Electrical Systems of Pumped Storage Hydropower Plants

Electrical Generation, Machines, Power Electronics, and Power Systems

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List of Acronyms

AS-PSH	adjustable-speed pumped storage hydropower
DFIG	doubly-fed induction generator
FC-PMSG	full converter-permanent magnet synchronous generator
IEEE	Institute of Electrical and Electronics Engineers
NERC	North American Electric Reliability Corporation
PMSG	permanent magnet synchronous generator
PSH	pumped storage hydropower
RMS	root mean square
SCC	short-circuit current
SCE	Southern California Edison

Executive Summary

While the concept of pumped storage hydropower (PSH) is not new, adjustable-speed pumped storage hydropower (AS-PSH) is equipped with power electronics; thus, it has more capabilities and is more agile and flexible to integrate with modern power systems. The composition of power systems from a century ago consist mostly of conventional synchronous generators delivering power to customers via a unidirectional power flow. As the ratio of conventional power plants with synchronous generators to variable generation decreases with increasing penetrations of renewables, future power systems will be more dynamic. With fewer synchronous generators, the level of the rotating inertia within the power system decreases, and balancing variable generation and load in a condition with low rotating inertia is not easy. Fortunately, AS-PSH can provide a quick and flexible response with the power converter control while balancing the supply and demand, thus securing power system stability. In a way, AS-PSH is a combination of energy storage (storing potential energy) and a conventional power plant.

This report covers the electrical systems of PSH plants, including the generator, the power converter, and the grid integration aspects. Future PSH will most likely be influenced by the technology (advancement of the electric machines, power converters, smart sensors, control systems, grid/microgrid configurations), the requirement and the need to maintain the reliability of power systems (grid code; local, regional, and environmental rules and regulations), the potential revenues from offering system reliability products (various ancillary services: ramping, reserves, inertial and frequency response; voltage and reactive power regulations), and energy arbitrage.

Chapter 1 describes the general energy conversion of the hydropower plant and the AS-PSH plant. Chapter 2 discusses the different types of AS-PSH at the generator level. Chapter 3 describes the AS-PSH from the power plant perspective.

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Introduction

Adjustable-speed pumped storage hydropower (AS-PSH) technology has the potential to become a large, consistent contributor to grid stability, enabling increasingly higher penetrations of wind and solar energy on the future U.S. electric power system. AS-PSH has high-value characteristics, such as a fast response to provide ancillary services to the grid, because it is a power converter interface with the grid (like battery storage), but at the same time it has the energy content large enough to supply both short-term (seconds to minutes) and long-term (minutes to hours) energy needs, like more conventional power plants. Designs must be optimized, however, to reduce capital expenditures and to provide a high-quality grid-interface capability (e.g., power quality, ancillary service provider, fault-tolerant or fault ride-through capability), which is a primary factor in the acceptance of AS-PSH into a utility's generation mix.

The capital expenditure will be greatly affected by the cost savings associated with the civil structure, turbine design, power electronics, control systems, or unique generator designs. A holistic design must be considered to get a full picture of the benefits of the technology proposed. AS-PSH can be controlled to reduce the impact of transient disturbances on a power system and to minimize subsequent component fatigue and potential oscillation modes within a plant, with the overall impact on reducing operational expenditures.

Generating clean power to meet standards such as the Institute of Electrical and Electronics Engineers (IEEE) 519 and International Electrotechnical Commission 1000-3-2 will be a continuing challenge. For many technology developers, however, improved AS-PSH technologies will become a key component of generator storage systems in the future given the prospects of increased performance and decreasing costs as well as the ever-increasing penetration levels of renewable generation (e.g., wind power and solar power).

1 Hydropower Energy Conversion

Conversion from the available energy in water into useful electrical energy delivered to the electric grid can be explained by understanding the characteristics of a hydropower plant. The detail of the overview section is derived from Kerkman et al. (1980). The power available in a stream of water is:

$$P = \eta \bullet \rho \bullet g \bullet h \bullet q' \tag{1}$$

where:

- P = power (J/s or W)
- η = turbine efficiency
- ρ = density of water (kg/m³)
- g = acceleration of gravity (9.81 m/s²)
- h = head (m). For still water, this is the difference in height between the inlet and outlet surfaces. Moving water has additional components, subtracted to account for dynamic friction losses, and added to account for the kinetic energy of the flow. The total head equals the *dynamic pressure head* plus *velocity head*.
- q' = flow rate (m³/s).

The parameters of the variable-speed operation are illustrated in Figure 1.

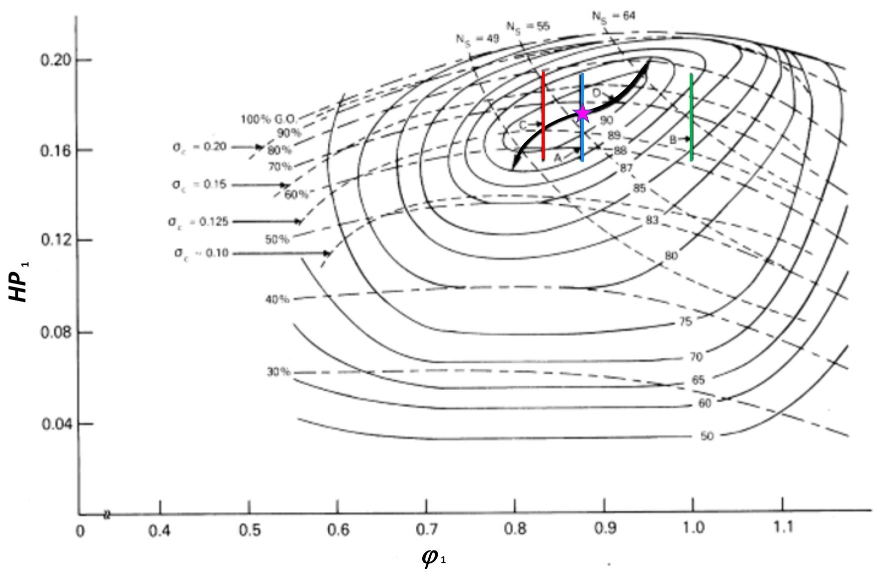


Figure 1. Performance characteristics for a hydraulic turbine model, 1-ft head

This figure shows the performance characteristic curves of a typical Francis turbine having 24 stationary gates and 18 rotating vanes.

$$\varphi_h = \frac{nD}{1840\sqrt{h}} \tag{2}$$

$$HP_h = P_u D^2 h^{\frac{3}{2}} \tag{3}$$

where h, the head, is equal to 1 ft; and D, the diameter of the turbine vanes, is equal to 12 in. Per unit (p.u.) is the unit power parameter, which is constant for similar turbines. The closed solid lines denote points of constant efficiency, whereas the dashed lines represent the locus for a fixed gate opening. The parameter is the cavitation susceptibility or “critical sigma,” and NS is the specific speed. The point of maximum efficiency can readily be located in the curve as 91% at a gate opening of 67% (magenta star on graph). Note that both φ_h and HP_h are functions of head, so the optimum efficiency point at a particular head can be reached only at one value of head and power output (rated speed and rated power). Other values of output power at rated head can be achieved only by changes in the gate opening, which follows the heavy vertical Line A (blue line) in Figure 1. This line is constructed for an assumed +10% variation in power level. As the reservoir is drawn down, it can be noted from Eq. 1 that the vertical line of the operating conditions moves to the right, shown as Line B (green line), resulting in reduced efficiency at all power levels. Line B shows such a condition corresponding to a 25% decrease in head. Conversely, during the spring runoff, head levels can exceed the rated value; again, however, the operating efficiency is decreased. A heavy Line C (red line) is drawn for a 10% increase in head with the same +10% power variation.

It is apparent that operation at constant speed constrains operation along a vertical line that is, regrettably, nearly along the direction for a maximum (rather than minimum) change in efficiency. In contrast, the possibility of adjustable speed would permit the operation to be maximized so that operation is along the “ridge” of the efficiency loci, resulting in a minimum reduction in efficiency for given power demand, as shown by Curve D (black line). Indeed, if the turbine is in a base-loaded plant and the power output of the plant is adjusted to meet the demands of the available head, the plant would be able to operate year-round at a constant efficiency of 91%.

Pumped storage plants would realize an additional payoff in efficiency if the variable-speed operation were adopted. Because the reversible Francis turbine uses one runner for both types of operation, it is difficult to change the turbine and pump characteristics independent of each other. As a result, the optimum speed for pumping ranges from 1.1–1.2, which is that of generating. It is evident that constant-speed operation at maximum efficiency cannot be achieved at any time for both modes with a single generator/motor. This problem would be overcome with variable-speed operation because the optimum speed-horsepower profile for pumping and generating could be set independently.

In addition to the promise of significant energy savings, several other important benefits will be realized if the speed of the turbine can be adjusted. These are detailed in the following sections.

1.1.1 Reduced Noise, Vibration, and Cavitation Problems

Vibration and noise are unavoidable with present designs under constant-speed operation. One such manifestation of this problem is turbine surging during overload, which occurs when guide vane openings exceed the design point. Certain vane openings result in an unacceptable relationship between flow angle and runner vane entrance angle. Excessive vane openings can also result in severe cavitation problems. Another area of concern is turbine surging during partial load. At loads from 40%–60% of rated, pressure surges are generated that often yield noise and vibration problems. Although these fluctuations can be reduced by providing compressed air, surging generally limits the range of automatic frequency control and partial-load operation.

Another undesirable characteristic occurs at low head during generation. In this case, the characteristic is a hysteresis phenomenon that tends to limit the operating head variation. These difficulties can be avoided, to a large extent, if turbine speed can fluctuate as demanded by the electrical load.

In pumping mode, two phenomena limit the range of operation. One is reverse flow at the high head, which causes cavitation growth, a decrease in efficiency, and an increase in both vibration and noise. The other results from operating at low head, requiring increased discharge. Such operation, again, leads to reduced efficiency and cavitation problems. These problems can be minimized if the power output is adjusted with an increase in speed rather than increased flow.

1.1.2 New Flexibility in Site Selection and Sizing of Hydropower Units

If the speed of the synchronous generator can be adjusted to accommodate the limitations of the hydraulic turbine, efficient operation will be possible over a much larger head variation than previously possible. This feature will, in turn, permit sizing of reservoirs and dams on a different basis because a wide range of operating head allows more flexibility in the design of the upper and lower pools for pumped storage. A wider variation in head would allow for the use of deeper ponds with less surface area, opening sites previously considered either marginal or requiring two distinct speeds. In addition, the variable-speed operation would provide greater flexibility in the selection of the number and size of units to be installed in a station because each individual unit is capable of operation over a wide, rather than narrow, power range. These advantages translate into inherent cost savings in the overall hydropower station design.

