Application of Islanding Protection for Industrial and Commercial Generators – An IEEE Industrial Application Society Working Group Report

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Purpose Statement **– "The purpose of this Working Group is to produce a document that discusses issues associated with the islanding of an industrial or commercial facility power system where a synchronous generator operates in parallel with the utility source."**

Abstract **– Many owners of Distributed Resources such as synchronous Industrial Plant or Commercial Facility Generators (ICG) are concerned about the requirements for protective relaying when connecting to a local utility. The connection may only be for a short transfer time of a few seconds during paralleling for periodic testing. A tendency is to look at the consequences of just their own ICG trying to serve a much larger utility load without considering that there may be other ICG connected to the same circuit. The power rating of an ICG is not important when considering protective relays required, because several small engine generators of 100 kW or a single larger ICG of 10.0 MW could form an island. Thus, all ICG connected to an electric power system usually are required to have the same protection in place at their point of common coupling.**

Different scenarios of islanding operation are presented, such as: Is it necessary to enforce separation of loads that are outside the premises of the owner of the energy source, while retaining service to loads within the owner's premises, or is it acceptable to simply shut down the ICG until the grid can be restored? A basic step in addressing islanding protection is to have a clear expectation of what is supposed to happen when an island is created. This paper elaborates on the proper required protection and how its operation will prevent undesired consequences to the ICG owner, the utility and to the general public.

The paper also discusses actions that take place when the utility supply is disrupted creating an islanding condition, and states reasons why protection required by regulatory agencies, local utilities and documents such as IEEE Standard 1547 "IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems" are required of an individual ICG. Consequences of not having the protection in place can permit damage to the generator and/or its prime mover, plus be a hazard to public safety. Examples of these consequences are given. This paper will provide a clearer understanding to ICG owners of why they are required to have specified protective equipment in place.

Index Terms – Distributed Resources, Interconnect, Islanding, Point of Common Coupling, Power System Protection, and Synchronous Generators

I. INTRODUCTION

Today there is much interest in connecting various sources of electrical energy, typically described as Distributed Resources (DR), to electric power systems. Much of this interest is due to deregulation of the electrical energy industry that has driven development of new industry standards such as IEEE Standard 1547 [1]. Many Industrial and Commercial power users have synchronous DR ranging from stand-by generator sets that may operate in parallel with the utility for only a few minutes each week or month during closed transition for testing purposes, to parallel operating generators that have their power output dispatched by grid operators. Other forms of DR such as micro turbines, fuel cells, wind turbines, photovoltaic arrays and other forms of energy conversion may also continually operate in parallel with the utility.

At times, owners of Industrial Plant or Commercial Facility Synchronous Generation (ICG will be used to denote either individual or multiple synchronous generators throughout this writing) question the necessity of all the protective relaying and control equipment required by a state regulatory commission at their Point of Common Coupling (PCC) with a utility, because they feel that their individual synchronous generator is too small to maintain load dumped on it by

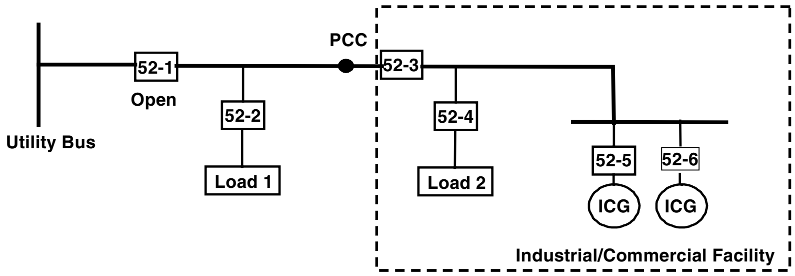

Fig. 1. Isolating a subsystem containing both Industrial/Commercial and utility loads

islanding conditions. Nevertheless, if multiple DR and/or ICG are connected to a utility circuit in the area, the total of the multiple power sources may be enough to sustain load during islanding conditions caused by a fault or abnormal conditions on the utility system. To provide owners of ICG (and other DR owners) a better understanding of protective elements that may be required by a state regulatory commission to ensure reliability to third party customers and safety to utility workers and the general public during these conditions, the following issues will be addressed:

- What is an islanding condition, either intentional or unintentional?
- How do generators and their prime movers react to islanding conditions?
- What impact will interconnect transformer configuration have on protection requirements?
- What are the consequences to my generator or prime mover if I do not have the required equipment in place at the intertie point?
- What is the function of protective elements required by regulatory agencies and why are they required?

II. What Is An Island?

A. Islanding Defined

Islanding is defined as "A condition in which a portion of the utility system that contains both load and distributed resources remains energized while isolated from the remainder of the utility system." [2]

In 2003, there were four widely publicized events in which large areas of the electricity grid failed (in Scandinavia, Italy, the UK and the US). There were untold additional events in which localized grid failures resulted from tripping operations of circuit breakers at the transmission, sub transmission or distribution level. While there is no way to quantify the number of ICG applications that may have been associated with these events, it is obvious that in any such event, ICG applications may be within the portion of the grid that is isolated or islanded by the failure.

