it may be possible to do a simultaneous group-close of all the primary feeders in the grid. In addition, the overcurrent protection settings have to consider the impact of the additional inrush current that is associated with an extended outage of the grid network.

6. Considerations for interconnecting DR with networks

6.1 Introduction

Traditionally, area EPS secondary networks were not designed to accommodate generation. Therefore, to avoid negative impacts on network system reliability, power quality, and safety, the major considerations for integrating DR into existing networks are discussed in the following subclauses.

6.2 Network protectors

The presence and operation of DR on networks:

— **Should not cause any NP to exceed its fault-interrupting capability**. NPs are not designed to separate generators from a fault. All engineered equipment is designed with a given set of operating limits. Operation of the equipment outside the original design criteria or nameplate ratings may lead to premature failure. Prior to interconnecting the DR , the limitations of the existing network design have to be thoroughly understood. For interrupting capability, the area EPS operator will need to look at both the maximum interrupting current rating and the X/R rating of the existing NPs. The area EPS operator will also need to take into account the actual capability of this legacy equipment. Because of the advanced age of most of the equipment, the allowance of additional operating margin may be advisable. NPs are designed and tested for an X/R between 6 and 8, which is typical for distribution systems. Synchronous generators with X/Rs in excess of 8 may lead to a transient recovery voltage that is higher than the NP withstand capability in the event that the NPs attempt to open because of the reverse flow. DR may provide additional fault current and at significantly higher X/R than those anticipated in the existing distribution network system design. For further information, refer to IEEE Std C37.108-2002. The high X/R also may lead to higher dc offset in the fault current and extend the duration of the dc offset.

— **Should not cause any NP to separate two dynamic sources**. NPs installed on area EPS secondary network are manufactured in accordance with IEEE Std C57.12.44-2005. Sublause 4.1.4 states that "network protectors designed and tested in accordance with this standard, in particular with 5.2, are intended to be applied to a system with power generation only on the high-voltage side of the transformer that supplies a network secondary without any secondary power generation." In addition, IEEE Std C37.108-2002 provides in Clause 9 the following: "An NP should not be used as a separation device between a constant frequency network system and a distributed source of generation. NPs were not designed nor tested to handle the recovery voltages involved when interrupting load currents or fault currents between two points that are not locked together (in synchronism)."

— **Should not cause any NP to connect two dynamic systems together.** NPs, manufactured in accordance with IEEE Std C57.12.44-1994, do not have synchronizing capability and, therefore, should not be used to connect two dynamic systems together. The phasing relay used to supervise the NP closing function does not measure the frequency of the voltages on both sides of the open protector breaker. This relay only checks voltage magnitudes and phase angle relationship. It does this with the understanding that the two voltages being compared originate from the same source (i.e., the supplying high-voltage distribution substation) and are synchronized with a very small angular difference.

  Interconnecting a DR with a rotating prime mover introduces a second dynamic voltage source that could, at some instance, provide the necessary instantaneous electrical conditions to cause adjoining secondary NPs to attempt to close. Once initiated, closing cannot be halted.

Most NPs in service today on area EPS network systems use an ac motor to achieve a closing function. The power to energize the motor is usually obtained from the transformer side of the NP. These ac closing motors develop long and inconsistent operating speeds, which could make the NPs' closing operation both lengthy and of variable duration. This could result in a situation where an NP may close to interconnect the area EPS with a DR out of synchronization. NPs are not capable of achieving consistent synchronized closing times. For DR designed for stand-alone operation, a synchronizing device along with a separate properly rated breaker would be required to allow proper synchronization of the DR with the grid.

6.3 Protection and controls

The presence and operation of DR on networks:

— **Should not cause any NP to operate more frequently than prior to DR operation.** The secondary network is designed to operate with the NPs normally in the "closed" position. In this position, they provide for the most reliable service (all parallel paths are available). NPs are designed to open for reverse power flow. The NP reverse power relay element may also cause the NP to open due to current imbalances caused by source feeder loading and impedance differences. Therefore, at minimum load levels, some of the NPs may experience reverse flow and open. It is expected that, normally, these NPs might experience an opening and reclosing at the most once or twice a day depending on the load cycle and perhaps once a month for unexpected events or scheduled maintenance, but numerous and unnecessary operations are to be avoided because they can result in failure of the NP equipment. The interconnection of DR for parallel operation may exacerbate this condition by displacing load and reduce the load level that the NP senses, resulting in an increase in the frequency of NP operations.

The DR design should enable fast response to facility load change and adjust generation levels to avoid inadvertent NP operation. The disconnection of a large load in the secondary network may reduce the load level below the required minimum level before some types of DR control can respond.

Under normal load conditions, a large DR whose generation level is not dynamically controlled (Coddington [B3]) or coordinated with the facility load may backfeed sufficient reverse power through the NPs on the network to cause the NPs to operate.[6] For a dynamically controlled DR, the dynamic control should be set to a value that makes certain that a minimum positive facility load draw is always present, under which condition the NPs will not sense any reverse power flow.

Under system fault conditions, with network feeders fed from a common substation bus, if the aggregate DR fault contribution can be limited to below the aggregate reverse power setting of the minimum number of NPs that are required to be in operations, with a safety margin, then the NPs should not mis-operate under system fault conditions. The behavior of dynamically controlled DR under remote fault conditions has not been definitively researched and may or may not operate with sufficient speed to prevent unintentional operations.

— **Should not prevent or delay the NP from opening for faults on the network feeders.** NPs and their associated reverse-power relaying are designed to trip at very high speed (on the order of 50 ms; see Baier, Feero, Smith [B1]) in response to reverse power flow under primary source fault conditions. High-speed tripping is desirable to limit damage to the source circuit, the network transformer, and other associated equipment (including network secondary equipment, such as network fuses, cables, and network limiters). Adding even a short delay to the tripping of the protector under certain fault conditions increases the risk of damage to equipment and possible danger to utility personnel, DR personnel, or the public.

