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Generator Basics
Applied to Field Problems

This article provides some theory for the operation of the most common generator systems for non-utility generators. It also describes a few of the field problems related to prime-mover and generator controls which the author has witnessed. "Much of it is quite basic and I find there is always something to learn from reviewing the basics of a subject and from hearing about another's experience in the field."

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Theory

Governor function

The governor system controls the power applied to the prime mover shaft. This means operation of the fuel rack position on a diesel engine or the gate and blade position on a hydropower plant.

The object of the control of power to the prime mover shaft can be for control of rotational speed (RPM) or generator output power (MW). In the case of electrical power generating plants, both are required.

The speed must be controlled until the generator is paralleled with a large grid. After paralleling, the governor controls generator power, not speed. (A variation of these is found in isolated systems as we shall see later.)

Generator speed (RPM) is related to generator frequency (cycles per second of the generator voltage) by a fixed linear equation which means that either of the two may easily be used for controlling the governor. The only problem with using frequency is the signal for generator frequency is not available until after the generator is excited. If the generator excitation fails and there is insufficient residual magnetism to bring the generator up to voltage, the governor using frequency as an indication of speed may continue to increase power until the prime mover is damaged by overspeed.

If generator frequency is used for the governor control, it is important to have a mechanical governor backing up the electrical governor or some other means of limiting the prime mover speed. For instance, the Woodward EGB series uses an electronic governor based upon generator frequency and a mechanical ball-head type governor within the same actuator housing. Whichever of the two is calling for the lowest speed or power will be in control of the engine's fuel rack.

Governor in Droop Mode

Speed droop is a decrease in speed or frequency, proportional to load. That is, as the load increases, the speed or frequency decreases (droops)

Speed droop is expressed as the percentage reduction in speed versus the speed setpoint that occurs when the generator is fully loaded versus the speed that occurs when the generator is unloaded. For instance, if the speed setpoint is 63 cycles per second and the actual speed is 60, the droop is approximatelly 5% ((63 - 60) / 63 = 0.048).

If speed setpoint, speed droop and grid frequency remain constant, generator power output will remain constant.

When isolated from the utility, if all generator sets in a speed droop system have the same speed settings and the same droop settings, they will each share load proportional to their full power capacity.

If the load changes, the isolated system frequency will also change. A change in governor speed setting will then be required to return the system to its original frequency. In order for each prime mover in the system to maintain the same proportion of the shared load, each governor will require the same speed setting change.

Governor in Isochronous Mode

Isochronous means having a fixed frequency. A prime mover and generator, operating in the isochronous mode will attempt to maintain the same frequency regardless of the load it is supplying up to the full load capabilities of the generator set.

The isochronous mode is normally used in isolated systems where the isochronous governor is responsible for maintaining consistent system frequency.

Governors in both modes

In an isolated system one prime mover-generator may operate in speed droop mode and another may operate in the isochronous mode. The isochronous unit is known as the swing machine. In this mode, the droop machine will run at the frequency of the isochronous unit. The droop and speed settings of the droop machine are adjusted so that it generates a set amount of power. The power of the swing machine will change to follow changes in the isolated load demand while the steady state load on the droop machine remains the same.

Maximum load for an isolated system in this mode is limited to the combined maximum output of the swing machine and the power output of the droop machine(s). The power output of the speed droop machine is determined by the speed setpoint, speed droop setting and grid frequency. If system load exceeds this maximum, frequency will drop.

If the isolated system load decreases below the output of the droop machine(s) the system frequency will decrease and the swing machine will be motorized and trip on reverse power.

If two generator sets operating in the isochronous mode are paralleled to the same loads in an isolated system, one of the units will try to carry the entire load and the other will shed all of its load unless the two isochronous unit governors are connected together with load sharing lines. Load sharing lines take the speed settings of the two (or more) generators and develop and average setpoint which all governors use as the target speed setpoint.

Modes of Operation-Power System

There are two modes of power system operation -- parallel with the utility and isolated from the utility. Power system modes define the controls and switchgear required for the project.

Paralleled with the Utility

In the paralleled mode, the generator supplies some of the facility electrical needs and the utility supplies the rest of the facilities electrical needs. When the facility electrical needs are less than the generators electrical output the generator may supply all of the facility's electrical needs and provide excess power to the utility system.

