Power System Engineering, Inc.

PSE

Distributed Generation Resources Connected to Distribution Systems

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Interconnection Policy

In order for the DG interconnection process to flow smoothly as well as assure that proper legal documentation is established, your cooperative should have a policy that covers:

- Application Process
- Interconnection Study Process
- Fees and Charges
- Metering Configurations
- Interconnection and Operation Contracts
- Insurance Requirements

Interconnection Contracts

Interconnection contracts are required to assure that there is a legal agreement and understanding between the DG owner and the cooperative of how the DG facility will be operated and maintained. Other items covered in these type of contracts include:

- Responsible party
- Limitation of Liability
- Testing
- Right of Access
- Disconnection
- Metering
- Insurance
- Assignment
- Schedule of Facilities

DG Classifications

- From a utility interconnection standpoint, can classify DG systems by type of electrical converter (or type of generator that interfaces the system to the distribution system)
  - Synchronous machines
  - Induction machines
  - Inverters and static power converters
  - Double Fed Induction Generator (DFIG)

Synchronous Machines

- Produce AC
- Has to be synchronized with the distribution system voltage, frequency and phase angle
- Requires complex controls
- Real power output (watts) controlled by the governor of the prime mover
- Reactive power output (VARs) controlled by level of field excitation
- Controllable power factor
- Significant fault contribution
- Capability for "islanding" to occur
- Commonly used for applications > 750 kW

Induction Machines

- Produce AC
- Basic control systems
- Rotational speed has to be higher than that required for exact synchronism with utility; otherwise, the generator becomes a motor and consumes power
- Flicker is a concern if machine is started as a motor
- Reactive power has to be supplied by an external source; therefore poor power factor can be a concern
- Reduced capability for islanding unless sufficient capacitance is in parallel to provide self-excitation
- Typical applications in modestly rated wind turbines (50 – 750 kW)

Inverters and Static Power Converters

- Convert DC or non-synchronous AC to synchronous AC (DC-to-AC or AC-to-DC-to-AC)
- Provide power conditioning
- Controllable power factor on some models
- Used with PV, small wind turbines, fuel cells, battery storage, DC generators
- Less familiarity at the utility level
- Protective functions can be integrated into the inverter (utility may require additional relaying and/or testing capability)
- Limited capability for islanding to occur
- Limited short circuit current capability

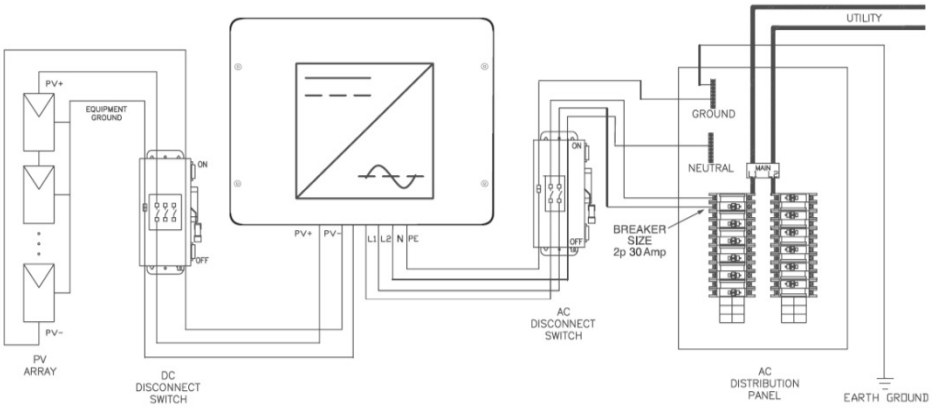
Inverter Basics

There are two basic types of inverters: Stand-alone or **off-grid** and **grid-tied**.

1. **Off-grid** inverters require battery storage.

2. **Grid-tied** inverter systems use the utility as a "storage battery" by delivering excess energy to the distribution system, and consuming energy from the utility when DG output is lower than energy needs.

Typical Inverter Installation



Source: SMA Solar Technology

Typical Inverter Protective Functions

- In addition to the disconnecting means shown, an inverter that is UL 1741 listed will have the following protective functions
  - Overcurrent protection → Primary purpose is to protect from overloads
  - Over/Under voltage protection
  - Over/Under frequency protection
  - Active anti-islanding protection
    - Check for an island by attempting to change voltage and/or frequency

  (Over/Under voltage protection, Over/Under frequency protection, Active anti-islanding protection) → Primary purpose is to prevent an unintentional island*

* Islanding is a condition in which the inverter continues to operate and energize a portion of the utility distribution system that is no longer being served from the normal utility source

Double Fed Induction Generators (DFIG)

- DFIGs are a hybrid power converter that utilizes an induction generator and inverter
- Basically an induction machine with rotor excitation supplied by an inverter
- Inverter typically rated at about 25% of machine capacity
- Allows variable speed operation and control over real and reactive power output in both directions
- During a fault, inverter is taken offline quickly and the machine behaves as a traditional induction machine
- Typically used with larger wind turbine installations (>750 kW)

DG Interconnection Technical Requirements

Technical requirements should be consistent with IEEE 1547

Published 1547 standards

- **1547- 2008** Standard for Interconnecting Distributed Resources with Electric Power Systems
- **1547.1 - 2005** Conformance Test Procedures for Equipment Interconnecting DR with EPS
- **1547.2 - 2008** Application Guide for IEEE 1547 Standard for Interconnection of DR with EPS
- **1547.3 - 2007** Guide for Monitoring, Information Exchange and Control of DR

Current P1547 Projects

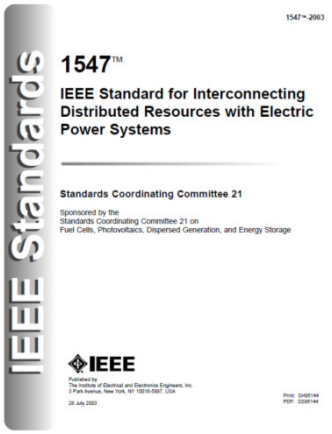
- P1547.4 Guide for Design, Operation, & Integration of Distributed Resource Island Systems with EPS (balloted 2010)
- P1547.5 Guidelines for Interconnection of EPS >10 MVA to the Power Transmission Grid
- P1547.6 Recommended Practice for Interconnecting DR With EPS Distribution Secondary Networks (balloted 2010)
- P1547.7 Draft Guide to Conducting Distribution Impact Studies for DR Interconnection
- P1547.8 Draft Recommended Practice for Establishing Methods and Procedures that Provide Supplemental Support for Implementation Strategies for Expanded Use of IEEE Std 1547

http://grouper.ieee.org/groups/scc21/index.html

IEEE 1547

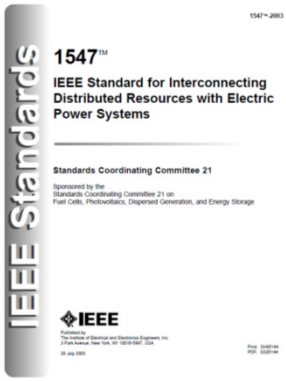
IEEE Standard for Interconnecting Distributed Resources with Electric Power System

- Brief and concise
- Focuses on interconnection at the distribution level
- Intended for systems with total capacity up to 10 MVA
- Strictly concerned with interaction at the point of common coupling



IEEE 1547 – Statements and Meanings

What IEEE 1547 States



* Source: IEEE 1547™-2003

What IEEE 1547 Means

We are only going to review some of the more important aspects of IEEE 1547 due to time limitations.

