Synchronous Generation in Distribution Systems

Introduction

This article covers aspects of synchronous generation that affect the design and operation of distribution networks. Of special concern are the limitations imposed by voltage, current and other constraints at various points in the network when generation is connected at selected locations.

In a distribution system, individual generator capacity is small in comparison with the distribution supply capacity. This generation can range from a few hundred kilowatts to over 50 megawatts. As the capacity increases, the technical design considerations, particularly feeder loading and voltage conditions become more critical.

For the purposes of definition in this article:

- small generators are those with a capacity of less than 1MW
- medium sized generators have a capacity of between 1-5MW
- large generators have a capacity in excess of 5MW

A synchronous generator driven by a prime mover affects the dynamics of the power system and is often part of an industrial co-generation process. Prime movers for synchronous machines are typically steam turbine, water turbine or reciprocating engine. Synchronous generators that are part of wind generation schemes are isolated from the distribution feeders by converter systems and are not considered further.

Generation Dispatch

Generation may be self-contained as part of the utility system or may be part of a commercial facility or industrial process. Generator power output is usually controlled:

- according to power system demand
- dependent upon the available energy source

In some cases, generation output is fixed at a specified maximum capacity and cannot be controlled (i.e. it is either connected or not connected). Generation associated with some form of industrial or commercial process (co-generation) uses part of the energy, often waste or surplus energy, with the objective of gaining greater efficiencies for the overall process. The level of generator output may or may not be controllable and will depend upon the nature of the process.

A generator is termed dispatchable if it is subject to the control of a system operator who will determine duration of connection to the system and the level of output at which the machine operates during the connection period. Almost invariably, small synchronous machines are excluded from dispatch because of the cost of allocating dispatch effort and the complication of providing the necessary control facilities to do so.

Generation regulating capacity required to balance system supply and demand is provided by other generation assigned by the system dispatcher for this purpose. Generally, generation attached to a transmission system is dispatchable, whereas generation attached to a distribution system is not.

Generator Connection

Generators are selected with terminal voltages appropriate to their size and are usually limited to less than 25kV. The larger the machine the higher the voltage in order to limit the magnitude of stator current. If the generator operates at low voltage, it is likely to be of limited capacity and is either connected to a low voltage sub-network via low voltage switchgear or through a step-up transformer to a high voltage feeder. The machine may therefore be connected directly to a feeder or, for higher voltage feeder systems, via a step-up transformer. The implications of direct connection are significant and will be discussed later.

Because of the limited freedom in choosing the point of connection to a distribution feeder, generation can be a challenge to integrate into a system in such a way that system voltage, loading, voltage stability and fault level constraints are met for all possible system conditions.

Feeder power flow directions and magnitudes change constantly with changes to load and generator output levels. The impact of voltage changes is particularly significant if the generation is connected at the end of a long feeder.

Protection

The introduction of even one generator complicates the selection and application of protection to distribution systems. Protection coordination analyses, in connection with fault studies, are essential to establish relay settings that will ensure correct protection operation.

Because of the relatively slow speed of fault detection from commonly used time-overcurrent protective devices, the sustained fault current supplied from the generator may be rather less than the initial high sub-transient and transient values. This can lead to questionable reliability in the operation of time-delayed overcurrent protection and consequent lack of coordination. To ensure reliable protection operation, generator protection should use current, voltage and/or frequency signals as a means of differentiating fault location and magnitude.

Modern multi-function relays usually incorporate all the necessary features. In terms of functionality, distributed generation protection can be separated into:

- Generator protection that uses fault infeed from the system to detect faults on the generator or any associated step-up transformer
- System protection to ensure that generator fault infeed can be disconnected from the faulted power system under all conditions
- Interface protection to ensure that generators are shut down if disconnected from the source of supply rather than be allowed to supply an island of local load

Protection coordination analysis programs can be quite sophisticated and are an essential part of any system study. There are numerous possible solutions to ensure proper protection of the plant involved. Consequently, protection application practice has been referred to as a ‘black art’ because of the intuition needed to choose the best relays and their settings to ensure a protection system that is reliable and discriminates properly for all fault types.

