Performance of Generator Protection Relays During Off-Nominal Frequency Operation

Dennis Tierney
Calpine Corporation

Bogdan Kasztenny, Dale Finney, Derrick Haas, and Bin Le
Schweitzer Engineering Laboratories, Inc.

This paper was presented at the 67th Annual Conference for Protective Relay Engineers and can be accessed at: http://dx.doi.org/10.1109/CPRE.2014.6799021.

For the complete history of this paper, refer to the next page.

Published in
Synchronous Generator Protection and Control: A Collection of Technical Papers Representing Modern Solutions, 2019

Previously presented at the
3rd Conference on Operation & Maintenance and Renovation, Modernization, Uprating and Life Extension of Hydro Power Plants, August 2017,
68th Annual Georgia Tech Protective Relaying Conference, April 2014,
and 67th Annual Conference for Protective Relay Engineers, March 2014

Originally presented at the
40th Annual Western Protective Relay Conference, October 2013

Performance of Generator Protection Relays During Off-Nominal Frequency Operation

Dennis Tierney, *Calpine Corporation*
Bogdan Kasztenny, Dale Finney, Derrick Haas, and Bin Le, *Schweitzer Engineering Laboratories, Inc.*

***Abstract*—This paper reviews the protection requirements for generators during periods of off-nominal frequency operation. It investigates the behavior of instrument transformers during these periods as well as the impact of frequency on the accuracy of protection operating quantities. Traditional methods for frequency tracking and compensation are reviewed. A novel approach, which provides excellent performance for very significant frequency deviations and can accommodate multiple frequency islands, is presented.**

I. Introduction

A generator can be energized and is therefore subject to damage when the machine frequency differs significantly from nominal. For instance, many hydrogeneration machines are designed to sustain speeds of up to 1.5 times nominal in order to accommodate the power mismatch that occurs from the instant that the generator is rejected from the power system to when the wicket gates close. Such machines are designed for this level of overspeed and should remain in operation so that they can be quickly reconnected to the system. At the other end of the range are combustion gas turbines and pumped storage units that are started as synchronous motors connected to adjustable speed drives. Total start time can be up to 30 minutes, during which time the frequency can be at or below 0.3 times nominal.

Although these periods of off-nominal frequency operation may be infrequent, damaging faults can occur because the generator is energized, so effective protection is still required. These protection functions must also not misoperate because this could delay placing a generator in operation.

Because protection functions are often designed to respond to the fundamental frequency component of system voltages and currents, significant deviations from nominal frequency can have a major impact on protection performance unless accounted for in the relay design.

This paper reviews various cases of off-nominal frequency operation (Section II), explaining the reasons, duration and machine, prime mover and system configurations at the time, and protection requirements. In Section III, the paper discusses the performance of instrument transformers under off-nominal frequencies. Next, in Section IV, the paper discusses the accuracy of electromechanical, static, and microprocessor-based relays under off-nominal frequencies. It teaches the basics of digital signal processing, frequency tracking, and phasor estimation in microprocessor-based relays. Section V presents a novel approach to frequency tracking that allows a generator relay to accurately measure frequency signals over a wide range that belong to different frequency islands. Section VI explains typical methods of measuring frequency for the application of tracking. Finally, Section VII discusses applications and solutions for cases when frequency tracking is not possible.

II. Off-Nominal Frequency Operation of Synchronous Generators

Generator governor control systems are designed to keep the unit operating at or near nominal frequency. During power swings, a machine can deviate from its nominal operating frequency. However, the frequency deviation from nominal during an unstable power swing does not deviate as much as the situations we review in this paper. In this section, we describe cases where a generating unit is intentionally operated at a frequency outside of its normal operating range. This is typically done on a temporary basis to address an operating condition, for example, a gas combustion turbine that is undergoing a starting sequence. Because the reasons for intentionally operating a unit outside of its normal operating range vary depending on the type of prime mover that is driving the machine, it makes sense to categorize the off-frequency operation of machines according to the prime mover.

A. Hydrogeneration Units

Hydrogenerators have two main operating conditions where they can operate well outside of the nominal frequency range: load rejection and dynamic braking. Load rejection results in extremely high frequencies, whereas dynamic braking results in low frequencies.

1) Load Rejection

Any sudden loss of load on a generator produces an increase in speed, regardless of the type of generator and prime mover driving it. Of particular interest is the case of load rejection, where a generator that is exporting power is quickly separated from the system by a breaker opening or by one or several tie lines tripping offline. In these cases, keeping the generator running so that it can be quickly synchronized and reconnected to the rest of the power system is desirable. Particularly in hydrogenerators, load rejection is important with regard to the discussion of frequency. In steam or combustion turbine generators, the sudden increase in acceleration can be detected and the supply of steam or fuel can be shut off or reduced quickly by fast-acting valves. The control system can quickly react to the loss of electrical load to prevent or limit overspeed conditions. For hydrogeneration units, their turbines are driven by a large volume of water moving at a relatively high speed. Quickly shutting off the water supply is not easily done, and quickly closing a wicket gate to stop the flow of water can result in a water hammer. The maximum and minimum design pressure levels of the penstock limit the rate of gate movement [1]. There are some solutions that can help mitigate this problem. Pelton turbines can be equipped with fast-acting deflectors that divert water flow and allow the needle valves to slowly close, avoiding the pressure spike and water hammer that would otherwise result from rapidly closing the needle valves. Other units have a pressure relief valve attached to the spiral casing. This valve operates when there is a fast closing of the guide vanes or wicket gates, depending on the particular technology. This action reduces the amount of overspeed by dumping the water from the spiral casing into the draft tube, bypassing the turbine. In general, however, a full load rejection by a hydrogeneration unit can result in speeds of up to 150 percent of nominal [1] [2].