1.1.3 Improved Implementation of Load Changes

To accommodate load changes that occur within the power system and to maintain constant speed, hydraulic and pumped storage plants rely on an assortment of devices. These control elements include movable gates and runners as well as a speed governor system that regulates the flow, power output, and speed to match the system demand. Such devices are cumbersome, difficult to maintain, and respond very sluggishly to the dispatcher’s commands. These problems are compounded in pumped storage plants. An important characteristic of the single-stage, reversible Francis turbine is that it is not generally capable of making load changes by means of wicket gate movement during pumping. In addition, where reversible turbines are used under high head situations, the pump turbine faces serious stress and vibration problems associated with the wicket gate operating assembly so that wicket gates are only infrequently adjusted. These restrictions can be entirely removed if the generating or pumping rate is adjusted by changing speed. Because synchronous motor torque can be developed at all rotor speeds, load changes can be made within a fraction of a cycle by simply changing the converter firing angle. The energy required to supply the momentary change in system load is taken out of the machine and turbine inertia as the machine and turbine rapidly slow down or speed up to satisfy the new load demand. Similar advantages could be gained during emergency braking of the unit because excess energy could be supplied to the electric grid to brake the unit, even if the wicket gates remain open.

1.1.4 Relaxation of Parameter Requirements

By decoupling the synchronous tie through a high-voltage DC link, many restrictions on machine design imposed by system stability requirements might be relaxed. For example, minimum inertia requirements based on allowable frequency excursions might be eliminated. This will allow the station units to be designed based on the site's hydrology, cost, best obtainable efficiency overhead, and load fluctuations. In addition, the need for bounds on machine parameters—such as the short-circuit current (SCC) capability, transient time constants, and damping—now depends only on the requirements of the site and not the electrical system.

1.1.5 Inherent Starting Capability in the Pumping Mode

One characteristic of pumped storage plants is the need to stop and reverse rotation to commence pumping. To date, when transitioning from generating to pumping mode, an auxiliary pump motor starting or induction starting of the main synchronous machine is used to bring the system up to speed. Induction starting has been used less often because of the requirement of massive bars in the armature windings and increased cost. In addition, this form of starting is often restricted by power system stability requirements. Because of cost and size considerations, pump motors must start the turbine in a dewatered state even though this is not necessarily desirable because much time is wasted bringing the unloaded machine up to speed. Synchronous starting methods require the dedicated use of at least one unit in the generating mode per site. This reduces the number of reversible pump turbines by one and adds to the cost of the pumping mode by prolonging the pumping time. If the synchronous machine is connected asynchronously to the AC grid by a DC link, the starting could be accomplished automatically without extra pump motors by proper control of the AC/DC. Because the converter is rated at full power, the adjustable-speed operation would allow pumping to commence nearly upon starting with minimum loss of operating revenue.

2 Types of Hydropower Generators

The previous section discussed the overview and energy conversion aspects of hydropower generation. As discussed, the power performance characteristic of a hydropower turbine plays a key role in hydropower energy conversion. From the electrical generation point of view, two types of hydropower generators are used. The first type is the fixed-speed hydropower generator, based on an induction generator or a synchronous generator. This type is characterized by a direct connection to the grid. The speed variation for an induction generator is normally around 1%–2%, whereas for a synchronous generator there is no speed variation, although there is a power angle variation. The second type is the adjustable-speed generator. One common choice of the generator is a doubly-fed induction generator (DFIG), which has partial power conversion that is processed through rotor winding via a power converter and then to the grid, and another part of conversion is through the stator winding directly delivered to the grid. Another choice is to use a synchronous generator with full power conversion. This type is characterized by the presence of a power electronics converter (power converter) in the system to allow for adjustable-speed operation.

Each section discusses normal operation first, followed by short-circuit operation. The short-circuit behavior is very important to design the infrastructure to protect the system during abnormal conditions (e.g., short circuits, unbalanced, overloads, voltage and frequency dips). Understanding the SCC behavior of different types of hydro turbine generators is important to size the switchgear (circuit breaker, disconnect, recloser, etc.); to set the system protection (trigger setting, coordination); and to know the transient and steady-state behavior of the SCC, the transient time before reaching steady state, and the maximum-minimum size of the expected SCC. Details on the short-circuit behavior found in this section can be found in Muljadi and Gevorgian (2011), Samaan et al. (2010), Gevorgian and Muljadi (2010), and Grainger and Stevenson (1994).

Short-circuit faults can occur in various locations of the power system in several different ways, including line-to-ground and line-to-line faults. For simplicity, we consider a symmetrical three-phase fault because it is the easiest to analyze. A simple per-phase equivalent circuit of a power system under such fault conditions is shown in Figure 2.

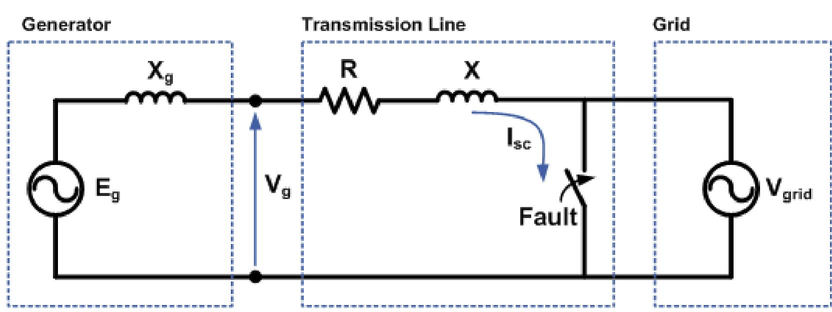


Figure 2. Per-phase equivalent circuit of a symmetrical fault

The fault in Figure 2 is represented by a shorting switch. Immediately after the fault, the SCC contribution from the generator can be found using the following equation:

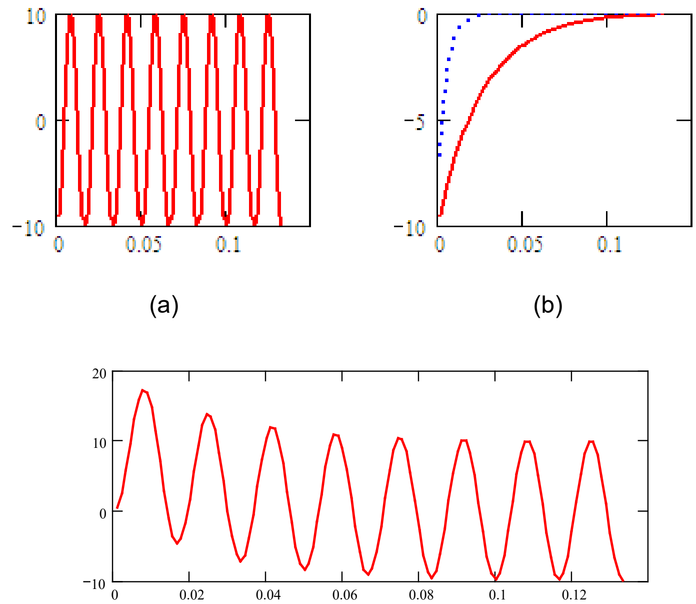
$$u_g = L\frac{di}{dt} + iR \tag{4}$$

where u_g is the instantaneous voltage on the generator terminals; and R and L are the line resistance and inductance, respectively. Solving Eq. 4 for current (i) yields:

$$i = \frac{V_g}{Z}\sin(\omega t + \alpha - atan(\quad)) - e^{\frac{R}{L}t}\left[\frac{V_g}{Z}\sin\left(\alpha - atan\left(\frac{X}{R}\right)\right)\right] \tag{5}$$

where:

- V_g is the peak generator voltage
- $Z = \sqrt{R^2 + X^2}$ is the line impedance
- α is the voltage phase angle
- ω = 2π f is the electrical frequency in rad/s, and f is the electrical frequency in Hz.



(c)

Figure 3. Short-circuit for an AC source connected to an R-L circuit: (a) AC component, (b) DC component, and (c) combined response

The solution to Eq. 5 has two components:

- The first component is stationary and varies sinusoidally with time. It represents the steady-state SCC.
- The second component decays exponentially with a time constant equal to R/L. It represents the DC component of the current.

The steady-state symmetrical fault current, I_{sc}, from the generator can be calculated from the first component of Eq. 6:

$$I_{sc} = \frac{V_g/\sqrt{2}}{\sqrt{R^2+X^2}} \tag{6}$$

The steady-state fault current depends on the impedance of the line. The closer the fault occurrence location to the generator terminals, the larger the SCC contributed to the fault. The peak magnitude of the transient component in Eq. 5 depends on the line impedance as well, and it depends on the impedance angle, $\varphi - atan\frac{X}{R}$, at the point of the fault. The DC term does not exist if $\alpha=\varphi$, and it will have its maximum initial value of Vg/Z where $\alpha - \varphi = \pm\frac{\pi}{2}$. So, depending on the time when the fault occurs and the circuit characteristics, the transient current waveform will be different. This means that in three-phase systems, the phase transient currents will have different peaks because of a 120° shift in voltages.

In large power systems with many generators and transmission lines, the actual fault current at any location on the grid will be the sum of the collective contributions from all generators, making the analysis extremely complicated. In this case, some sort of simplification is needed for the fault current calculation.

2.1 Fixed-Speed Hydropower Generator: Directly Connected to the Grid

2.1.1 Conventional Hydropower Based on Synchronous Generator

A conventional hydropower plant uses a synchronous generator (see Figure 4). At a minimum, it is equipped with the governor (to regulate the frequency) and exciter (to regulate the voltage via its excitation winding). An additional component might include a power system stabilizer to dampen power oscillations as they occur on the grid. This type of generation has been in place for more than a century, and it has been accepted and is a mature technology. The excitation is accomplished by feeding DC current to the field winding to adjust the flux on the rotor poles via rotating slip rings. Newer synchronous generators might use a brushless concept to perform the excitation control. In that case, there is no need to use the slip rings.

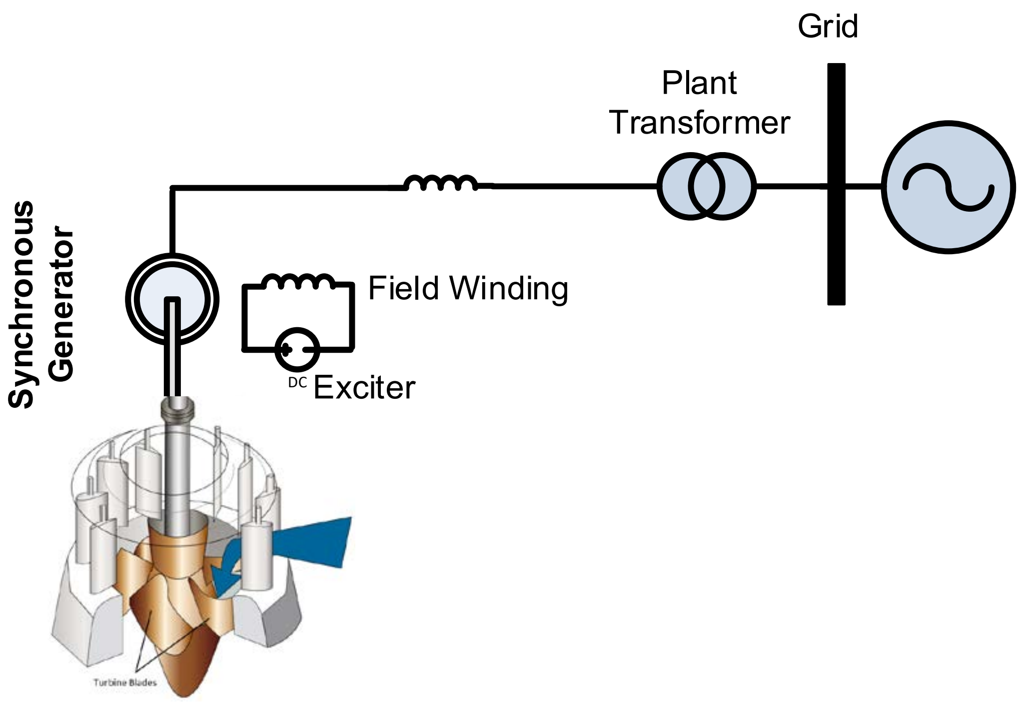


Figure 4. Hydro turbine with synchronous generator directly connected to the grid

2.1.1.1 Normal Operation

Figure 4 illustrates the simplified diagram of a hydropower turbine with a synchronous generator directly connected to the grid operating in synchronous speed. A hydropower plant is usually operated with low rotational speed (e.g., 300 rpm); thus, the number of poles can be significantly larger than off-the-shelf induction machines (e.g., a 40-pole synchronous generator connected to a 60-Hz grid rotates at 180 rpm). Because of the excitation and the field winding, a synchronous generator normally operates without capacitor compensation. Instead, the excitation can be controlled very smoothly to vary the reactive power generated by the synchronous generator.

