REPORT ON BACKUP GENERATION SYSTEM

FOR ARMED FORCES RETIREMENT HOME –

GULFPORT, MS

KOHLER PROJECT NO. SGP-1297

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Power Systems & Automation Design

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JULY 23, 2012

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1. SCOPE OF REPORT

Hood EE Consulting, PLLC was commissioned by Tampa Armature Works, Inc. on July 20, 2012 to investigate why the Schweitzer Engineering Laboratories SEL-300G relays on the two Kohler 2250 kW, 13.8 kV diesel engine generator sets at the Armed Forces Retirement Home in Gulfport, MS trip at about 43% of generator load. This report details the field investigation.

2. BACKGROUND

2.1 The two 2250 kW, 13.8 kV backup engine-generator sets have been installed and in operation for approximately one year.

2.2 The generators are shown on the Kohler drawings as being solidly grounded.

2.3 At the time of the field investigation, Generator No. 2 was down for repairs. The exciter PMG had been damaged, probably at the time a fault occurred in a potential transformer (PT) that was mounted adjacent to the exciter.

2.4 According to on-site personnel, when Generator No. 1 was started and loaded, the generator was tripped by the SEL-300G relay when load reached 43% of maximum, as indicated on the generator PLC/HMI. The trip targets indicated on the front of the SEL-300G were 40 (Field Failure) and 87 (Differential). The trip seems to have occurred when a certain large chiller motor was started. This has occurred repeatedly since the original installation. Even though one generator is supposed to be able to carry the entire facility load, one generator can't carry the entire load if it trips at 43% load.

2.5 It's not known who set the relays originally.

2.6 On July 20, a Mississippi Power Co. relay engineer reviewed events and settings on the SEL-300G, but didn't report any problems. A technician from Holland Industrial Services was also on hand on July 20 for testing Generator No. 2.

3. REVIEW OF RELAY SETTINGS AND CT CONNECTIONS

3.1 A review of the differential CT polarities revealed that the polarities for the CT's mounted on the neutral side of the generator were opposite to the required polarity. Kohler three-line diagram drawing No. SGP-1297, Sheet E6 shows the correct required connections. However, the CT's are physically mounted in the generator compartment with the H1 polarity side toward the neutral side, instead of toward the generator winding side, as shown on the drawing. Since the primary side of the CT was rolled, and the secondary side of the CT was not rolled, the currents were shifted 180^0 form the required polarity. The differential currents in the relay were adding, instead of cancelling each other, causing the differential relay word bits to pick up. I've found this same problem on two other similar Kohler installations.

3.2 Review of the relay settings revealed the following:

3.2.1 General Settings

3.2.1.1 The generator nominal voltage was set at 13.2 kV to match the utility voltage. Generator operating voltage was 13.4 kV to 13.5 kV.

3.2.1.2 Both settings groups were turned off (set to 0), but apparently the relay defaults to Settings Group 1 if both are turned off.

3.2.2 Settings Group 1

3.2.2.1 Neutral CT ratio – The neutral CT ratio was set to 20, even though there is no neutral CT.

3.2.2.2 25 (Sync Check) Elements – The maximum allowable difference in closing angles to allow synchronization was set at 20^0, which is unusually high. Also, the allowable voltage window for sync appears to be abnormally wide.

3.2.2.3 32 (Power) Elements – Reverse power elements were disabled.

3.2.2.4 40 (Field Failure) Elements – The Zone 1 field failure elements were set slightly different from SEL recommendations, and the Zone 2 element reach was significantly shorter than recommended. Possibly, correct generator reactance data was not available at the time of original setting.

3.2.2.5 50 (Instantaneous Overcurrent) Elements – Both phase and neutral instantaneous overcurrent elements are set. It's unusual to see instantaneous overcurrent elements on a generator, especially one in standby service. What's more unusual is that a neutral instantaneous overcurrent element is set, when there is no neutral CT. The ground instantaneous overcurrent element, which derives a neutral current from the three phase currents, is not set.

3.2.2.6 51 (Time-Overcurrent) Elements – The 51NP neutral time-overcurrent element is set to pick up at 20 amps primary current in the generator neutral. However, there is no neutral CT to provide this current input to the relay. The 51GP ground time-overcurrent element, which could derive a ground current from the three phase currents, is not set.