Fig. 1 shows a plot of frequency versus time for a partial load rejection event. The event shows the frequency measured out on the system following a trip of a large 500 kV line. For this particular event, the frequency of the generator and part of the power system increased to 65 Hz before the governor speed controller responded. The governor speed controller will typically respond within 100 milliseconds. The plot in Fig. 1 shows the response of the machine (including the gates) and the governor.

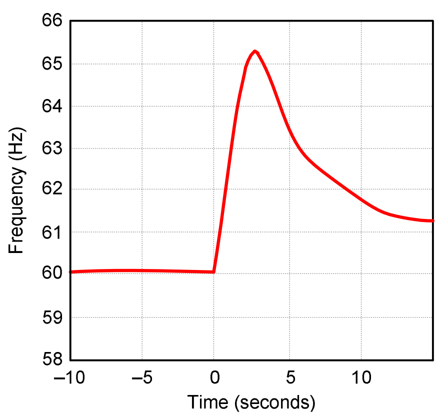

Fig. 1. Frequency versus time plot during load rejection.

Hydrogeneration units are designed to withstand an increase in speed, and their speed governors can respond so that the unit can be brought back online without damage. If there is a governor malfunction, the speed can quickly reach levels of 200 percent of nominal. At these speeds, damage to the machine can occur. To handle such a case, mechanical overspeed and overfrequency protection are applied to detect any governor malfunction and to shut off the supply of water to prevent machine damage.

Hence, having protection elements that can perform securely and sensitively during a load rejection with frequencies of up to 200 percent is desirable. Because the machine is running with excitation during a load rejection period (and, in the case of a partial load rejection, still serving some load), many of the typical protective elements that are enabled during normal operation of the generator (both current- and voltage-based elements) need to be active, enabled, and functioning. Having backup overfrequency protection that can measure and react to frequencies of up to 200 percent of nominal is desired.

2) *Dynamic Braking*

Another process commonly applied to hydrogeneration units is dynamic braking. Dynamic braking essentially has been used as a way to electrically slow down synchronous motors and generators, with documented successful results dating back to 1932 [3]. Dynamic braking places an intentional three-phase resistance or short circuit on the stator windings while maintaining excitation. This has the effect of slowing down the machine as the rotational energy is effectively dissipated as heat.

Hydrogenerators are typically salient-pole generators that are oriented vertically. Unlike their wound cylindrical rotor counterparts in high-speed steam-powered generators, the weight of the moving rotor structure is supported by a thrust bearing because of the vertical orientation. With many of these installations, at normal speeds the centrifugal force of the rotor circulates the lubrication or self-lubricates the thrust bearing. However, at lower speeds with lower centrifugal force, the thrust bearing may not self-lubricate. As a result, a machine that is turning at a slow speed may damage the thrust bearing, hence the need to stop the machine quickly after it falls below a certain speed.

Traditional solutions to slow a hydrogeneration machine involve frictional brakes, similar in concept to the disc braking systems in automobiles. The brakes produce dust, so that is one disadvantage to this type of system.

Dynamic braking is an alternate solution. An example dynamic braking sequence is shown in Fig. 2.

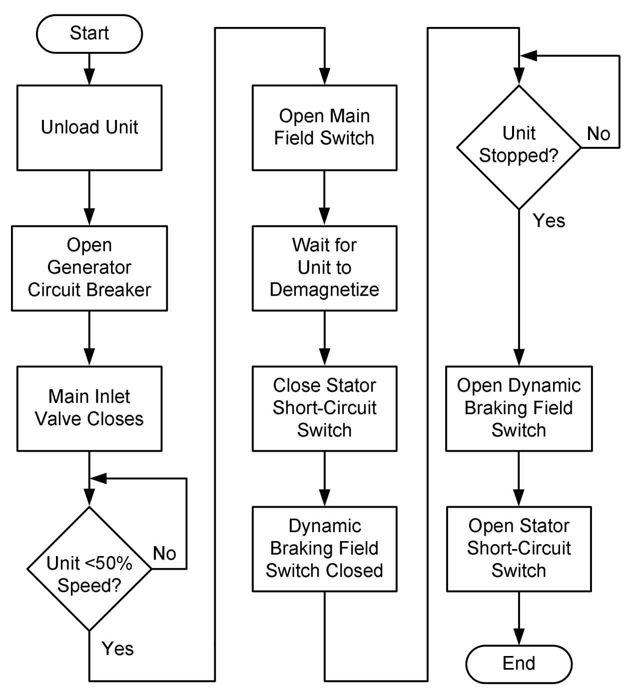

Fig. 2. Flow chart of a simplified dynamic braking sequence.