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

Interlocking the tripping of the NP with DR protective equipment (i.e., sequential tripping or preventing the NP from tripping under fault conditions until the DR has ceased to provide fault current) has the same effect of delaying the operation of the NP and increasing the possibility of equipment damage.

Any equipment failure or misoperation (for example, the failure of a communications link, the failure of the DR to trip properly, or a slow DR interface device) could cause the NP to open before the DR is de-energized, possibly subjecting the protector to power system conditions in excess of its design capabilities.

Some area EPS operators use a time delay before NP tripping for low-level reverse power flow (for example, to desensitize the protector to prevent unwanted operations because of large regenerative loads; see Behnke, et al. [B2]). This may be necessary on spot networks with regenerative loads but is not applicable on area networks because of the characteristics of the loading of area networks. The NPs of an area network are typically set to trip with no intentional delay to provide the fastest response to faults.

— **Should not delay or prevent NP closure.** The secondary network is designed to operate with the NPs normally in the "closed" position because it is in the closed position that they provide for the most reliable service (all parallel paths are available). The addition of DR should not delay or inhibit proper closing of the NPs. There are at least two known conditions that can inhibit proper closing of NPs:

  1) Reduction of load because of the addition of DR, particularly during minimum loading conditions, can prevent closing of NPs. The area EPS operator will have to investigate how the interconnection and operation of the DR will affect power flow on the secondary network. In addition, it may be necessary to apply a "minimum load level requirement" to the area network for proper closing of NPs. This will also define maximum DR output levels during minimum loading conditions for each spot network.

  2) Capacitivevar flows from a DR or from operation of power factor (PF) correction capacitors can prevent automatic closing of NPs that use straight-line close characteristics.

— **Should not energize a de-energized network.** IEEE Std 1547-2003, 4.1.5, states that "The DR shall not energize the area EPS when the area EPS is de-energized." In the event of a network service interruption, steps should be taken to prevent a DR from energizing any network it is connected to. A DR energizing a de-energized network effectively creates an island. Islanding on a network could create a potentially dangerous condition, which includes risk of injury to the public and utility personnel and damage to network equipment, and should be avoided. When the network service is restored, NPs may attempt to close, and the NPs are not designed to parallel two dynamic systems. Overvoltage conditions may also be present across the open contacts of an NP connected to two independent power systems. IEEE Std 1547.2-2008, 8.4.1.2.2, states that "Network protectors, built in accordance with IEEE Std C57.12.44-2005, are not required to withstand the 180º out-of-phase voltages that could exist across an open switch with DR on a network."

— **Should not require the NP settings to be adjusted except by consent of the area EPS operator.** Application of DR requiring changes to the relay setting of a few of the NPs creates nonstandard operation for the utilities and increases chances of mistakes and issues with safety of operation. Utility systems are set up to be operated and maintained by the labor force, which performs tasks or tests based on standard written procedures. A secondary network with a large population of NPs and large work force working on a system follows the clearly defined procedures to avoid mistakes. If various NPs have different settings in a network, chances of mistakes will increase, especially during emergencies, which may result in reducing the reliability to the current beneficiaries of the network system.

  Changing settings of NPs (e.g., adding time delays) in a secondary network (especially in an area network where NP settings are typically set to operate instantaneously) will require extensive study for many contingencies and most likely will require changes to all the NPs in the network. This could result in a reduction in reliability and may increase the damage because of a fault on the primary of the transformers and increase mechanical stresses on the primary and secondary sides of the transformer.

— **Should not cause an islanding condition within part of a grid network.** In the event that all NPs supplying a grid network are open, any DR operating within the grid network is a potential source to the loads within the island. If these loads are on the area EPS side of the PCC, the DR may not be capable of supplying voltage and frequency within the area EPS's mandated parameters. Other customers receiving this potentially degraded power may possibly experience equipment damage, inability to maintain operations, or other power quality-related concerns.

  In addition, NPs do not have synchronizing capability, but they are capable of reclosing. In an islanded situation on the grid network (or portion thereof), any or all of the associated NPs may identify the swinging islanded system conditions as a reclose condition. Once identified, the NP will reclose regardless of any subsequent system conditions, and when it eventually recloses, the DR-supplied islanded network (or portion thereof) and the area EPS may be far out of phase. This can cause the NP to immediately open again on reverse power, but it also can cause damage to both the NP and the DR.

— **Should not remain connected to the network if 50% or more of the NPs serving the network are open.**

6.4 System planning and reliability considerations

The presence and operation of DR on networks may necessitate the need to conduct an interconnection study, evaluation of work practices, and maintenance.

6.4.1 Interconnection study considerations

Many concerns are associated with the application of DR on secondary networks. To address these concerns, a detailed study of the proposed installation will be required. An interconnection study should determine the effect of parallel operation of the DR on the distribution system, verify that operation of the DR will not adversely affect any aspect of network performance, and determine the scope and cost of system modifications needed to accommodate parallel DR operation. A precondition of the study is that the DR has to meet all the requirements of IEEE Std 1547-2003 and IEEE Std 1547.1-2005. The area EPS interconnection study includes consideration of all relevant site-specific local electrical network characteristics, including the network supply sources and aggregate DR.

An interconnection study should address, at minimum, the following:

— DR fault current contribution to a fault on any part of the network

— DR output compared with facility load over time

— DR type (i.e., induction, synchronous, or inverter) and associated operating concerns

— Means to prevent real and reactive power flow from the DR into the network

— Means to maintain the minimum required number of NPs that need to remain in operation

— Any area EPS requirements regarding DR response to abnormal frequency and voltage that may apply based on the capacity rating of the DR

— Relevant electrical aspects (including limitations) of the network at the proposed interconnection site.