Normally, it is undesirable for generation sources to serve loads within the island that are not owned by the entity that owns these sources. There are valid technical reasons for this prohibition, as well as commercial and legal concerns. For example, referring to Fig. 1, if circuit breaker 52-1 opens or if the Utility Bus loses voltage for some reason, an islanding condition results. The ICG generators will be connected to the Load 2 (intended) but also to Load 1 (unintended) and perhaps the utility system beyond the utility bus. Because Load 1 is a direct customer of the host utility, a means must be established to separate the ICG sources from Load 1 and the Utility System. The concern is that generation from sources, such as the ICG, other than under the control of the grid operator, may output voltage and frequency beyond limits specified by state regulation. Voltage and frequency swings may damage that customer's equipment.

A solution is to provide circuit breaker 52-3 at the PCC, with protection and control devices to detect the islanding condition and open it, so the ICG will only supply Load 2.

It might be noted, however, that serving Load 1 is the subject of considerable debate. As technology evolves and the commercial and legal issues are resolved, the current prohibition against supporting such loads from islanded ICG may change. Even utility companies responding to requests for greater reliability from key customers are intentionally placing ICG or other types of DR as close as possible to the customer's service to provide redundant, independent energy sources for reliability purposes. Considerable thought, engineering and coordination with the host utility company will be required. An example is: If utility circuit breaker 52-1 includes a reclosing relay, allowing reclosing will do serious damage to an ICG. The ICG should be separated before the utility begins automatic reclosing on the feeder with the ICG. Transfer tripping or special high speed protective relaying must be employed at the PCC to open circuit breaker 52-3 before the first reclosure occurs. This situation is discussed in Section VI (G).

B. Islanding Boundaries

How can it be determined that an islanded condition has been created? The challenge is to provide an unequivocal means of detecting that an island has been created. This requires more than just voltage and frequency protection elements at the PCC. In

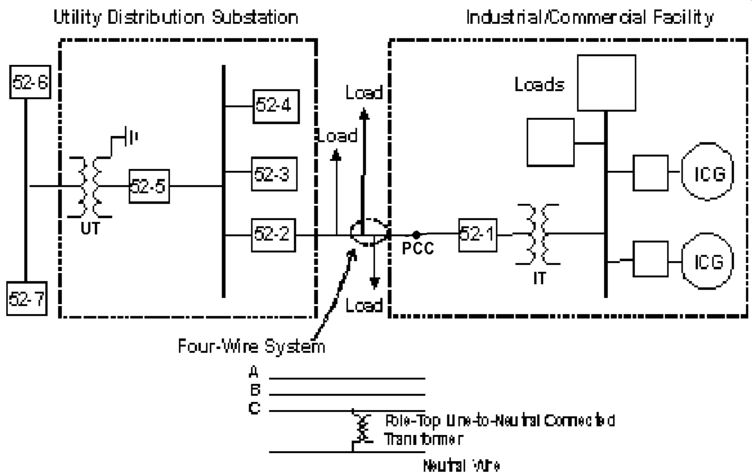

Fig. 2. Expanded System Island

Fig. 1, tripping of circuit breaker 52-1 either for fault conditions, planned opening or inadvertent opening creates an island involving the two loads and two ICG sources. Capturing the status of an auxiliary contact from this circuit breaker provides useful information, but there are many other points further back into the utility grid where circuit breaker tripping or other events can create islands. Thus, the status of the single circuit breaker 52-1 is not complete and conclusive evidence that a localized island has been formed.

Fig. 2 shows that an expanded system island could be formed by the opening of circuit breaker 52-5 or circuit breakers 52-6 and 52-7, which adds the loads on feeders 52-3 and 52-4 to the island with the two ICG as the sources. While the expanded island will add more load to the ICG, if there are additional ICG on the other feeders it is feasible that together they could support their own loads as well as the utility loads. Therefore, expanded islands will need protection such as directional overcurrent or impedance relay protection in addition to the basic voltage and frequency protection at each PCC. This subject is discussed in Section VI.

III. HOW DO GENERATORS REACT TO ISLANDING CONDITIONS?

Synchronous generators are the most commonly used machines for converting mechanical energy into electrical energy. Such generators are designed to run at constant (synchronous) speed that corresponds to the grid frequency and the number of poles.

Hence, frequency-measuring devices will give an indication of generator speed.

Synchronous generators can be classified in accordance with their cooling methods, pole arrangements (salient and non-salient), and excitation system (static and rotating exciters). However, in general, they all consist of a rotating DC field winding (Rotor), an AC armature winding (Stator), and a mechanical structure, which includes cooling systems, lubricating systems and other auxiliaries.

In a generation or cogeneration configuration, generators convert mechanical energy into electrical energy and "push" such energy into the interconnected electric system (the grid). In typical industrial or institutional in-plant generation, there are many possibilities of one or more generators islanding with some assigned load. To evaluate the islanded system dynamic behavior, appropriate generator modeling is necessary. Several textbooks discuss the modeling of a generator for the purpose of evaluating the impact the occurrence of "transient" phenomena such as "islanding" of such generators would have, or evaluating them in abnormal system conditions, such as "local area system oscillations" or system adjacent faults. With the development of user-friendly affordable computer programs that simulate system dynamic behavior, modeling generators and grids is no longer a tedious engineering task. The purpose of modeling a system would be to examine the impact of islanding on both sides of the PCC with particular attention to the island that separates from the larger portion of the power system. It is important, however, for the system engineer to understand the essence of modeling to avoid conceptual mistakes in interpretations of computer program results. A generator in a power system can be analyzed as three blocks or systems connected together: mechanical system, coupling field and electric system.