Figure 5 illustrates the operating point of the hydro turbine, which moves along the dashed red line (constant at synchronous speed) as the output power is varied by adjusting the wicket gate opening (α). Note that the conversion efficiency of the operating turbine will vary as the output power changes at constant rotational speed (synchronous speed). As for any output power, there will be only a single matching rotational speed that will yield maximum efficiency.

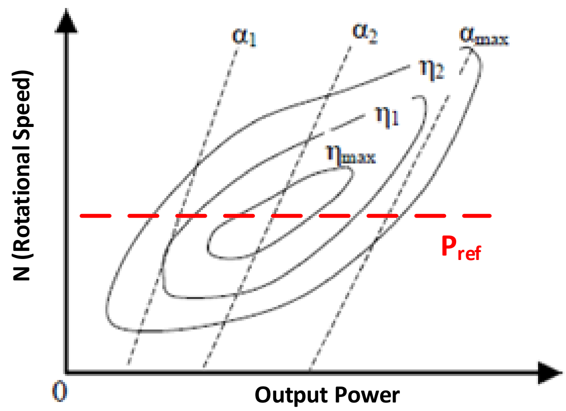


Figure 5. Operating point (along the dashed red line) to illustrate the constant-speed operation

2.1.1.2 Short-Circuit Operation

The synchronous generator short-circuit has a specific characteristic, especially in the initial formation of the SCCs (the first few cycles before reaching steady state). The SCC characteristics (shown in Figure 6) are influenced by the fluxes from the field windings, the armature windings, and the damper windings. The three important periods of the SCC are known as the subtransient, transient, and steady-state periods. In the subtransient period, the subtransient SCC is the largest; in the next period (transient period), the transient SCC is less than the subtransient SCC; and in the steady-state period, the sustained SCC is the lowest SCC among the three. Similarly, the subtransient reactance (X_d''), transient reactance (X_d'), and steady-state reactance (X_d) have increasing values ($X_d'' < X_d' < X_d$); and the corresponding SCC has decreasing magnitudes ($|I''| > |I'| > |I|$). As the three-phase faults commonly used as the metric to size the switchgear to disconnect the SCC from the circuit, the symmetrical three-phase fault is considered in the next few sections.

$$I(t) = \frac{|E_i|}{X_d} + |E_i|\left(\frac{1}{X_d'} - \frac{1}{X_d}\right)e^{-\frac{t}{T_d'}} + |E_i|\left(\frac{1}{X_d''} - \frac{1}{X_d'}\right)e^{-\frac{t}{T_d''}} \quad (7)$$

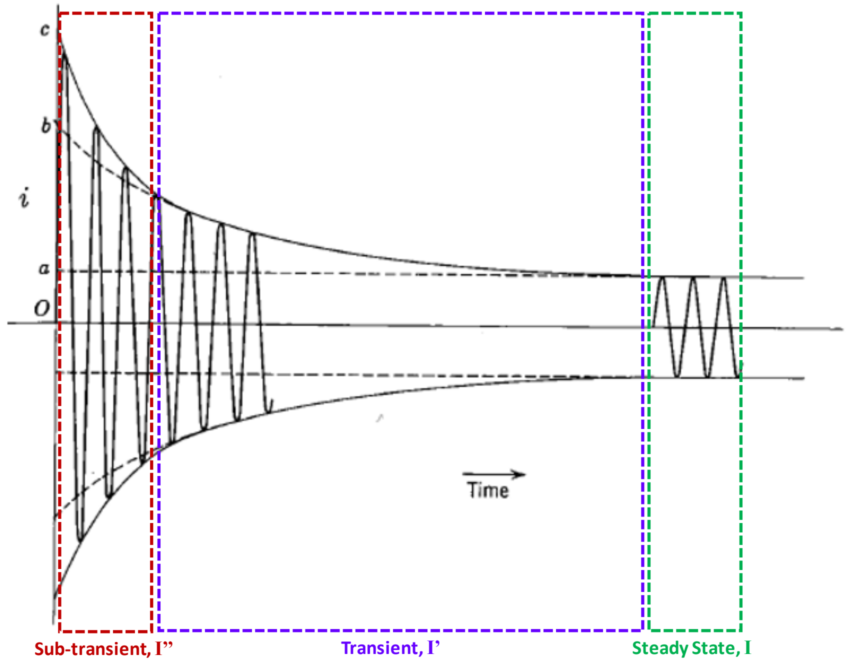


Figure 6. Illustration of a three-phase symmetrical fault with DC offset removed

The initial symmetrical root mean square (RMS) current (I'') or the subtransient current can be computed from the graph as follows:

$$|I''| = \frac{oc}{\sqrt{2}} = \frac{|E_i|}{X''_d} \tag{8}$$

where the emf voltage, E_i, is the no-load terminal voltage.

This is the value of the SCC immediately after the fault occurred. This indicates the size of the current acting and producing mechanical forces on the structure of the circuit breaker that must be withstood by the circuit breaker before the current must be extinguished from the grid.

$$|I'| = \frac{ob}{\sqrt{2}} = \frac{|E_i|}{X'_d} \tag{9}$$

This is the RMS value of the current representing the transient SCC between which the contacts within the circuit breaker must be separated to extinguish the SCC.

$$|I| = \frac{oa}{\sqrt{2}} = \frac{|E_i|}{X_d} \tag{10}$$

This is the RMS value of the SCC that will be sustained if the circuit breaker fails to disconnect the faulted circuit; thus, the backup protection must be able to detect the fault to activate the backup circuit breakers farther from the faulted region and the current used to predict the heat generated by sustained SCC in the cable carrying the SCC. The typical values of the steady-state, transient, and subtransient reactances for a variety of synchronous generators are shown in Table 1 (Prentice 1937). Note that it is very important to understand that the subtransient SCC is very high compared to the steady-state sustained SCC, and a modern circuit breaker can disconnect within 3–4 cycles; thus, the design must consider the subtransient contact separation and the forces it must overcome to separate contacts to clear the fault within a short time.

Table 1. Components of Synchronous Machine Reactances

Source: Prentice 1937

Table I. Components of Synchronous Machine Reactances

Symbol	Name of Reactance	Position of Magnetomotive-Force Fundamental	Magnitude of Magnetomotive-Force Fundamental	Synchronous Motors		Synchronous Condensers	Water-Wheel Generator**	Turboalternator	
				General Purpose	Heavy Starting Duty			Solid Rotor	Laminated Rotor
x_d	Direct synchronous	Directly over pole	Constant	0.80 1.5	0.65 0.90	1.60 avg.	0.60 1.25	1.15 avg.	1.15avg.
x_q	Quadrature synchronous	Midway between poles	Constant	0.60 1.10	0.50 0.70	1.00 avg.	0.40 0.80	1.0 avg.	1.0 avg.
x_d'	Direct transient	Directly over poles	Changing	0.25 0.45	0.15 0.35	0.40 0.50	0.20 0.45	0.13 0.25	0.15 0.25
x_q'	Quadrature transient	Midway between poles	Changing	0.60 1.10	0.50 0.70	1.00 avg.	0.40 0.80	0.13 0.25	1.0 avg.
x_d''	Direct subtransient	Directly over pole	Changing	0.20 0.40	0.10 0.25	0.25 0.3	0.15 0.35	0.08 0.15	0.08 0.12
x_q''	Quadrature subtransient	Midway between poles	Changing	0.30 0.50	0.12 0.30	0.25 0.35	0.25 0.45	0.10 0.20	0.20 0.30
x_2	Negative sequence	Moving relative to poles	Changing in each axis	0.25 0.45	0.11 0.27	0.25 0.32	0.20 0.40	0.08 0.13	0.11 0.21
x_0*	Zero sequence	No fundamental		0.04 0.27	0.02 0.15	0.04 0.10	0.02 0.21	0.01 0.08	0.01 0.08

* x_0 varies from about 15 per cent to 60 per cent of x_d'', depending upon winding pitch.
** These values apply to machines with amortisseur windings. For water-wheel generators without amortisseur windings, $x_d'' = x_d'$, $x_q'' = x_q' = x_q$. x_2 will be an average of x_d'' and x_q'' and x_0 will be unchanged.

2.1.2 Conventional Hydropower Based on Induction Generator

An induction generator is often used in micro-hydro turbines. It uses a squirrel-cage induction generator. This is the simplest type of AC induction generator, where there is no winding in the rotor of the generator. Instead, squirrel-cage-like copper or aluminum bars are casted within a cast iron or other ferromagnetic materials to function as the rotor winding. This generator does not require access to the rotor circuit of the generator. This is different from a wound-field AC generator (e.g., wound-field synchronous generator or wound-field induction generator), where a set of slip rings is required to access the rotor winding. The operating speed varies by a very narrow range (e.g., 1%–2% range). Note that the slip range is an indication of the efficiency of the generator; thus, for practical purposes, the range of operating speeds of the hydro turbine using an induction generator is very narrow, so it can be considered as having fixed-speed operation.

2.1.2.1 Normal Operation

Figure 7 illustrates an induction generator connected to a hydro turbine and connected to the grid. This type of generator is sometimes used for small (micro-hydro) power generation. Usually, three-phase power factor correction capacitors are connected to the terminals of the induction generator so that the reactive power is mostly provided by the AC capacitor compensation. Output power can be adjusted by adjusting the wicket gate; thus, adjusting the water flow drives the turbine, producing mechanical torque, which in turn drives the electrical generator. Note that an induction generator is less efficient than a synchronous generator; however, it is mass-produced for motors to drive machinery in factories. In addition, it is very rugged, cheap, and requires no maintenance. In water pumping applications, it is often used as the motor to drive the pump. In small water pumps, an induction motor is immersed in the water with the rotor, laminated with thin stainless steel, and the water flows through the surface of the rotor, cooling it down at the same time.