If the generator output is greater than the facility's loads, power will be shipped out to the utility. There is no significance to whether a little power is being shipped out or a little power is taken in at the utility interconnect point. The condition is analogous to having two water sources piped together with users of water on either side of the interconnection point; small flows either direction across the interconnection point make no difference to the water users.

When paralleling electrical generators with a utility grid the utility will determine the frequency. The utility will control the frequency and act as a large isochronous swing machine absorbing any normal change in load. Usually the generator has to be operated in the droop mode when paralleled with the utility. The governor's speed and droop settings are adjusted so that the generator supplies a fixed amount of power. A more modern system with an import/export controller and load sharing lines allows the generators to remain in isochronous mode with an adjustable import or export quantity.

If the generator's governor is operated in the isochronous mode and paralled to the utility, its setpoint will not be exactly the same as the grid frequency therefore the prime mover will be driven to either full power (against the load limit stop) or into reverse power. An appropriate analogy is trying to balance a ball on top of another ball; eventually it will roll off to one side.

If the facility system load increases, the utility will supply the load increase with essentially no change in frequency.

If the frequency setting of the generating unit or system is reduced, the generator output will decrease and the utility will supply the difference. The opposite would be true if the plant load decreased or if the frequency setting was increased. In that case, the utility would reduce its power supplied with essentially no change in frequency.

Isolated from the utility grid

In the isolated mode, the utility is disconnected from the facility and the cogeneration plant supplies all electrical power to the host facility. The term "islanded" mode is sometimes used to mean isolated and sometimes used to describe the condition which exists when the utility's relays have acted to cut off a section of the utility grid while still connected to a generator which has the power capability to hold up voltage and frequency for that section of the grid. Islanding is one of the major concerns of the utilities for cogeneration plants.

In isolated mode, the generator(s) whose governor is in isochronous mode will control the frequency of the isolated system.

Synchronization

Most generators are synchronous. They are intended for operation in exact step with the grid. Induction generators do not operate in step with the grid but have slip with respect to grid frequency in proportion to load. To further complicate matters there are some synchronous machines which have amortisseur windings which allow them to be initially connected to the grid out of synchronism. For this article, we will examine only the common synchronous generator without the amortisseur windings.

A generator must meet the following criteria to be successfully connected to the grid.

- **It must be at the proper speed (frequency)**
- **It must have the correct phase rotation**
- **Its phase voltages must be in-phase and close to the same voltage**

A synchroscope and lamps are commonly used to indicate the voltage difference between one phase of the grid and the same phase of the generator. When the lamps are out and the synchroscope indicator is at the twelve o'clock position, the two phases are in phase and there is little or no voltage between them.

An automatic synchronizer usually initiates automatic generator breaker closure. A synchronization check relay is commonly used to supervise the automatic synchronizer signal and the manual breaker closure switch.

Bus and Generator (also referred to running and incoming) voltmeters are used to manually match voltage levels in the manual mode. In the automatic mode, voltage levels are usually checked and adjusted by the auto-synchronizer and verified by a synchronism check relay.

Voltage regulation and excitation control

The excitation control is used to adjust voltage when the generator is not connected to the utility. Increasing the excitation field current increases the generator output voltage and decreasing the excitation field current decreases the generator output voltage. This is true even when the generator is connected to isolated loads. When the generator is paralleled to the utility, the voltage is essentially fixed by the utility grid voltage.

Increasing excitation while paralleled simply increases the amount of Reactive Volt-Amperes (VARs) produced by the generator. If other generators do not lower their excitation in response, the entire grid voltage will increase slightly. This increase may be so slight that the grid operator does not notice it.

If the generator was on line at full power and a generator trip occurred, the sudden change in power flow will cause a slight reduction in voltage because of I^2R losses in transmission and distribution lines.

Final Exam

To test your understanding of governor systems see if you agree with the following true statement:

At generator breaker closure when paralleling with the utility the governor changes practical function from a speed control to a power control. Also at breaker closure, the voltage regulator changes from a voltage control to a power factor (or VAR) control. When closing the generator breaker while isolated from the utility however, the governor remains a speed control and the voltage regulator remains a voltage control.