In a steady state, what goes into the block in a mechanical form comes out from the other end in an electrical form (after deducting the losses). With a sudden change in either end, the system balance will be disrupted and will try to establish a new balanced state. Islanding is such an example of a possible disruption. An island is created when a portion of the electrical system containing electrical generator(s) and electrical load(s) separates from the utility power system. Since the islanded portion is no longer operating in parallel with the utility system, the ICG governor(s) and voltage regulator(s) must control the voltage and frequency of the island. At the moment of islanding, there could be one of three possible scenarios:

a. If the island loads are larger than the generation, the electric energy demand will exceed the mechanical energy input; the generators will tend to slow down causing an underfrequency status.
b. If the island loads are less than the generation, the mechanical energy will suddenly exceed the electrical energy, which would cause a momentary speed up and an overfrequency status.
c. If, as in some rare occasions, the island electric loads and generation are almost equal, the change in the prime mover speed will be minimal, so the island frequency and voltage will hardly change.

Because controlled changes in the mechanical system are slower than the sudden change in the electrical system, a corrective action, such as closing a prime mover valve, may not be fast enough to avert an over-frequency trip on the generator system. However, modern controls allow very fast governor control, which may be fast enough to allow the generator to remain online when an islanded load is smaller than the generator capacity. In the case of islanding with a load that is larger than the generator capacity, a load shedding scheme must be implemented in order to re-establish load/generation balance in the island.

IV. Reaction of Prime Movers to Island Conditions

Islanding is detected primarily by frequency excursions. These frequency excursions are caused by the ability of the prime mover to change speed since it is no longer synchronized with the utility grid. The magnitude, rate, and duration of these frequency changes affect the ability to detect an islanding condition.

The behavior of the prime mover at this time is affected both by the inherent response of the prime mover to its controller, and to the mode of control in which it is operating. There are three basic modes of control during paralleled operation known as droop, fixed or constant power and load following output. Isochronous speed control is not one of the options while in the parallel mode, as the governor will be unstable since it cannot hold the generator frequency constant if the utility frequency varies.

A. Droop Mode Control

The slope of a governor response in a droop mode has a stable intersection with the fixed frequency of the utility while in parallel, so that the fuel admission to the prime mover will stay constant unless the fixed frequency of the utility changes. (Note that the term *fuel*, which is being applied to all prime movers, might be more properly called *energy*, since it may be in the form of steam pressure or water pressure, but admitting fuel to an engine is a widely understood concept.) If the utility frequency changes, the governor will admit more or less fuel in accord with the new intersection point, and the generator output changes accordingly. When separated from the grid generation, the governor will alter the fuel input as a function of the generator speed until its output matches the load remaining connected to the generator. That is, if the load is increased it will "bog down" the generator and the diminished speed will cause the governor to admit more fuel.

B. Constant Power Mode Control

If the generator prime mover is operating in a constant power output mode, there is essentially no governing action. If the islanded load is greater than its output after separation from the grid, the generator will slow down and the system will collapse.

C. Load Following Mode Control

If the generator set is operating in the "load following" mode, normally by holding export or import at the utility interface constant, it will change its output if the local plant load changes. However, if the generator becomes islanded with a portion of the utility load not exactly the same value for which the export control was set, the control will become unstable since it is open loop, and any feedback is positive instead of negative. The generator will either overspeed or shut down in an attempt to correct the amount of power being exported. If the control is regulating for import, the generator will shut down in its futile attempt to re-establish the import level.

Except in the unlikely event that the islanded load exactly matches the existing export (including a value of zero) the generator speed will change and be detected by a frequency relay. This will assume that such a frequency excursion is indicative of islanding and will trip the intertie breaker at the PCC, thus terminating service of the utility's loads and terminating the constant power or load following mode of control, or perhaps even the droop mode.

The rate of change of the generator speed after inception of islanding, while in the constant power mode or the constant import/export mode, will determine the speed of the relay action. In the droop mode it will also require a change in the connected load sufficient to change the operating speed to reach the set point of the frequency relay, either as a steady state or transient mode. Performance in the transient mode is a function of the governor capability and the inherent response of the prime mover to the governor's control.

D. Various Prime Mover Reactions

The controllers and governors are reactive devices. They must sense a change to initiate a correction. So even in the droop mode, there will be a transient excursion from the droop curve until this correction is accomplished. Various prime movers have various speeds of response as a function of inertia, fuel control, or combustion control. The response of a prime mover is best described as its ability to accept or reject steps of loading. The most familiar prime mover, the gasoline engine, is relatively good at both although it used to require combustion enrichment with the accelerator pump for rapid load pickup. The diesel engine has excellent load rejection because the fuel can be reduced quickly, but suffers from lack of combustion air on load pickup until the turbocharger can get up to speed. Naturally aspirated engines perform much better but have excessive size, cost, and air pollution. These machines have low inertia, and the H factor (or inertia constant) may be less than 1.0.

Gas fueled piston engines (natural or LPG) tend to be quite limited in load pickup and rejection. The control valves are often relatively slow acting, and there is a compressible column of fuel between them and the cylinders.

The single shaft gas turbine has a history of good load acceptance and rejection in that the majority of the turbine loading is the compressor, which does not change with a change in the electrical load. However, recent lean burn turbines require critical adjustment to avoid combustion instability. Their scrubbers, if so equipped, also require fine-tuning. Inertia of these machines varies from medium to high, with H factors of 2.5 to 6.0. There are also one or two small machine designs with low inertia (H=1) on the market.

