Standards, Rules, and Issues for Integration of Renewable Resources

M.Y. Vaziri-Senior Member IEEE, S. Vadhva-Member, S. Ghadiri-Member
C. J. Hoffman-Student Member, K. K. Yagnik-Student Member

Abstract- **The purpose of this paper is to gather and document the existing criteria, rules, and practices used by the Investor Owned Utilities (IOUs) in California for physical interconnection of Distributed Resources (DR). The criteria set by the National Standard IEEE 1547, State of California Public Utilities Commission (CPUC) Rule 21, and the standard practices used by a sample major IOUs will be presented and compared. Adequacy, practicality, and controversial implementation problems associated with the presently used rules and criteria will be documented and discussed. Suggestions and recommendations for future research and studies in the interest of practicality and implementation uniformity will be identified.**

Index terms: **Interconnection Criteria, Island, Distributed Energy Resources (DER), Distributed Resources (DR), Smart Grid (SG), Islanding, Relay de-sensitization, Transformer Replacement**

I. Introduction

To support the California Renewables Portfolio Standard (RPS) which was created on November 17, 2008, a mandated RPS of 33% by 2020 awaits in addition to the 20% by 2010 order. All non-conventional generation sources are considered as part of fulfilling the RPS [1]. The biggest issue in California is the constraint on the transmission system. Constructing a new transmission line is a complicated process where extensive planning, time, and money are needed. If the distribution system design is modified such that it can support the two-way flow of powers, then addition of DR on distribution system can help with the objectives of RPS, and the transmission constraints by postponing construction of new transmission lines.

Distributed Resource (DR), Distributed Energy Resources (DER), and Distributed Generation (DG) are all referenced as small, local electric energy generating units from various resources. A DR has no distinction between its source of energy whether combustion turbine or reciprocating engine, wind, photovoltaic, or emerging technology such as energy storage systems. Conventional plants are much larger and usually transmit electricity from longer distances. A significant advantage of a DR is that it can help minimize the need for construction of new high-voltage transmission lines. Power transmission efficiency will improve since power losses through lines will decrease due to the close proximity of the distributed resource.

There are many issues which need to be addressed for the implementation of DR: Planning / Design, Power Quality, and System Protection / Reliability problems arise when a DR is interconnected to the current distribution grid. One reason behind these problems is that the distribution system has not been designed for “two-way” power flow and DR will alter power flow in such a way. National Standard IEEE 1547 and California Public Utilities Rule 21 criteria have addressed many of the common problems of interconnection although; there are still many noteworthy issues.

National Standard IEEE 1547 and California Public Utilities Commission Rule 21 provide the essential criteria for interconnection of Distributed Resources (DR) to distribution systems. Many advantages including postponement of expensive transmission lines can be realized by proper interconnection of DR. To make this happen, the distribution system should be designed to allow bi-directional power flow and be equipped with the new “smart technologies” for measuring and controlling power flows, voltage regulation, system protection, and quality of power deliveries. These new concepts are being considered in the design of the future electrical supply systems known as the “Smart Grids”.

Some of the main objectives of the Smart Grid initiatives in the State of California are:

The funding for this project was provided by the California Energy Commission.
M. Y. Vaziri, S. Vadhva, C. J. Hoffman, K. K. Yagnik are with California State University Sacramento, CA 95819 (e-mail: vazirim@ecs.csus.edu, vadhva@ecs.csus.edu, choff07@gmail.com, kk_yagnik@yahoo.com)
S. Ghadiri is with California Energy Commission, Sacramento, CA-95814 (sghadiri@energy.state.ca.us)

a. Integration of up to 33% generation coming from central & local renewable sources;
b. Reduction of Green House Gas (GHG) emissions to below 1990 levels;
c. Creation of sample zero net-energy facilities by 2020 and 2030 for residential and commercial respectively.

Energy efficiency and demand response policy objectives have led to CPUC approvals for:

a. IOU investments in Advanced Metering Infrastructure (AMI);
b. Opt-Out time-differentiated electricity pricing for consumers enabled with AMI meters.

The main objectives of this paper are to gather, document, and compare the existing rules and criteria used for DR interconnection, and to address the major issues and concerns. The focus will be in three main areas where the criteria for interconnection of DR with an Area Electric Power System (Area EPS) are given from established rules and standards. Although various tariffs and associated metering, monitoring, and maintenance issues are also the part of the DR interconnection process, our concentration will be in the areas of "Planning / Design", "System Protection / Reliability", and "Power Quality". Commonly used terms as defined by the various standards and rules will be listed. Interconnection criteria will be listed and discussed under the main categories of; IEEE 1547, California Rule 21, and a sample IOU. Engineering concerns are discussed under "Areas of Concern" & "Areas in Need of future Research."

II. Definitions

Definitions are given to provide explanation of commonly used terms from National Standard IEEE 1547, CPUC Rule 21, and other sources.