Placing a three-phase short circuit at the stator terminals through a suitable shorting switch will not damage the machine during dynamic braking and, in fact, will generally produce near-rated current on the windings. In the flow chart in Fig. 2, the generator breaker has been opened and the unit has had time to spin down, which means that the static exciter has lost its source and the main field breaker also opened before applying the short circuit. This implies that the fluxes in the rotor and air gap have decayed. The fact that there is little or no flux in the rotor or air gap when the short is applied means that the typical fault decrement curve that we see for faults applied when a unit is excited with a fixed level of field current is not applicable here. The current will not go through a decrement and will remain near its synchronous value, which is at or less than the rated generator current for typical values of synchronous reactance for hydrogeneration machines.

From a protection standpoint, while the unit is undergoing dynamic braking, it has a field, is rotating, and is feeding current at the level of the rated current to the short circuit through the shorting switch. Therefore, appropriate protection elements should be enabled and active. For instance, an internal stator fault could occur, and this would prove damaging. If any problems are detected during dynamic braking, the only thing that can be done is to trip the field offline because the prime mover is already shut off and the generator breaker is already opened. Because there is a short at the terminals of the machine, many protection functions cannot operate and should be disabled. Absence of terminal voltage also makes frequency tracking infeasible, further limiting protection availability. Phase fault protection (87G) and ground fault protection (59N and 64G) can be enabled and active. Because frequency tracking is unavailable, nonconventional methods are required to implement these functions (see Section VII).

One added complication to protection during dynamic braking is the differential element. Fig. 3 shows an example one-line diagram with a static exciter, a stator shorting switch, a dedicated braking rectifier, and switches to swap between the automatic voltage regulator (AVR) and braking rectifier.

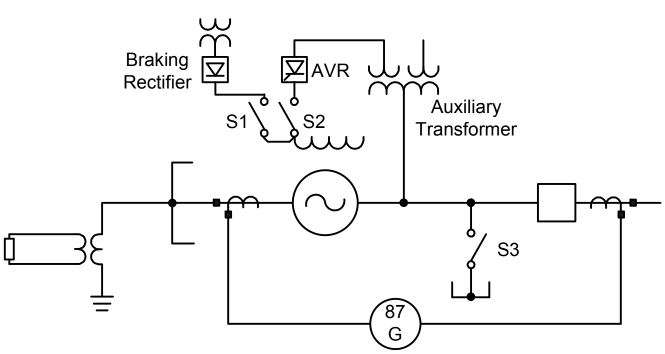

Fig. 3. Simplified one-line diagram illustrating dynamic braking.

During dynamic braking, when the dynamic braking field switch is closed and the generator breaker is open, we have a clear case where the differential relay sees differential current. There are two main ways to resolve this: disable the differential element during dynamic braking or include the stator shorting current in the differential zone. To disable the differential element during dynamic braking, a logic input into a microprocessor-based relay can disable the differential element. For the second solution (including the stator shorting current in the differential zone), Fig. 4 shows a one-line diagram with the stator shorting current transformer (CT) included.

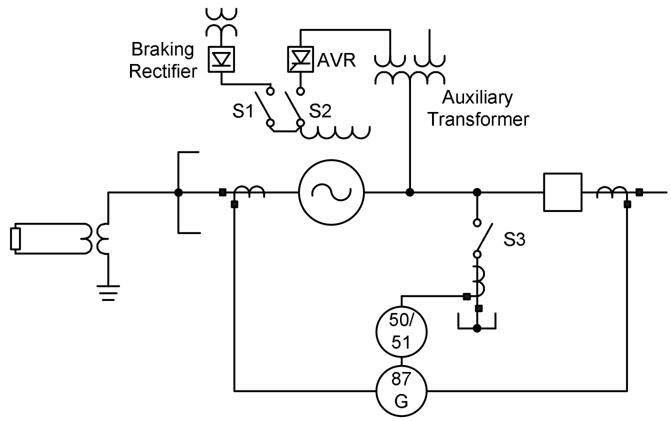

Fig. 4. One-line diagram with stator shorting switch CTs included in differential circuit.

While adding this CT solves the problem by making the differential element secure during dynamic braking, extra care must be taken to provide protection against accidental closing of the breaker while the short is applied because the short is now outside the zone. Additional security is gained by interlocking with the generator breaker, fast backup protection (shown as a 50/51 element looking at only the stator shorting switch CTs in Fig. 4), or both. To provide both effective protection for the stator and protection against accidental breaker closing, a modern microprocessor-based relay would need differential and overcurrent elements that are capable of operating when the frequency cannot be measured.