Steam turbines are at the mercy of the boilers for load pickup, and many larger units cannot tolerate the thermal shock of large load pickup. Smaller units supplied from a boiler with a good head of steam can be excellent at load pickup. Single stage and even smaller two stage (high pressure and low pressure) machines can reject full load without over speeding. This becomes more difficult on large units with multiple cylinders and reheat boilers, particularly if the inertia is low. However, these are not normally found in industrial plants.

Hydraulic turbines (waterwheels) have poor response because the inertia of the water column precludes rapid changes in its flow. They have excessive overspeed on load rejection so they are quick to trip if islanded.

Micro-turbines would be expected to have a fairly good response, but this has not been confirmed as a general characteristic. These variable speed machines have to change speed to pick up load. Their size precludes the ability to support much load during islanding, so they trip quickly on under frequency and undervoltage relaying.

V. Impact of Intertie Transformer Connections on Islanding Protection

A major function of interconnection protection at the PCC is to disconnect the ICG when it is no longer operating in parallel with the utility system. Smaller DR and ICG are often connected to the utility system at the distribution level, if the ICG voltage can be matched to the utility voltage. In the United States, utility distribution systems range from 4.16 to 34.5 kV, and are typically multi-grounded 4-wire systems. The majority of industrial facilities use either three-wire solidly grounded, or three-wire resistance grounded systems. The use of multi-grounded four-wire configuration by utilities allows single-phase, pole-top (or padmount) transformers, which typically make up the bulk of the feeder load in rural areas, to be rated at line-to-neutral voltage. Thus, on a 13.8 kV distribution system, single-phase transformers would be rated at 13.8 kV/$\sqrt{3}$ or approximately 8 kV as shown previously in Fig. 2 for a typical feeder circuit.

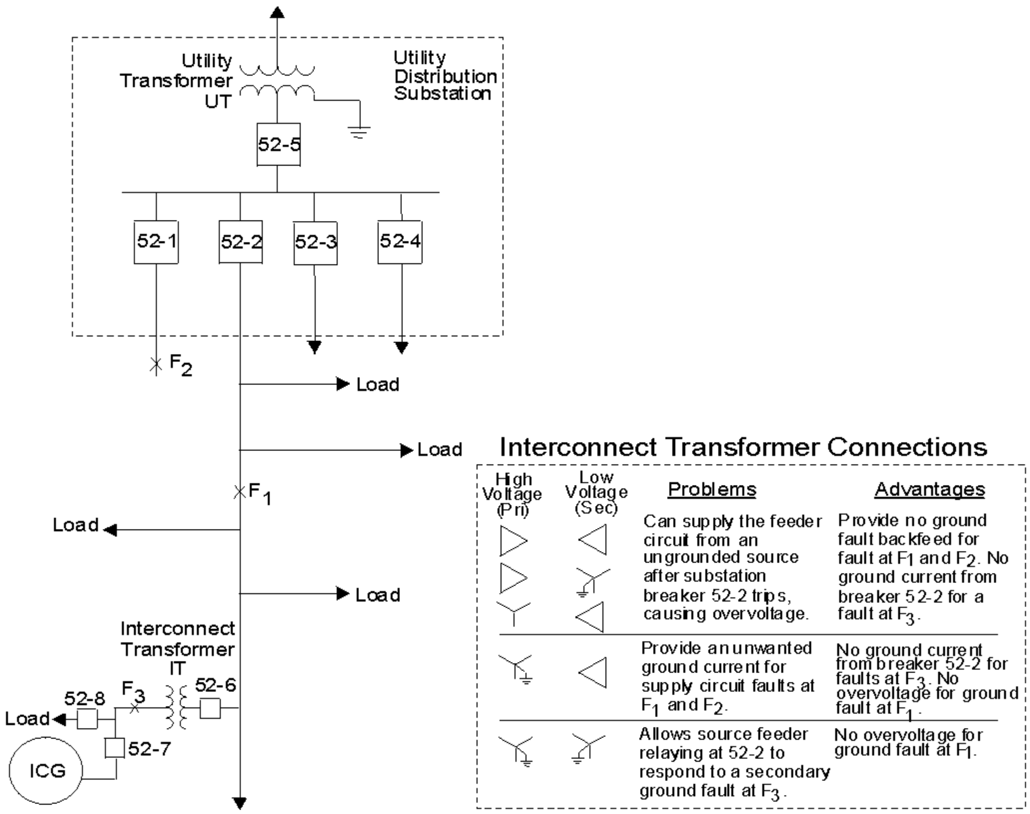

Fig. 3. Interconnection Transformer Protection Delta (Pri)/Delta (Sec), Delta (Pri)/Wye-Grounded (Sec) and Wye-Ungrounded (Pri)/Delta (Sec) Interconnect Transformer Connections

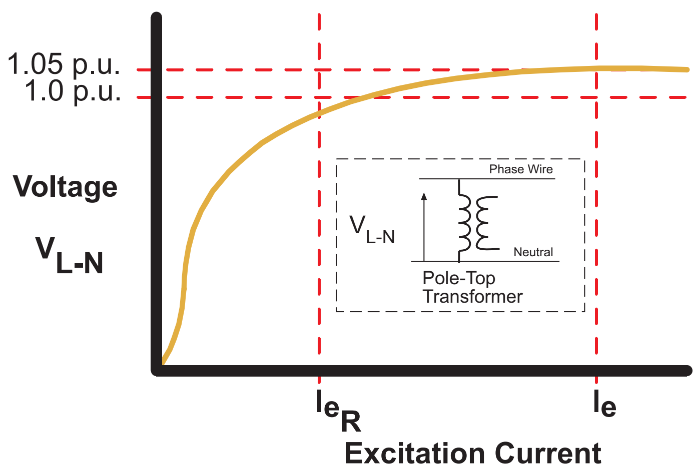

Fig.4. Saturation Curve of Pole-Top Transformers

Five transformer connections as shown in Fig. 3 are possible to interconnect between the utility system and the Industrial or Commercial system [3]. Each has advantages and disadvantages. The following provides some of the advantages/problems associated with three of the connections.