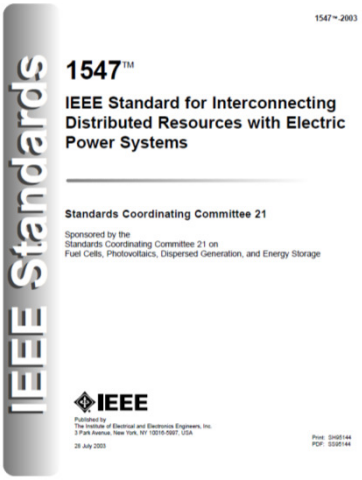
IEEE 1547 – Voltage Regulation

IEEE 1547 States

" The DR shall not actively regulate the voltage at the PCC."

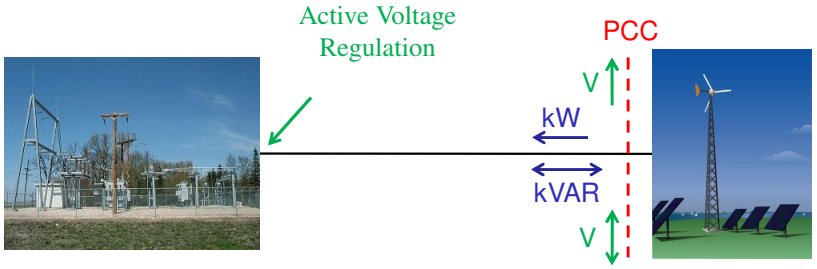
- and -

"The DR shall not cause service voltage at other local EPSs to go outside the requirements of ANSI C84.1-1995 Range A."



* Source: IEEE 1547™-2003

IEEE 1547 – Voltage Regulation



Primary Source

- Point of active voltage regulation.
- Voltage set point to support system voltage under all loading conditions.

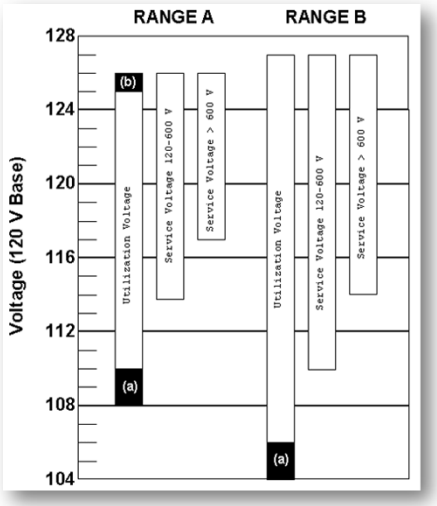
Secondary Source

- Voltage at the PCC follows the distribution system's response to real and reactive power flow.
- The DR's reactive power compensation capability can be important.

IEEE 1547 – Voltage Regulation

IEEE 1547 Means

- The DR cannot actively regulate the distribution system voltage or work in opposition to voltage regulation equipment.
- The DR cannot cause voltage at the PCC or at an electric distribution customer service entrance to go outside the required limits stated in ANSI C84.1.

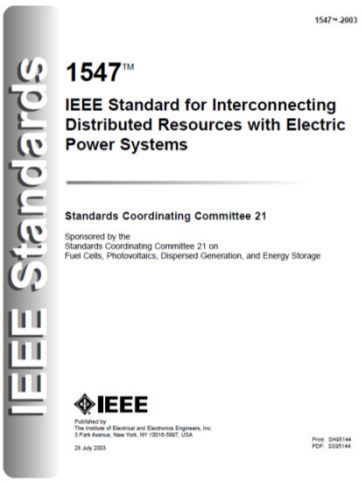


IEEE 1547 – Voltage Regulation

Items to verify include:

- Possible low voltage due to interaction with voltage regulators using line drop compensation settings.
- Possible low voltage due to significant reactive power (kVAR) draw by the DR facility.
- Possible high voltage due to significant real (kW) and reactive power (kVAR) injection by the DR facility.
- Possible voltage imbalance due to single phase DR interconnections.
- Possible excessive operation of voltage regulating equipment due to fluctuating DR output.
- Possible improper voltage regulation due to reverse power flow.

IEEE 1547 – Integration with EPS Grounding



* Source: IEEE 1547™-2003

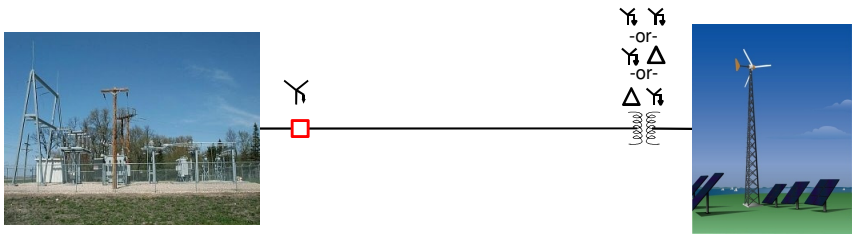
IEEE 1547 States

" The grounding scheme of the DR interconnection shall not cause over-voltages that exceed the rating of the equipment connected to the Area EPS"

- and -

"Shall not disrupt the coordination of the ground fault protection on the Area EPS"

IEEE 1547 – Integration with EPS Grounding



Primary Source

- Typically grounded-wye connected to the distribution system.
- Distribution system insulated for line-to-ground voltage.

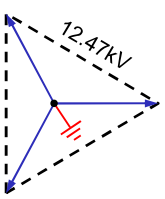
Secondary Source

- Could be connected to the distribution system via delta, wye, or grounded-wye.
- Each connection configuration has its own pros and cons.

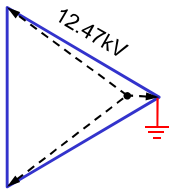
IEEE 1547 – Integration with EPS Grounding

IEEE 1547 Means

If the DR interconnection is delta connected with the distribution system, provisions must be in placed to prevent damaging phase-to-ground voltages in the event of line-to-ground fault during an island condition.



Grounded-Wye Source Intact

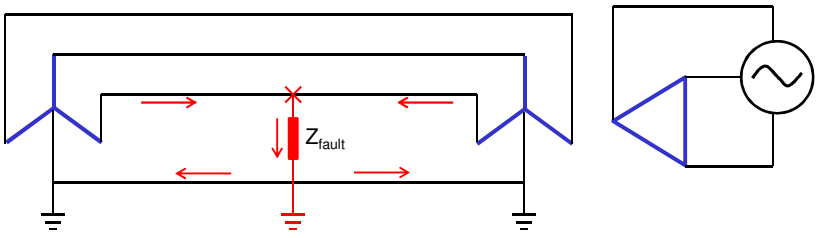


Grounded-Wye Source Lost
Line-to-Ground Fault

IEEE 1547 – Integration with EPS Grounding

IEEE 1547 Means

If the DR interconnection is grounded-wye connected with the distribution system, desensitization of the utility's ground fault protection device should be limited to acceptable settings.