B. Pumped Storage Units

A pumped storage hydrogeneration installation has the capability to pump water from a lower reservoir to a reservoir at a higher elevation to be stored and used later. This capability allows the unit to operate as a pump during off-peak periods and then as a generator during peak periods. Therefore, the generators at a pumped storage hydrogeneration facility have the capability to run as either motors or generators.

Many pumped storage facilities swap between pumping mode and generating mode by changing the direction of the rotation on the turbine. This change of direction is accomplished by transposing the positions of the primary electrical leads on the generator and, by so doing, reversing the phase sequence. This is done automatically using breakers and switches. An alternative is to have a tandem combination of a separate motor and generator. For the former case, where a single machine acts alternately as a motor or generator, care must be taken in the protective relays to ensure that all relaying that is sensitive to the phase sequence is accounted for. There are several ways to handle this, but because this is outside of the scope of the frequency control of machines, we direct the readers to [4]. For the latter, a tandem combination where a separate motor and generator are used, the phase sequence and direction of rotation does not need to be changed when changing from pumping mode to generating mode.

In either case, of particular interest in the discussion on frequency tracking is the starting of the unit in pump mode. There are a variety of methods to start the machine as a motor when the unit is in pumping mode. These methods include direct across-the-line starting; synchronous starting, where one unit operating as a generator brings the unit operating as a motor up to speed; reduced frequency (or semisynchronous) starting, which can be considered a hybrid of the first two methods; and static converter starting, which is similar to combustion gas turbine starting (see Section II, Subsection C).

For the latter three methods, the unit is energized with the field applied while the frequency is increasing to bring the unit up to nominal speed. The frequency ranges and times vary depending on the method of starting employed, but in terms of generator protection, the protection elements should have an operating range down to low frequencies. Phase and ground fault protection (87 and 59N) are required. In the past, electromechanical relays that had poor performance at low frequencies were employed (see Section IV). Consequently, for phase faults, a supplementary overcurrent relay that had improved frequency response was sometimes applied. Similarly, a supplementary relay was applied for the neutral overvoltage function. However, this relay typically had no capacity to reject the third harmonic, and this resulted in degraded performance. Volts/Hz protection is required to ensure that the unit is not overexcited during the start process. Because these machines use a reversing switch to change from generator to pump mode, phase balance protection (46 and 47) is used to ensure correct operation of the switch [4].

C. Combustion Gas Turbine Units

Combustion gas turbine units operate outside of the normal operating frequency range when they are started as motors connected to adjustable speed drives. The speed and frequency in this case are well below normal. In addition, combustion gas turbines are run at low speed to clean or wash the compressor blades. During the wash cycle of the machine, the frequency is well below normal. We again address each case in detail in the following subsections.

1) Static Starting

One unique feature of a gas turbine is that generally it must be brought up to a certain percentage of rated speed before ignition of the fuel can begin. The sequence of bringing the unit up to a certain speed to purge the compressor, allowing the unit to coast down, igniting the fuel, and aiding the turbine coming up to a higher speed is typical of combustion gas turbines. In traditional gas turbine installations, this was done by mechanically coupling a starting motor or gas engine to the shaft of the machine (through at least a clutch) so that the starting motor (or engine) could bring the unit up to the required speed before igniting the fuel. An example schematic diagram of a simple open-cycle, single-shaft 5 MW unit is shown in Fig. 5 [5].

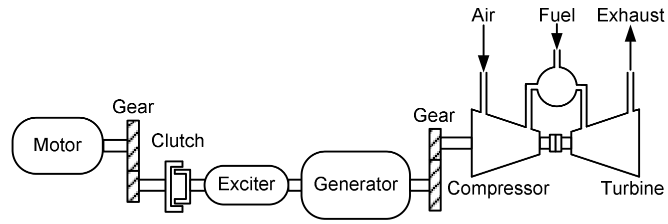

Fig. 5. Example schematic diagram of a gas turbine equipped with a starting motor.

As an alternative to Fig. 5, where a motor or engine on the mechanical system is used to bring the compressor and turbine up to speed, the generator can be temporarily operated as a motor and run through its starting cycle. This is typically done using an adjustable speed drive so that the speed can be precisely controlled. A simplified one-line diagram showing a gas turbine that employs static starting is depicted in Fig. 6.

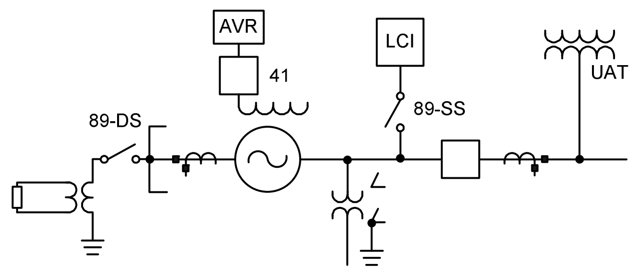

Fig. 6. Simplified one-line diagram of combustion gas turbine with static starting.