3.2.2.7 51C (Voltage Controlled Generator Backup Overcurrent Protection) Elements – Voltage controlled overcurrent was selected as the method of backup protection, and the torque control equation is entered as 27P1*!60LOP. However, 27P1 is the relay word bit for relay setting 27P1P, which is phase undervoltage pickup. Since open delta PT's are used, the phase undervoltage setting used in the torque control equation should be 27PP1 for the phase-to-phase voltage. Setting 21P1 is grayed out and not available for open-delta PT's. The torque control equation would not be satisfied, and backup overcurrent protection could not function. I would use 51V Voltage Restraint Backup Overcurrent Protection in this application.

3.2.2.8 59 (Overvoltage) Elements – Phase-to-phase overvoltage element 59PP1 is set at 132 volts, which is 115% of nominal voltage (15,180 volts phase-to-phase primary). This voltage is unusually high and would likely result in damage to the loads (especially lights and ballasts) and the generator if it persisted very long.

3.2.2.9 87 (Differential) Elements – The type of differential protection enabled is "T", which is applicable when a step-up transformer is included within the generator differential zone. Of course, there is no step-up transformer. I can't imagine why "T" would be selected, unless someone tried to gain access to some of the differential settings that are grayed out when "G" is selected. Possibly, this was done to attempt to keep the differential elements from tripping, when the actual problem was the incorrect polarity of the CT's in the generator compartment. Of course, this didn't help, and may have contributed to, the problem.

3.2.2.10 SELogic Variables – SV2 uses relay word bit 27P1, which should be27PP1, as described above.

3.2.2.11 Trip, Close, ER, Output Elements

3.2.2.11.1 Trip Elements – **The relay word bits for the differential elements (87U and 87R) were not included in the trip equations! Even though the relay appeared to trip on differential, it did not! There were always two targets illuminated on the relay, so I understand, and the other target (40) actually caused the trip. The 87 target was lit, but the 87 elements did not cause the trip contacts to close! In my opinion, the 87 elements were removed from the trip equations at the time of original startup to keep the generator breaker from tripping as soon as any load was picked up. The generator ran at low load. Then the field failure (40) elements caused the trip on increasing load. I didn't notice in the field that the 87 elements were not in the trip equation, since it did appear that they were tripping the breaker. It's difficult for me to comprehend that someone would disable the differential protection on a generator and not notify anyone about it. Since the 87 elements are now functioning correctly and will not trip unnecessarily, the 87 trip relay word bits should be inserted into the trip equation as soon as possible!**

3.2.2.11.2 Trip Elements – The trip equations are confusing, in that there are a number of items in the trip equations that aren't being used.

3.2.2.11.3 Output Contacts – Any trip that's generated by the SEL-300G causes a trip of the generator and shuts down the engine. I'm used to having certain functions only trip the generator breaker and not shut down the engine.

3.2.3 Communications Ports – Communications ports were set to the slow speed of 2400 Baud.

4. RELAY SETTINGS CHANGED IN FIELD AND CT WIRING CORRECTIONS

4.1 The purpose of the field work on July 21 was to get Generator 1 operating reliably to carry the entire load required by the facility, while Generator 2 was unavailable. We concentrated on eliminating the unnecessary trips that were apparently being caused by the 40 and 87 elements.

4.2 The following personnel were present during the field work on July 21:

4.2.1 Danny Hood – Hood EE Consulting, PLLC

4.2.2 Fred Durner – TAW Power Systems, Inc.

4.2.3 Joe Johnson – TAW Power Systems, Inc.

4.2.4 Geoffrey Gollotte – CMI Management, Inc.

4.2.5 Tim ______ -Holland Industrial Services

4.2.6 Other AFRH facility maintenance personnel

4.3 Since I strongly suspected that the differential CT's in the generator compartment were wired with incorrect polarity, I had the technicians check them. We verified that they appeared to be wired backward. However, I told the technicians not to swap the wires until we could run the generator under load and I could verify for certain what was wrong with the current polarities by observing the SEL-300G current phasors on the computer.