Substation LG Fault DR Transformer

Step-Up Transformer Impacts

- Primary winding (utility side)
  - Ungrounded (delta or wye) may cause overvoltages on utility distribution system for ground faults
    - If distribution feeder load is >> than DG capacity, then this can be avoided
    - Rule of thumb – do not use ungrounded primary winding if minimum feeder load is < 2x the DG capacity
  - Grounded primary allows DG to supply ground current for faults on utility distribution system
    - Can de-sensitize utility ground protection schemes
    - Can interfere with fuse saving schemes

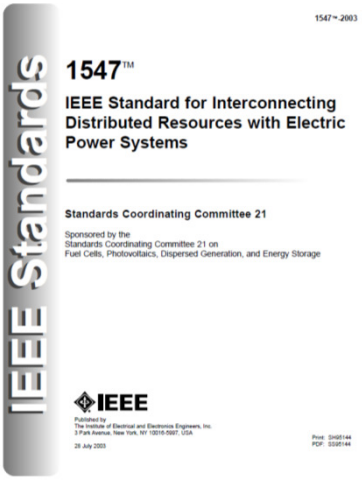
Step-Up Transformer Impacts

- Secondary winding (DG side)
  - Delta – If the primary is grounded-wye, ground current will be supplied to the distribution system as long as the transformer is connected, even if the DG is offline
  - Grounded-wye – allows ground fault contribution from the utility distribution system for faults on the DG side of the transformer

IEEE 1547 – Synchronization

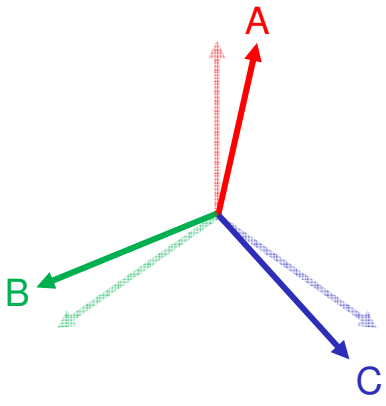
IEEE 1547 States

" The DR unit shall parallel with the Area EPS without causing a voltage fluctuation at the PCC greater then ±5% of the prevailing voltage level of the Area EPS at the PCC, and meet the flicker requirements of section 4.3.2"



* Source: IEEE 1547™-2003

IEEE 1547 – Synchronization



IEEE 1547 Means

- Synchronization requires the matching of:
  - Voltage Magnitude
  - Phase Angle
  - Frequency
- Mainly applies to synchronous generators.
- Standard provision also includes asynchronous generators in terms of voltage flicker at the time of interconnection.

IEEE 1547 – Synchronization

IEEE 1547 Means

For synchronous and inverter-based interconnection systems that produce a fundamental voltage before paralleling, the following synchronization limits shall apply:

Table 5—Synchronization parameter limits for synchronous interconnection to an EPS, or an energized local EPS to an energized Area EPS

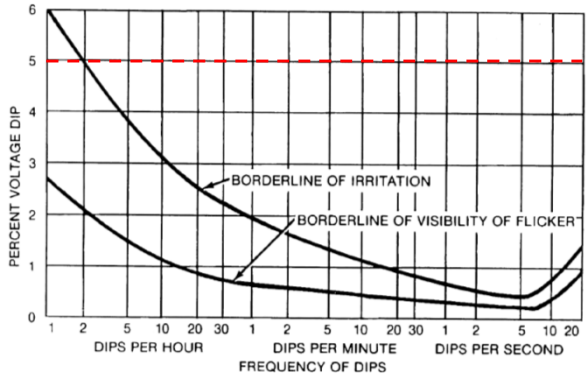
Aggregate rating of DR units (kVA)	Frequency difference (Δf, Hz)	Voltage difference (ΔV, %)	Phase angle difference (ΔΦ, °)
0 – 500	0.3	10	20
> 500 – 1 500	0.2	5	15
> 1 500 – 10 000	0.1	3	10

* Source: IEEE 1547™-2003

IEEE 1547 – Synchronization

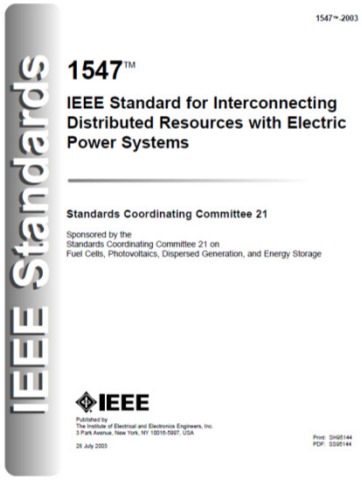
IEEE 1547 Means

For asynchronous and inverter interconnections, the maximum start-up (in-rush) current drawing by the DR shall not cause a voltage flicker greater than 5% on the distribution system.



* Source: IEEE Std 141-1993 "IEEE Recommended Practice for Electric Power Distribution for Industrial Plants"

Inadvertent Energization of the Area EPS



* Source: IEEE 1547™-2003

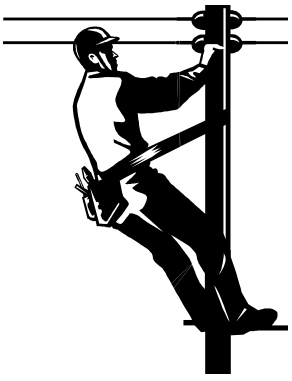
IEEE 1547 States

" The DR shall not energize the Area EPS when the Area EPS is de-energized"

Inadvertent Energization of the Area EPS

IEEE 1547 Means

- When the utility distribution is de-energized, the DG unit cannot inadvertently energize the system.
- Required to ensure personnel safety during line maintenance or service restoration activities.

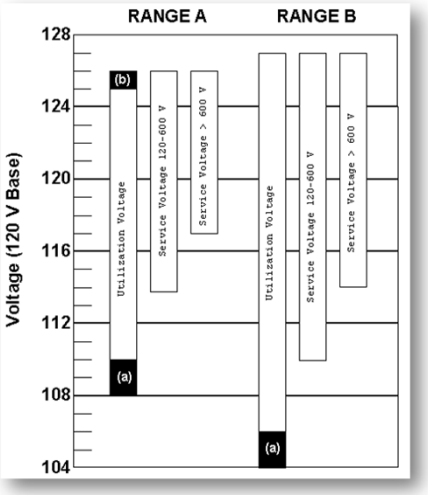


Inadvertent Energization of the Area EPS

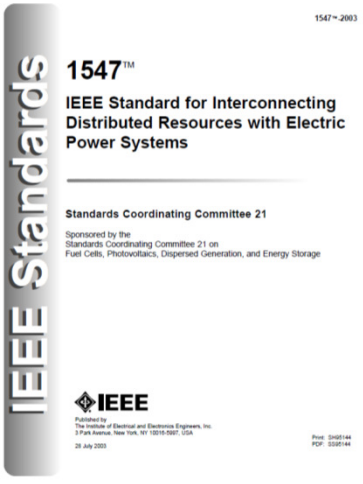
Reconnection to Area EPS

After an Area EPS disturbance, no DG reconnection shall take place until:

1. The Area EPS voltage is maintained within Range B of ANSI C84.1 for a stabilized period of 5 minutes
2. Frequency is in the range of 59.3 Hz to 60.5 Hz for a stabilized period of 5 minutes.