A detailed analysis of local system loads and their expected effect on system performance that may be included in a load analysis might be the following:

- Maximum and minimum expected loads.
- Cyclic nature of loads.
- Large regenerative loads that may act together with DR to further diminish apparent system loads (which may increase the chance of unintended operations).
- The nature of loads that may be added or interrupted unexpectedly. For example, the loss of a large network secondary load may result in unintended NP operations; the addition of generation to the secondary network may increase the possibility of protector operations.
- The nature of any connected loads on the network primary feeders energizing the local area system to which the DR is connected.

For the operation of DR on secondary networks, the anticipated minimum network load may be the determining factor on the ability of a DR to cause reverse power flow through the protectors under non-fault conditions (for example, to cause conditions that could lead to NP cycling). Consequently, minimum network load information is required for feasibility studies and to configure any remedial protection solution (for example, to configure a proposed underpower relay solution).

In addition to historical load information, ongoing operational load data measured at an interval suitable for the application may be required for periodic review. System load (particularly on a building spot network but also possibly on grid networks) may change at any time as tenants move into or out of the local load system, or as other load is changed.

Proposed DR operating parameters and characteristics that may impact the interconnection study would include the following:

- The nature of the DR may influence its feasibility. For example, the capabilities of an inverter-based DR to cause an islanding situation or to supply fault current will differ from those of a synchronous machine.
- The nature and capacity of a proposed DR may adversely affect (or exceed the capabilities of) other customer-owned equipment on the secondary network.
- The nature of the proposed DR may also affect local personal protective equipment (PPE) requirements and arc flash mitigation strategies at the network vault or elsewhere on the system.
- The ability of a DR to supply fault current, and the duration of its ability to feed into an abnormal system condition, should be known.
- The aggregate capacity of all DR connected (or that may be connected) both to a secondary network and, where allowed, to the network primary feeders of a secondary network should be known and evaluated.
- Consequently, all relevant DR parameters should be known for system impact studies. Included in this should be any proposed protection schemes.

The planning of DR interconnection to networks should evaluate the provision of monitoring at multiple locations on the area network. When a protector opens up because of a fault on primary feeders, it will close automatically when system conditions are back to normal. Application of DR on an area network may lead to an increase in the frequency of issues such as the following:

- Cycling
- Not letting NP close automatically
- Nuisance trip of NP
- Opening of NP because of reverse current without any fault on the primary side of the transformer

As most of the existing systems of secondary networks are not monitored, application of DR could lead to a situation in which only one or a few NPs are closed out of many in the network. Further, this condition may exist for a long time without anybody being aware of it, thus leading to a reduction of reliability of the network. For DR installations with significant impact on the network system, it may be necessary to install a monitoring system on all NPs and to transmit information to the area EPS operator.

Planning engineers generally do not have power flow data for the various network elements. Customer-side meters provide very limited visibility for the overall system. Monitoring various electrical variables and the condition of the NPs of the secondary network can provide visibility to the operations of the network, including load additions to the system that may otherwise be masked by the operation of the DR (where such loads may affect the system operation in the event the DR ceases to generate). A properly monitored system may allow the area EPS to facilitate the resolution of these issues. The use of some of the newer NP relays may provide the necessary NP position as well as local power flow data, however, this requires a suitable communications system to get this information to a central location. The installation and use of suitable communications from all NPs may allow for alarming as NPs open and additional warnings if NPs continue to open.

6.5 Work practices

The presence and operation of DR on networks could change available fault current, clearing time, and associated arc flash energy to a level where area EPS workers would have to use the next level of PPE and/or restrictive work methods above and beyond what the workers would normally use for work at the same location without the DR present. As a result, the area EPS operator may require that the DR be isolated from the network prior to any work being performed in the network system environs. More detailed studies may be required to determine if changes to practices would be required. If a DR is present there is potential to energize the area EPS from the DR. Proper work practices need to be observed.

6.6 Maintenance

Scrupulous attention to maintenance of the interconnection system and associated control and communication interfaces is essential for maximizing the likelihood of proper and reliable functionality of the interconnection in all respects.

7. Potential solutions for the interconnection of DR on network distribution systems

An overview of DR characteristics is provided in 7.1. Alternative example concepts for DR interconnection to network distribution systems are presented in 7.2 to 7.5.

7.1 Overview of distributed resource characteristics

A distributed resource may take several forms. When considering DR interconnection at spot networks and grid networks, attention should be given to the energy source and generation type as well as capacity rating. For grid networks, there may be numerous potential sites for DR interconnection requiring only minimal evaluation when the rating of the DR is small in comparison with the minimum demand of the facility (see 7.2). Regarding spot networks, there may be opportunities for the interconnection of DR when appropriate DR operating, protection, and control strategies are implemented. Analysis of the opportunities for DR interconnection requires understanding not only the point of DR connection relative to the network and network characteristics but also the proposed DR generation technology, whether it is machine- or inverter-based, and available operating strategies. For additional information on DR and interconnection see IEEE Std 1547.2-2008.

7.1.1 DR energy sources

The energy source of a DR will play a significant role in determining the suitability of interconnection. Energy sources include such renewable energy technologies as solar photovoltaic (PV) systems and wind turbines (both characterized by varying and unpredictable output) and fuel cells. There are also residual energy DR systems, which operate on the reduction in the energy state of working fluids from other processes. Reduction of pressure in steam or other working fluids from another process can provide energy to drive an electric generator. Another class of DR operates through the combustion of a fuel in a reciprocating or turbine engine. The output of these sources is typically adjustable over the full range of the generation technology employed.