Power factor correction capacitors are usually three-phase capacitor banks that enable its effective capacitance to be varied as the output power of the generator varies with the operating slip. Power factor correction is needed because the induction generator, by its nature, always absorbs reactive power during motoring or generating modes. The size of the reactive power is proportional to the quadratic function of the real power generated. In isolated operation, it is possible to operate an induction machine driven by a pico-hydro to generate by self-excitation, where the excitation comes from AC power factor correction capacitors. A set of capacitor banks is used to regulate the voltage and frequency, although the frequency and the voltage regulation depend on the ability to vary the mechanical torque from the turbine and the capacitor values of the switched capacitor banks.

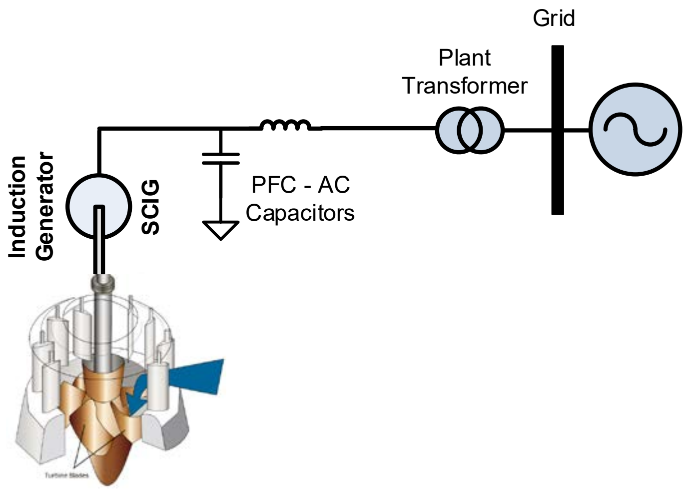


Figure 7. Hydro turbine with an induction generator directly connected to the grid

2.1.2.2 Short Circuit

Some small hydropower generators (e.g., micro-hydro, P < 100 kW) are operated at a fixed speed with a squirrel-cage induction generator. The squirrel-cage induction generator generates electricity when it is driven above synchronous speed. The difference between the synchronous speed and the operating speed of the induction generator is measured by its slip (in per unit or in percentage). A negative slip indicates that the induction generator operates in generating mode. Normal operating slips for an induction generator are between 0% and -1%. The simplified single-phase equivalent circuit of a squirrel-cage induction machine is shown in Figure 8.

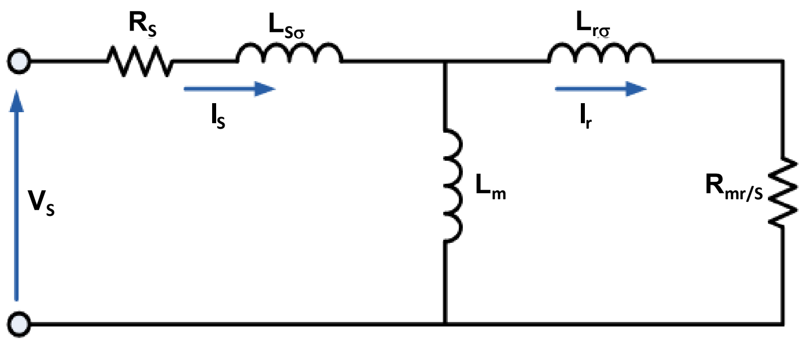


Figure 8. Equivalent circuit of a squirrel-cage induction generator

The circuit in Figure 8 is referred to as the stator, where R_s and R_r are the stator and rotor resistances, and $L_{S\sigma}$ and $L_{r\sigma}$ are the stator and rotor leakage inductances, respectively; L_m is the magnetizing reactance; and s is the rotor slip. In the case of voltage fault, the inertia of the rotor drives the generator after the voltage drops at the generator terminals. The rotor flux might not change instantaneously right after the voltage drop resulting from the fault; therefore, voltage is produced at the generator terminals, causing the fault current to flow into the fault until, gradually, the rotor flux decays to zero. This process takes a few electrical cycles. The fault current produced by an induction generator must be considered when selecting the rating for circuit breakers and fuses. The fault current is limited by the generator impedance (and can be calculated from the parameters shown in Table 1) and the impedance of the system from the short-circuit point to the generator terminals.

The initial value of the fault current fed by the induction generator is close to the locked rotor inrush current. Assuming a three-phase symmetrical fault, an analytical solution can be found to estimate the current contribution of the generator. The SCC of an induction generator can be calculated as:

$$i = \frac{\sqrt{2}V_s}{X_s'}[\, e^{-\frac{t}{T_s'}} \sin(\alpha) + (1-\sigma\,)e^{-\frac{t}{T_r'}}] \tag{11}$$

where α is the voltage phase angle for a given phase, σ is the leakage factor, $X_s'{=}\omega L_{S'}$ is the stator transient reactance, and T_s' and T_r' are the stator and rotor time constants for damping the DC component in the stator and rotor windings. The transient stator and rotor inductances, L_s' and L_r', can be determined as:

$$L_s' = L_{s\sigma} + \frac{L_{r\sigma}\, L_m}{L_{r\sigma} + L_m} \qquad L_r' = L_{r\sigma} + \frac{L_{s\sigma}\, L_m}{L_{s\sigma} + L_m} \tag{11-a}$$

$$L_s \ = L_{s\sigma} + L_m \; L_r \ = L_{r\sigma} + L_m \tag{11-b}$$

$$T_s' = \frac{L_s'}{R_s} \qquad T_r' = \frac{L_r'}{R_r} \qquad \sigma = 1 - \frac{L_m^2}{L_s L_r} \tag{11-c}$$

The current calculated from Eq. 11 is shown in Figure 9 using parameters for a typical 2-MW induction generator when $\alpha{=}30^0{+}\pi/2$ and prefault voltage VS=0.7 $p.u.$ As shown in Figure 9, the current reaches the maximum value at t=T/2 (the first half a period); therefore, it might be a good approximation to calculate the maximum (peak) current by substituting t=T/2 into Eq. 11. The resulting equation for peak current will be:

$$i_{max} = \frac{\sqrt{2}V_s}{X_s'}\left[e^{-\frac{T}{2T_s'}}\sin(\alpha) + (1-\sigma)e^{-\frac{T}{2T_r'}}\right] \qquad (12)$$

It was demonstrated experimentally that Eq. 11 gives satisfactory accuracy for peak current assessment. The resulting current is shown in Figure 9.

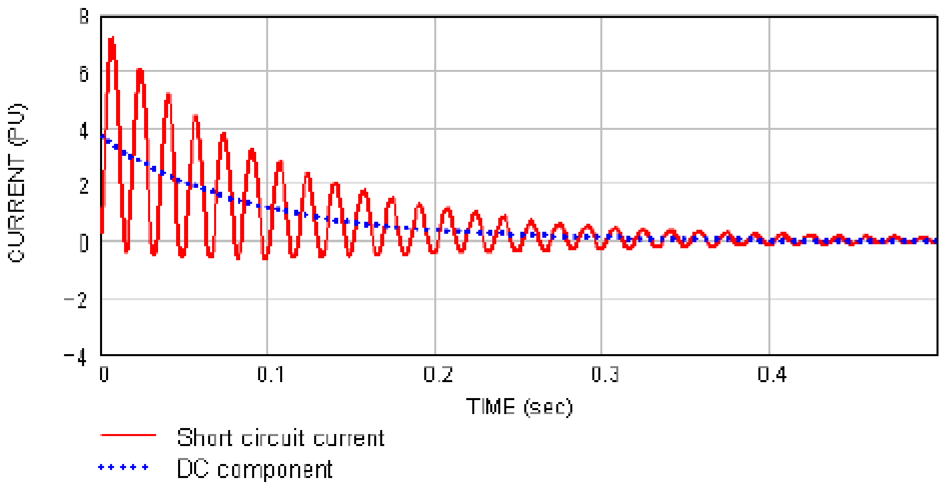


Figure 9. SCC from a Type I induction generator

2.2 Adjustable-Speed Hydropower Generator: Inverter-Based Hydropower Generation

2.2.1 Adjustable-Speed Hydropower Based on Doubly-Fed Induction Generator

An adjustable-speed hydropower plant can be used to control the conversion efficiency to its optimum operation based on the present conditions. A single-line diagram of the system is presented in Figure 10. The first implementation of this type of generation can be found in Japan. Many other similar configurations have been built at different sites around the world (China, Europe, etc.). The first implementation was based on the original synchronous generator, where the excitation winding of the generator was replaced by a wound-field induction generator with a set of three-phase rotating windings fed by a three-phase power converter. Rebuilding the rotor winding was constructed by using a narrower air gap than the original synchronous generator because an induction generator with so many poles will have a low magnetizing L_m, resulting in low power factor, which affects the overall efficiency. A more detail discussion about this type of AS-PSH can be found in Muljadi et al. (2015) and Muljadi et al. (2017).

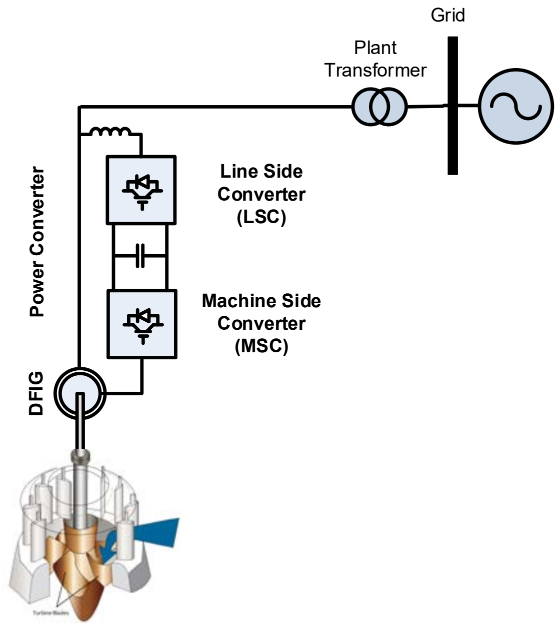


Figure 10. AS-PSH plant with a DFIG

Since it was invented by Nikola Tesla in 1883, the induction machine has been preferred for extensive industrial applications because of its numerous advantages. Recently, the use of wound-rotor induction machines has been revived in the form of induction generators for wind turbine and hydro turbine applications. With the power converter connected to the rotor winding, the induction generator can be operated at variable speed using a partial-rating power converter.

Of the total air gap power of the generator, only a small fraction is dissipated in the rotor circuits. The total electrical output power generated to the grid is given by:

$$P_{total} = (P_{ms} - P_{mr}) = (1 - s)P_{ms} \tag{13}$$

where:

- P_{ms} = power output through the stator winding
- P_{mr} = power output through the rotor winding
- s = operating slip.

Thus, the total power generated by the DFIG is converted into electrical power delivered to the grid, the majority via the stator winding and the rest via the rotor output power. For example, if the turns ratio of the stator-to-rotor winding is one, the DFIG needs to be operated at +30% slip. The power converter to be used must have a rated voltage of approximately 30% and a rated current of 100%. The implication is that using a DFIG in variable speed with slip variation from -30% to +30% requires the size of the power converter to be approximately 30% of the rated power of the induction generator.