Isolation Devices



* Source: IEEE 1547™-2003

IEEE 1547 States

" Where required by the Area EPS operating practices, a readily accessible, lockable, visible-break isolation device shall be located between the Area EPS and the DR unit."

Isolation Devices

IEEE 1547 Means

If your utility's practices and procedures require a visible break isolation point to properly reconfigure the system from its normal service mode to provide safe working conditions, then a similar device should be installed between the DG unit(s) and the Area EPS.

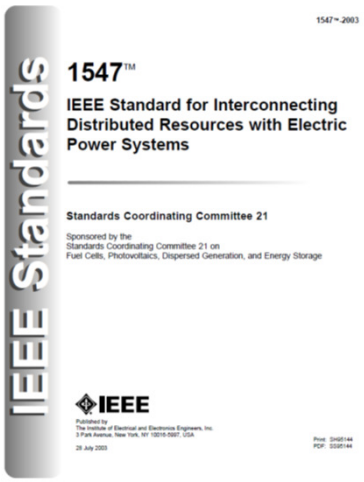
Isolation Device - Issues

- Addition of DG to distribution system may increase time to troubleshoot an outage
  - Time to open, lockout and tag all locations (what if there is a significant number of locations?)
  - What impact might this have on reliability indices?
- Specific switching orders may need to be created for those areas with DG installed
- Specific policies dealing with DG interconnections and related work rules may need to be created and then enforced
- What do you do if utility personnel do not use DG disconnects during emergencies and large outages?

Area EPS Reclosing Coordination

IEEE 1547 States

"The DR shall cease to energize the Area EPS circuit to which it is connected prior to reclosure by the Area EPS."



* Source: IEEE 1547™-2003

Area EPS Faults

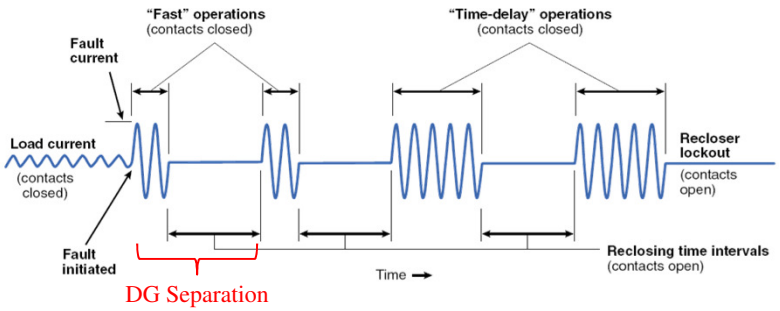
Items to be Aware of Include:

- Increase in the maximum available fault current that existing protection devices may be exposed to due to the contribution of DG.
- If the DG fault current contribution is substantial, the utility's contribution to the fault may be reduced and could affect the time it takes the utility's protection equipment to respond to a fault, or in the extreme case, prevent the utility's protection equipment from detecting a fault.
- Proper coordination between protection devices between the DR and fault.

Area EPS Reclosing Coordination

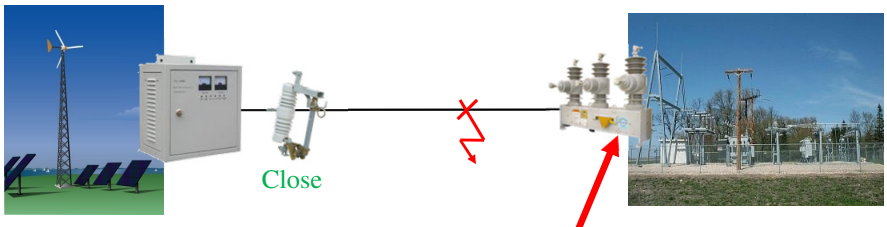
IEEE 1547 Means

The DR unit(s) tripping must coordinate with the utility's reclosers such that the DG unit separates before the recloser goes through its first operation.



Area EPS Reclosing Coordination

Items of Concern



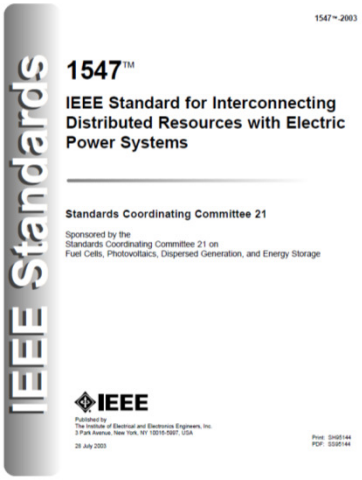
Utility's reclosing device may not have a sync check relay element.

Area EPS Reclosing Coordination

Items of Concern

If a fault is temporary in nature and the DG unit does not cease to energize during a reclosing event on the distribution system, the fault arc will most likely not have a change to extinguish.

Voltage



* Source: IEEE 1547™-2003

IEEE 1547 States

"The protection function of the interconnection system shall detect the effective (rms) or fundamental frequency value of each phase-to-phase voltage, except where the transformer connecting the Local EPS to the Area EPS is a grounded wye-wye configuration, or single-phase installation, the phase-to-neutral voltage shall be detected….

Voltage

IEEE 1547 States

"…when any voltage is in a range given in Table 1, the DR shall cease to energize the Area EPS within the clearing time as indicated. Clearing time is the time between the start of the abnormal condition and the DR ceasing to energize the Area EPS. For DR less than or equal to 30kW in peak capacity, the voltage set points and clearing times shall be either fixed or field adjustable. For DR greater than 30kW, the voltage set points shall be field adjustable."

Voltage

Table 1—Interconnection system response to abnormal voltages

Voltage range (% of base voltage[a])	Clearing time(s)[b]
V< 50	0.16
50 ≤ V< 88	2.00
110 < V < 120	1.00
V ≥ 120	0.16

[a]Base voltages are the nominal system voltages stated in ANSI C84.1-1995, Table 1.
[b]DR ≤ 30 kW, maximum clearing times; DR > 30kW, default clearing times.

* Source: IEEE 1547™-2003

Voltage

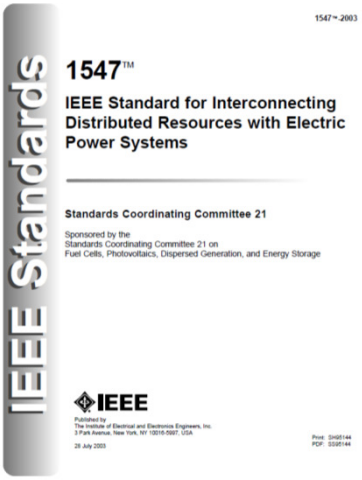
IEEE 1547 Means

- Rapid undervoltage protection: Detect faults on the distribution system.
- Rapid overvoltage protection: Detect potentially damaging overvoltage that can occur in an unintentional island.
- Delayed O/U voltage protection: Detect more sustained voltage abnormalities on the distribution system.