7.1.2 DR Electric power generation technologies

The energy source will, in many cases, determine the generation technology employed. Some technologies can be employed for the full range of energy sources; others may be restricted to a specific type of prime mover. The three primary types of electric power generation technology are discussed as follows:

Inverter. This technology converts dc power to ac power at grid voltage. Inverters are typically configured to provide a power output at a preset power factor consistent with the energy available from the energy source employed as input. Inverter power output is controlled to make optimum use of the energy source, particularly with variable resources such as PV or wind energy systems. Inverter fault current contribution is typically limited by the resident controls to 125% or less of rated current. In the event of a fault, inverters with adjustable clearing times may be capable of disconnecting within one to two cycles. Output voltage is determined by the area EPS bus with which it is interconnected. Inverters may be islanding (capable of providing sustained output energy in the absence of an external connection to an ac energy source) or non-islanding (designed to cease providing output energy within some fixed time from separation from an ac energy source, typically the area EPS).

Induction generator. An induction generator requires interconnection to an energized ac bus to begin to produce power. Induction generation is derived from an induction motor driven by a prime mover such as an engine or by a wind or hydro turbine. Without the presence of an excitation source (the area EPS or capacitance from power factor correction capacitors and/or underground cables), the induction generator will not produce any significant electrical output. The induction generator has a limited capability to produce fault current. Without an external excitation source, the bolted fault current contribution from an induction generator could be as high as 700% of rated current output but will decay to a negligible value within 10 cycles. The actual fault magnitudes and durations are a function of the machine characteristics, circuit characteristics, available capacitance, fault impedance, and the available voltage prior to the fault. A self-excited induction generator should be treated as a synchronous generator for interconnection.

Synchronous generator. A synchronous generator has an excitation source and will produce an electrical output either interconnected with an area EPS or isolated from it. For that reason, controls will include the means to produce synchronism with the area EPS prior to interconnection. This will include systems to control output voltage and frequency. When interconnected with the area EPS, synchronous generator controls regulate the power factor and prime mover loading to desired values. In accordance with IEEE Std 1547-2003, when the DR is connected with the area EPS, it shall not regulate voltage. Also, the DR shall not export power through any NP.

Synchronous generators on the order of 5 MW or less may provide a fault current contribution of 6 to 10 times rated output current. The fault current value may decrease to less than 40% of its initial fault value within 4 cycles of the initiation of the fault and reduce to 300% or less of rated full load output for up to 10 s. Typically, generators are designed to withstand 300% of rated current for 10 s.

7.2 The *de minimus* interconnection concept: definition and examples

De minimus is a legal phrase that translates to a minimal or insignificant effect on the subject in question. Here, *de minimus* is used to imply a level of DR capacity that may be interconnected to a network without the need for detailed studies by the utility or installation of additional protective systems. For spot networks, it is generally agreed that limiting the DR capacity ($\mathbf{C_{dr}}$) to a small fraction of the expected annual minimum load ($\mathbf{L_{min}}$) in the facility at the proposed DR interconnection site will prevent the DR unit from causing inappropriate NP operation or impeding proper NP operation under normal operating conditions. A de minimus $\mathbf{C_{dr}/L_{min}}$ criterion may be defined considering the aggregate DR capacity and load at a specific facility.

For the simplest case on a grid network, it may be possible that limiting $\mathbf{C_{dr}}$ to a small fraction of $\mathbf{L_{min}}$ in the facility at the proposed point of DR connection will provide a means to determine whether or not the DR unit will cause inappropriate NP operation or impede proper NP operation.

Additionally, for a grid network it may be possible to define a de minimus $\mathbf{C_{dr}/L_{min}}$ criterion considering the aggregate DR capacity and load at a specific facility and the aggregate DR and load of multiple facilities at a specific area on a grid network. For aggregated DR directly connected to the grid or having virtually no local load at the DR, the area to be studied would be limited by the surrounding NPs connecting that specific section of the grid. It is worth noting, however, that the area EPS typically will not have records of loads in this area. The advent of advanced metering infrastructure (AMI) may allow the calculation of load in this area to determine the minimum load for the application of the de minimus concept.

Preferably, $\mathbf{L_{min}}$ is determined through actual facility or network load measurements over a full year of operation. In some cases—for example, new construction or when considering aggregate load on a network—such measured data may not be available, so an estimate of $\mathbf{L_{min}}$ may be used. The DR operating profile may affect the value of $\mathbf{L_{min}}$ chosen. A DR unit limited to a certain period of operation, such as a PV system without energy storage that is limited to daytime operation, should be compared to $\mathbf{L_{min}}$ during the same operational period. For the case of PV or wind energy systems with energy storage capability, the criterion specified in the preceding paragraph regarding annual minimum load will apply.

An acceptable $\mathbf{C_{dr}/L_{min}}$ ratio will depend on how well $\mathbf{C_{dr}}$ and $\mathbf{L_{min}}$ are known. A lower ratio of $\mathbf{C_{dr}}$ to $\mathbf{L_{min}}$ may be needed for load measurements collected at slower data rates or for estimated load. Additional care should be taken when determining an acceptable $\mathbf{L_{min}}$ for sites with limited load diversity (for example, for spot networks with few connected customers) to account for the possibility that $\mathbf{L_{min}}$ may change drastically as site occupancy changes.

Regarding generating technologies, to date only inverter-based DR units have been allowed by utilities employing the de minimus criterion. This is because the fault current contribution of an inverter-based DR unit is usually limited to 125% or less of rated current. Further, modern inverters can be programmed to shut down within a fraction of a cycle upon receipt of a control signal indicating a network anomaly (such as a fault), so that the inverter would not contribute any significant current to the fault. Inverters are also now available with the ability to reduce output in response to a control signal. An example of such a control signal may be one sent from a system that monitors facility load, in response to a load decrease that brings facility load unacceptably close to the level of DR output. Inverters compliant with IEEE Std 1547-2003 will also disconnect upon the loss of area EPS voltage and not reconnect until area EPS voltage has been reestablished steadily for a prescribed time period.