A. *Definitions from National Standard IEEE 1547*:[2]

- Generating Facility (GF): Electric generation facilities connected to an Area EPS through a PCC; a subset of DR.
- Distributed Resources (DR): Sources of electric power that are not directly connected to a bulk power transmission system. DR includes both generators and energy storage technologies.
- Area Electric Power System Operator (Area EPS Operator): The entity responsible for designing, building, operating, and maintaining the Area EPS.
- Inverter: A machine, device, or system that changes direct-current power to alternating-current power.
- Island: A condition in which a portion of an Area EPS is energized solely by one or more Local EPSs through the associated PCCs while that portion of the Area EPS is electrically separated from the rest of the Area EPS.
- Island, intentional: A planned island.
- Island, unintentional: An unplanned island.
- American National Standard Institute (ANSI)

B. *Definitions from CPUC Rule 21*: [3]

- Electric power system (EPS): Facilities that deliver electric power to a load.
- Electric power system, area (Area EPS): An EPS that serves Local EPSs.
- Electric power system, local (Local EPS): An EPS contained entirely within a single premises or group of premises.
- Interconnection: The result of the process of adding a DR unit to an Area EPS.
- Point of common coupling (PCC): The point where a Local EPS is connected to an Area EPS.
- Point of distributed resources connection (point of DR connection): The point where a DR unit is electrically connected in an EPS.
- Cease to energize: Cessation of energy outflow capability.

C. *Definitions from other source*:

- DR System Impact: DR interconnection can result in electric grid operating conditions that normally would not occur without the DR installed—these resulting conditions are called as DR system impact. [10]

- Short Circuit Current Ratio (SCCR): The ratio of the short circuit current contribution of the Generating Facility to the short circuit current contribution of the Distribution System at the PCC. [4]

III. Summary of Interconnection Requirements

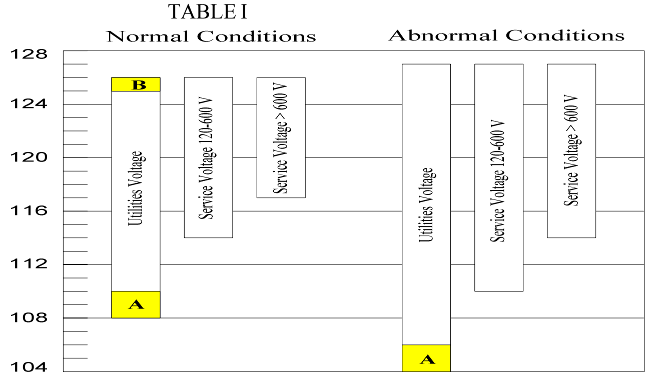
Integration of DR into the distribution systems often introduces some Design / Planning, System Protection / Reliability, and Power Quality problems. National Standard IEEE 1547 has established criteria and requirements for interconnection of DR with the area EPS to identify and address many of the major issues and to define a common set of rules. The California Public Utility Commission has established a set of rules i.e. Rule 21 for DR interconnection which recently adopted most of the interconnection criteria set by the IEEE 1547 standard. Further, Rule 21 also provides an Initial Review Process (IRP) which can speed the process of DR interconnection. Generation Facilities which don't pass the IRP will be evaluated via what is known as the "Supplemental Review" process. In a Supplemental Review further studies are used to determine any specific issues that maybe caused by the Generating Facility interconnection. Summarized below are the interconnection criteria for IEEE 1547, CPUC Rule 21, and a sample IOU, Pacific Gas and Electric Company (PG&E).

A. National Standard IEEE 1547: [2]

IEEE Standard 1547 is the first of its kind for the U.S. power system. It has specified many of basic rules for the interconnection of Distributed Resources. Considering IEEE Std-1547 as reference, the criteria for DR interconnection in the categories of; "Planning / Design", "System Protection / Reliability", and "Power Quality" are presented as follows:

1. Planning / Design:
   a. ANSI specification C84.1-1995, Range A requires that the DR will not actively regulate the voltage at PCC or cause the Area EPS service voltage at Local EPS's to go outside Range, A. ANSI ratings are shown in Table I.

TABLE I



ANSI Ratings (120 V Base)

   b. IEEE 1547- 4.1.3 has a paralleling specification where the DR must parallel with the Area EPS without causing a voltage fluctuation at the PCC greater than ±5% of the prevailing voltage level of the Area EPS.
   c. IEEE 1547-4.1.7 design standard requirement states that isolation devices must be accessible, lockable, and provide a visible-break between the Area EPS and the DR.
   d. IEEE C37.90.2-1995 specifies that the Inter connection system must have the capability to withstand electromagnetic interference for proper operation of its protection devices.
   e. Interconnection system must be capability to withstand voltage and current surges according to IEEE Std C62.41.2-2002 or IEEE Std C37.90.1-2002.