Frequency

IEEE 1547 States

"When the system frequency is in range given Table 2, the DR shall cease to energize the Area EPS within the clearing time as indicated. Clearing time is the time between the start of the abnormal conditions and the DR casing to energize the Area EPS. For DR less than or equal to 30kW in peak capacity, the frequency set points and clearing times…"



* Source: IEEE 1547™-2003

Frequency

IEEE 1547 States

"…shall be either fixed or field adjustable. For DR greater than 30kW the frequency set points shall be field adjustable."

"Adjustable under frequency trip settings shall be coordinated with Area EPS operations."

Table 2—Interconnection system response to abnormal frequencies

DR size	Frequency range (Hz)	Clearing time(s)[a]
≤ 30 kW	> 60.5	0.16
	< 59.3	0.16
> 30 kW	> 60.5	0.16
	< {59.8 – 57.0} (adjustable set point)	Adjustable 0.16 to 300
	< 57.0	0.16

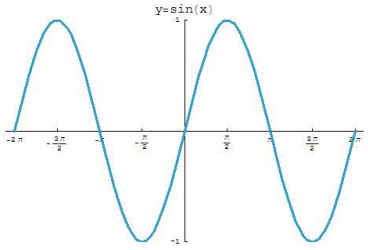
[a]DR ≤ 30 kW, maximum clearing times; DR > 30 kW, default clearing times.

* Source: IEEE 1547™-2003

Frequency

IEEE 1547 Means

- The operation of protection devices on the distribution system following its detection of a fault on the distribution system.
- Method to detect islands.
- Coordination with some load-shed schemes.

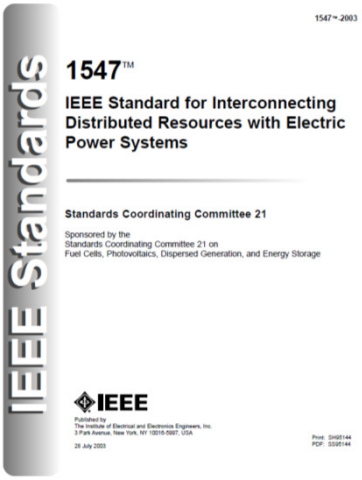


- Prevention of overfrequency or underfrequency damage to distribution system and customer equipment.

Monitoring Provisions

IEEE 1547 States

"Each DR unit of 250 kVA or more or DG aggregate of 250 kVA or more at a single PCC shall have provisions for monitoring its connection status, real power output, reactive power output, and voltage at the point of DR connection."

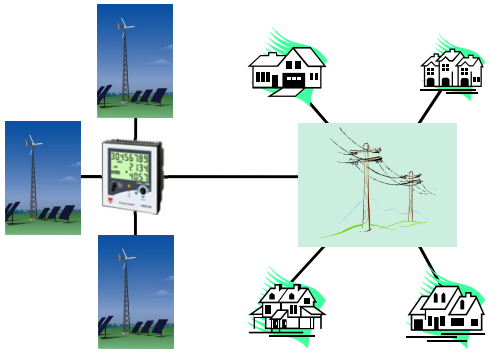


* Source: IEEE 1547™-2003

Monitoring Provisions

For DG unit(s) with greater output than the size limit of the Area EPS, real time monitoring (SCADA) might be necessary.

- ❑ Connection status
- ❑ Real power
- ❑ Reactive power
- ❑ Voltage
- ❑ Current flow
- ❑ Power factor
- ❑ Frequency
- ❑ Critical Alarms



Now that we have a little better understanding of IEEE 1547, let's talk about engineering studies…

What types of studies are needed?

When do I need to complete one of these?

What is the process?

What data do I need?

What tools are available?

Engineering Studies

- Comprehensive and complete review may be required to identify adverse system impacts
  - Adverse system impacts means that operational limits of utility facilities are exceeded with the interconnection of a DG facility, which may compromise safety or reliability
- It is common to divide the review process into several steps, which:
  - Provides stakeholders information at decision points
  - Allows process to be more manageable and efficient

Types of Engineering Studies

- Feasibility Study
  - A preliminary technical assessment of the proposed interconnection of a DG facility with the utility electric distribution system.
- System Impact Study
  - An engineering study to assess the ability of the existing utility electric distribution system to accommodate connection and safe operation of a DG facility.
- Facilities Study
  - An engineering study conducted to determine the specific modifications to the existing utility system that will be needed to accommodate connection and safe operation of a DG facility, including detailed cost estimates.

Typical Application Process

- Application
- Preliminary Review
- Screening Process

Used to determine whether an engineering study is needed

- Engineering Studies
- Study Results and Construction Estimates
- Final Go / No-Go Decision
- Final Design Review
- Order Equipment and Construction
- Inspection and Testing

Preliminary Review & Screening Process

- Purpose is to determine
  - If DG facility qualifies for a "simplified" or "expedited" interconnection (if the interconnection process is divided as such)
  - If engineering studies are required
- Streamlines the process and relieves some of the burden on engineering staff when reviewing applications
- Typically, "rules of thumb" are used to determine whether any engineering studies are required

Typical Screens to Determine if a Study is Required

Is the interconnection requested on a radial distribution system?

↓

Can the interconnection be accommodated without any construction of facilities by the utility?

↓

Is the aggregate generation capacity, including the proposed DG facility, less than 15% of the protection zone peak load, and is that total also less than 1/3 the protection zone minimum load?

↓

Is the short circuit contribution of the proposed DG facility ≤ 2.5% of the maximum short circuit current on the distribution feeder?

Typically a "***no***" answer to any of these screens means that additional study is required.

Power System Engineering, Inc.

Typical Screens to Determine if a Study is Required

Is the short circuit contribution of the aggregate generation capacity, including the proposed DG facility, ≤ 10% of the maximum short circuit current on the distribution feeder?

↓

Does the short circuit contribution of the aggregate generation capacity, including the proposed DG facility, still allow all protective devices to be less than 85% of their short circuit interrupting capability?

↓

If the interconnection is requested on a three-phase, four-wire distribution system, is it an effectively grounded three-phase or single-phase line-to-neutral interconnection?

Typically a "***no***" answer to any of these screens means that additional study is required.

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Power System Engineering, Inc.

Typical Screens to Determine if a Study is Required

If the interconnection is requested on a three-phase, three-wire distribution system, is it a three-phase or single-phase, phase-to-phase interconnection?

↓

If the interconnection is requested on a single-phase shared secondary, is the aggregate generation capacity on the shared secondary less than 20 kW?

↓

If the interconnection is being requested on a single-phase center tap transformer, is the imbalance created between the two sides of the 240V service less than 20% of the transformer nameplate rating?

Typically a "***no***" answer to any of these screens means that additional study is required.