The adjustable speed drive shown in Fig. 6 is a load commutated inverter (LCI). During starting, the starting switch, 89-SS in Fig. 6, is closed. If a ground fault develops on the dc link in the drive, the dc current will flow in the grounding transformer (if left connected) and through any wye-connected transformer windings (for example, the voltage transformer [VT] windings). This will quickly drive the transformers into saturation, causing damage. Either dc ground fault protection must be employed or the grounding transformer must be disconnected from ground during starting and open-delta VTs must be employed to remove any ground paths and avoid this problem [6]. Therefore, in many systems, the high-impedance ground is removed and the generator is started as an ungrounded machine. Hence, the grounding disconnect switch, 89-DS in Fig. 6, is opened.

An example of the speed in per unit (pu) of the unit during a starting sequence is shown in Fig. 7. During a startup sequence, the machine is operated at a low frequency of 0 to 18 Hz for a period of 10 to 15 minutes during purge and ignition and the associated acceleration and coast time periods and slowly accelerated from approximately 10 Hz to its full speed over a period of about 15 minutes.

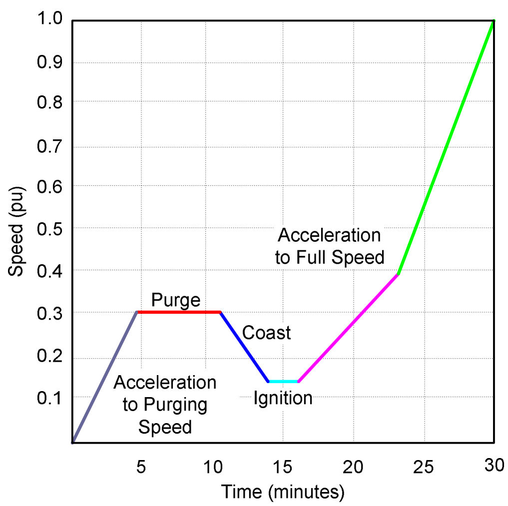

Fig. 7. Example start sequence, speed versus time [6].

In terms of protection during the period when the LCI is applied, the ground fault protection may not be connected and active, depending on the design of the static starting system. Elements that are not needed are backup protection, such as 21, 51V, loss-of-field protection, reverse power, undervoltage and overvoltage, underfrequency and overfrequency, and current unbalance. Overexcitation is optionally applied.

Because the static starting LCI is inside the differential zone, there is differential current during the static starting sequence. The following three options are commonly used to address this differential current during static starting:

- Add a CT between the LCI output and the generator input, effectively excluding all or part of the LCI from the differential zone.
- Turn off the differential element completely during static starting. In modern microprocessor-based relays, this is a simple matter of wiring a logical input into the relay and using that input to enable and disable the differential function.
- Desensitize the settings instead of shutting off the differential element completely, specifically raising the minimum pickup setting above the maximum expected LCI current only during static starting. This can be done a variety of ways, ranging from using settings groups to simply having two differential relays with only one active during static starting.

Ideally, the protection elements that are active during static starting need to be capable of operating at a range from 60 Hz down to very low frequencies. This includes the differential, ground fault (machines with permanently connected neutrals), and overexcitation elements. In addition, detection of blown fuses (60 or loss of potential [LOP]) in the form of a voltage balance element is provided. There is also dedicated protection for the LCI drive mechanism itself, including protection against dc faults. This protection, while important, is outside the discussion of frequency, and we refer interested readers to [6].

2) Wash Cycle

Approximately 50 to 60 percent of the total losses occurring in a gas turbine originate in the compressor. Therefore, keeping the compressor operating as efficiently as possible is an important part of operating a plant efficiently. Fouling of a compressor happens when solid and/or condensing particles precipitate on rotating and/or fixed blades in a compressor, adversely affecting the performance of the compressor. Causes of fouling include airborne salt, industrial pollution, insects, other airborne materials like dust, and so on. Factors such as the relative humidity, ambient temperature, and incidence of fog and rain all have an effect on how susceptible a compressor is to fouling [7]. With such a wide variety of causes of compressor fouling, it is assumed that turbine fouling will occur, and the key is to mitigate its effects.

To mitigate turbine fouling, the obvious method is to make sure the incoming air supply to the compressor is filtered and the filtering system is well maintained. In addition, as a turbine fouls, efforts must be made to clean or wash the blades in the compressor.

There are two main ways in which a compressor can be washed: the first is the offline or wet wash and the second is the online wash. The first method involves shutting down the turbine and allowing it to cool. Then water and detergent are injected into the compressor as it is rotated at a low cranking speed. This process involves washing, soaking, and rinsing cycles of varying duration and sequence. Online turbine washing is done by injecting water into the compressor while the turbine is running. This method has the distinct advantage of being done with the unit online. However, because the compressor is running, the water evaporates as it moves through the compressor. Hence online washing does not clean all of the blades. Even with online washing, it is generally recognized that at some point an offline wash cycle is still required. Using a combination of online and offline washing at varying intervals has been shown to provide benefits in efficiency [8].