4.4 Before running the generator, I noted that the reverse power (32) elements were not enabled, and I enabled them and inserted them into the trip equation. Also, I revised the settings of the 40 elements in line with SEL's recommendations, using generator reactances from the data sheet for a 10M1428 alternator for a 2250 kW unit, which I had brought with me. Fred Durner indicated that it was acceptable to use the data sheet, even though it was for a different installation, since they were the same size generator.

4.5 See the attachments to this report for the following relay setting comparisons:

4.5.1 Generator 1 as found vs. Generator 1 as left

4.5.2 Generator 2 as found vs. Generator 2 as left

4.5.3 Generator 1 as found vs. Generator 2 as found

4.5.4 Generator 1 as left vs. Generator 2 as left

4.6 On starting and loading Generator No. 1, I was able to verify for sure that the polarity of the CT's in the generator compartment was backwards. The generator ran a very short time before being tripped by the SEL-300G, which showed both 87 and 32 targets.

4.7 I removed the 32 elements from the trip equation, since Fred said that reverse power protection was executed in the generator control PLC also.

4.8 The Kohler technician swapped polarity at the switchgear shorting terminal block of the differential CT's in the generator compartment for Generator 1 only. Since the breaker for Generator No. 2 was racked out, the CT shorting block was inaccessible, and it was inconvenient to remove the breaker from the cubicle. The technician will reverse polarity of the CT's for Generator No. 2 when he returns to complete repairs on the generator exciter.

4.9 We then started and loaded the generator again. I verified on the computer that the differential current phasors were correct and that the differential operating currents were essentially zero. I also verified that the phase sequence was ABC. There were no trips, and no targets were illuminated. The generator was loaded up higher than 43% and assumed the largest load that it ever had. The generator carried the entire load required by the facility at that time (a hot day) and gradually increased to 66% load (about 1500 kW). The generator operated long enough for facility maintenance personnel to gain confidence that it could indeed carry the facility load. Then the engine/generator was manually shut down, and facility load was transferred back to the utility.

5. OBERVATIONS OF THE INSTALLATION

5.1 While familiarizing myself with the installation, I noticed several deficiencies that should be corrected.

5.1.1 The Kohler drawings show that the generator neutrals are solidly grounded. However, the Generator 2 neutral does not have a secure ground connection to the neutral bus and may not be grounded at all!

5.1.2 It's very unusual to me to see generators of this size and voltage solidly grounded (or ungrounded). Based on the neutral overcurrent setting on the SEL-300G, it seems obvious to me that whoever originally established the settings for the SEL-300G thought that the generator had a 100Ω neutral grounding resistor. Facility maintenance personnel said that they thought that neutral grounding resistors were originally in the scope for the generators, but may have been deleted due to "value engineering."

5.1.3 The switchgear building has a connection point on each building corner for a safety ground. There is no grounding conductor connected to any of the four connection points.

5.1.4 The concrete floor on which the engine/generators and switchgear building sit is elevated approximately 16 feet above grade. The engine/generator enclosures and switchgear building extend about 10 feet above the floor of the concrete structure. Given the lack of grounding on the equipment, the equipment and structure are very susceptible to being damaged by lightning. I didn't observe any lightning rods on the structure.

5.1.5 It was noted that when both generators were down, the 60LOP (loss of potential) target was lit on Generator No. 1, but not on Generator No. 2. Both relays were enabled and the relay status screen indicated that everything was okay with the relays. I had never seen this occur before, and I contacted an SEL applications engineer on July 23 to ask if there was a potential problem with the relay for Generator 2. He directed me to the page in the SEL-300G user manual that details what causes the 60LOP target to activate. 60LOP activation depends on a number of different parameters. Voltage and current sequence values are monitored and compared to detect a true loss of potential. When Generator 2 returns to normal service, it's likely that the 60LOP targets for the two generators will agree with each other.