Two examples of how the $\mathbf{C_{dr}/L_{min}}$ approach has been applied by utilities under existing tariffs are discussed as follows:

— *Example 1:* A utility is allowing a DR unit with inverter output, if the inverter meets IEEE Std 1547-2003 and IEEE Std 1547.1-2005, with maximum capacity $\mathbf{C_{dr}}$ up to 1/15th of the facility's measured annual $\mathbf{L_{min}}$ (i.e., $\mathbf{C_{dr}}/\mathbf{L_{min}}$ = 0.0666). This de minimus criterion is applied to both grid and spot network interconnection applications and is intended to prevent backfeed from the DR into the area EPS.

— *Example 2:* Another utility DR interconnection tariff applies specifically to grid networks. As with Example 1, the tariff requires IEEE 1547.1 compliant inverter-based DR. For applications of DR > 1 kW, there is a capacity limit of either 50% of the facility's $\mathbf{L_{min}}$ or 11 kW, whichever is less. There is also an aggregate DR limit (sum of all DR capacity on the network) of 2% of the grid network's estimated minimum load. Here, the per-facility criterion of $\mathbf{C_{dr}}/\mathbf{L_{min}}$ = 0.5, means there will be an acceptably small risk of backfeed from any individual facility into the grid network, while any backfeed that does occur will be absorbed within the grid network as a result of the aggregate criterion, $\mathbf{C_{dr\text{-}network}}/\mathbf{L_{min\text{-}network}}$ = 0.02.

7.2.1 General example of a DR grid network

Figure 4 is an example of a grid network modified to include DR within a customer facility. The symbols shown within the dashed-line rectangles represent utility customers on the network, in one case with DR connected to circuits within the customer's facility.

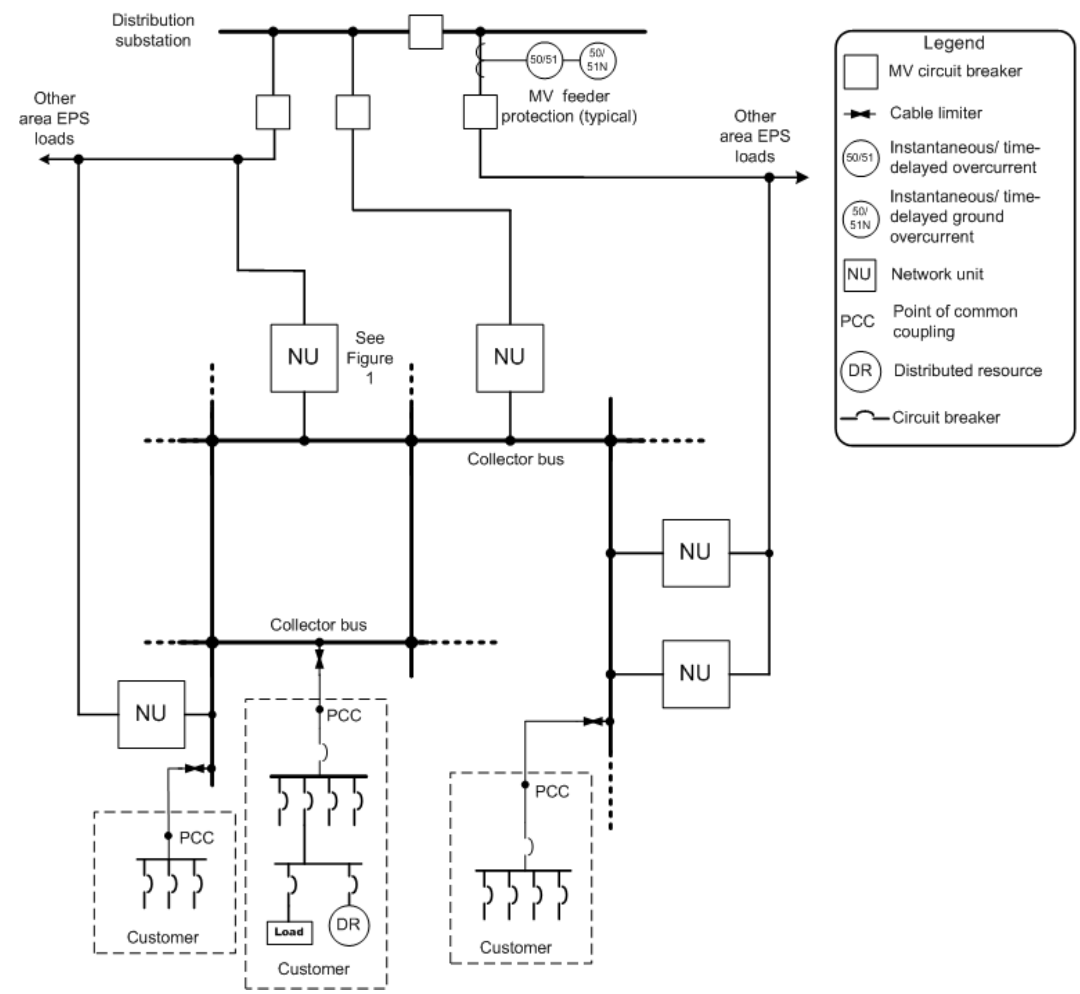

Figure 4—Illustrative example of a grid network with interconnected DR

7.3 A concept of limiting DR output relative to facility load

Several utilities and engineering consultants have examined and implemented the concept of (a) monitoring both the customer facility load (as seen by the network) and the DR output and (b) developing a system or means of controlling the DR output to a level less than the facility load with a mutually-determined kilowatt buffer. For inverter-based DR, it may be possible to implement this type of load following scheme with a response time of less than a cycle, under both normal and network fault conditions. These schemes may provide a minimum facility load and minimize DR current contribution to faults on the network. The value of this concept is to control DR output so that it will not export power to the network. If the facility does not export power and a minimum load level can be maintained through the NPs, then the requirement of precluding NPs opening due to DR operation is achieved.