2.2.1.1 Normal Operation

The power converter and the DFIG are controlled based on the equations derived in the previous section. The reference power is the commanded power output of the turbine. The DFIG has two separate paths of generation: the stator output power and the rotor output power. The output power from the stator winding (always flowing out of the stator to the grid) can be described as:

$$P_{ms} = \frac{P_{total}}{(1-s)} \tag{14}$$

The stator power generated by the DFIG as a function of the total power is illustrated in Figure 11. As shown, the variation of the stator power is very narrow. For example, in the span of 0.2 p.u. total power variation, the stator power varies by approximately 2%.

Thus, the power entering the rotor winding of the DFIG as shown in the previous equation can be computed based on the desired total power (also refer to Figure 12). As described in the previous equation, the slip (s) is negative above synchronous speed, and it is positive below synchronous speed. Thus, the power flows can flow into (in subsynchronous speed range) or out of (in supersynchronous speed range) the rotor winding depending on the rotor speed.

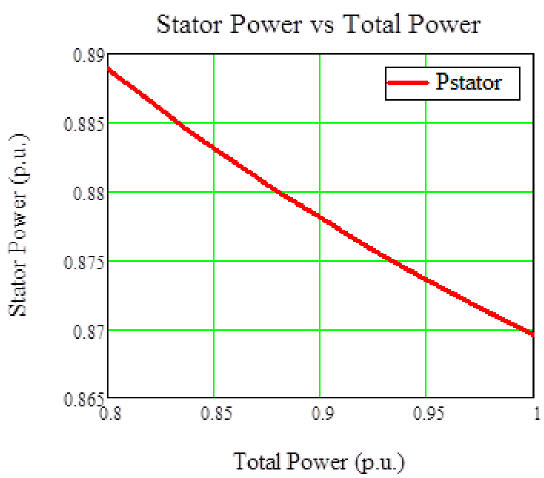


Figure 11. Stator power as a function of total power

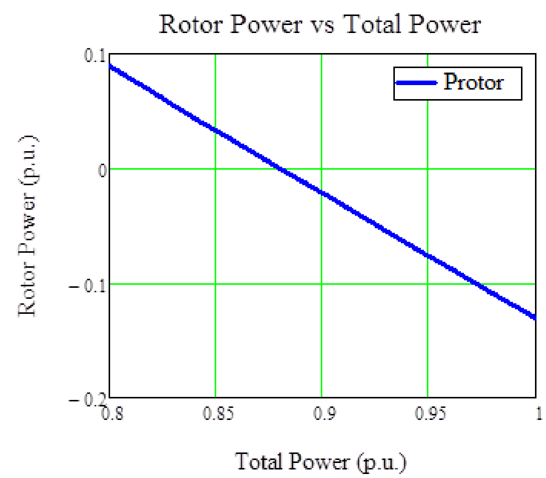


Figure 12. Rotor power as a function of total power

The rotor power can be computed as:

$$P_{mr} = \frac{s}{(1-s)} P_{total} \tag{15}$$

2.2.1.2 Control Implementation

As shown, the variation of the rotor power is linear to the total power variation. For example, in the span of 0.2 p.u. total power variations, the rotor power varies by approximately +/-12%. Note that the rotor power becomes zero at the synchronous speed (slip=0). Below the synchronous speed, the rotor power flows from the grid into the rotor winding; above synchronous speed, the rotor power flows out of the rotor winding to the grid.

As shown in Figure 13, the machine-side converter is used to control the commanded stator output power ($P_{stator\text{-}ref}$) based on the calculated reference that will optimize the hydro turbine. And the reactive power is controlled to follow the commanded reactive power output of the stator winding ($Q_{stator\text{-}ref}$). The real power component of the stator current, I_{pS}, and the reactive power component of the stator current, I_{qS}, are controlled by the machine-side converter.

As shown in Figure 14, the line-side converter is controlled to maintain the DC bus constant and the reactive power contribution from the line-side converter to the grid. Note that by controlling the DC bus constant, the line-side converter automatically transfers the rotor power to the grid. The real power component of the current, I_{pLSC}, is controlled to maintain the DC bus voltage, whereas the reactive power component of the current, I_{qLSC}, is used to control the requested reactive power from the line-side converter.

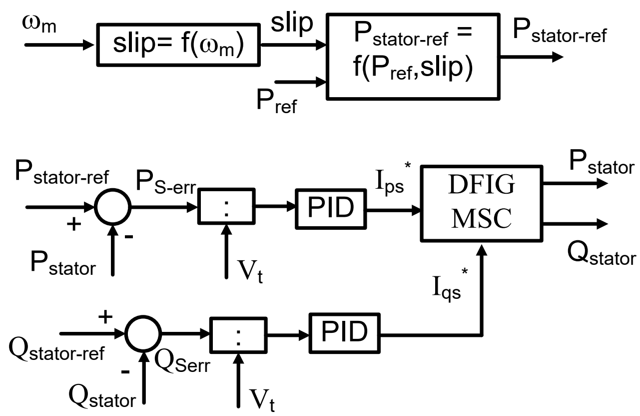


Figure 13. Simplified diagram of a machine-side converter

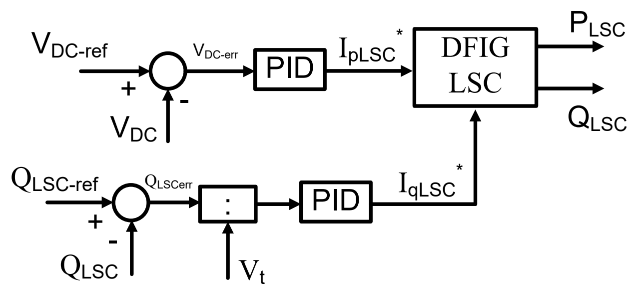


Figure 14. Simplified diagram of a line-side converter

The numerous benefits derived from variable-speed operation justify a renewed look at pumped hydro station operation from the point of view of adjustable speed. The needed technology for such an application is only now emerging, and much research is needed to approach an optimum design of a hydro turbine that can be controlled with the commanded power to follow the maximum efficiency of the energy conversion. As shown in Figure 15, by allowing the rotational speed and the wicket gate opening to follow the desired output power, the operating point of the hydro turbine can ride along the ridge of the conversion efficiency (maximum efficiency). In addition, the power converter can be controlled with an additional loop that can be added to damp the mechanical resonance modes or electrical power system mode; thus, it is practically designed to mitigate the possible damaging impacts on the generator, turbine, or power system stability.

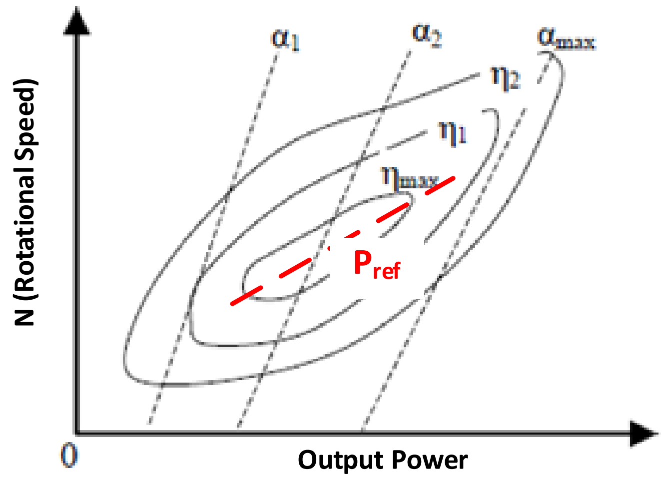


Figure 15. Illustration of the optimum efficiency operation of a hydro turbine

The performance characteristic presented in Figure 1 can be simplified in the form of a hill diagram, shown in Figure 15, wherein the optimum efficiency can be maintained by adjusting the water flow (via the wicket gate angle, α, control) and the rotational speed, n (directly via speed control or indirectly via power control).

AS-PSH is normally optimized to maximize the efficiency of the hydro turbine. The typical optimum operation of a hydro turbine can be found in several publications. For each different head, there is a linear relationship between the rotational speed and the output power of the hydro turbine, and it can be written as:

$$\omega_m\left(head, P_{ref}\right) = -0.05 + 1.25\left(P_{ref} - 0.8\right) - 0.25(head - 0.8) \tag{16}$$

Similarly, for different head levels, there is a linear relationship between the wicket gate positions (to adjust the water flow) as the output power is changed from one value to another, which can be described by:

$$Gate\left(head, P_{ref}\right) = 0.8 + \left(P_{ref} - 0.8\right) - (h - 0.8) \tag{17}$$

The equation for the rotational speed and the gate adjustment can be implemented as shown in Figure 16. In Figure 16, the steady-state optimum operation of the hydropower can be achieved if we can adjust the wicket gate opening and the corresponding rotational speed at any desired output power.

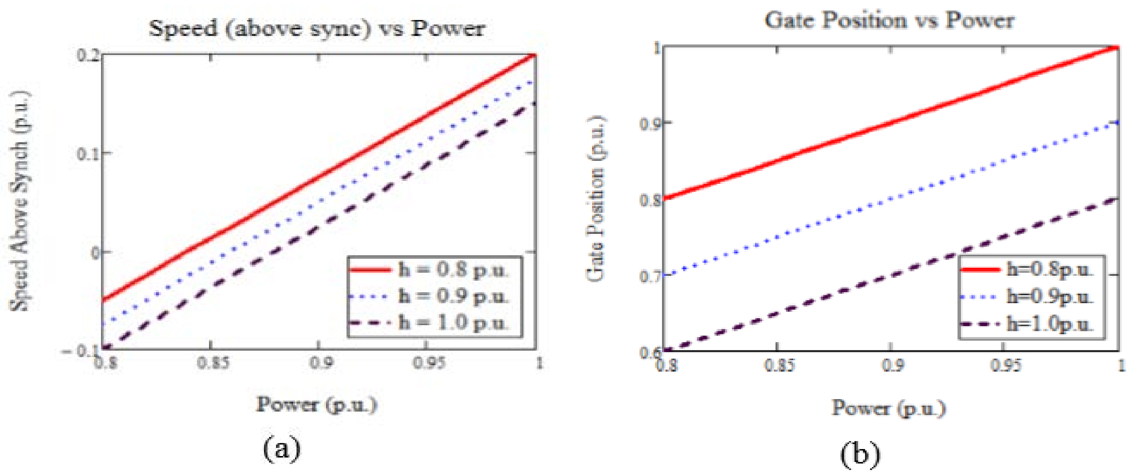


Figure 16. Optimum operation of AS-PSH at different power levels as a function of the head (a) rotor speed and (b) gate position

The relationship is adjusted as the head varies overtime. Note, however, that the variation of the head is much slower than the variation of the reference power, especially during short-term transients when the turbine is required to perform ancillary services (e.g., to accomplish frequency regulation). This characteristic matches the behavior of future power systems, especially in situations with high penetration levels of renewable generation. Examples of successful combinations of hydropower to compensate renewable generation are hydropower and wind power in the Pacific Northwest of the United States within the Bonneville Power Administration. Another example is a combination of photovoltaic generation (850-MW photovoltaic plants) and a hydropower plant (1.3 GW) in Longyangxia Lake in Qinghai, China.