Governor Characteristics

The governor of the synchronous generator prime mover controls the mechanical power input to the generator according to the governor control characteristics. Since the actual prime mover speed is fixed by the system frequency and cannot be changed by varying the power input to the prime mover, the governor setting determines the load level at which the machine operates rather than the machine speed.

Figure 1 shows the effect of changing the prime mover governor setting from position 1 to 2, and then to 3. Since the system frequency is, to all intents and purposes fixed, the governor setting simply changes the amount of energy supplied to the prime mover. This, in turn, increases the electrical output of the generator.

In practice, the characteristics may be modified electronically to achieve a particular relationship between the power output of the machine and some measurable parameter used for control purposes, often from a process in which the machine is embedded. However, the governor also has the task of ensuring the machine does not overspeed in the event of loss of electrical load.

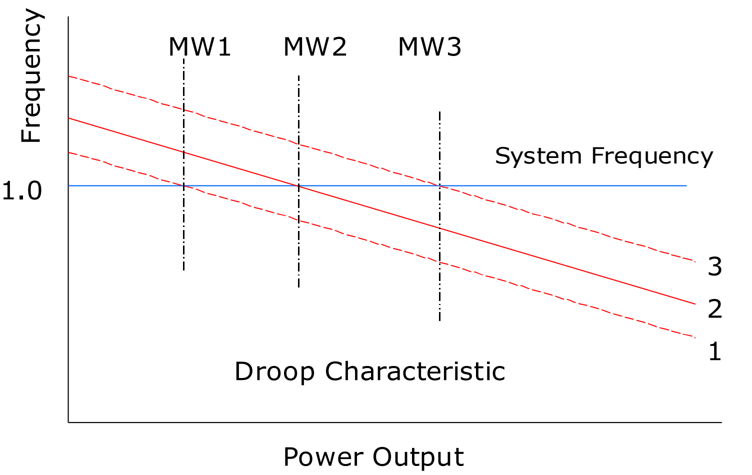

Figure 1: Effects of changing governor settings

Voltage Regulator Characteristics

The generator automatic voltage regulator (AVR) is essential to the machine performance under steady-state and transient conditions and controls the generator excitation level, and therefore the terminal voltage and reactive power output of the generator. Figure 2 represents a simplified case of a generator connected directly to a fixed source of supply, designated as an infinite bus, because no changes in the network load can change the voltage at this bus. It is a convenient simplification, particularly in the case of distribution systems supplied from the transmission system.

The terminal voltage of the machine is fixed by the infinite bus and the change in the AVR setting changes excitation and thus the reactive power output of the machine, in much the same way that the governor changes the real power output. If desired, the measured machine terminal voltage is modified by a current injection proportional to the reactive power load; this ensures that the machine responds to an increase in reactive power load by increasing the excitation, thus providing some measure of reactive power support for the system with increased load. This characteristic is known as quadrature droop compensation. If the machine reactive power output is to remain constant, this characteristic is not used. In practice, there will always be an impedance between the machine terminals and the point of supply. Any change in the AVR setting will modify both the machine terminal voltage and the reactive power output.