A. Delta Primary - Wye-Grounded Secondary Considerations

The transformer Delta – Wye Grounded connection is the most desirable and commonly used connection for industrial and commercial facilities [4]. The primary system is normally solidly grounded upstream from the interconnect transformer IT by the utility transformer

UT as shown in Fig. 3. This connection serves to isolate the facility system from ground faults on the solidly grounded utility system. This presents no problems if the facility has no generation or never intends to operate in parallel with the utility. However, when the facility includes ICG connected at the IT transformer secondary voltage, the wye point needs to be resistance grounded to reduce fault damage to the generator during ground faults [5] [6].

From the utility standpoint, there are concerns with the Delta (Pri) - Wye-Grounded (Sec) connection. Protective relaying and control must be provided to quickly disconnect the facility from the utility feeder at the PCC. Otherwise, the ICG system will back feed the utility line, which can be a danger if human contact is made with the line. Also, if utility system grounds no longer ground the line, it will be an energized ungrounded circuit, which is subject to overvoltages.

Furthermore, if the utility feeder also must serve residential customers, then a major concern to facilities with ICG is illustrated in Fig. 4. After substation breaker 52-2 of Fig. 3 is tripped for a ground fault at location F_1, the utility power transformer secondary winding solid connection to ground is lost. On distribution systems, pole-top transformers and/or padmount transformers are typically connected L-N (line-to-neutral, the neutral being multi-grounded) and would be subject to an overvoltage that will approach Line-to-Line voltage. This occurs if the ICG does not separate from the system. The resulting overvoltage will saturate the pole-top transformer, which normally operates at the knee of the saturation curve as shown in Fig. 4 [3]. For this reason, circuit breaker 52-6 must have relaying and control to open it immediately upon loss of voltage from the utility system. This allows the facility generation to supply selected islanded loads and to protect the utility system by disconnecting it from the ICG generation.

Some utilities may permit use of ungrounded inter-connection transformers only if a 200% or more overload on the generator occurs when breaker 52-2 trips. During ground faults, this overload level will not allow the voltage on the unfaulted phases to rise higher than the normal L-N voltage, avoiding pole-top transformer saturation.

Thus, relaying to detect loss of voltage from the utility system for all possible causes must be provided at the Interconnect Transformer or PCC to trip/and block closing of circuit breaker 52-6. This must be done quickly, before the utility circuit breaker can reclose. Fast tripping also helps to maintain stability of the loads islanded with the ICG.

B. Wye-Grounded Primary - Delta Secondary Interconnect Transformer Connections

The major disadvantage with this connection is that it provides an additional ground fault current source to faults at F_1 of Fig. 3. Also, it requires the addition of a grounding transformer and circuit breaker to the secondary system, to permit the recommended resistance grounding of the ICG and motor buses.

When the ICG is off-line (generator breaker 52-7 is open), zero sequence ground fault current still will be provided to the utility system if the interconnect transformer remains connected. The interconnect transformer acts as a grounding transformer with zero sequence current circulating in the delta secondary windings. This additional ground current source out on the feeder may desensitize the feeder ground relay in the utility substation. In addition to this problem, the unbalanced load current on the system, which prior to the addition of the ICG transformer had returned to ground through the substation transformer UT's neutral, now splits between the utility transformer and interconnect transformer neutrals. This can reduce the load-carrying capabilities of the ICG transformer and create problems when the feeder current is unbalanced due to operation of single-phase protection devices such as fuses or line reclosers. Even though the wye-grounded/delta transformer connection is universally used for large generators connected to the utility transmission system, it presents some major problems when used on 4-wire utility distribution systems. The utility and facility should evaluate the above points when considering use of this configuration.

C. Wye-Grounded (Pri)/Wye-Grounded (Sec) Interconnect Transformer Connections

The major concern with an interconnection transformer with grounded primary and secondary windings is that it provides a path to undesirable ground fault locations. If the utility ground feeder relays are set at very low pickup settings at the substation, they may respond to a ground fault on the secondary of the IT transformer at F_3 in Fig. 3. When the ICG is on line, it provides both phase and ground fault current to the utility system faults which can change the sensitivity and operate time of the relaying at the utility substation, depending on the location of the fault.

D. Intertie Transformer Summary

An often-used intertie transformer connection for industrial and commercial facilities is the Delta (Pri) - Wye-Grounded (Sec) connection with secondary resistance grounding to reduce ground fault current damage to motors and generators.

The ownership of the interconnection transformer, plus selection of its connections and its grounding method plays an important role in how the ICG will interact with the utility system and the selection of protective relaying. The ownership and control of the circuit breaker at the PCC also must be determined. There is no "standard" transformer connection for all applications.