Optimum operation of the adjustable-speed hydropower plant can be illustrated in the block diagram shown in Figure 17.

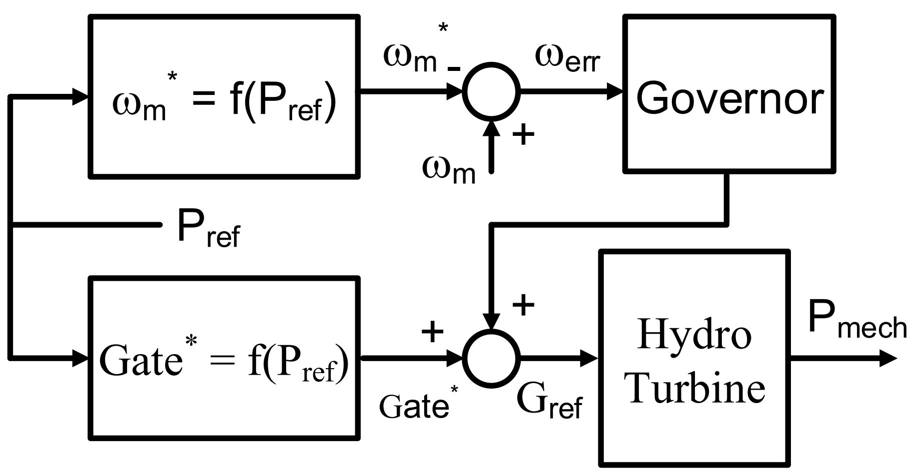


Figure 17. Optimum operation of AS-PSH at different power levels as a function of the head (a) rotor speed and (b) gate position

The fact that the rotational speed of the generator can be adjusted brings a new dimension to operating a hydropower plant with optimum efficiency. In addition, operating the AS-PSH with a power converter makes it possible to operate the system in a fast and flexible manner, thus contributing to power system stability.

2.2.1.3 Short Circuit

An equivalent circuit of a DFIG generator is shown in Figure 18. It is similar to one for a regular induction generator except for an additional rotor voltage, representing voltage produced by a power converter. A crowbar system is usually used to protect the power electronics converter from overvoltage and thermal breakdown during short-circuit faults. Additional dynamic braking on the DC bus is also used to limit the DC bus voltage.

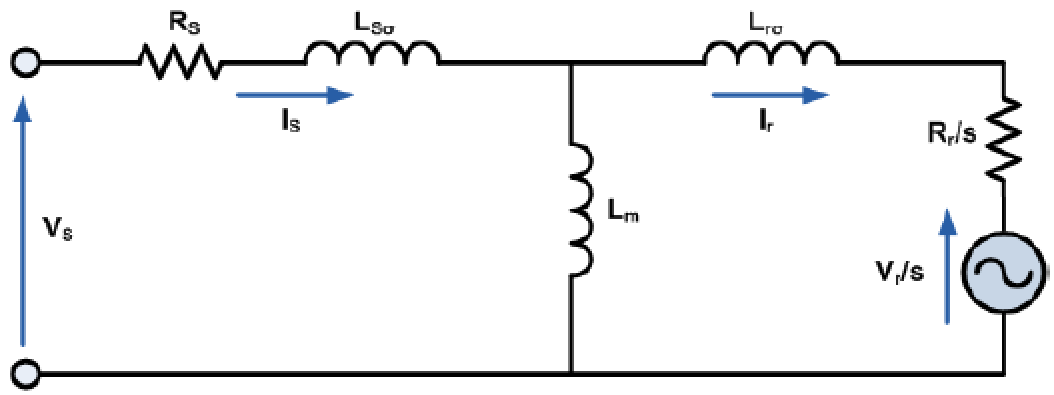


Figure 18. Equivalent circuit of a DFIG

During faults, the rotor windings are essentially short-circuited by an equivalent crowbar resistance, RCB. The transient time constant for a DFIG generator will be:

$$T'_{r.CB} = \frac{L'_r}{R_r + R_{CB}} \tag{18}$$

And the maximum SCC of a DFIG will be:

$$i_{max} = \frac{\sqrt{2}V_s}{\sqrt{{X'_s}^2 + R_{CB}^2}}\left[e^{-\frac{\Delta T}{T'_s}} + (1-\sigma)e^{-\frac{\Delta T}{T'_{r.CB}}}\right] \tag{19}$$

If $R_{CB} \gg R_r$, then $T'_{r.CB}$ is small, and the time of the first peak $\Delta T \rightarrow 0$. In such a case, it is proposed that the equation can be simplified for DFIG maximum SCC. Calculated SCCs for a DFIG for two different crowbar resistance values are shown in Figure 19. In this case, $R_{CB2} > R_{CB1} \gg R_r$. The red plot represents zero crowbar resistance when Rr = 0.005 $p.u.$ The blue and green plots represent cases when RCB = 0.05 $p.u.$ and RCB = 0.1 $p.u.$, respectively. From Eq. 18 and Eq. 19, and as shown in Figure 19, a larger crowbar resistance will lead to lower peak current and smaller AC component. The maximum value of crowbar resistance, $R_{CB.max}$, can be found from the equation if the maximum allowable rotor voltage is specified.

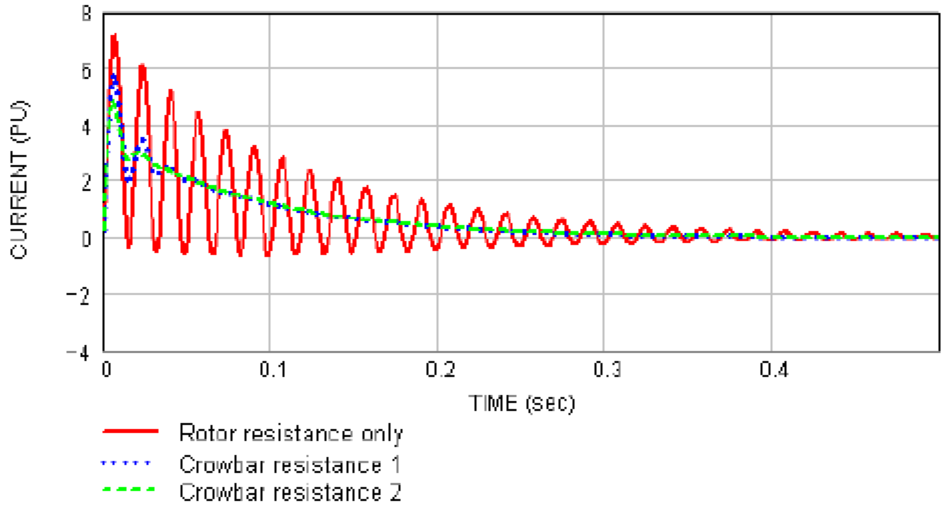


Figure 19. Effect of the crowbar on maximum DFIG current for a fault on the terminal of the generator

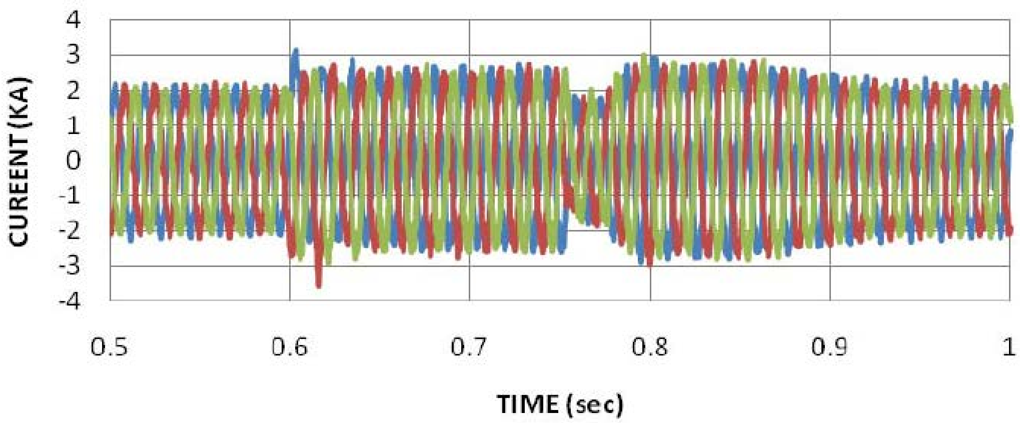


Figure 20. Stator current of a DFIG during the fault on the transmission line

Note that there is a major difference between a DFIG with a regular induction generator because the excitation in a regular induction generator comes from the grid; thus, for an induction generator, if the grid is short-circuited, all the electromagnetic energy will be dumped into the grid. In a DFIG, however, the excitation comes from both the grid and the power converter feeding the rotor winding; thus, in case where the fault occurs on the transmission line—i.e., far from the plant—the output of the DFIG is sustainable because the grid voltage did not completely dip to zero, and thus the excitation from the power converter connected to the rotor winding can still be maintained. Figure 21 illustrates this condition from the test result. Although there is a small transient when the fault starts at t=0.6 seconds, the stator can be maintained constant at its maximum condition (i.e., 1.1 p.u. values), and another transient is noticeable at the end of the fault, around t=0.75 seconds.

Figure 21 illustrates the rotor currents of a DFIG during the fault. Note that the rotor current is controlled to shape the stator current output of the stator winding. The harmonics current content shown is the typical output of the current-regulated pulse-width-modulated power converter. And the variable frequency shown in the current waveform indicates that the rotor speed varies during the observation. Note that during the fault it is common that the turbine is commanded to provide reactive power to support the voltage on the grid; thus, the output is normally intended to produce reactive power to the grid to satisfy the fault ride-through capability of the generator.

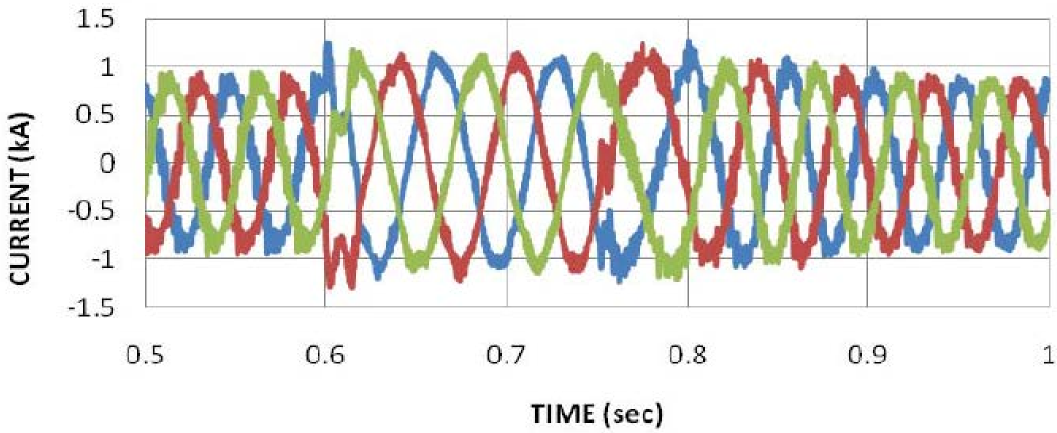


Figure 21. Rotor current of a DFIG during the fault on the transmission lines

2.2.2 Adjustable-Speed Hydropower Based on Full Conversion Generator

Figure 22 illustrates the physical diagram of a full conversion (FC) generator connected to the grid. Although a permanent magnet synchronous generator (PMSG) is used to illustrate this concept, the generator can be replaced by a wound-field synchronous generator or even an asynchronous generator.