A new device, called the network protector monitor (NPM) has been incorporated as part of the DR control system. Figure 5 illustrates an NPM system on a spot network. This device monitors the number of closed NPs to determine if the DR installation meets the minimum criterion of >50% established in IEEE Std 1547-2003 and opens the circuit breaker feeding the DR circuit when the criterion is not met.

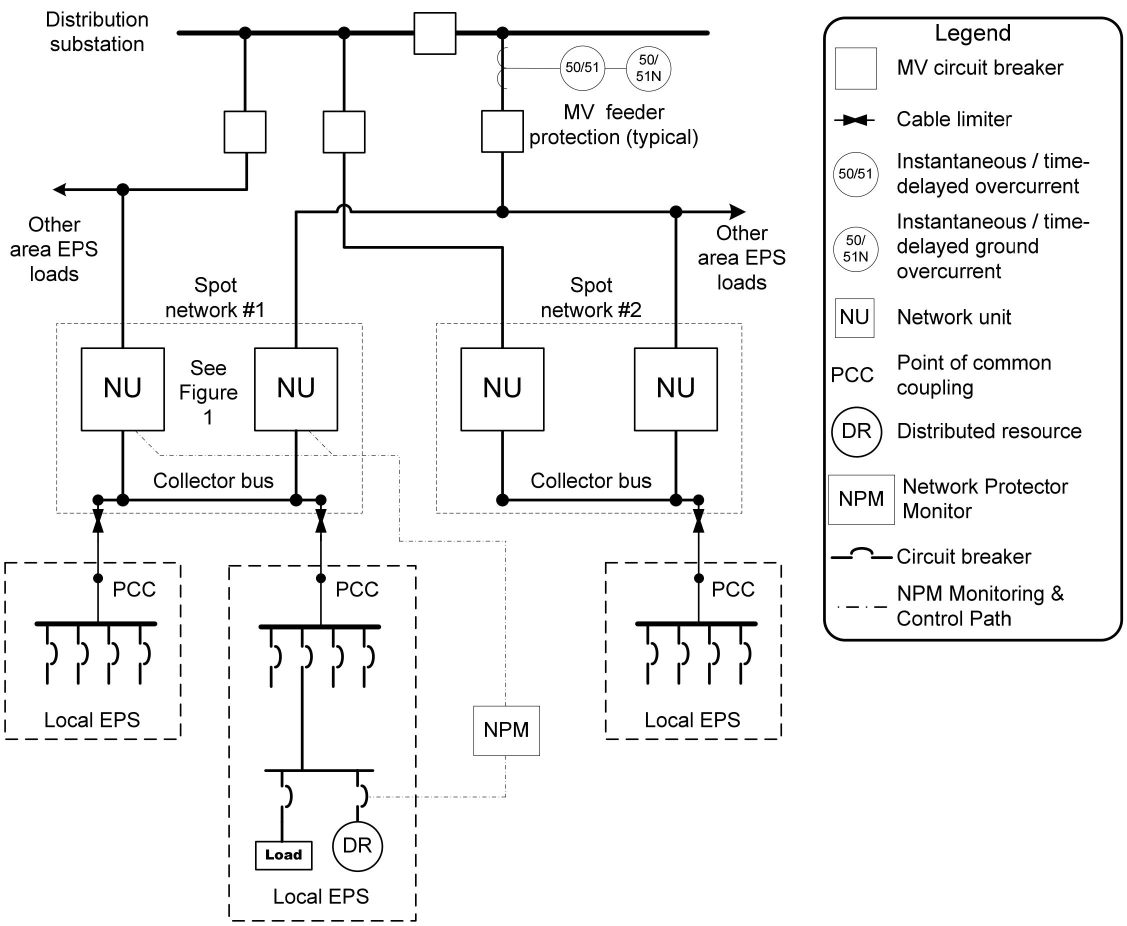

Figure 5—Illustrative example of DR interconnection using a network protector monitor

A device called the dynamically controlled inverter (DCI) has been incorporated as part of the DR control system. Figure 6 illustrates the use of a DCI on a spot network. Installation on an area network is also possible. This device monitors facility load at the PCC and controls the DR output so that it is always less than the facility load. In addition to the DCI, other protective devices should be considered.