5.1.6 Each SEL relay (the SEL-351-7 on 52U and the two SEL-300G relays) have alarm contacts that function as follows. The alarm contact pulses momentarily when the settings group changes, when anyone enters a security level in the relay that allows settings changes, or when settings changes are made. The alarm contact actuates and stays actuated upon failure of the relay. Kohler seems unaware of the pulse operation of the contact, used by utilities as a security measure, and has designed the PLC code to trip the generator and/or utility breaker with no time delay if the alarm relay operates at all, making the generator breaker fail safe. Fail safe breakers are not very reliable, especially in a backup generation application. Relay failure should send an alarm and not trip the breaker. The present arrangement prevents the uploading of events from the relay with the generator in operation. On a previous project, I was able to convince Kohler to add a time delay in the PLC code so that the breaker won't trip if the contact merely pulses. Anyone working on these relays should be made aware of the situation.

5.1.7 The wiring from the 130 volt station battery to the charger and switchgear consists of #10 solid copper conductors. The voltage drop to all 13.2 kV breakers should be checked for the worst case condition, which is a fault in the tie breaker. Such a fault would simultaneously trip both bus differential relays, which would in turn simultaneously trip all five breakers.

5.1.8 There are no arc flash hazard warning labels on any equipment. Such labels are required by the National Electrical Code (NFPA 70), by NFPA 70E and by OSHA. An arc flash hazard study is required to generate the labels, which identify the degree of hazard and notify maintenance personnel of the type of personal protective equipment required to service energized equipment.

6. RECOMMENDATIONS

I strongly recommend that the following be done in response to the above findings:

6.1 Relay Settings

6.1.1 **Insert differential relay word bits 87U and 87R into the trip equation as soon as possible!**

6.1.2 Perform a system study, based on the entire facility power system that will allow correct relay element applications and settings to be determined. **Do this as soon as possible.** Some protective elements are not enabled. At present, there is nothing to protect the generator against ground faults on the system. The study should include protective device time-current curves and be based on generator damage curves and decrement curves.

6.1.3 Test the relays by applying secondary voltages to the relays and injecting secondary currents into the relays after the settings have been determined and loaded into the relays.

6.1.4 The 2011 National Electrical Code (NFPA 70), Article 701.27 says: "Legally required standby system(s) overcurrent devices shall be selectively coordinated with all supply-side overcurrent protective devices." If no coordination study can be located, then a coordination study for the entire facility should be performed. Even if a study is available for the facility, then the medium voltage portion of the study involving the backup generators should be evaluated in light of what we now know. Overcurrent devices should be coordinated for both phase and ground protection and for supply from either the utility or the backup generators.

6.1.5 Consider installing a real time automation controller that will allow remote communication with all SEL relays in the switchgear via modem or the Internet. This will allow offsite engineers to upload events from the relays to determine if the relays operated properly for a fault and to reconstruct faults for evaluation.

6.2 Generator Grounding

6.2.1 Generator grounding should limit thermal and mechanical stress to the machines during internal ground faults, limit transient overvoltages, and provide means for detecting ground faults. In ungrounded generators, ground faults can cause high transient overvoltages. In solidly grounded generators, ground fault currents may be higher than three phase fault currents and may cause thermal or mechanical damage to the generator windings. Therefore, the normal practice, especially for medium voltage machines, is to ground generators through an impedance (reactance or resistance). The 2250 kW, 13.8 kV machines are normally low resistance grounded using 100 amp to 400 amp grounding resistors.

6.2.2 Evaluate the facility power system to determine if there's a valid reason that the generator neutrals must be solidly grounded (unlikely). If no valid reason exists, then install neutral grounding resistors with CT's on both generators. Some system review is necessary to determine what size neutral grounding resistor is required.

6.2.3 As mentioned in 5.1.1 above, it appears that the generator neutrals may not be grounded at all. If so, high transient voltages can be expected during system faults. I understand that there have been unexplained failures of some 13.2 kV transformers. The lack of a secure neutral ground (or any ground at all) for the generators may be a factor in the transformer failures and in the failure of the PT in Generator 2.

6.2.4 **Resolve the grounding issue as soon as possible. Preferably, if possible, install neutral grounding resistors. If some part of the power system requires solid grounding of the generators, then install dedicated ground connections to the generator neutral busses and enable some form of coordinated ground fault protection for the generators.**

6.3 Safety Grounding and Lightning Protection

6.3.1 Connect equipment grounding conductors (#2/0 AWG minimum) directly from the ground grid to safety ground connections on the switchgear building, engine/generator enclosures, fuel tanks and all other equipment at the backup generator site.