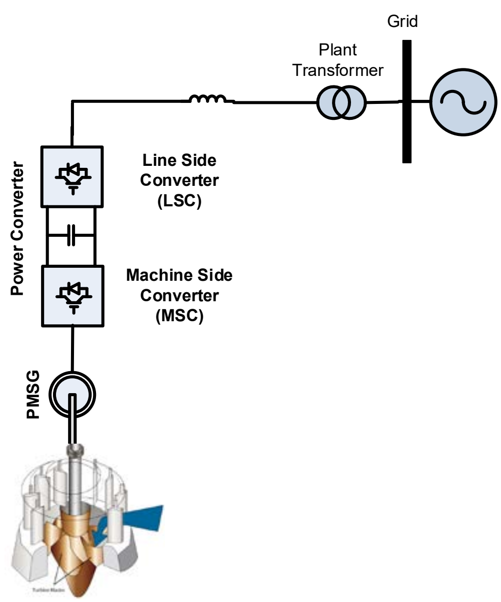


Figure 22. Full conversion hydropower generator with a direct-drive PMSG

A synchronous generator from the electrical design perspective is different from a wound-field induction generator found in a DFIG because a synchronous generator can have many poles without reducing the power factor of the synchronous generator, and thus it does not directly affect the overall efficiency. Another difference between the FC-PMSG and the AS-DFIG is that the AS-DFIG requires only a partial-size power converter. Considering that the range of operation of the variable speeds currently installed is from 0% to 20%, the size of the power converter for a DFIG with 20% range is only 10% of the rated power of the stator winding. The requirement for a speed range operation might be a consideration in choosing the system to be considered for AS-PSH applications.

Although the theoretical limit of the speed range for an AS-PSH is limited, in theory the range of the rotational speed variation of the AS-PSH can be very wide considering that the power converter and generator in an FC-PMSG are normally capable of delivering rated torque for the range of the operating speed range. Another fact not often discussed in DFIG operation is that the operation below synchronous speed (positive slip) will have caused the power to flow from the grid into the rotor winding. This can affect the efficiency of energy conversion (because of the circulating power flow between the grid and the generator via the rotor winding), although the power flow from the stator winding has the same direction regardless of the slip.

Table 2 and Table 3 show the comparison between the DFIG and full converter systems.

Table 2. AS-PSH Comparison of Electromechanical Interactions

	FC-PMSG	DFIG
Theoretical variable-speed range	rpm theoretical limit 0.0 p.u. < ω_m < 1.0 p.u.	rpm theoretical limit for 30% slip variation 0.7 p.u. < ω_m < 1.3 p.u. In many cases, the range of slip is from $\pm$5% to $\pm$10%.
Grid coupling	Stator winding completely decoupled from the grid; thus, this is electrically and electromagnetically decoupled from the grid. Power system oscillations can be buffered to stay on the grid and not affect the rotor and hydro turbine.	Electrically and electromagnetically coupled to the grid. Stator winding connected to the grid, and rotor winding decoupled from the grid Power system oscillations might impact the rotor and the hydro turbine (via electromagnetic coupling from the grid-connected stator)
Impact of grid faults on control coordination	During the voltage dip, there might be a temporary imbalance between the mechanical input and the electrical output to the grid (because of the voltage dip). This requires control coordination to ensure that kinetic energy in the water flow and rotating mass can be diffused through the gate control and the power control.	The same as FC-PMSG

Table 3. AS-PSH Comparison of Grid Integration

	FC-PMSG	DFIG
Reactive power controllability	Adjustable up to max limit and down to min limit	The same as FC-PMSG
Reactive power and voltage control—normal operation	Reactive power is controllable up to its maximum limit for a PQ bus, or it is used to control the voltage for a PV bus. Note: PQ and PV are power system terms often used to describe the control implemented on the generating bus—i.e., power, P, and voltage, V, controllable for PV and for PQ bus; the Q means reactive power is controllable.	The same as FC-PMSG
Reactive power and voltage control—fault events	During the fault, the bus voltage is often dropping significantly; thus, the available power that can be delivered is also limited because of the voltage drop. Thus, the maximum power converter current cannot be exceeded.	**For distant faults:** The same as FC-PMSG **For near faults:** Often the power converter connected to the DFIG loses its capability to control the machine. Survival mode requires disconnection or, to a lesser degree, crowbar insertion during the near-fault events.
Impact of grid faults on the power converter	**For distant faults and near faults:** Output currents controllable up to 1.1 p.u. rated current (assuming the 10% overcurrent design of the power converter). Very often during the fault the power converter is commanded to supply reactive power to support the grid voltage.	**For distant faults:** Output currents controllable up to 1.1 p.u. rated current (assuming the 10% overcurrent design of the power converter). Very often during the fault the power converter is commanded to supply reactive power to support the grid voltage. **For near faults:** Output currents might not be controllable during the fault. Crowbar protection is often used to avoid overvoltage on the DC bus of the power converter.
Fault ride-through	Fault ride-through is often implemented based on the grid requirement. It is basically the requirement that the power plant stays connected to the grid during a fault event. Often it is defined by the lower and upper limits of the voltage and frequency range, within which the plant must stay connected, and beyond which the plant can be disconnected from the grid.	The same as FC-PMSG

3 Hydropower Plant

3.1 Reliability Concepts

The North American Electric Reliability Corporation (NERC) defines the reliability of the interconnected bulk power system in terms of two basic and functional aspects (NERC 2013):

- Adequacy
  - The ability of the electricity system to supply the aggregate electrical demand and energy requirements of the end-use customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements.
- Operating reliability.

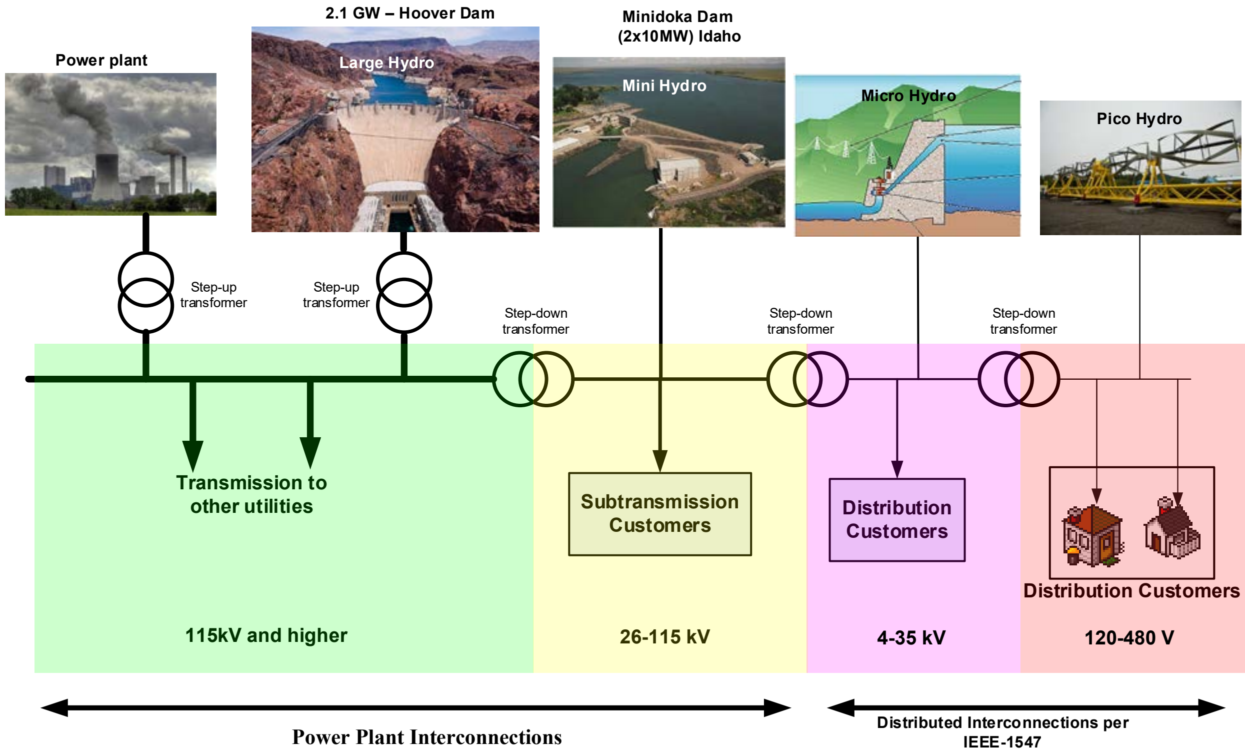
The ability of the bulk power system to withstand sudden disturbances, such as electrical short circuits or an unanticipated loss of system elements from credible contingencies, while avoiding uncontrolled cascading blackouts or damage to equipment.

Hydropower plants in general address the adequacy aspect of power systems with predictable energy resources available to be deployed to supply power within a specific duration. AS-PSH addresses the operating reliability of the power system by its capability to react and to quickly rectify the temporary power imbalance between supply and demand during both pumping and generating operations.

3.2 System Integration

Connection to the grid is often the subject of power system integration, where the plant is connected to the grid at different levels of the voltage depending on the power rating of the power plant, as illustrated in Figure 23. Based on capacity, hydropower can be classified as: pico (<5 kW), micro (5 kW–100 kW), small (101 kW–2,000 kW), mini (2,001 kW–25,000 kW), and large (>25,000 kW). These categories might vary from one country to another, but the general rules are the same (low power rating is connected to low-voltage level, high power rating is connected to the subtransmission or transmission voltage levels).

In general, a very small hydro turbine is connected at the low- or medium-voltage (distribution network). A large hydropower plant is the same size as a conventional power plant (e.g., steam, gas, wind, photovoltaic power plants), and it must be connected to a higher voltage level (subtransmission or transmission voltage levels). A variable-speed design normally incorporates advanced power electronics components that increase overall turbine cost. These components are required to change varying AC power to a constant voltage and frequency. Electrical distribution grids, to which the turbine is connected, must maintain steady frequency and voltage levels to avoid damaging equipment (at the point of common coupling) of other users on the same utility, such as motors and sensitive electronics. Electrical harmonics are also a critical issue for any variable-speed design. Harmonics distort the normally smooth sinusoidal variation of utility voltage. Among many other drawbacks, harmonics increase losses and heating in transformers and motors, do not contribute to motor output torque, cause unbalanced currents in power systems, and are harmful to many modern computers and communications system components.