2. System Protection / Reliability:
   a. During the condition of inadvertent energization, the DR must not reclose into the Area EPS when the Area EPS is de-energized.
   b. "The interconnection system paralleling device must withstand 220% of system rated voltage." [2]
   c. The DR must detect and interrupt connection with the Area EPS for faults on the Area EPS circuit.
   d. "The DR must not energize the Area EPS circuit to which it is connected prior to reclosure by the Area EPS." [2]
   e. DR grounding scheme must not cause overvoltage beyond equipment ratings or disrupt the coordination of the Ground Fault Protection.
   f. In the case of an unintentional island, the DR interconnection system must detect the island and separate from the Area EPS connection within two seconds of the formation of an islanding.
   g. Provisions are made for reconnection after an Area EPS disturbance, whereby the DR must not reclose until the Area EPS voltage is within Range B of ANSI C84.1-1995, Table I, and frequency range of 59.3 Hz to 60.5 Hz. [2, 7]

h. A protection function where the detection of effective (rms) voltage or fundamental frequency at the PCC is required in the case that voltage is in the range of Table II, or frequency is in the range of Table III. This protective function provides that the Area EPS break within the clearing times specified.

i. Voltages are detected at the PCC when the conditions are as follows:

i. "Aggregate capacity of DR Systems at a single PCC is less than or equal to 30 kW," [2]

ii. "Interconnection equipment is certified to pass a non-islanding test for that system," [2]

iii. "Aggregate capacity of DR Systems is less than 50% of the total Local EPS minimum annual 15 minute time demand and export of real and reactive power by the DR to the Area EPS is not permitted." [2]

Table II shows the specified system response to abnormal voltages and respective clearing times as stated by IEEE 1547 [2].

TABLE II
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 ≤ 30kW, maximum clearing times; DR > 30kW, default clearing times.

Table III shows the system response to abnormal frequencies and respective clearing times as stated by IEEE 1547 [2].

TABLE III
Interconnection system response to abnormal Frequencies

DR size	**Frequency range (Hz)**	**Clearing time (s)[a]**
≤ 30kW	> 60.5	0.16
	> 59.5	0.16
> 30kW	> 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.

TABLE IV SHOWS THE SYNCHRONIZING PARAMETER LIMITS FOR SYNCHRONOUS INTERCONNECTION AS STATED BY IEEE 1547 [2].

TABLE IV
Synchronization parameter limits for synchronous interconnection

Aggregate rating of DR units (kVA)	**Frequency difference** (Δf,Hz)	**Voltage difference** (ΔV,%)	**Phase angle difference** (ΔΦ,º)
0-500	0.3	10	20
>500-1500	0.2	5	15
>1500-10000	0.1	3	10

3. Power Quality:

a. Limitation of dc injection: "The DR and its interconnection system must not inject dc current more than 0.5% of the full rated output current at the point of DR connection." [2]

b. Limitation of flicker induced by the DR: The DR must not create out of limit flicker for other customers on the Area EPS[1].

[1]Out of limit flicker is flicker that causes a modulation of the light level of lamps sufficient to be disturbing to humans.

c. Harmonics: Harmonic current injection into the Area EPS at the PCC shall not exceed the limits stated in Table V. The harmonic current injections are exclusive of any harmonic currents due to harmonic voltage distortion present in the Area EPS without the DR connected.

Table V shows the limits on harmonic current injections into the Area EPS as specified by IEEE 1547 [2].

TABLE V

Maximum Harmonic Current Distortion in Percent of Current (I)[1,2]

Individual Harmonic Order h, (Odd Harmonics)	**Max Distortion** (%)
h < 11	4.0
11 ≤ h ≤ 17	2.0
17 ≤ h ≤ 23	1.5
23 ≤ h ≤ 35	0.6
35 ≤ h	0.3
Total demand distortion (TDD)	5.0

1. IEEE 1547-4.3.3
2. I = the greater of the maximum Host Load current average demand over 15 or 30 minutes without the GF, or the GF rated current capacity (transformed to the PCC when a transformer exists between the GF and the PCC).
3. Even harmonics are limited to 25% of the odd harmonic limits above.

B. *CPUC Rule 21*: [4]

The California Public Utility Commission Rule 21 has adopted many of the interconnection criteria of IEEE 1547. An important addition with Rule 21 is that it provides an Initial Review Process (IRP) where an efficient review process of DR applicants speeds up the interconnection process. Supplemental Review is provided for applicants not meeting IRP criteria in which further review is needed.