6.3.2 Install lightning rods to prevent direct strokes to equipment enclosures.

6.4 Station Battery Wiring

6.4.1 Calculate voltage drop to all breakers for the case with all breakers tripping simultaneously, with the present conductors. Replace the wiring with the required size of stranded conductors if the voltage drop is too high.

6.5 SEL Relays Alarm Contact Application

6.5.1 Request that Kohler eliminate tripping the breaker if an SEL alarm contact actuates. If Kohler won't eliminate tripping on a relay failure, then have them add a timer in the PLC code to prevent tripping if the relay contact pulses.

6.6 Arc Flash Hazard Study

6.6.1 Perform an arc flash hazard study for the entire facility as required in the 2011 NEC, Article 110.16 and in NFPA 70E.

6.6.2 Install arc flash hazard labels on all equipment requiring a label.

6.6.3 Train maintenance personnel in the use of and requirements for personal protective equipment.

7. Execution of Recommendations

7.1 Hood EE Consulting, PLLC can perform any or all of the engineering and study work described above, except for field construction.

Table Of Contents

Device Information	
Report Generated:	July 23 2012 03:55:54 pm
To Device	Generator 1_ 7_21_12 as found
From Device	Generator 1_ 7_21_12 as left

Hidden Settings	Changed Settings	UnChanged Settings
Missing Settings	Invalid Settings	

Global

Top

Compared Settings

Setting	Current Value (Generator 1_ 7_21_12 as found)	Compared Value (Generator 1_ 7_21_12 as left)
LER	15	60
SS1	0	1

Settings that could not be compared

Setting	Generator 1_ 7_21_12 as found	Generator 1_ 7_21_12 as left

Group 1

Top

Compared Settings

Setting	Current Value (Generator 1_ 7_21_12 as found)	Compared Value (Generator 1_ 7_21_12 as left)
25ANG1	20	15
25ANG2	20	15
32P1P	-0.0500	-0.1000
32P2P	-0.1000	OFF
40XD1	-1.8	-2.0
40XD2	-1.8	-2.0
40Z1P	21.5	21.4
40Z2P	33.6	40.7
E32	N	Y
E81	2	N
E87	T	G
O87P	0.20	0.30
SLP2	60	100
TAPD	2.97	3.10

Settings that could not be compared

Setting	Generator 1_ 7_21_12 as found	Generator 1_ 7_21_12 as left

Group 2

Top

No changes

Port 1

Top

No changes

Port 2	**Top**
No changes	

Port 3	**Top**
No changes	

Port F **Top**

Compared Settings			**Settings that could not be compared**		
Setting	**Current Value (Generator 1_ 7_21_12 as found)**	**Compared Value (Generator 1_ 7_21_12 as left)**	**Setting**	**Generator 1_ 7_21_12 as found**	**Generator 1_ 7_21_12 as left**
SPEED	2400	19200			

SER	**Top**
No changes	

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Device Information		
Report Generated:	July 23 2012 04:07:41 pm	
To Device	Generator 2_ 7_21_12 as found	
From Device	Generator 2_ 7_21_12 as left	
Hidden Settings	Changed Settings	UnChanged Settings
Missing Settings	Invalid Settings	

Global

Top

Compared Settings

Setting	Current Value (Generator 2_ 7_21_12 as found)	Compared Value (Generator 2_ 7_21_12 as left)
LER	15	60
SS1	0	1

Settings that could not be compared

Setting	Generator 2_ 7_21_12 as found	Generator 2_ 7_21_12 as left

Group 1

Top

Compared Settings

Setting	Current Value (Generator 2_ 7_21_12 as found)	Compared Value (Generator 2_ 7_21_12 as left)
25ANG1	20	15
25ANG2	20	15
27VSP	16.0	26.0
32P1P	-0.0500	-0.1000
32P2P	-0.1000	OFF
40XD1	-1.8	-2.0
40XD2	-1.8	-2.0
40Z1P	21.5	21.4
40Z2P	33.6	40.7
E32	N	Y
E87	T	G
O87P	0.20	0.30
SLP2	60	100
TAPD	2.97	3.10