The offline wash cycle primarily affects the electrical system and protection. Traditionally, personnel would simply rotate the turbine shaft at a low cranking speed using a mechanically coupled motor through a clutch to drive the turbine (similar to the traditional starting sequence shown in Fig. 5). However, the generator can intentionally be motored at a low speed using the LCI converter that is also used to start the gas turbine. So for an offline wash cycle, the generator will be rotating at a very low speed (about 9 Hz) and motoring with excitation applied. An example of a speed-versus-time profile for a wash cycle is shown in Fig. 8.

The protection requirements for the machine during a wash cycle are similar to the requirements of the machine during static starting.

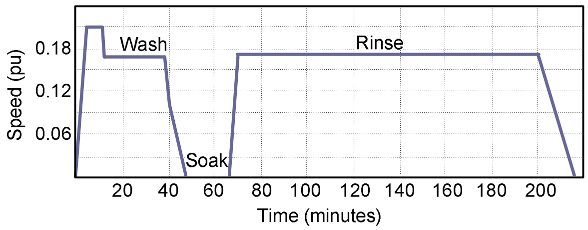

Fig. 8. Speed versus time during wash cycle.

D. Thermal Units

At the beginning of the startup process and following a shutdown, thermal units must be placed on turning gear to ensure even heating and cooling and thereby prevent shaft bowing. Depending on the size, the unit can remain on turning gear from several hours to several days following a shutdown. The starting process for a tandem-compound thermal unit entails running the unit up to nominal speed, applying the excitation, and then synchronizing the unit to the system. These machines are quite sensitive to speed variations when online. Therefore, the requirements for off-nominal frequency operation are not onerous. The startup and shutdown processes for cross-compound machines differ in the way that the excitation is applied. These units are composed of two generators, each connected on separate shafts to different turbine stages. During startup, the excitation is applied at a very low frequency in order to lock the rotor of the second generator to the first generator. On cross-compound units, one generator is physically connected to the turning-gear motor and, as a consequence, the excitation remains applied while on the turning gear in order to maintain rotation of the second generator. Because the excitation is applied, protection is required. However, because the turning-gear speed is very low, the electrical frequency is low, typically less than 2 Hz. Consequently, protection is limited to rms overcurrent for the detection of faults on the stator winding and volts/Hz protection to ensure that full excitation is not inadvertently applied.

E. Summary of Off-Nominal Frequency Requirements

Table I summarizes the functions that can be applied for all previously discussed applications. Some functions respond to an rms magnitude, for example, the voltage measurement of the volts/Hz element. Others respond to the fundamental magnitude and must reject other frequencies, such as the fundamental neutral overvoltage element. Some functions use both the magnitude and angle components (i.e., phasors) of a measured quantity, such as the stator differential or the backup distance. In Section III, we discuss how these various measurements are impacted during periods of off-nominal frequency operation.

TABLE I
PROTECTION REQUIREMENTS BY APPLICATION

	Hydrogeneration Load Rejection	Hydrogeneration Dynamic Braking	Pumped Storage Starting	Combustion Gas Turbine Starting	Cross-Compound Startup/Shutdown
Backup Distance	X				
Volts/Hz	X		X	X	X
Loss of Excitation	X				
Current Unbalance	X		X		
Voltage Unbalance			X		
Overcurrent*		X			
Voltage Restrained Overcurrent	X				
Split-Phase Overcurrent	X				
Phase Overvoltage	X				
Ground Fault	X	X	X	X	X
Stator Differential	X	X	X	X	X
Generator Step-Up Transformer (GSU) Differential	X		X	X	
Overall Differential	X		X	X	
Loss of Potential	X		X	X	

*Protection against accidental breaker closing with shorting switch applied

III. Performance of CTs and VTs During Off-Nominal Frequencies

Protection functions need accurate representations of the primary voltage and current. Instrument transformers provide galvanic isolation and scale these signals down to secondary levels (e.g., 69 V, 5 A nominal). Internal relay VTs and CTs further isolate and scale the signals to levels usable by electronic circuitry. Because these are iron-core magnetic devices, they are subject to saturation if they develop excessive levels of flux. In general, the core flux magnitude is directly proportional to the voltage at the transformer terminals and inversely proportional to the frequency. As a consequence, some impact on performance is anticipated at off-nominal frequencies.

Conventional transient performance analysis of a CT takes into account a dc exponentially decaying offset in the fault current waveform. Assuming that the system is a series inductance (L) and resistance (R) circuit and that the CT burden is resistive, the CT saturation voltage is given by (1).

$$v_s = I_s R_B \left[e^{-\frac{R}{L}t} - \cos\omega t \right] \tag{1}$$

The flux in the CT core is the integral of v_s in (1):

$$\varphi = I_s R_B \left[\frac{L}{R}\left(1 - e^{-\frac{R}{L}t}\right) - \frac{1}{\omega}\sin\omega t \right] \tag{2}$$

Equation (2) consists of an exponentially decaying dc component that is frequency independent and an ac component with a magnitude that varies inversely with frequency. Fig. 9 plots (2) at various frequencies.