1. Planning / Design:
   a. The PCC must not be interconnected through a secondary network. Interconnections on the secondary network are outside the scope of this rule and will be reviewed on a case by case basis.
   b. Rule 21 was originally designed for "Non Exporting" generating units. This ensures that no export of power takes place across the PCC. The following options are made available:
      i. Reverse Power protective function at the PCC with default setting of 0.1% of transformer rating, and a maximum time delay of 2.0 seconds.
      ii. Minimum Import of power, where an Under-Power protective function must be implemented at the PCC. The default setting value is 5% import of the Generating Facility Gross Nameplate Rating, with a maximum time delay of 2.0-seconds.
      iii. To limit the incidental export of power, all of the following conditions must be met:
      - The aggregate capacity of the Generating Facility must be no more than 25% of the nominal ampere rating of the customer's Service Equipment.
      - The total aggregate Generating Facility capacity must be no more than 50% of the service transformer rating.
      - The Generating Facility must be certified as Non-Islanding.

      iv. To insure that the relative capacity of the Generating Facility compared to facility load results in no export of power without the use of Additional devices, the Generating Facility capacity must be no greater than 50% of the customer's verifiable minimum load over the last 12 months.
   c. Interconnection Equipment must be certified under Rule 21.
   d. The aggregate Generating Facility capacity on the Line Section is 15% of Line Section Peak Load insures the line capacity is below its maximum capacity.
   e. The Starting Voltage Drop must be within Acceptable Limits as determined by the area EPS. This criteria is to ensure that the distribution system will not experience out of limit voltage flickers during start ups (or tripping) for large generators.
   f. The Power factor must be between 0.9 leading and 0.9 lagging although; a correction is possible if outside this range.

This IRP and the associated flowchart were developed to expedite the approval process of generating units that meet certain predetermined criteria.

The IRP provides a systematic and consistent process for the utility to follow when reviewing an interconnection. By providing a series of screening thresholds, the utility can quickly determine whether an interconnection will be a Simple one with minimal requirements, or if it requires a Supplemental Review.

Supplemental review means that additional consideration must be given to interconnection requirements and the need for a possible interconnection study will be examined.

Fig. 1 flowchart shows the screening thresholds of the Initial Review Process. [4]

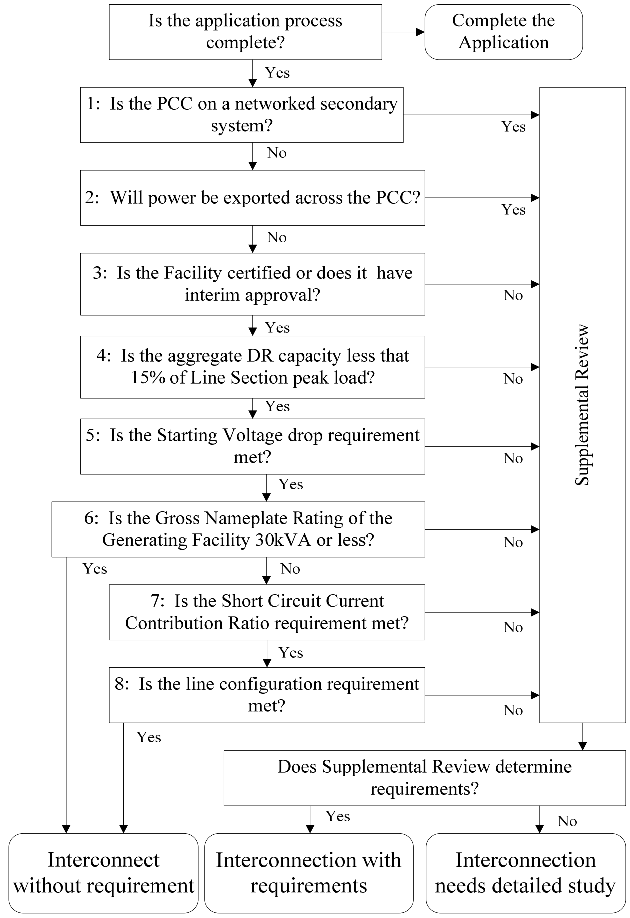


Fig.1 Initial Review Process Flowchart

2. System Protection / Reliability*:*
   a. Short circuit current contribution requirements are meant to show that the Generating Facility has a small enough impact such that it is unnecessary to perform a short circuit contribution analysis.
      i. At high voltage side of the Dedicated (or the Interconnection) Distribution Transformer, the sum of the Short Circuit Contribution Ratios (SCCR) of all Generating Facilities on the Distribution System circuit may not exceed 0.1. This is cumulative criterion on a first come – first serve basis. Once the cumulative SCCR of 0.1 has been surpassed, additional "Fault Detecting" schemes[i] must be added at PCC. The schemes are to enable the new interconnecting facility detect and clear for "Faults" occurring on the area EPS system.