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Engineering Study Review Areas

- Short circuit analysis
- Protection and coordination
- Power flow and voltage drop analysis
- Voltage unbalance
- Flicker analysis
- Harmonics and DC current injection
- Reliability and system operation
- Monitoring
- Communications

Short Circuit Analysis

- Contribution to fault current by the DG installation on the distribution system is reviewed
  - Make sure utility equipment is not pushed outside operational limits
  - Make sure utility equipment will operate as expected during a system fault
- Interconnection step-up transformer size and connections plays a big role

Protection and Coordination Review

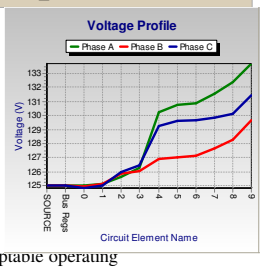
- Utility protection schemes designed for radial operation may be impacted by the addition of DG
- Review
  - Potential for out-of-synch reclosing
  - Need for a DTT scheme
  - Impact on fuse saving / fuse sacrificing schemes
  - Desensitizing of utility protection schemes
  - Coordination between utility and DG protection devices
  - Reverse power flows through protection equipment
  - Impact of step-up transformer connections

Power Flow and Voltage Drop Analysis

- Review potential for islanding (can load and generation match close enough at times that frequency and voltage relaying does not detect an island)
- Review loading of utility facilities
- Review impact on voltage regulation schemes
- Review power factor and VAR flows

DG Impact: High Voltage Example

If the generation output is significant during times of light loading, voltage rise can be a concern.



The American National Standards Institute (ANSI) Standard C84.1 establishes acceptable operating tolerances for voltage levels. The established maximum and minimum Range A (optimal voltage range) levels are as follows.

Location	Maximum (V)	Minimum (V)
Substation regulated bus	126	--
Transformer	126	118
Meter or entrance switch	126	114
Point of utilization	126	110

Voltages outside of these ranges can be detected through a deployed AMI system, voltage monitors, SCADA, field measurements, or through consumer complaints. There are several options available to limit voltage rise caused by DG installations. These include allowing the proposed generation to absorb reactive VARs (if possible), the installation of voltage regulators, limiting the amount of real power output from the DG unit, adding load, or a combination of these.

Flicker Analysis

- Voltage swings during DG start-up and when DG goes offline
  - Large wind turbines can be of particular concern
  - Synchronous generators can be operated to limit voltage swings if they trip offline
- Flicker associated with variable wind speeds and cloud cover
- Perception of “flicker” is based on magnitude of the voltage swing and the frequency of events
- Maximum voltage swing allowed should be defined in technical requirements (typically in the range of 3–6%)

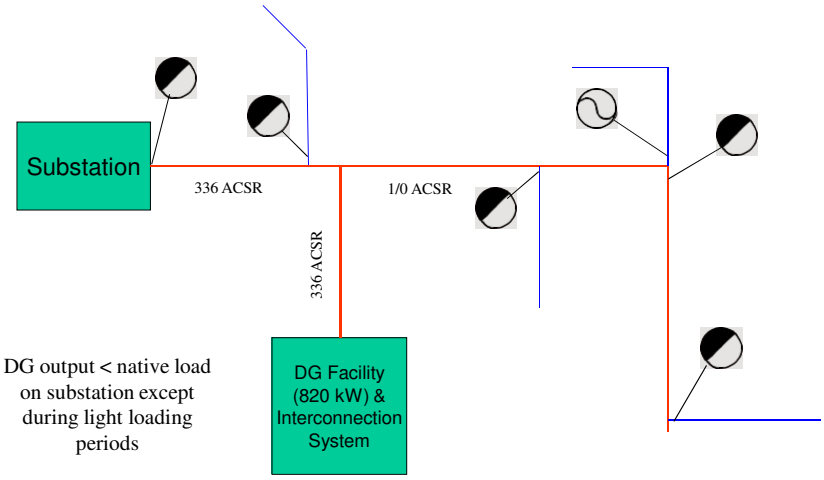
Reliability and System Operation

- Is reliability of the distribution system impacted with the addition of the DG system?
- Are special operating procedures required?
- Reclosing and out-of-synch operation issues?
- Are limitations on the operation of the DG required?
- Are there any operational VAR requirements?

LFGTE Case Study

- Landfill gas generator interconnecting to 12.47/7.2 kV distribution feeder
- Caterpillar 820 kW /1,025 kVA methane-fueled synchronous generator with output at 480V
- Generator protection = Basler relays
- Intertie protection = SEL-351S relay

Simplified Circuit Diagram



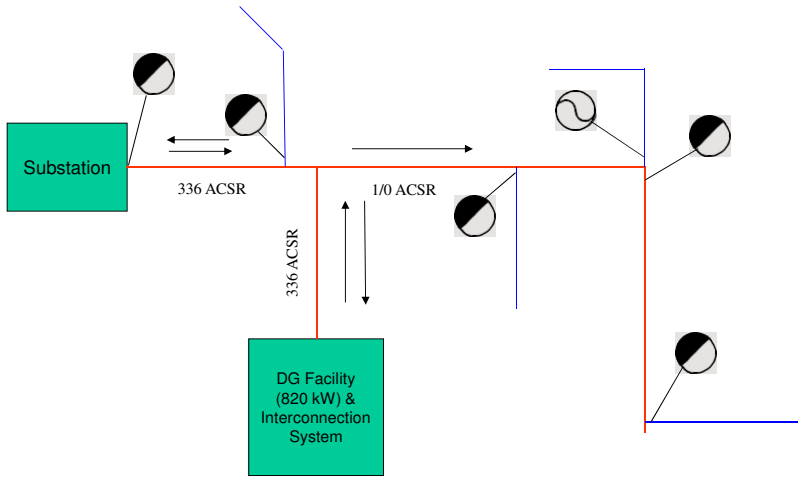
Transmission Provider Review

- Reverse power flow on to transmission provider's 34.5 kV sub-transmission possible during light loading periods
- Transmission provider review required
  - No thermal or voltage issues found
  - Flicker when DG trips offline may be > 3% (transmission provider standard)
  - Limiting generation operation range to .95 pf lagging to .98 of leading may mitigate flicker concern
  - No additional protection required from their standpoint since DG output does not exceed 30% of min load

Power Flow and Voltage Drop Analysis

- Engineering model used to complete analysis
- 4.8 miles of 336 ACSR installed between utility substation and DG interconnection
- No thermal or voltage issues from addition of DG
- Voltage regulation
  - Bus regulation present at utility substation
  - Line drop compensation (LDC) is not being used
  - No changes required to existing bus regulator settings

Power Flows



Transient Analysis

- Following transmission provider recommendation to limit the operating range of the generator will mitigate flicker concerns on the utility distribution system as well
- The intended use of the DG facility is for constant operation
- Expected frequency of flicker events is limited
- A larger voltage dip may be tolerated if it does not occur very frequently

Interconnection Transformer

- 1000 kVA padmount transformer grounded-wye (utility side) – delta (generator side)
- Transformer connection
  - Allows generation to supply ground fault current to the utility distribution system (even if the generator is offline) as long as the transformer is connected to the system
  - Mitigates overvoltages on the utility distribution system during line-to-ground faults