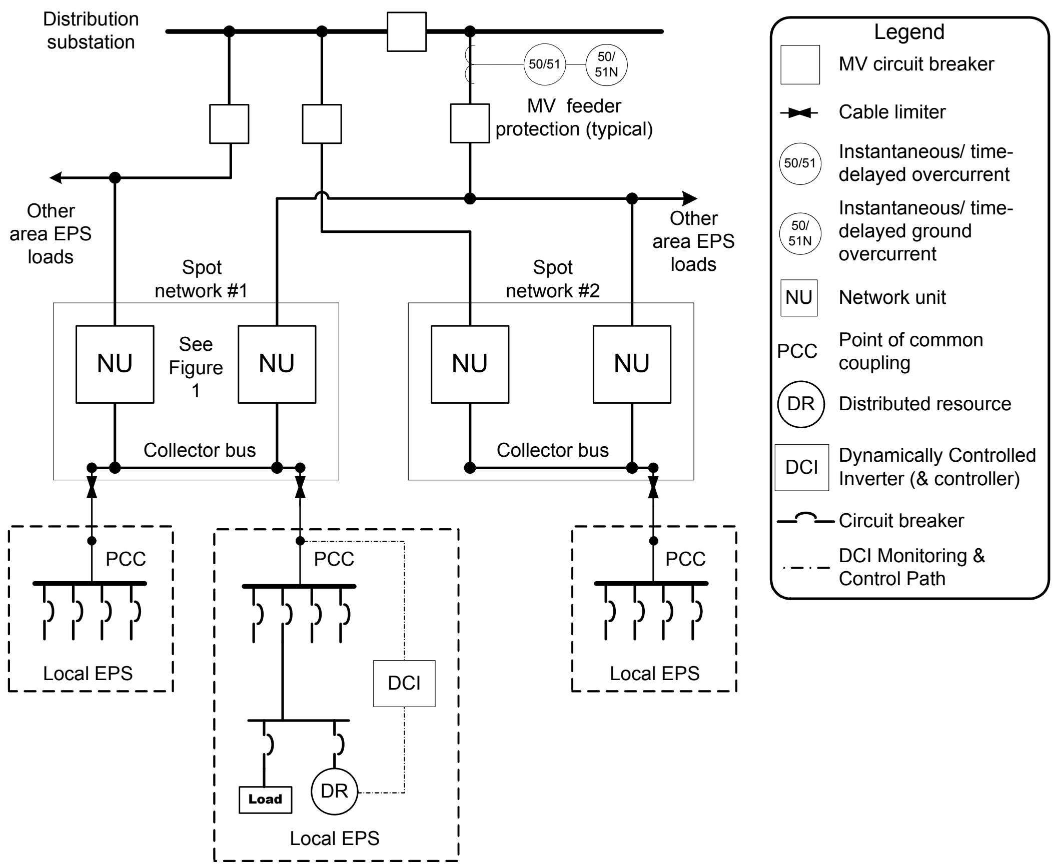

Figure 6—Illustrative example of DR interconnection using a dynamically controlled inverter

Establishing a minimum power import threshold at a facility is intended to prevent potential negative impacts of the DR on NP operations. Monitoring facility power demand through the PCC and using this data to control DR output achieves this operation. Various methods of accomplishing this desired outcome, which may also be referred to as a *minimum import power level,* have been employed.

7.4 Implementation of reverse-power control measures

For DR units relatively small compared to network power levels, but not de minimus, some utilities have specified that conventional reverse-power protection devices should be employed at the PCC to minimize the consequences of potential power export from the facility into the network. In addition to the reverse-power function, some utilities have employed devices to monitor incoming power levels, and used these devices to disconnect the DR units when incoming power falls to a utility-determined preset level (as discussed in 7.3).

7.5 Interconnection via combinations of control measures

7.5.1 Grid network operating strategies

The operating strategies for interconnection of DR with a grid network should take into consideration DR output rating, host facility loading, network transformer loading, secondary network power flow, load profile, generation technology, and abnormal operating conditions among other things. Refer to 6.4 for additional information.

When the DR capacity is less than the de minimus threshold, the area EPS operator may choose to allow interconnection without further review. When that de minimus level is exceeded, operating strategies should include the means to control the DR interconnection so that it does not adversely affect the grid network operation, reliability, or performance.

When the DR output is always less than the facility load (demand) and a minimum load level can be maintained through the NPs, power flow is always from the grid into the facility. Under normal operating conditions, and when the required minimum load level through the NPs can be maintained, DR output simply displaces load that would otherwise be furnished by the grid.

Under conditions of network system fault current, the DR current contribution shall cease per IEEE Std 1547-2003. It is recommended that the DR either cease to provide output current or be disconnected on the occurrence of a system anomaly that causes DR output current to exceed its full load rating. For induction and synchronous technology under fault current conditions, certain advanced protection systems may be able to disconnect the DR in up to 3 cycles and limit the current contribution. However, since this generation technology usually has three-phase output, additional protection should be included to provide the same speed of separation for the anomalies of single-phasing and excessive unbalanced current flows from the DR.

In the event the DR is connected to the network via a delta-connected transformer, additional ground fault detection and relaying may be required.

For adjacent feeder faults the following items are relevant:

— On a grid network, the backfeed from a DR for an adjacent feeder fault, will be seen by all of the NPs. This condition may cause all of the NPs to operate in accordance with the current division among the multiple paths and the level of reverse current. These reverse current flows are seen simultaneously by the NP master relays and the DR protection. Once an NP's master relay sees the current, it will operate and the NP will trip even if the DR was isolated very fast, and prior to the opening of the NP. The only apparent way to provide coordination for higher DR penetration would be to delay the operation of the NP to allow operation of the DR breaker and the reset of the NP master relay. However, delaying the NP for reverse power flow may increase the potential damage to the feeder under a network feeder fault condition and this risk needs to be evaluated by the area EPS operator. In general, NP operations on grid networks are not time delayed.

— An area EPS operator has studied this issue of adjacent feeder faults and has concluded that grid networks would only be allowed to have inverter-based DR installed, while spot networks could have either inverter-based or rotating generation installed.

Where the DR has potential to provide power flow into the grid network, the operating strategy should be designed such that there is always sufficient facility load supplied by the grid so that NP operation is not affected adversely under normal operating conditions. Examples of such considerations can be time-of-day or weekend-operation restrictions. Another example is to interlock the breakers serving large loads in the facility with the DR breaker, so that whenever any large load breaker is tripped, the DR is tripped at the same time. This avoids the so-called "race condition" between the DR breaker and the NP breaker that may occur if a sequential scheme were to be proposed.

7.5.2 Spot network operating strategies

One potential operating strategy for integration of DR into a spot network without negatively impacting the performance of the network requires positive power flow from the network into the facility. DR interconnection should not cause inadvertent operation of the NPs.

The distributed generation should be operated so as to maintain a preset value of positive power flow from the network into the host facility. This preset value should be as mutually agreed to by the area EPS operator and the DR owner.