      [i]Fault Detecting schemes are referred to equipment that detect and interrupt multiphase and ground faults on the utility systems.

      ii. For customers that are metered at the low voltage (secondary) levels of a shared distribution transformer, the short circuit contribution of the proposed Generating Facility must be less than or equal to 2.5% of the interrupting rating of the utilities service equipment.
   b. The Line Configuration is acceptable for Simplified Interconnection:[4]
      i. If the primary distribution circuit serving the Generating Facility is of a three-wire type, or if the Generating Facility's interconnection (distribution) transformer is single-phase and connected in a line-to-neutral configuration, then there is no concern about over-voltages to the Distribution System or other customer's equipment caused by loss of system neutral grounding during the operating time of anti-islanding protection.
      ii. If the Generating Facility is served by a three-phase four wire service or if the Distribution System connected to the Generating Facility is a mixture of three and four wire systems, then aggregate Generating Facility capacity that exceeds 10% of the Line Section peak load must be reviewed. This screening process is to limit overvoltages to the Distribution System or customer's equipment caused by loss of system neutral grounding during an Unintentional Island before the operating time of anti-

islanding protection scheme. The 10% limit ensures that the local load is much greater than the output of the Generating Facility so that the load causes a significant voltage drop and prevents the possibility of overvoltage caused by loss of system neutral grounding.

c. Table II, the system response to abnormal voltages, has been adopted by Rule 21 where clearing time limits are specified.
d. Table III, the system response to abnormal frequencies and the respective clearing times limits, has been adopted by Rule 21.
e. Table IV has been adopted by Rule 21 and provides the required synchronizing parameters limits.

3. Power Quality*:*

Rule 21 has adopted the power quality requirements IEEE standard-1547.

a. Harmonic distortion limits: GF harmonic distortion must be in compliance with IEEE STD 519-1992. Exceptions shall be evaluated using the same IEEE STD 519-1992 criteria for the loads at host load site.
b. DC injection limits: DC injection must be less than 0.5% of GF rated output current.
c. Table V, which specifies the limits on harmonic current injection into the Area EPS, has been adopted by Rule 21.

C. Major IOU –PG&E:

PG&E has adopted the CPUC Rule 21 as its DR interconnection criteria. PG&E has two sets of interconnection handbooks: one for Transmission interconnections which differs from the Rule 21, and the other for Distribution interconnections. For DR interconnections, major focus is given to the Distribution interconnection handbook.

1. Planning / Design: [5]

PG&E uses the screening thresholds as given in the Rule-21 IRP screening.

a. Simplified Interconnections:

Small, certified, non-exporting generators are included in this category.

b. Supplemental Interconnection:

i. 15% Rule – The applicant's generating system combined with existing generation does not exceed 15% of the maximum loading of the line section.

ii. Overloading – PG&E's equipment and line rating are not overloaded by the applicant's generating system.

iii. Voltage operating levels – in the steady state operating conditions, the applicant's generating system does not create a voltage drop or rise that goes above or below the allowable operating-voltage bandwidth. Allowable operating voltage levels have been specified in the CPUC Rule 2 which is the same as the ANSI standards.

2. System Protection / Reliability:[5]

a. The sum of the Short Circuit Contribution Ratios (SCCR) of all Generating Facilities on the Distribution System circuit must be less than 0.1. [4]

Table VI below summarizes the protective device schemes for various power levels for PG&E systems. The minimum protection devices are prescribed with respect to the power limits.

TABLE VI
PG&E Generator Protective Device Scheme

Generator – Protection Device	**Device Number**[1]	**Upto 40** kW	**41 to 400** kW	**Above 400** kW
Phase Overcurrent	50/51	X[2]	X[2]	
Overvoltage	59	X	X	X
Under-voltage	27	X[3]	X	X
Over-frequency	81O	X	X	X
Under-frequency	81U	X	X	X
Ground-Fault-Sensing Scheme	51N		X[4]	X
Overcurrent with Voltage Restraint or Overcurrent with Voltage Control	51V 51C		X[5]	X

Reverse-Power Relay	32	X[6]	X[6]	X[6]
Direct-Transfer Trip	TT	X[7]	X[7]	X[7]

Notes:

1. Standard Device Numbers, definitions, and functions are given in PG&E handbook of interconnection.
2. When fault-detection is required, per CPUC Rule 21, the phase overcurrent protection must be able to detect all line-end phase and phase-fault conditions.
   The generator must be equipped with a phase instantaneous-overcurrent relay that can detect a line fault under subtransient conditions.
   The generator does not have to be equipped with a phase Instantaneous-overcurrent relay if the generator uses a 51V or 51C relay. PG&E determines if a 51V or a 51C relay is better suited for the specific project.
3. For generators rated at 40 kW or less, installing a contactor undervoltage release may meet the undervoltage protection requirement.
4. If CPUC Rule 21 requires fault protection, the ground-fault detection is required for any noncertified inverter-based, induction, or synchronous generating facility.
   Synchronous generators with an aggregate generation over 40 kW and induction generators with an aggregate generation over 100 kW require ground-fault detection.
5. When CPUC Rule 21 requires fault protection, a group of generators, each less than 400 kW but whose aggregate capacity is 400 kW or greater, must have an overcurrent-relay with voltage restraint (or voltage control, if determined by PG&E) installed on each generator rated greater than 100 kW.
6. For nonexport generating facilities operating under the proper system conditions, and having a finite "minimum import" (excluding any possibility of an "incidental" or an "inadvertent" export), a set of three single-phase, very sensitive reverse-power relays, along with the dedicated transformer, may be used in lieu of ground-fault protection.