Interconnection Protection

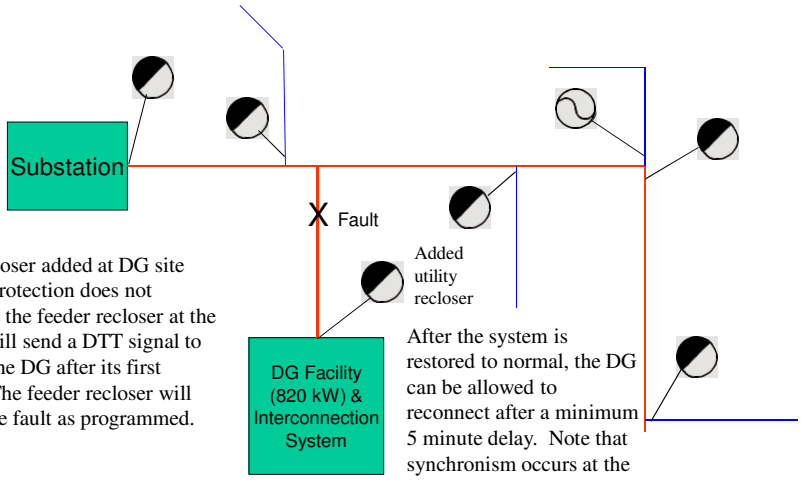
Proposed DG relaying consistent with utility technical requirements

- Utility grade relays
- Overcurrent relaying (50/51, 50/51G, 50/51N)
- Voltage controlled overcurrent relaying (51V)
- Over-voltage relay (59) / Under-voltage relay (27)
- Over/Under Frequency relays (81O/U)
- Synchronism check relay (25)
- Lockout relay (86)

Interconnection Protection

- Utility three-phase recloser recommended
  - Provides sensitive ground fault protection
  - Provides backup protection (under utility control)
  - Integration into a Direct Transfer Trip (DTT) scheme
    - Islanding possible due to possibility of generator output matching load on utility feeder
    - DTT scheme involves utility feeder recloser at substation sending a trip command to this recloser when abnormal system conditions are detected
  - Allows for interconnection transformer to be disconnected from the system

Fault in First Protection Zone



If utility recloser added at DG site and/or DG protection does not operate first, the feeder recloser at the substation will send a DTT signal to disconnect the DG after its first operation. The feeder recloser will then clear the fault as programmed.

After the system is restored to normal, the DG can be allowed to reconnect after a minimum 5 minute delay. Note that synchronism occurs at the generator paralleling switchgear.

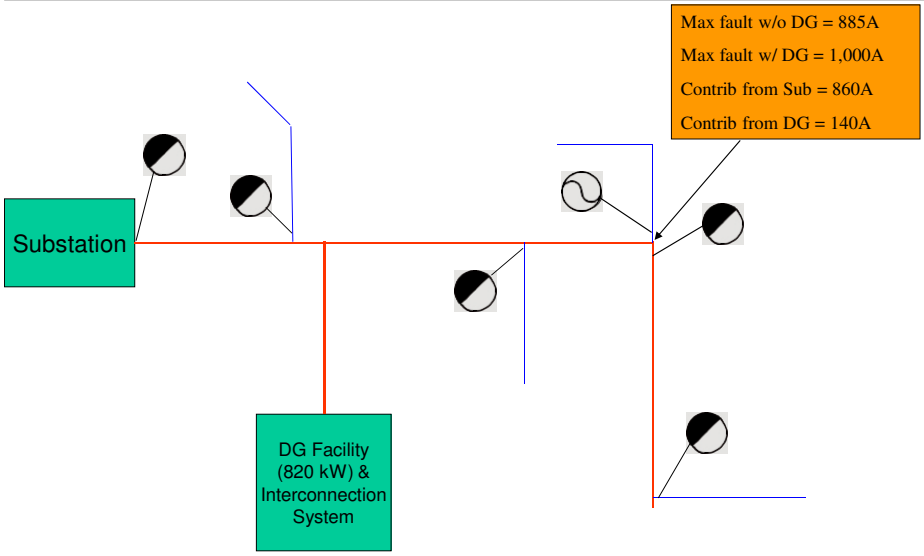
Distribution System Protection Scheme Impacts

1. Increased available fault current resulting in protection device ratings being exceeded or mis-coordination occurring
   - One device found where rating was exceeded due to DG

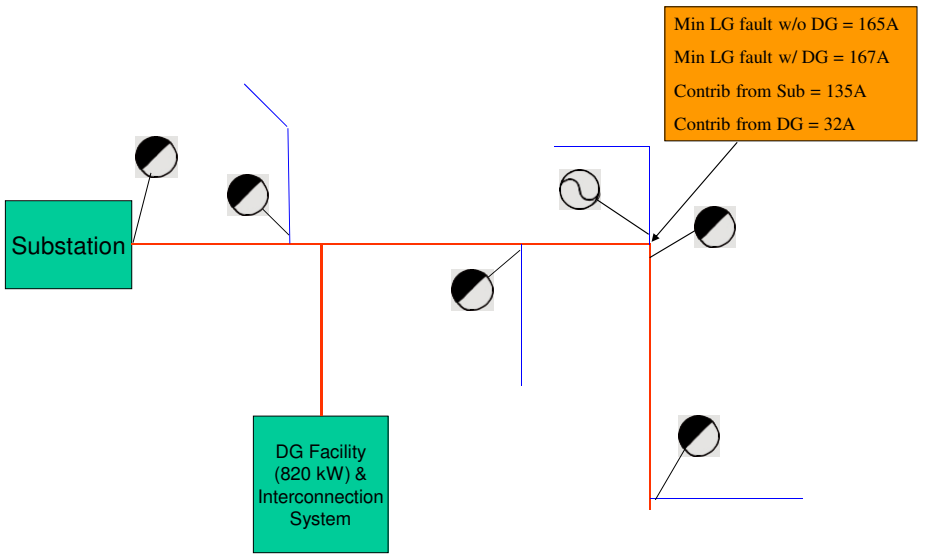
Distribution System Protection Scheme Impacts

2. Reduced ground and phase overcurrent protection sensitivity
   - Feeder recloser at substation ground pickup required to be lowered