Field Problems

Voltage control on an island

An operator at the Indian Point Nuclear Power Plant failed to understand the excitation system function during a loss of off-site power test in 1992. The plant's emergency diesel generators (EDG) are tested monthly by paralleling with the grid and increasing the speed setpoint until the EDG was at full load. At the same time, the voltage setpoint was adjusted so that the power factor of the outgoing power was 0.9. During a special test in 1992 however, a different procedure was required.

In the special test the EDG was to supply power to an isolated grid, separated from the utility grid. After closing the generator breaker opening the switchgear feed breakers to create the island, the operator attempted to adjust the power factor to 0.9 as he had for the monthly test. Needless to say, the power factor did not change but the voltage did and the EDG was tripped on over voltage by the 27/59 relay.

Electronic governor versus fuel rack problem

I always carry a seven-dollar-on-sale, Radio Shack analog multimeter in case I need a meter function that my digital units do not easily provide. I was quite happy to have it with me on a diesel generator startup in the Philippines when the diesel had a fuel rack sticking problem. (If you use a meter like this, be careful to evaluate the meter's ratings and internal construction and do not use it on a circuit which could be dangerous to the user or the equipment. Your first step should be to throw away the cheap test leads and use durable, professional leads rated for higher voltage than the meter. Also be aware that the voltage produced by the meter for certain meter functions could damage electronic components being tested.)

Generator power was hunting regardless of the changes made to the settings on the electronic governor control (Woodward EGA with a EGB actuator). The sensitivity and gain settings could be used to make the hunting problem worse but would not eliminate the problem. By using my trusty seven-dollar multimeter, I was able to demonstrate to the diesel engineer that the signal to the actuator was rock steady with proper adjustment of the EGA. I said that there must be a problem with the fuel rack sticking a bit. Sure enough, we looked closely at the bearing blocks supporting the fuel rack shaft and found they were misaligned causing binding. The bearings were realigned and the unit ran smoothly.

Synchronization circuit verification at startup and places for errors

I find it difficult to believe that every year generators get paralleled with the utility out of phase. As you can imagine the resulting high currents, high conductor forces and high torques can damage generators and mountings.

Many of these incidents occur during initial startups. There are a number of techniques for verifying the synchronism circuits are functioning properly but there is only one way which I fully trust: using a phase-to-phase hot-stick voltmeter to confirm all synchronism instrumentation is in agreement:

With the voltage sticks on A-phase of the line and A-phase of the generator the voltmeter should read zero voltage when the following four conditions are true:

- **The position of the synchroscope indicator is at the twelve o'clock position**
- **The lamps associated with the synchroscope are out**
- **The output contacts of the synchronism check relay close**
- **The output contacts of the auto-synchronizer close**

For 3 and 4, use buzzers connected into the breaker close circuit to minimize the disruption of the circuit. The buzzers allow you to keep your eye on the hot stick voltmeter and use one ear for each contact. 1 and 2 may be verified by an associate calling out synchroscope positions.

An important part of the test is to make sure all four conditions are not true when the hot-stick voltmeter reads voltage.