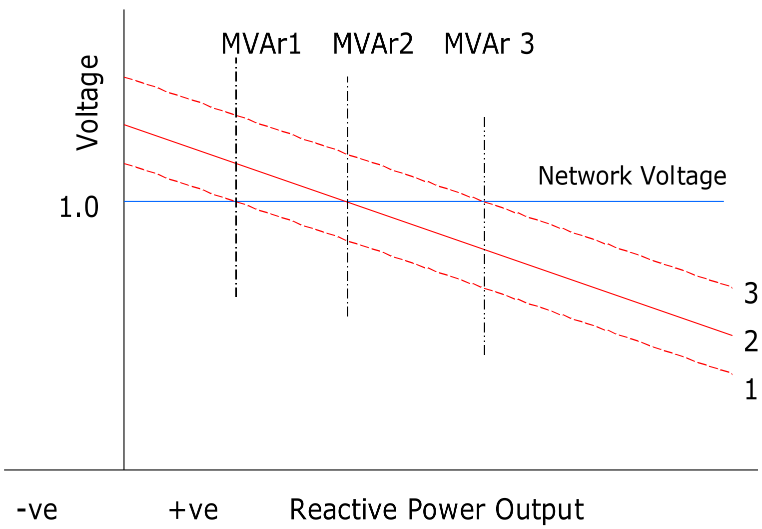

Figure 2: Generator AVR, reactive power and voltage

If the AVR characteristic is moved down vertically from 3 to 2 to 1 in Figure 2, the reactive power output will reduce until it eventually becomes zero. Any further downward movement will cause the generator to absorb rather than generate reactive power. This movement will have no effect upon the governor setting and the machine real power output remains constant.

Synchronous Generator Controls

Figure 3 shows the arrangements for controlling the real and reactive power/voltage of a synchronous generator. As already mentioned, the governor loop effectively controls the real power output, although the signal to the governor is actually the difference between the prime mover shaft speed and the speed reference setting. This is transformed into a change in the setting of the energy input to the prime mover according to the governor characteristics.

The voltage at the machine terminals is compared with the reference voltage setting and the differential signal adjusts the generator excitation control to increase or decrease the excitation according to the AVR characteristics. In this case, both reactive power output and terminal voltage change because the terminal voltage is only partially constrained by the voltage at the infinite bus as a consequence of the impedance between the generator and the infinite bus.

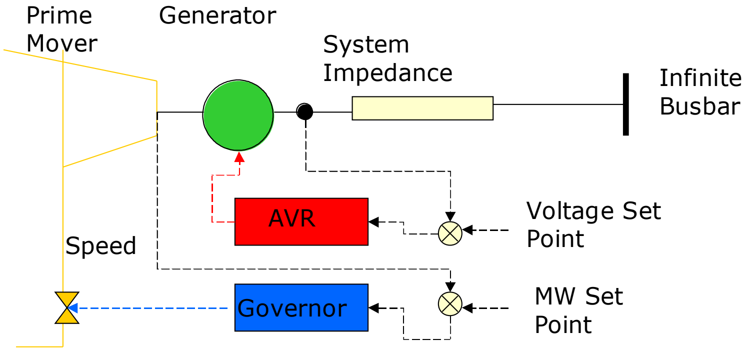

Figure 3: Synchonous generation controls

Synchronous generators are designed to operate within specified upper and lower terminal voltage limits. In addition, the reactive power load must be constrained to ensure stable operation and to comply with current loading limits for both the machine stator and rotor. A reactive power limiter, which is part of the AVR control, ensures that these limits are not violated. Once a limit is reached, any further change in excitation is prevented. At this point, the excitation will remain unchanged and the machine behaves as a fixed excitation machine where the AVR no longer has any control. This condition persists until a change external to the machine causes the terminal voltage to move outside the limits set. Now the AVR resumes control.

Tap Change Transformer

Frequently, generators supplying a network may be connected through a step-up power transformer so that the optimum design voltage can be chosen for the size of generator. Almost invariably, these transformers have tap changers that can be set to accommodate a suitable range of reactive power settings determined by the network requirements for varying load conditions. Because of cost limitations, most tap changers are of the off-load type and, usually, it is possible to select a tap that will satisfy the required range of reactive power output required from the generator.

If network conditions are such that reactive power requirements cover a wide range, a load tap change is chosen, at additional expense, that allows a wider range of reactive power needs to be met. The choice is determined largely by the size of generator connected and the potential for providing reactive power support to the system. Obviously, a small machine cannot be expected to supply more than the reactive power rating of the machine.