All transformer connections have advantages and disadvantages; thus, selection of the intertie transformer connection needs to be addressed by the utility and the facility with the ICG at the onset of a project to avoid later delays. The choice of transformer connection also has a related impact on selection of required interconnect fault protection. Some states have interconnect transformer requirements in their interconnection guidelines, which aids in reaching agreement on the interconnect transformer connection.

VI. Function of Protective and Synchronism Control Elements for Islanding Operation

Location of islanding protection for synchronous generators depends on whether the generator is to continue supplying any designated load while separated from the utility. If so, in the following discussions the protective relay should be located so that it will trip the circuit breaker at the Point of Common Coupling (PCC) of the two systems. If facility load is not to be supplied by the ICG, thus shutting down the facility, then the protection should operate the ICG circuit breaker as quickly as possible.

A common practice of utilities is to use transfer tripping to open the PCC any time the utility circuit breaker is opened [7]. This includes fault and abnormal system conditions plus manual or remote switching operations. The protective relay elements listed in Table 1 and shown in Figs. 5 and 6 are discussed in the following text and can be required as backup to a transfer trip system. Cost of transfer trip and its communication channel to the ICG on a utility circuit is expensive but provides an effective primary method of preventing islanding occurrence.

Most modern multi-function numerical relays containing the following elements have an advantage over discrete solid-state or electromechanical relays of being able to be internally switched to different settings based on external input conditions or logic programming and element activity in the relay.

The basic minimum protective relaying for islanding or loss of parallel is a scheme using under and overvoltage (27/59) relaying and over and under frequency (81O/U) relays set in accordance with state regulatory specifications for the window of acceptable band limits of voltage and frequency to the utility customers.

A. Under and Over Voltage 27/59

When an islanding condition occurs, the ICG facility most likely will experience a momentary drop in voltage at the point of intertie. Depending on the available generation, the voltage level could recover slightly and then continue to drop or it could simply continue to drop until the system becomes unstable and collapses or goes black.

Instantaneous undervoltage relays (27) can sense this drop in voltage when the supply line has tripped and can provide fast separation from the utility. This becomes advantageous when the utility is using high-speed reclosing. Normally, this relay is set to a very sensitive level to detect and provide separation as quickly as possible. However, the disadvantage with this approach is that problems elsewhere on the utility system may produce a voltage drop at the ICG sufficient enough to cause the relay to operate. Therefore, the pickup should be set such that these nuisance operations are eliminated or at least kept to a minimum. An alternative is to use a time delay operation to allow the voltage to recover.

Time delay undervoltage relays can be used to reduce the nuisance operations as described above or for applications where the generator is capable of isolated operation. This can be achieved with a pickup setting of 90 to 95% of nominal voltage and a time delay of one second [8]. Of course, in eliminating nuisance operations, the primary disadvantage of inserting a time delay is that separation is delayed. This could result in loss of stability for the ICG or possibly severe equipment damage.

The undervoltage (27) element will operate for a time-delayed decrease in voltage if the generator does not have the capacity to sustain load after opening the utility circuit breaker. A time delayed overvoltage (59) element will operate for overexcitation of the generator that can occur under light load conditions after opening the utility breaker.

B. Frequency (81O/81U)

When an island condition occurs, the system frequency will drop if the generator cannot support the required load. It is necessary to shed load or to remove the ICG as quickly as possible when this happens. Frequency relays can achieve separation using any of three different methods – *underfrequency, overfrequency, rate-of-change of frequency*.

TABLE I
INTERTIE PROTECTION AND RESTORATION ELEMENTS

Intertie Protection Objective for Islanding	**Protection Element Function Numbers**
Detection of loss of parallel operation with utility system	27/59, 81O/U, TT**
Fault back feed detection, Phase	51,50 51V,67 or 21
Fault detection, Ground	51N, 67N, 87TG
Unbalanced system conditions	46, 47
Abnormal Power flow detection	32
Restoration synchronism to permit parallel or momentary operation	25
** Transfer Trip from Utility	

The amount of frequency deviation will vary depending on the generator and the system. Today, most frequency relays include multiple setting levels to coordinate blocks of load to be shed. These schemes typically will expand the amount of load tripped with increasing frequency deviation. A deviation of ±5% is considered an extreme condition where the ICG should be separated from the utility. On facility systems not using a load-shedding scheme, the underfrequency relays (81U) should be set with a minimum time delay.

Overfrequency relays (81O) are used on ICG systems that are capable of isolated operation and especially on synchronous machines where the governor controls can push the speed above the acceptable maximum levels. Overfrequency can occur when the islanded load is much smaller than the ICG capacity. Overfrequency also can occur when load is interrupted on an adjacent utility circuit fed from the same utility bus. Overfrequency relays should be set for a maximum pickup of 60.5 Hz and a maximum time delay of 0.1 second.

Relays measuring the rate-of-change of frequency (81R) have been used sparsely over the past 20 years; however, their application and acceptance for superior operation is growing significantly. As their name implies, these relays measure the rate at which the frequency is changing. An ICG operating in an unstable islanding condition will experience a greater rate of frequency drop than that expected from other utility system problems. As a result, the rate-of-change of frequency relay can distinguish somewhat a severe frequency drop caused by an islanding condition from other conditions. Therefore, there is no need for a time delay to be inserted, allowing instantaneous operation and separation.

Consequences to the ICG owner of not having the under and over voltage and under and over frequency protection can be damage to the generating unit from exceeding its thermal limits under sustained overload conditions. Also, off frequency operation can cause vibrations to turbine blades leading to mechanical failures. Another consequence could be lawsuits from the utility customers wanting payment for damaged equipment because the ICG did not supply power within the Regulatory Commission window of operation for voltage and frequency.