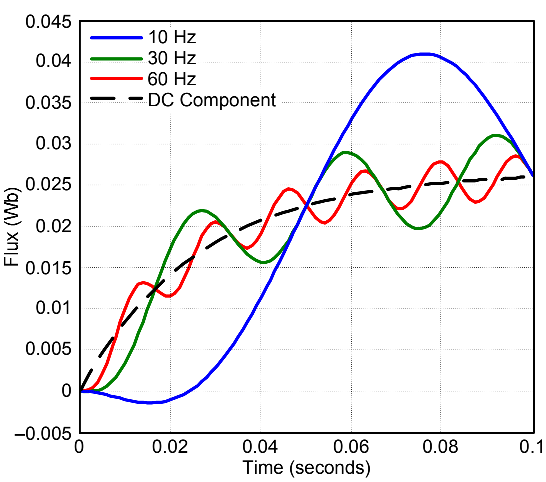

Fig. 9. Flux developed in a CT during a fault on an LR branch at various frequencies of the source (L/R of 30 milliseconds).

As shown in Fig. 9, the ac component in the flux becomes increasingly larger at low frequencies. We can investigate more thoroughly through the use of the following computer model.

Assuming zero remnant flux at the fault inception, the ratio current $\frac{I_{primary}}{N}$, secondary current, excitation (in ampere-turns), and flux waveforms in their transient state are plotted in Fig. 10 for a fault at 60 Hz.

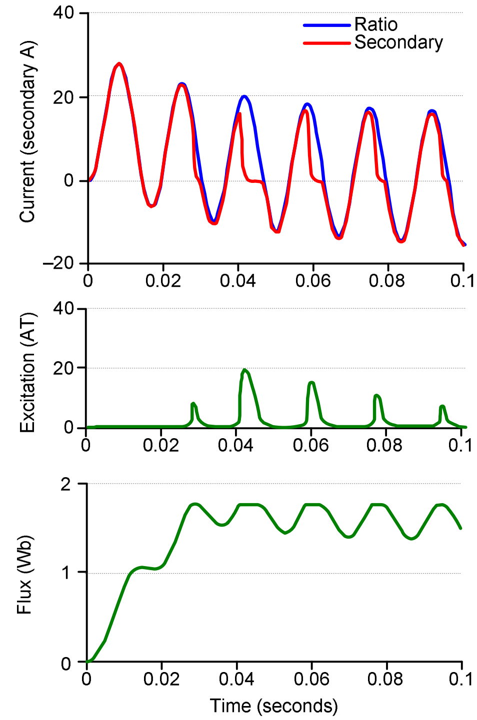

Fig. 10. CT performance at 60 Hz.

It can be observed that there is minor saturation between the third and fifth cycle as the integrated flux density reaches the saturation level on the B-H curve, increasing the magnetizing current.

Next, we consider the impact of reducing frequency for the same primary current waveform. A common concern for CT performance is that the magnetic core is more likely to saturate at lower frequencies because the area under the positive side of the offset fault current gets larger. For comparison, Fig. 11 takes the primary current of Fig. 10 and applies it to a CT at 30 Hz. At 60 Hz, it takes 0.142 seconds for the fault current to reverse direction and start decreasing the flux, while the same process takes twice as much time at 30 Hz. Integrating an identical waveform at 30 Hz causes the flux density to reach the saturation level in the first cycle of the fault, resulting in faster and deeper CT saturation.

However, as we discuss next, applying the same primary current wave shape derived at 60 Hz to a CT operating at 30 Hz is not a realistic scenario.

Note that the time constant at which the dc component of the fault current decays is $\tau = \frac{L}{R}$, which is constant regardless of the frequency. In addition, a machine is operated at a constant volts/Hz ratio during low-frequency conditions, limiting the electromagnetic force driving the ac component of the short-circuit current. The effect is shown in Fig. 12, where the peak fault current value that appears at the first half-cycle point is lower than that in the 60 Hz fault case. The CT core does not saturate until 1.5 cycles into the fault, and the CT transitions back to its linear operating region on the B-H curve faster in comparison with Fig. 11. Therefore, the danger of CT saturation at a lower frequency is not as high as we would initially expect.

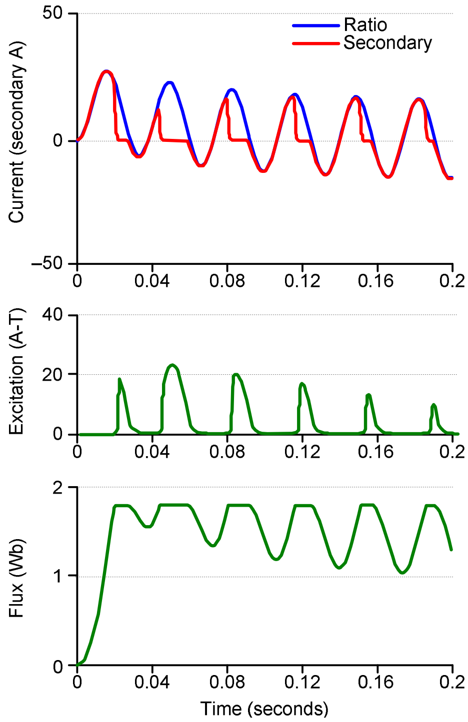

Fig. 11. CT performance at 30 Hz with a 60 Hz fault current waveform.