The DR should cease to provide power whenever power flow into the facility is less than the value agreed and for abnormal conditions as agreed to by the area EPS and DR operators. This action should have no intentional delay.

On spot networks, a time delay for small levels of reverse power flow may be acceptable to some area EPS operators, and is occasionally used in the case of regenerative loads, for example elevators. If the area EPS can tolerate the sequential operation without negative impacts to the network operation, the spot network may be modified to accept either inverter or rotating machine generation after the existing equipment capability is thoroughly evaluated and replaced with appropriately rated equipment if necessary. The consideration is that for correct operation of this type of scheme the sequential operation of the DR breaker and the NP will be required. This type of operation will tend to be site-specific and needs to be reviewed for each location.

Another potential interconnection option can be envisioned in Figure 7, where a separate generator and facility load bus are shown with an additional breaker (A) at the main service board. For this scenario, it should be determined that the capabilities of the NP are not exceeded per IEEE Std C57.12.44-1994. Breaker A at the main service board opens under system fault or other reverse power conditions while the generator continues to serve the facility load via a transfer means. For a subcycle static disconnect switch it may be possible that the high-speed control system can minimize the fault current contribution. This becomes one type or subset of an intentional island condition (see IEEE Std 1547.4-2011).

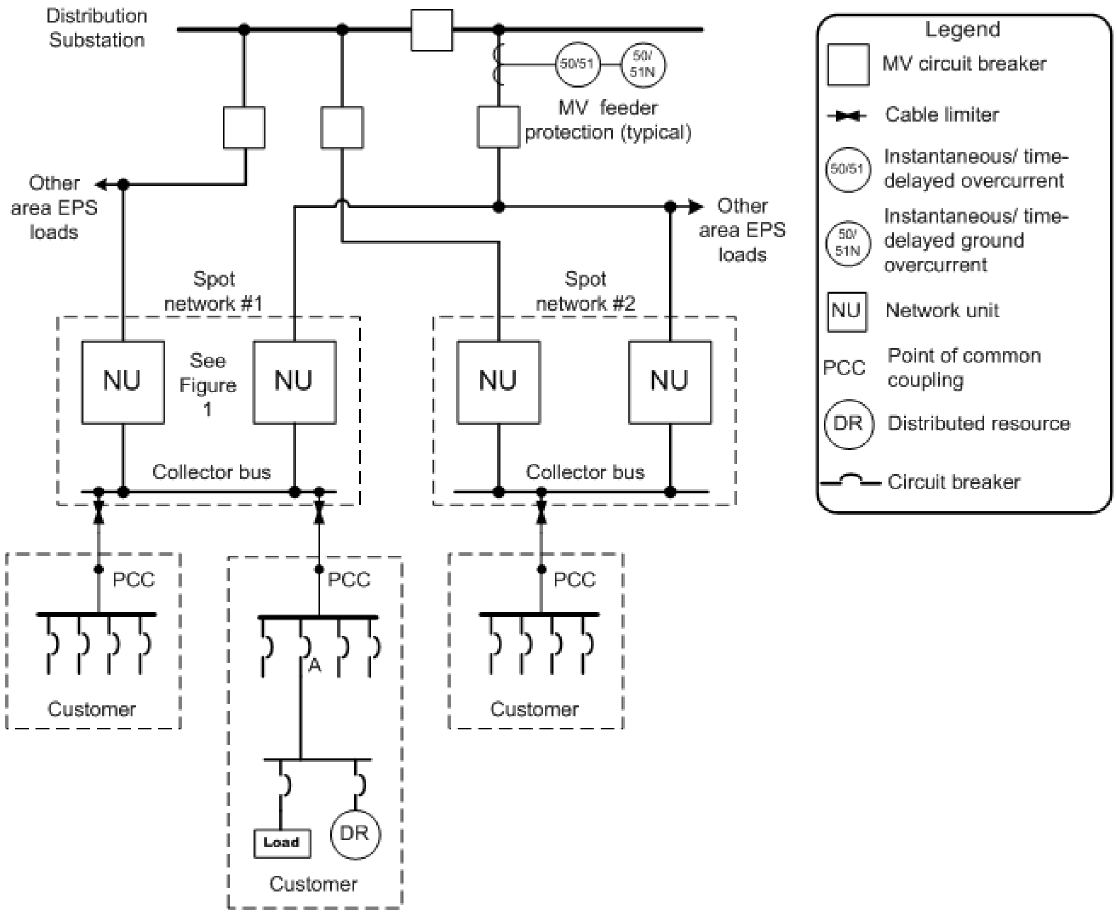

Figure 7—Illustrative example of a spot network with interconnected DR and a dedicated load

Annex A

(informative)

Bibliography

Bibliographical references are resources that provide additional or helpful material but do not need to be understood or used to implement this recommended practice. Reference to these resources is made for informational use only.

[B1] Baier, M., Feero, W. E., and Smith, D. R., "Connection of a Distributed Resource to 2-Transformer Spot Network," IEEE, 2003.

[B2] Behnke, M., et al., "Secondary Network Distribution Systems Background and Issues Related to the Interconnection of Distributed Resources," NREL, 2005.

[B3] Coddington, M., et al., "Photovoltaic Systems Interconnected onto Secondary Network Distribution Systems—Success Stories," NREL, 2009.

Annex B

(informative)

Glossary

network phasing relay: A monitoring relay that has as its function to limit the operation of a network master relay so that the network protector (NP) may close only when the voltages on the two sides of the protector are in a predetermined phasor relationship.

network protector (NP) fuse: A back-up device for the network protector.

network secondary distribution system: A system of ac distribution in which the secondaries of the distribution transformers are connected to a common network for supplying electricity directly to consumers' services.