Protection Impacts – Maximum Fault



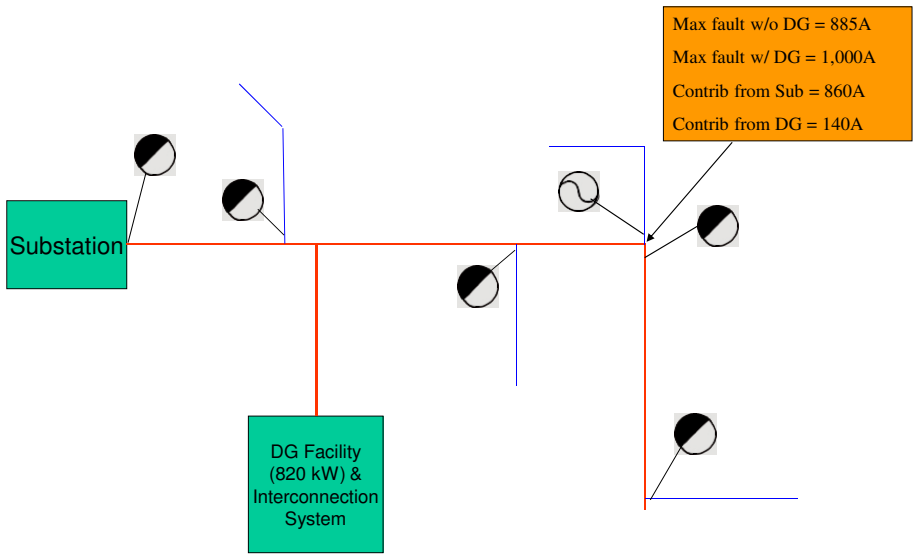
Protection Impacts – Minimum Fault



Distribution System Protection Scheme Impacts

3. Interference with fuse saving schemes
   - Fuse saving scheme attempts to keep fuses from blowing during temporary faults by allowing upline recloser to operate on fast operations first
   - Reduction in fault current from substation, coupled with overall increased fault current at fault location due to DG can interfere with these schemes

Protection Impacts – Maximum Fault



Distribution System Protection Scheme Impacts

4. Reverse power flow
   - The only existing protection device that might see reverse power flow is the feeder recloser installed at the substation during times when the DG output is > load on the feeder
   - Directional overcurrent protection recommended with the feeder recloser such that the recloser only operates for faults on the DG feeder
   - Fault flow from DG on to other feeders out of the utility substation will be limited

Distribution System Protection Scheme Impacts

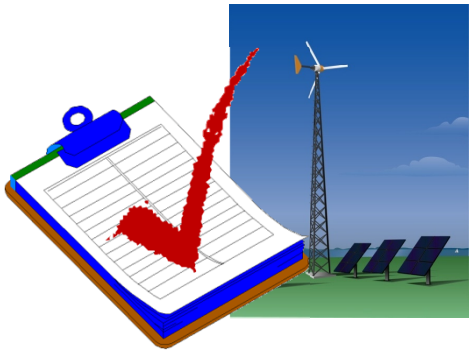
5. Out-of-synch reclosing
   - The possibility of out-of-synch reclosing exists with the feeder recloser installed at the substation
   - A PT is installed on the load side of this recloser and the existing SEL-351R relay is programmed to block reclosing if voltage is present

Once it has been determined what is required to safely interconnect a specific DG facility to your system, then what?

Inspection and Testing

Inspection and testing of DG equipment and its associated interconnection system is important for safety and system reliability. Applicable standards and codes should be referenced when developing or adopting procedures.

- IEEE 1547
- IEEE 1547.1
- UL 1741
- ANSI
- NEC
- NESC



Commissioning Tests - Before Energizing

Prior to paralleling the DG facility with the distribution system, an installation inspection and number of commissioning tests should be considered.

- Grounding
- Instrument Transformers
- Breaker/Switches
- Relaying
- Trip Check
- Remote Control / SCADA
- Phasing
- Synchronism
- Anti-Islanding Protection

Impact of Adding DG to Work on the System

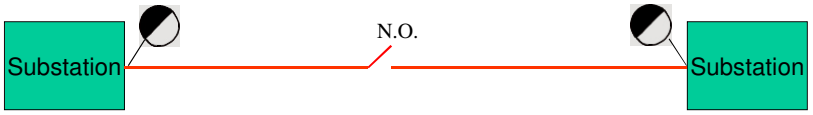
- The addition of DG has the potential to increase available fault currents and incident energy levels during arc flash events
- When working in areas with DG present, we need to make sure that during a fault condition the DG separates quickly and does not close back in to the system until the system is restored to normal for at least 5 minutes
  - IEEE 1547 requirement
  - An inverter meeting UL 1741 disconnects in 2 seconds or less and only reconnects after 5 minutes of normal utility conditions
- Best practice is to disconnect DG during energized work

Impact of Adding DG During Maintenance

- The addition of DG has the potential to complicate maintenance procedures
- Example:
  - A recloser is to be bypassed and removed for service
  - This recloser is integrated with a Direct Transfer Trip (DTT) scheme such that any trip condition or manual open sends a trip signal to a remote breaker at a DG installation
  - Maintenance procedure now may need to be modified to include disabling the DTT feature while this recloser is bypassed

Impact of Adding DG During Maintenance

- Example:
  - An area of the system has been backfed from an adjacent substation area while a substation is taken offline for maintenance
  - A recloser at the temporary open point is planned to be closed and briefly parallel the two substations together for a short time while the normal open point is re-established
    - Both substations are in phase
    - Eliminates the need for a brief outage during switching



Impact of Adding DG During Maintenance

- Example - continued
  - However, this recloser is programmed to block closing if voltage is present on the load side due to a downline DG installation
    - This ensures that out-of-synch reclosing does not occur
  - Switching procedure now needs to be modified to include disabling the voltage block feature while this switching is being done

Things We Hope You Take Away…

Interconnection policies and contracts should be put in place if you haven't already addressed this.

Things We Hope You Take Away…

One or more engineering studies may be required to determine any adverse system impacts

- Preliminary review and screening process identifies when studies are required
- Small inverter-based systems certified to meet UL 1741 and IEEE 1547 typically do not require an engineering study
- For interconnections requiring an engineering study, there are a number of review items that may need to be studied

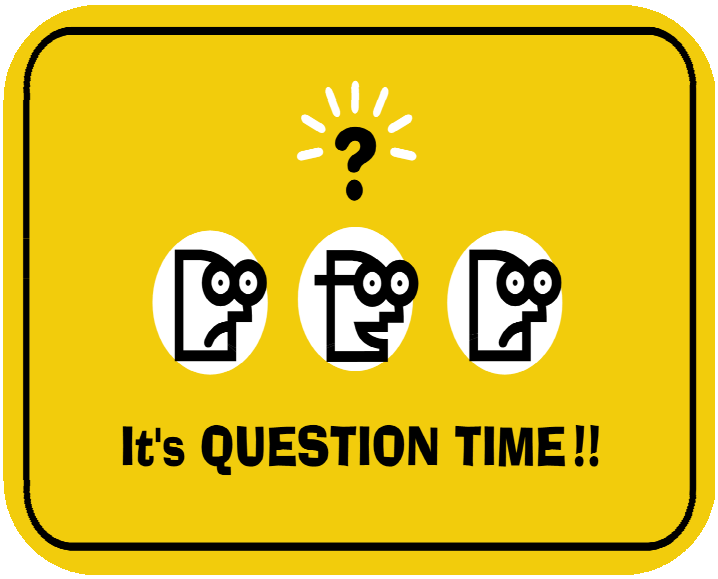
Things We Hope You Take Away…

Inspection & Testing of DG systems is important for safety and reliability

- Verify that your technical requirements are being met
- Co-op may need to complete certain commissioning tests to verify correct operation of anti-islanding protection, direct transfer trip schemes, etc.

Things We Hope You Take Away…

Maintenance procedures, work practices on the system and switching orders should be reviewed when adding DG to your system and modified as needed.



Thank You:

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