   PG&E prefers that the relay be set as an "under-power" element. As specified by CPUC Rule 21, the relay can be set at 5% of the customer's minimum import power (despite the generator's maximum output) for each phase, to trip the main circuit breaker at a maximum time delay of 2 seconds.
   As a "reverse-power" element, the relay must be set for 0.1% of the transformer rating with a time delay of 2 seconds, as specified by the CPUC Rule 21.
7. PG&E determines, based on PG&E's circuit configuration and loading, if the distribution-level interconnections require transfer-trip protection [ii].

   [ii] A transfer-trip scheme may be required if PG&E determines that a generation facility cannot detect and trip on PG&E's end-of-line faults within an acceptable time frame, or if PG&E determines that the generation facility is capable of keeping a PG&E line energized with the PG&E source disconnected.

3. Power Quality*:*
   a. PG&E has adopted the Table V power quality requirements as specified by IEEE 1547/Rule 21. In the case that the limits may not be met, a dedicated transformer may be required to reduce the generator harmonics entering the PG&E system.
   b. The generating facility must minimize any adverse voltage effects, such as voltage flicker at the point of common coupling (PCC) caused by the facility. The limits must not exceeded as defined by the "Maximum Borderline of Irritation Curve" [8]

IV. COMPARATIVE DISCUSSION OF VARIOUS CRITERIA

DR standard IEEE 1547, establishes criteria and requirements for interconnection of DR with the area EPS. The criteria for interconnection are specified in which the operation, performance, equipment conformance testing, safety considerations, and maintenance of the interconnecting facilities are evaluated. IEEE 1547 voltage requirements are stated "to be met at the PCC" between the Local EPS and the Area EPS where an aggregate capacity 10 MVA or less is specified at the PCC. Rule 21 has intentionally avoided any size limits for the facilities interconnecting to the distribution systems. This makes Rule 21 much more liberal in allowing interconnections. The existing limitations in the loading area (15% loading rule) and protection area (0.1 SCCR rule) sufficiently monitor the system for additional reviews and implementation of additional requirements. Some of the other differences are as follows:

a. PG&E has addressed the possibility for requiring a dedicated transformer, where as IEEE 1547 or Rule-21 have no provisions for a dedicated transformer requirement.
b. IEEE-1547 and Rule-21 have specified IEEE-519 as the reference for voltage flicker though IEEE-519 has no defined voltage limits for this purpose. PG&E provides a 6V limit on 120V base.
c. Protection against automatic reclosure for out of phase systems has not been specifically addressed in IEEE 1547 or Rule-21. PG&E emphasizes "Reclose Blocking Schemes" to inhibit automatic reclosing into energized systems whereas, other utilities have different criteria.

V. Areas for Concern

The interconnection of DR complicates feeder design, where one or more generators connecting to the existing distribution feeder may create various problems. Common areas for concern are Islanding, Relay Desensitization, Voltage Regulation, Voltage Flicker, line / transformer replacements, and resonant conditions.

A. Islanding problems: Unintentional Islanding problems exist though there is no clear understanding about how the islanded systems can be developed automatically. DR units with stand-alone capabilities such as synchronous generators or voltage source inverter based units can easily form unintentional electrical islands and serve isolated loads. Some crude formulas or rules of thumb have been used as bases in formation of islands. A widely used criterion is the one that considers an island maybe formed when the aggregate size of generating units is equal or larger than half of the load of the system at the instant of formation of the island. Options to prevent an island or to cease its continuation include; "Anti-Islanding Certification" of inverter based units, Reverse Power relaying schemes, or Transfer Trip schemes.

Fig. 2 shows Transfer Trip schemes referred to the DR's PCC with the Local EPS.

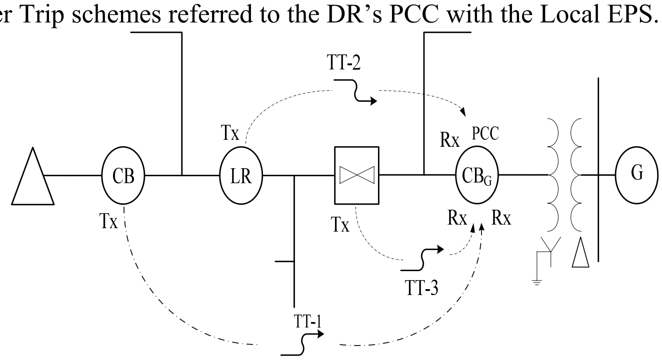
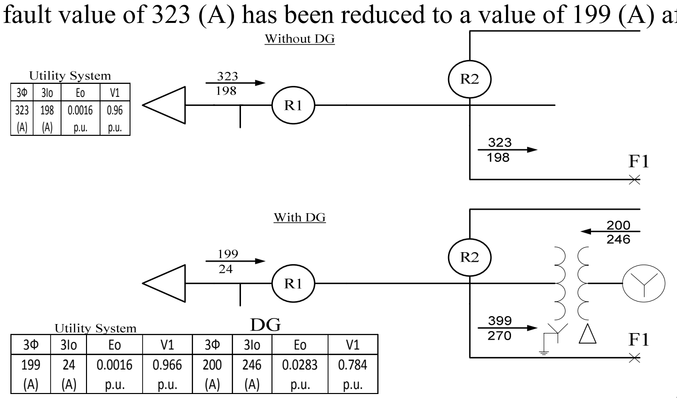