C. Fault Detection (50/51, 51V, 67, 67N, 21)

The next most important protective elements are those detecting short circuits or faults on the utility system that can be backfed by the ICG during an island condition. These are necessary to protect the public and utility workers from unsafe fallen power lines [9]. Fault detectors must be able to detect faults on the longest length of circuit the utility will have connected for both normal and islanded conditions and also for load transfer or emergency conditions. The protection must be time coordinated so the fuse or recloser closest to the fault will operate first and keep the customer outage area to a minimum.

Fault back feed detection is accomplished with instantaneous and time overcurrent relays (50/51), directional overcurrent (67) relays or impedance (21) relays. The 50/51 non-directional overcurrent protection will operate for fault current flowing in either direction through the PCC. Directional overcurrent (67) protection may be needed to prevent opening the PCC circuit breaker for faults on the local plant system when the ICG operational mode is to intentionally supply local loads when the utility source is open.

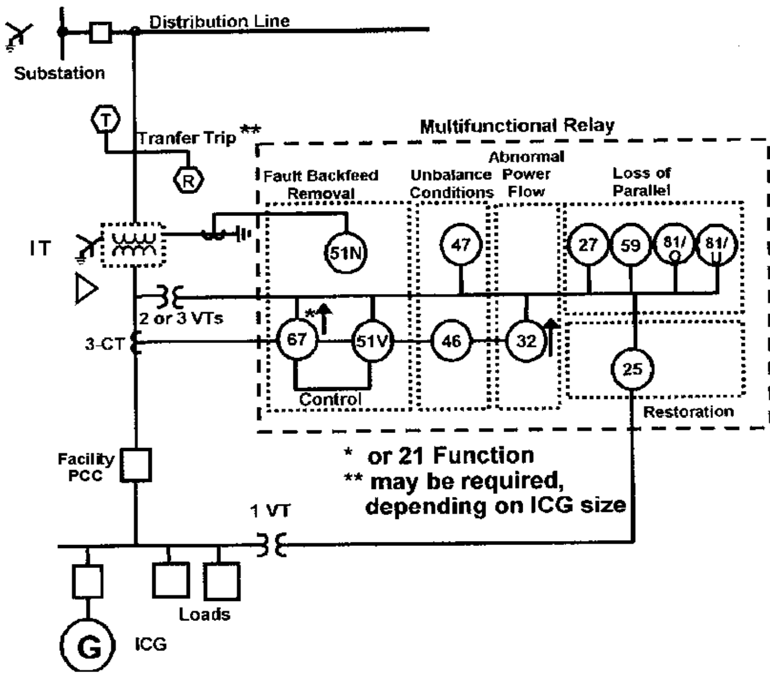

Fig. 5. Typical Protection for Moderately Sized ICG with Interconnection Transformer

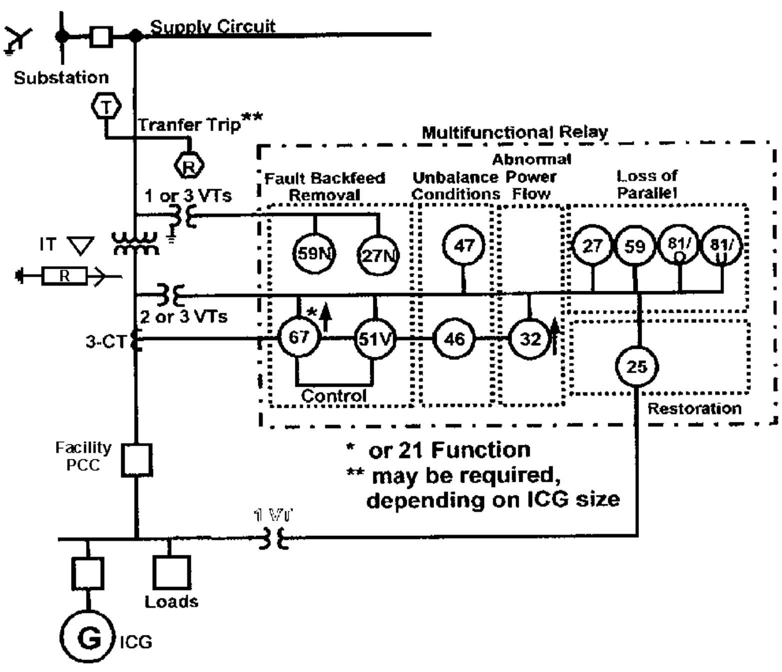

Fig. 6. Typical Protection for Moderately Sized ICG with Ungrounded Primary Intertie Transformer

The voltage polarized directional overcurrent relays (67) are directionalized primarily to operate for faults only on the utility system. Impedance relays (21) may be required when the PCC terminates at the low voltage side of the utility transformer such that protection must look through or include the impedance of the transformer and the connected circuits on the high voltage side of the transformer [10]. If the transformer is a delta high voltage side and wye low voltage side, a special zero sequence overvoltage detector (59N) in Fig. 6 connected on the high voltage side of the transformer will be needed to detect single phase to ground faults on the high voltage side. These faults are undetectable by overcurrent or power elements looking from the low voltage side of the transformer.