Source: National Renewable Energy Laboratory

Figure 23. Grid interconnection at different voltage levels determined by the power rating of the plant

In addition to these well-known electrical harmonic problems, there is the special case of sudden jumps in voltage. Such voltage surges can usually be analyzed as a combination of many high-frequency harmonics. The past few years have shown a remarkable increase in insulation failures of motors and generators driven by adjustable-speed drives that employ power electronics. This phenomenon appears to be related to the sudden drive voltage changes that some power electronic circuits can supply to their associated motor or generator. The problem appears to get worse as the distance between the generator and power electronics increases. This problem is especially significant for some applications where the electric machines are usually remote from their driving electronics on the ground (e.g., submarine oil pump for oil exploration, wind turbine, some water pumping and hydro turbine applications).

A key factor in dealing with these two issues is the control methodology for the adjustable-speed turbine. A properly designed control scheme can smooth the time-varying loads that are transmitted through the machine components by using wicket gate (gate) control or the ability of advanced power electronics to smooth rotor loads by limiting torque excursions within the drivetrain. Optimum power electronic designs are still under study, as are new control methodologies. Despite the issues and unknowns, the increased gain in energy capture by the application of adjustable-speed design, together with torque spike reduction and excellent grid integration, have made the pursuit worthwhile.

3.3 Hydropower Plant

A typical single-line diagram of a hydropower plant connected to the grid is shown in Figure 24. The generator is connected to the generator bus (Bus 5), and unless the grid is very weak, a turbine-level shunt compensation is normally not necessary. The generator side step-up transformer steps up the voltage from the generator output terminal voltage to a higher voltage for distribution throughout the distribution network or to be transmitted along the transmission line to a distant load center. For a small hydropower plant supplying local loads, the generator output voltage is usually in the medium-voltage range (three-phase, 60 Hz, 4.16 kV); however, for a large generator, the generator output voltage is usually at a higher voltage rating (e.g., 22 kV or 33 kV). Similarly, the generator step-up transformer is an important bridge connecting the generation side to the distribution or transmission side. It is often operated day and night at full load and sometimes in very high swings of output generation (e.g., when operated to provide ancillary services to the grid in cases of high penetrations of renewable generation). It is intended to withstand extreme thermal loading to avoid premature aging or even failures of winding insulations.

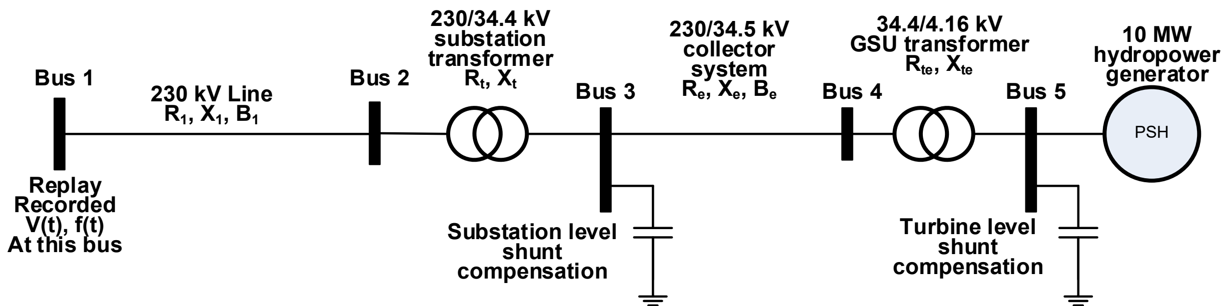


Figure 24. Typical one-line diagram of a hydropower generator

The generator step-up transformer (at the transformer bus: Bus 4) is usually located near the generator in the generating station complex. This generator step-up might be combined with the substation transformer in cases where the voltage and the size of the plant are large enough, and this arrangement might reduce capital costs of the plant. The output of the generator step-up transformer is connected to another line either to supply the local loads (if connected to the distribution network) or to deliver the power over long distances to load centers. In some cases, it can be very far from the power plant. In this case, the line feeders connecting the generator step-up transformer to the substation transformer will be rated at a higher voltage (e.g., 34 kV–110 kV) to ensure that the voltage drop along the line and the line losses will be minimum, especially if there is a significant distance between the generating station and the substation transformer. This line is connected to the substation bus (Bus 3), and there is provision to connect the substation level shunt compensation (e.g., which might be needed if it is connected to a weak grid).

At the substation, a substation transformer steps up the voltage from the subtransmission level to the transmission level (e.g., 110 kV/230 kV). This stepping up of the voltage is very important to deliver power over a long distance so that for the same power level, the delivered power requires only small/low current to be transmitted over long distances (minimum voltage drop and minimum line losses). At the transmission bus (Bus 2), the output power of the plant is delivered to the load centers (e.g., at Bus 1). It is customary to see renewable generation sources located in rich resource areas, which are sometimes far from load centers, where the generated power can be used.

3.4 Summary of Short-Circuit Current Contribution for Different Types of Hydropower Generator

This section considers three-phase-to-ground faults. Other types of faults are normally smaller, and thus the resulting SCC is not used to size the switchgear nor to set the system protection setting values. The SCC for different types of hydropower generators is not the same, as described in the previous section. For each turbine type, the peak value of the magnitude of the SCC is affected by the transient reactance, the prefault voltage, the effective rotor resistance, the existence of constant excitation (synchronous generator or DFIG), the distance from the faults, and other circumstances at the instant the fault occurs.

Table 4. Comparison of SCC Contribution for Different Types of Hydropower Plants

AS-PSH	Synchronous Generator	Induction Generator	DFIG	FC-PMSG
Max I_{SC_PEAK}	$\frac{2\sqrt{2}V_s}{X_d''}$	$\frac{2\sqrt{2}V_s}{X_s'}$	$\frac{2\sqrt{2}V_s}{X_s'}$	1.1 I_{RATED}
Min I_{SC_PEAK}	$\frac{\sqrt{2}V_s}{X_d}$	$\frac{\sqrt{2}V_s}{X_s'}$	1.1 I_{RATED}	0

Table 4 shows the tabulated SCC contribution, including the maximum and minimum values. A grid-connected synchronous generator has the largest SCC as a result of small X_d'' and X_d' (influenced by the presence of the damper and startup windings) and the sustained SCC because of the presence of excitation by the field winding. The induction generator has a large SCC, but it has a very short duration because the electromagnetic flux dies out during the fault. The SCC behavior of the inverter-based DFIG hydropower generator is affected by the crowbar and the dynamic braking actions. For a very near fault, the crowbar might be fully deployed, thus short-circuiting the rotor winding, and the SCC behavior resembles the grid-connected induction generator; however, if the crowbar and the dynamic braking can maintain operation of the rotor-side power converter, the SCC behavior is very close to that of an inverter-based FC-PMSG. For almost all the SCC for a DFIG, only a small SCC current is passed through the power converter because of the current limit of the power semiconductors. The FC-PMSG has a full power converter between the generator and the grid; thus, the SCC is very well regulated, and the SCC can be maintained at 1.1-p.u. rated current.

Because power system planners at utility companies are concerned about worst-case scenarios, the generator representation is very suitable to determine the SCC contribution from a power plant to perform a system impact study, to set and coordinate the system protection of the power plant, and to size the switchgear within the power plant.

For a grid-connected synchronous generator, the SCC is well understood and well documented. For a grid-connected induction generator, the maximum SCC assumes that the DC offset is at the worst condition, and the minimum SCC is calculated by assuming that the DC offset is zero. For a DFIG, the maximum value is computed when the crowbar shorts the rotor winding, and the minimum value is computed when the power converter can follow the commanded current (i.e., in case the fault occurs far from the point of interconnection, the remaining terminal voltage is sufficiently high enough to let the power converter operate normally and supply the commanded currents). Note that for a symmetrical fault, the actual fault current for each phase is different from the other phases because the time of the fault occurs at a different phase angle for different phases, thus affecting the DC offset. For an FC-PMSG, the stator current can always be controlled because of the nature of the power converter, which is based on a current-controlled voltage source converter.

3.5 Generator Interconnection

Grid interconnection for a generator or power plant usually follows guidelines provided by the host utility. It is necessary to provide the interconnection guidelines when the power plant is to interconnect to a host utility's electric system to comply with the local rules and regulations set up by the host utility. The interconnection often includes supplying ancillary services required to support the operation and the reliability of the power system.

These requirements are needed for any generator connected the grid at the distribution network or larger power plants (e.g., wind power plants or hydropower plants) connected at the transmission level and delivering power to the grid. Interconnection requirements are subject to federal regulation (e.g., Federal Energy Regulatory Commission), public utility commissions (e.g., California Public Utilities Commission), and the host utility regulations (e.g., Southern California Edison). A good reference on power plant interconnection to cover renewable energy power plants can be found in the Southern California Edison (SCE) *Interconnection Handbook* (2016). The handbook is revised periodically; thus, the latest edition should be checked at the SCE website. The handbook is divided into three distinct parts based on the customer project type that is being connected, planned to be connected, or facility additions and modifications to existing customer facilities interconnected to SCE's electric system. Note that the handbook can be updated from time to time to reflect the changes in the power system network, the incoming new types of generators, the new technologies in the power system implemented at the distribution or transmission networks, and the new grid codes requirement from the regional reliability organization and from NERC.

The three parts of the handbook address:

- Generator interconnections
- Transmission interconnections
- End-user facility interconnections.

4 Conclusion

In summary, although an AS-PSH facility is a modern power plant with a combination of AC generator and power converter, the electrical systems of pumped storage hydropower (PSH) plants are similar to any other power plant. During the past few decades, numerous renewable power plants have been installed, some of which have a power rating of several hundreds of megawatts; thus, power system planning (feasibility studies, system impact studies, etc.) facilities planning (sizing the switchgear, transformer, system protections) have been implemented on other renewable power plants with similar capacities and capabilities.

From the resource point of view, the main difference between AS-PSH and other renewables (wind, photovoltaics) is the availability of the resource (water) and the ability to adjust the source (water flow). In comparison, wind (photovoltaics) cannot really increase the output power if the wind speed (or solar irradiance) stays the same.

From the available energy stored, the main difference between AS-PSH and a conventional battery energy storage system is the capacity (the level of potential energy available). A large PSH plant might be able to store 1 GW-hour (assuming 100 MW at 10 hour). At this level of capacity, a battery energy storage system will be too expensive to construct.

Regarding the life span, PSH can last more than 100 years, whereas a battery energy storage system must be replaced within 10–20 years. Wind power plants and photovoltaic plants are designed to last 20–30 years.

The following can be summarized for AS-PSH:

- Power, voltage, and current ratings are similar to those of conventional power plants (steam, gas, large renewable plants).
- In AS-PSH plants, individual generators are typically much larger than the individual generators in other renewable power plants (e.g., a large wind turbine is between 3–10 MW, whereas an AS-PSH plant could consist of multiple 100 MW generators).
- There are many types of hydropower generators (induction, DFIG, synchronous generator, adjustable-speed generator), similar to wind power generators; thus, the start-up procedure and the SCC contribution depend on the generator types. And the switchgear and the setting of the system protections must be specified according to the type of generator used for the AS-PSH.

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