Settings that could not be compared

Setting	Generator 2_ 7_21_12 as found	Generator 2_ 7_21_12 as left

Group 2

Top

No changes

Port 1

Top

No changes

Port 2	**Top**
No changes	

Port 3	**Top**
No changes	

Port F **Top**

Compared Settings			**Settings that could not be compared**		
Setting	**Current Value (Generator 2_ 7_21_12 as found)**	**Compared Value (Generator 2_ 7_21_12 as left)**	**Setting**	**Generator 2_ 7_21_12 as found**	**Generator 2_ 7_21_12 as left**
SPEED	2400	19200			

SER	**Top**
No changes	

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Device Information

Report Generated:	July 23 2012 04:23:10 pm
To Device	Generator 1_ 7_21_12 as found
From Device	Generator 2_ 7_21_12 as found

Hidden Settings	Changed Settings	UnChanged Settings
Missing Settings	Invalid Settings	

Global Top

No changes

Group 1 Top

Compared Settings		
Setting	**Current Value (Generator 1_ 7_21_12 as found)**	**Compared Value (Generator 2_ 7_21_12 as found)**
27VSP	26.0	16.0
E81	2	N

Settings that could not be compared		
Setting	**Generator 1_ 7_21_12 as found**	**Generator 2_ 7_21_12 as found**

Group 2 Top

No changes

Port 1 Top

No changes

Port 2 Top

No changes

Port 3 Top

No changes

Port F Top

No changes

SER	**Top**
No changes	

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Device Information

Report Generated:	July 23 2012 04:19:58 pm
To Device	Generator 1_ 7_21_12 as left
From Device	Generator 2_ 7_21_12 as left

Hidden Settings	Changed Settings	UnChanged Settings
Missing Settings	Invalid Settings	

Global	Top
No changes	

Group 1	Top
No changes	

Group 2	Top
No changes	

Port 1	Top
No changes	

Port 2	Top
No changes	

Port 3	Top
No changes	

Port F	Top
No changes	

SER	Top

SER	Top
No changes	

LOSS-OF-POTENTIAL (60LOP) PROTECTION

Element Description

Functional Description

The SEL-300G provides an easy method to detect loss of relaying potential caused by blown potential fuses or operation of molded case circuit breakers in the potential circuit secondary. The relay declares a loss-of-potential if there is a 10 percent drop in the measured positive-sequence voltage with no corresponding change in positive-, negative-, or zero-sequence currents.

If the condition persists for 60 cycles, it latches in. 60LOP resets when V1 returns to greater than 0.43 • VNOM, and V0 and V2 are both less than 5 V secondary.

Setting Descriptions

This function has no settings and is always active.

Relay Word Bits

Relay Word Bit	Function Description	Typical Applications
60LOP	Loss of Relaying Potential Detected	Indication, Control

100% STATOR GROUND PROTECTION ELEMENTS

Element Description

Functional Description

The SEL-300G provides a two-zone function designed to detect stator winding ground faults on resistance and high-impedance grounded generators. The Zone 1 element, 64G1, uses a fundamental-frequency neutral overvoltage element that is sensitive to faults in the middle and upper portions of the winding. The Zone 2 element, 64G2, uses a third-harmonic voltage differential function to detect faults in the upper and lower portions of the winding. By using the two zones together, the relay provides 100 percent stator ground fault coverage.

Note: Most generators produce enough third-harmonic voltage for proper application of the 64G2 element; however, some generators (e.g., those with 2/3 pitch winding) may not. In those cases the element based on the third-harmonic voltage, such as the 64G2, cannot be used for 100 percent Stator Ground Protection.

When a ground fault occurs high in the winding of a resistance or high-impedance grounded generator, a voltage appears at the generator neutral. The neutral voltage magnitude during the fault is proportional to the fault location within the winding. For instance, if a fault occurs 85 percent up the winding from the neutral point, the neutral voltage is 85 percent of the generator rated line-neutral voltage. The SEL-300G asserts the 64G1 Relay Word bit when neutral voltage is greater than the 64G1P setting.