D. Voltage-Dependent Overcurrent (51V)

Voltage dependent overcurrent relays come in two types – voltage-controlled and voltage-restrained. These relays will sense faults on the system and trip based on the sensed terminal voltage. The voltage drop at the ICG intertie point to the utility will vary depending upon where the fault occurs. The farther away from the ICG, the less the voltage drop will be. Therefore, for a fault on the connected line to the ICG, the voltage most likely will drop significantly at the time of the fault. In addition, when the utility trips the line, the voltage will go to zero instantly if the line load is much greater than the ICG capacity.

Voltage dependent relays sense the fault current and adjust their pickup level based upon the voltage measured. Voltage-controlled relays operate like a switch. When the voltage is reduced to a specified level, the relay will allow the operation of the overcurrent function. Therefore, the sensed voltage must be below the relay's voltage set point and the fault current must be above the current set point.

The voltage-restrained overcurrent relay adjusts its current pickup as a function of the voltage level deviation from nominal. Most relays will operate for a current at 100% of setting when the voltage is at nominal (i.e. 120V). When the voltage decreases, the current pickup reduces in proportion to the decrease in voltage. For example, if the voltage drops to 60% of nominal (or 72V), the pickup of the current element will be reduced to 60% of its nominal setting. Assuming a nominal pickup setting of 2.0 amps, the adjusted pickup would be 1.2 amps.

The main disadvantage of the voltage dependent overcurrent relay elements is the timing characteristics increase the time to separate from the fault or abnormal condition.

Two of the consequences of the ICG not having the utility specified fault protection are exceeding the thermal limits of the generator and lawsuits from the general public for failing to interrupt fault conditions in a timely manner.

E. Directional Power Relays (32)

Power relays (32) are another type of protection that may be required to detect abnormal power flow, especially if the ICG is to operate in parallel with the utility. When an islanding condition occurs, the power produced by the ICG will flow from the ICG to the remaining load on the island. This power flow can be measured at the point of intertie. When the power flow to the utility exceeds a specified level, the directional power relay will initiate tripping and separation from the island. The pickup setting should be above the maximum level of export power if the ICG contracts to supply or export power to the utility customers. A slight time delay will allow for power flow regulation due to system faults.

Power relay elements typically use voltage and current quantities that are essentially in phase to detect real power (watts). These quantities are stable and do not vary greatly over a few cycles as a fault condition does. Because they are looking for watts to make them operate, they are not a good means of fault detection. Directional overcurrent fault detectors use a quadrature polarizing design such that the polarizing voltage is lagging the phase current by ninety degrees. The voltage and current both will be fluctuating each cycle during the fault condition.

Consequences of not using a power element range from failing to open the PCC per contract requirements to giving away power to the utility.

F. Vector Jump Relay

In addition to the traditional means of islanding protection, another method has been initiated within the last few years. The *vector jump* relay provides protection for islanding conditions by detecting a significant phase displacement, or *vector jump,* within the measured voltage signal. As indicated in [11], when an island condition occurs, the ICG will experience a phase shift in its voltage signal. This phase shift characteristic is specific to the occurrence of an islanding condition. Other types of system abnormalities will not produce a waveform of similar characteristics. Therefore, this method provides quick detection of an islanded condition and fast separation but is difficult to coordinate, which may lead to excessive nuisance trips.

G. Synchronism and Closing Control

Utilities generally employ automatic reclosing of residential and rural feeders. Since most system faults are momentary in nature, automatic reclosing provides greater reliability to consumers and less down time. However, between automatic reclosing intervals, the ICG typically is no longer in synchronism with the utility system. Should the utility feeder automatically close with the ICG out of synchronism, severe damage could occur to the shaft, windings, bearings or other components of the ICG equipment. This risk of damage supports the need for quick separation from the utility. After separation by islanding detection elements, should the generator be able to maintain voltage and speed for the ICG facility loading, the high-speed separation can be advantageous for maintaining intentional facility islands with critical plant loads until synchronizing back to the utility.

An automatic synchronizing or synchronism check relay (25) is required to supervise the synchronism of the PCC breaker to the utility when restoring the intertie after a separation (see Figs. 5 and 6). This relay measures the voltage, angle and slip between the utility and the generator and permits closing of the PCC breaker only when the slip angle of the generator is within a safe closing angle.

The consequence of not having this restrictive control relay is that the generator could be closed in out-of-phase causing severe damage to the coupling between the prime mover and the generator. In very severe cases personnel in the vicinity of engine-generators have been injured from flying parts.

H. Unbalance Detection (46 and 47)

For larger generators, consideration should be given to applying negative sequence current (46) and/or voltage relays (47) as unbalance detectors. These relays detect severely unbalanced loads on the power system that can occur during single phase switching operations to transfer load or during the operation of fuses feeding large individual customers or blocks of smaller customers during storms.

A possible consequence of operating during unbalanced load conditions is exceeding the thermal limits of the generator.

VII. CONCLUSION

This paper has provided a definition of islanding and how an island's boundaries may be determined, reviewed how synchronous generators and prime movers react to islanding conditions, the impact of intertie transformer configurations on overcurrent protective relaying and protective relay elements to apply at the PCC for islanding situations. All of these different issues impact the protective relaying required for each unique ICG location. Islanding protection requirements can be conditional depending upon whether the island is unintentional or intentional. Different types of protection are required for these two situations, thus the cost of protection is much higher for some types of generators and prime movers. Islanding protection is based on the art of applying protective relay elements in accordance with regulatory agency requirements.

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