Fig. 2 Transfer Trip Schemes (TT-1, 2, 3)

B. Relay Desensitization: It can be analytically shown that although integration of generating units increases the total short circuit duty at any point of the system, it tends to decrease contributions from each of the sources. This decrease in contribution from any source is known as "Relay Desensitization". For this reason, fault contributions at the end of the protective zones for each protective device between the utility and the DR must be checked to ensure that End of Line (EOL) Protection from each source is maintained. If any protective device is desensitized such that it no longer protects, its zone ends, then additional protective equipment is required.

Fig. 3 shows an example of a typical desensitization of protective equipment (Reclosure R1) where a 3-phase fault value of 323 (A) has been reduced to a value of 199 (A) after the addition of DR.



Utility System (Without DG):

3Φ	3Io	Eo	V1
323 (A)	198 (A)	0.0016 p.u.	0.96 p.u.

With DG:

Utility System				DG			
3Φ	3Io	Eo	V1	3Φ	3Io	Eo	V1
199 (A)	24 (A)	0.0016 p.u.	0.966 p.u.	200 (A)	246 (A)	0.0283 p.u.	0.784 p.u.

Fig. 3 Three Phase and Three Io Currents for Faults at F1

C. Voltage Regulation and Flicker issues: Under normal conditions with a generator on line, back-feeding a portion of a utility circuit cause power flows from the substation to a "null point" on the circuit where the loading is balanced with generation. Power flow in this direction causes voltage drop through the line, although between the "null point" and the source station. From the "null point" towards the generator, the power flow in the reverse direction causes a voltage rise. Now, when a generator trips off line abruptly, the powers flow from the "null point" to the generator location changes direction, creating an additional instantaneous voltage drop where it rose before. This may cause an unacceptable low voltage condition if there are no regulators to respond. Even when there are regulators available, because they cannot respond instantaneously, an unacceptable voltage fluctuation can occur. After a short time the regulators readjust to the new load. However the worst case total instantaneous voltage flicker is seen due to the change from steady state voltage at the generator immediately before and immediately after the unit is disconnected from the system. [9]

Another example of unacceptable voltage flicker has been shown in Fig. 4. Here, a maximum voltage flicker for a full load rejection of a DR is shown. The voltage profile is developed from two study cases. The first case is a voltage profile obtained from minimum load and maximum generation. In this case it is noted that the line regulator is bucking the voltage from 125.8 to 122.7 volts (2.53% buck). The second case is a voltage profile with no generation and the regulators blocked at the position of 123 volts for the substation regulator and the line regulator blocked for the same 2.53% as in the first run. The result is a voltage flicker of 8.6 volts which is larger the acceptable level of 6 volts.

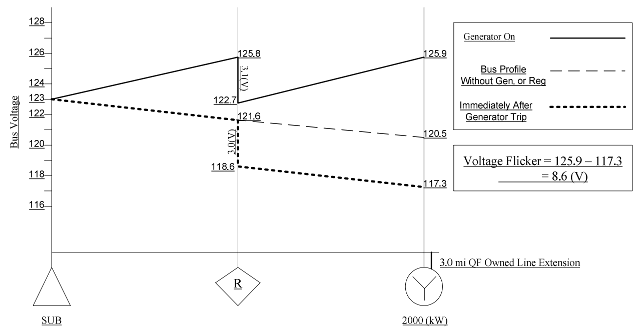


Fig. 4 Minimum Load Voltage Profile

D. *Transformer Replacement*: Transformer replacement criterion used by major utilities due to overloading is different than the criterion suggested by Rule 21 for integration of DR. Rule 21 states that a transformer must be replaced when the aggregate size of DR exceeds the nameplate rating of the transformer. However, PG&E allows overloading of the distribution transformers to over 140% of their nameplate ratings. It has been suggested that same criterion should be used for transformer replacement whether the overload is caused by DR integration or by loading. This issue is currently under investigation by the Rule 21 technical committee.

E. *Ferroresonance:* During islanding conditions ferro resonance can occur with DR acting as the driving source in the circuit. The ferroresonance effects can result in significant overvoltages where peak voltage can reach 3 to 4 per unit [11]. This type of ferroresonance can occur with both induction and synchronous generators, and it can occur with all three phases connected. There are four conditions necessary for DR islanding ferroresonance to occur:

1. The generator must be operating in an islanded state.
2. The generator must be capable of supplying the island load.
3. Sufficient capacitance must be available on the island to resonate (typically 30-400% of the generator rating).
4. A transformer must be present on the island to serve as the non-linear reactance [12].