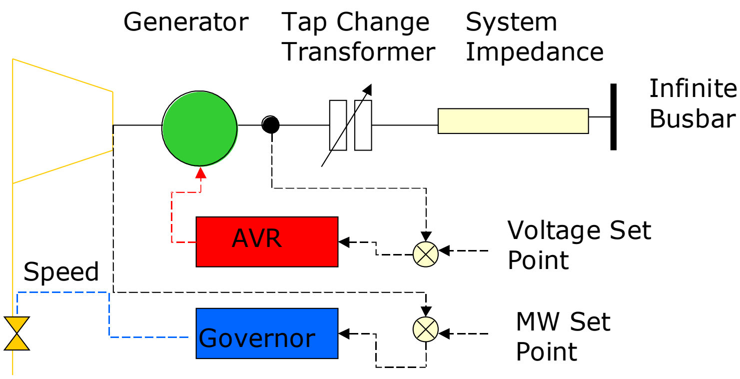

Figure 4: Generator with tap change transformer

represents a simplified form of generator performance diagram that translates the vectors representing the rotor excitation current and terminal voltage into the complex (real and reactive) power axes. Thus changes in excitation level or terminal voltage affecting the reactive power produced by the machine are reflected in the diagram.

Returning to the simplified case of a generator connected directly to an infinite bus, changing the transformer tap will change the machine terminal voltage. The AVR senses this change and acts to restore the machine voltage to its previous value. In doing so it changes the reactive power output of the machine. A tap that initially increases the machine terminal voltage results in a reduction of reactive power generated, from Q1 to Q2, as shown, until the original terminal voltage is restored. Conversely, a tap in the opposite direction decreases this voltage and will increase the reactive power output.

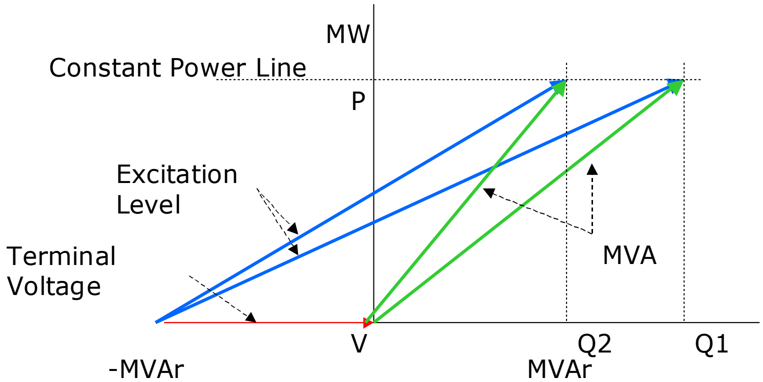

Figure 5: Simplified performance diagram

In a practical case, the change in reactive power output also depends upon the sum of the transformer impedance and the equivalent impedance from the transformer high voltage terminals to the infinite bus. A tap change will result in some change to the generator voltage. To ensure that a fixed tap position chosen is capable of providing the range of reactive power needed to support the network reactive power demand, a series of loadflow analyses is required over all real and reactive power loading levels. If the range of reactive power support is not possible with a fixed tap, a load tap change will have to be specified

Performance Diagram

The complete performance diagram (Figure 6) incorporates the limits imposed by power capacity, stability and thermal constraints.

The maximum prime mover mechanical energy input determines the maximum generator real power output (purple line); the difference between the mechanical input and electrical output results from the mechanical and electrical losses arising in the energy conversion process

The rotor conductor thermal limit (blue curve) imposes a limit on the maximum rotor current and thus on the MVA output of the generator. Because of the rotor conductor cooling arrangement on modern machines, there is little difference between the short-term and continuous limit.