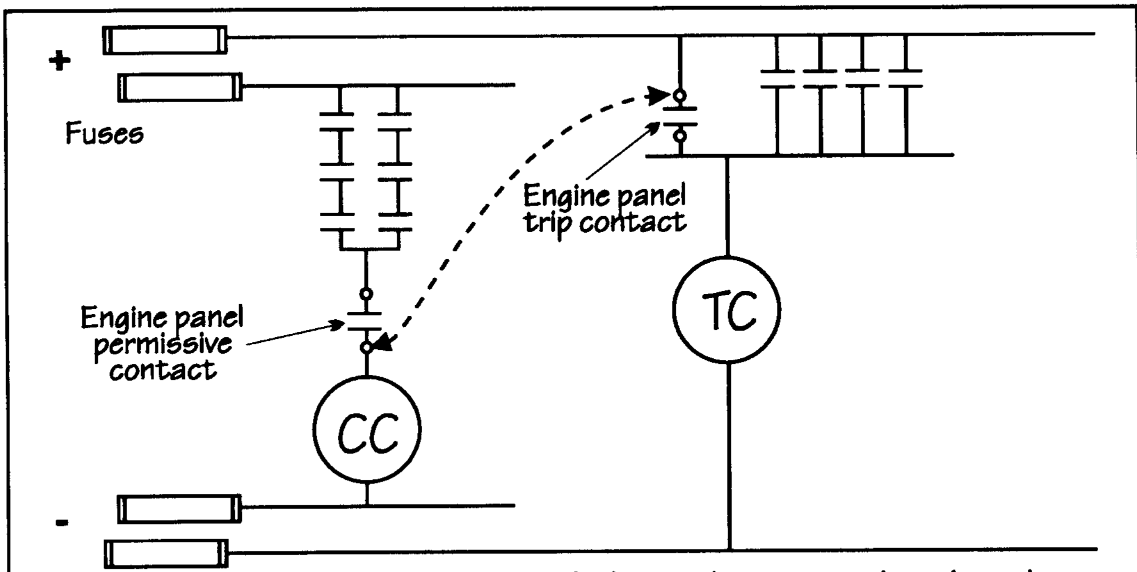
The test must be repeated on at least one other phase to confirm proper phase rotation but I require the test be performed on the third phase as well to confirm our results. In addition, I require a cross-phase test from A to B, B to C and C to A. For the cross-phase test, all four conditions should be met with voltage present and the voltage should read zero at the four o'clock or eight o'clock synchroscope positions. A recheck of the A-A and B-B test at the end of the test is made for its warm feeling value.

While eating lunch at a large diesel power plant in the Philippines (twenty units ranging in size from 1.5 MW to 7 MW in three buildings), the lights dimmed, the units running in our building groaned with the strain and then recovered. We jumped up to find a frazzled operator in building one. He had paralleled a generator out of phase.

The synchronism check relay was an old electro-mechanical type and gave very narrow windows for manual breaker closure (often slid a bit past dead center on the synchroscope). The operators had adjusted the relay so that the contact gap was very small, perhaps only a few millimeters so that the window would be as large as possible. That was still not enough to allow breaker closure at every attempt because the grid was weak and its frequency shifted about by tenths of hertz as the operator tried to adjust the speed of the slow-to-respond diesel.

Their habit was to take the cover off the synchronism check relay and manually help the disk turn to allow breaker closure! The situation was worse than that because their habit degenerated into holding the breaker control switch closed and then using their knee to pull the disk over when the synchroscope indicated an in-phase condition. You can now figure out what happened; with the cumulative effect of a knee on the disk every breaker closure the disk bearings were a bit rough and the contact was already closed when the operator turned the breaker control switch to the close position (more than 120 degrees out of phase).

We inspected the end windings of the generator and fortunatelly found no damage.



Disconnected wires in engine panel shorted to cause breaker closure

Unexpected generator breaker closure because of poor circuit design coupled with poor maintenance practice

The circuit shown in the figure is a simplified version of the circuit which allowed a breaker closure on a diesel generator while the diesel and generator were out of service for maintenance. The diesel technician at the engine control panel had several wires disconnected to perform tests on the engine panel. Two of these wires touched each other and the breaker closed! Fortunately the overcurrent relays opened the breaker quickly and there was no apparent damage.

The two wires are marked on the sketch; the positive side of trip circuit came into contact with the negative side of the cable from the close circuit. The result was power to the breaker closing coil with no contact in series! The contact from the engine panel was moved to the top of the circuit and the engine technician will request the breaker be racked out or its control fuses removed for future work.

The utility demanded "safety" lockout switch for a generator

We argued against the safety lockout switch which the utility demanded we install. The outdoor enclosed switch would be an extra thousand dollars cost to the project and it gave a false sence of security. The utility demanded it so that they would have control over the gas-turbine generator breaker for emergencies or for line maintenance. We felt the switch would give a false sense of security and was little advantage to walking an extra twenty feet to ask the operator to trip the generator and rack out the generator breaker.

We explained that we require the breaker be racked out and locked to perform maintenance safely and that a control switch was not as good as a lock. They finally agreed when we got their field forman involved; he said that he would trust only his <u>own lock</u> on a <u>racked-out breaker</u> and that we could install as many control switches as we wanted but he would not use them.

There are dozens of stories to tell. The common thread is that each problem bears with it a gift. The gift of learning something new, seek out these problems for their gifts. If you have other interesting stories about generator control problems, please write, I would like to hear them.