VI. IDENTIFICATION OF AREAS IN NEED FOR RESEARCH

One challenge to DR interconnection is that the electric grid was not designed to accommodate generation at the distribution level. The addition of DR involves two-way distribution of power where a DR could send power back into the distribution system thereby causing relay desensitization, unacceptable voltage or flicker conditions, unintentional islanding, or undesirable ferroresonance conditions. Existing grids will need to be evaluated through system impact studies to determine whether they should be remodeled or they are suitable to accommodate DR interconnection Better justification based on engineering analyses is required to establish methods and procedures that have verified applicability for system impacts, understanding, and mitigation for accommodating increasing use of distributed resources. The advanced utility distribution system of the future known as the “smart grid” should be capable of extracting the full benefits offered by DR for both the DR owner and for other customers of the distribution system.

Although creation of national standards such as the IEEE1547 has made significant improvements in acceptability and uniformity of DR interconnections, further research and development in this area seems inevitable. Further revision of interconnection criteria, identification of smart grid attributes, and formation design criteria for grids of the future are among the areas in need of further studies and research. Future distribution systems need to have the following key capabilities to exercise the full advantages of smart grid and DR capabilities:

a) Enhanced technology features;
b) System impact studies where modeling, simulation, and real-time comparative analyses and operations;
c) A layered control system that satisfies the needs of the customers and loads, the local distribution system, and the transmission grid;
d) A well-defined hierarchy of priorities in the control logic;
e) A protection system that will accommodate routine two-way power flow with localized generation/storage;
f) Ability to rapidly change configuration, island, re-align, and start and stop generation.

VII. Concluding Remarks

In order to prepare the electric power system for smart grid load management and DR interconnection, well established criteria for planning /design, system protection/ reliability, and power quality must be maintained throughout the electric power system.

DRs will prove to have great benefits to the electrical power system although; the electrical distribution system needs to evolve in several important ways. A complete systems approach must be determined which addresses systems integration in order to fully understand and alleviate the undesirable impacts of DR interconnections.

Further development of DR integration can be accomplished despite lack of: (1) universally accepted approaches to systems impacts, (2) comprehensive analyses to account for grid modernization with distributed resources; and (3) the prerequisite qualification of modern interconnection systems. Satisfying these deficiencies will establish more effective development, planning, building, operating, and maintaining of the modern grid that includes DR. [10]

VIII. Acknowledgment

The authors gratefully acknowledge and appreciate the support of Mr. Mike Gravely of California Energy Commission and Dean Emir Macari of California State University, Sacramento on this project.

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X. Biographies

Mohammad Vaziri received BS EE- 1980, MS EE -1990, and Ph.D. EE - 2000 degrees form UC, Berkeley, CSU, Sacramento, and WSU, Pullman WA, respectively. He has 22 years of professional experience at PG&E, and CA ISO, and over 14 years of academic experience teaching at CSU Sacramento, CSU San Francisco, and WSU Pullman. Mohammad has authored and presented technical papers and courses in US, Mexico, and Europe. He is a senior member of the IEEE and serves on various technical committees. Currently, he is a Senior Consulting

Engineer at PG&E, and a part time faculty at CSU Sacramento and San Francisco. Dr. Vaziri is a registered professional engineer in the state of California, and his research interests are in the areas of Power System Planning and Protection.

Suresh Vadhva received BS - 1974, MS -1976, and Ph.D. - 1982 degrees form University of Tulsa, University of New Mexico, respectively. Currently he is Chair and Professor of Electrical & Electronics Engineering department and Computer Engineering Program Coordinator at California State University, Sacramento. He is also Associate Director of Research at the California Smart Grid Center, Sacramento. He is member of organizing committee and financial chair for IEEE IRI 2008 -2010 conferences. Previously he was chair of Computer Science Department at the University of Montana.

Steve Ghadiri received BS EE- 1979 from CSU, Sacramento. He has 27 years of professional experience with various Departments of the State of California, among which are the Transportation, General Services, Electricity Oversight Board, and CEC. He is currently at California Energy Commission, Division of Technology Research and Development. Mr. Ghadiri a member of the IEEE and is a registered professional engineer in the state of California since 1986, and his research interests are in the areas of Distributed Energy Resources and their interconnection to the grid.

Charles Hoffman received BS EE – 2009 from California State University, Sacramento and is currently pursuing his Master's in EE from California State University, Sacramento. His area of interest is Power System Protection.

Kunjal Yagnik received the B.E. degree in Electrical Engineering from the Gujarat University, India, in 2007 and is currently perusing M.S. in EE with major concentration in Power Systems from California State University-Sacramento. Since 2009, he has been an Engineering intern at California Independent System Operator, and working on the renewable integrations in the C