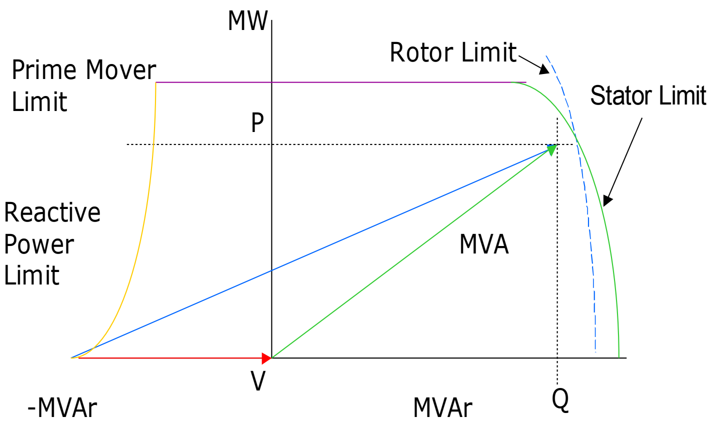

Figure 6: Detailed performance diagram

The stator conductor thermal limit (green curve) imposes a limit on the maximum stator current and also on the MVA output of the generator. There is less latitude in modern machines to go beyond the stated rating but, occasionally, some increase in output is possible. Any continuous enhanced rating is best determined by actual field tests since machine design varies significantly between manufacturers and is affected by local conditions.

The permissible negative reactive power limits (yellow curve) are determined by machine stability considerations when operating at leading power factor. It is usual to allow a margin for safety and this is included in the position of the curve.

The more reactive power generated at the thermal limits, the less real power output is possible. For various reasons, the MVAr support required from a generator in a distribution system is limited and the machine is likely to operate within a power factor range of 0.98 to 0.9.

Cogeneration Controls

When a generator is part of a process, the process requirements usually take precedence over network real and reactive power needs in deciding upon the operating point of the generator. It is common to set the controls to produce a fixed MW output at a fixed power factor. Figure 7 shows the changes from the previous control arrangements. Now the set points are MW and MVAr or power factor. A transducer computes these values from the voltage and current outputs at the generator terminals. Comparison with the set points sends signals to the governor and AVR to correct any discrepancies between the outputs and settings.

If the power source to the prime mover can be varied, independent of the process, then some adjustment in generator output is possible. An example is the option to dump a portion of the steam generated by a process rather than pass it through the prime mover. Changing the amount of steam dumped allows changes in the electrical output of the plant. Since most processes can make use of the electrical energy generated, the quantities of energy required for the process itself and for supplying the generator are defined in the plant design to ensure maximum overall efficiency.

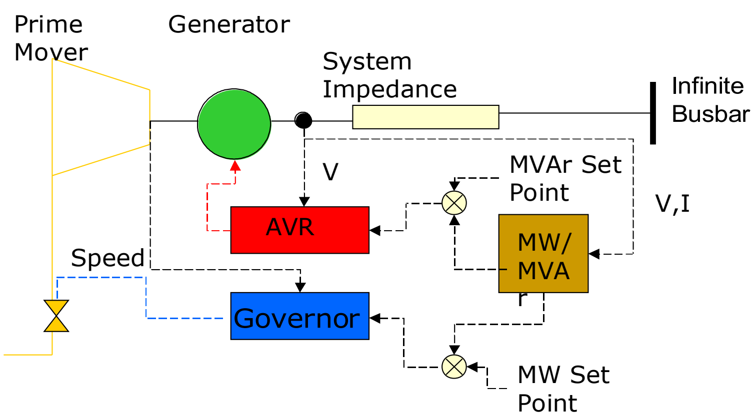

Figure 7: Cogeneration controls

Negative Sequence Current

Virtually all distribution systems are unbalanced in that there are a considerable number of single phase loads. The generation of negative sequence currents in a balanced system are of concern, primarily under fault conditions. For unbalanced systems, the presence of generator negative sequence currents is inevitable as a consequence of the imbalance between phases. This is of particular concern if the generator is some distance away from the supply and adjacent to unbalanced loads, in which case it may absorb a significant proportion of such loads, especially if the machine is direct connected.

The ability of generators to withstand negative phase sequence currents indefinitely, or over shorter periods, is defined by a squared law heating curve ($I2^2t$) shown in Figure 8. This curve relates the time duration permissible for given levels of negative sequence current without imposing damage on the machine rotor and is shown in the graph below. The withstand capacity is dependent upon the size and type of machine and the cooling medium used for the rotor. Modern

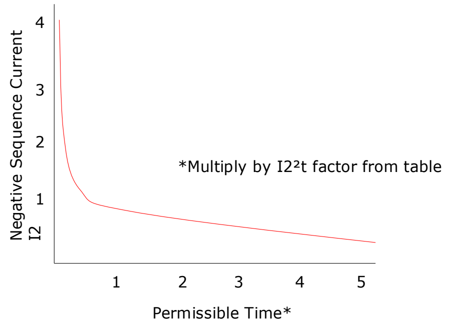

Figure 8: I2 squared t curve

machines have less withstand capability than older machines; the former are more likely to be connected to distribution systems.

shows that hydrogen cooled machines have less capacity than air cooled, and direct cooled than indirect cooled. The continuous negative phase sequence current withstand of indirect cooled machine rotors is 15% and of direct cooled rotors only 10% in per unit on machine rating. The tendency over the years is for machines to be designed with lower reserve heating capacity and this is reflected in the table values.

Cooling	Indirect Factors %	Direct Factors %
Air	20	
Hydrogen 0.5 p.s.i.	20	14
Hydrogen 15 p.s.i.	15	10
Hydrogen 30 p.s.i.	12	7

Short Circuit Infeed

Connecting generation can increase fault current levels significantly in the vicinity of the generator to the point where existing switchgear is overstressed. The machine fault contribution to the system depends upon the proximity of the fault to the machine and whether the machine has a generator transformer or not. Synchronous machines with transformers are capable of sustaining up to three times the full load current into a fault indefinitely if fitted with a suitable automatic voltage regulator.

The fault infeed is dependent upon the transient impedances of the generator and can attain up to five times full load current initially for a terminal fault, decaying rapidly to its steady state value. The fault contribution of remote machines to a fault is not easy to determine and reference to the IEEE and IEC standards will determine how each machine is represented.

Transient Stability

Synchronous machines will respond to close-up faults with rotor swings that depend upon the machine loading, excitation control, the fault location and the speed and action of protective gear. Excessive rotor oscillations result in large current flows between the machine and system and lead to eventual tripping of the machine from the system. Modern excitation systems are effective in damping oscillations to a certain extent but the configuration of the network and loading conditions are significant factors in determining stability. For most cases, the size of the generator compared to the capacity of the distribution feeder source to which it is connected is small. However, if machine size approaches the feeder source capacity, the implications of fault disturbances or the loss of the machine have to be considered much more carefully and will almost certainly result in the imposition of a limit on generator size.

In practical terms, transient stability analysis for a distribution system is not as significant a problem as for a transmission system. Generators are typically isolated onto individual feeders supplied from separate substations. Consequently, the impedances between generators imposes a limit on the the synchronizing power that can flow between machines and a fault affecting one machine has very limited impact on another. Synchronizing power almost invariably flows from the supply source to stabilize the machine.

A common regulatory requirement imposed by most supply utilities is that a generator connected at distribution level be removed from the system in the event of machine operation that jeopardizes the integrity of the system. Under and overvoltage protection is commonly applied to disconnect the machine from the system. Another example of a suitable device is a rate-of-change of frequency protective device that removes the machine from the network in the event that the instantaneous frequency difference between generator and system exceeds a certain value. This feature is used also for cases where a generator is islanded onto local load on the loss of connection to the distribution source. In many cases, the complications of accommodating all eventualities raises technical and cost issues and tripping the machine off the supply system is the only practical resort.