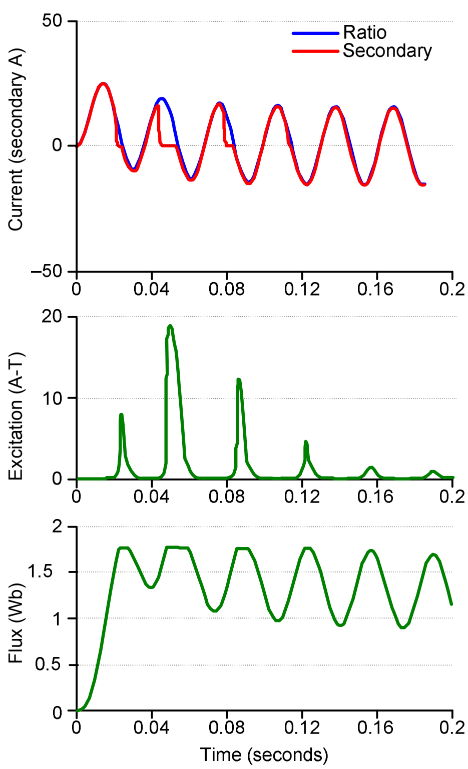

Fig. 12. CT performance at 30 Hz, assuming a generator with limited volts/Hz and a short circuit behind constant LR branch.

From (2), it is also noted that flux is dependent on fault current magnitude that is, in turn, dependent on generator impedance and terminal voltage. For a generator operating offline, we can anticipate that impedance will drop with frequency. However, when we consider normal operation of the machine at reduced frequency, then we can also expect that the terminal voltage will be reduced in proportion with the frequency. The machine resistance and system resistance both remain constant when the power system frequency varies. Fig. 13 shows the relationship of fault current level with respect to frequency for a sample LR branch.

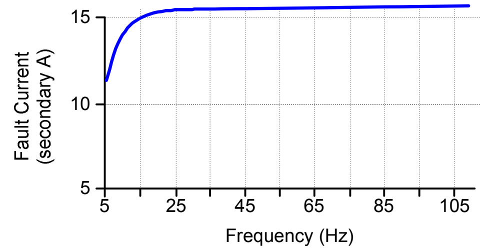

Fig. 13. Fault current magnitude versus frequency.

Considering a relatively high system X/R ratio, the trace in Fig. 13 is fairly flat as the frequency varies. Only when the frequency decreases considerably does the fault current decrease in proportion to the frequency because the resistance component (constant with respect to frequency) dominates the fault impedance. At standstill, the fault current is only limited by the resistance.

The final consideration for CT performance is the protection application. At low frequencies, the machine is offline, which means security for external faults is not a concern. Low-set overcurrent fault protection can be applied, but there can still be some stator current flowing in starting applications (pumped storage or combustion gas turbine starting) or during dynamic braking. Therefore, a differential element can provide more sensitive fault detection. However, in either case, these functions can be set to operate instantaneously. Time-to-saturate calculations described in IEEE C37.110 are applicable at off-nominal frequencies and can be used to check that protection elements pick up before saturation occurs [9]. Note that the protection response is also impacted by frequency. An element that takes 1 cycle to operate at 60 Hz will still require 1 cycle to operate at 10 Hz but will be six times longer when measured in milliseconds.

We now turn the discussion to VTs. These devices are designed to operate close to rated flux at nominal voltage, as illustrated in Fig. 14.

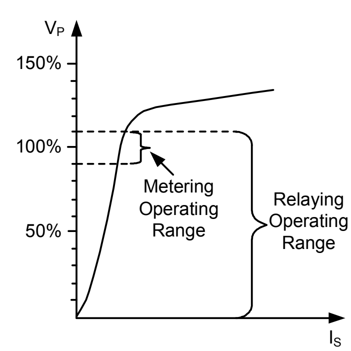

Fig. 14. Typical VT operating characteristic.

At nominal frequency and with typical applied settings, voltage-dependent generator protection functions are expected to operate within the linear region of this characteristic.

When the generator is operated at frequencies higher than nominal, the flux in the VT decreases, which has the effect of increasing the knee point shown in Fig. 14 and making saturation less likely as a result. Conversely, operating the machine at frequencies lower than nominal has the opposite impact, increasing core flux and effectively lowering the knee point. However, in order to safely operate a generator at lower frequencies, the machine voltage must also be reduced because the stator flux is subject to the same physical laws as the instrument transformers and overfluxing will damage the machine. Therefore, under normal machine operation at low frequencies, the expected reduction in generator voltage means that the instrument and relay VTs are still expected to operate in their linear regions.

Volts/Hz protection requires special attention. In order to coordinate with the generator and GSU capability curves, a combination of definite-time and inverse-time characteristics is typically employed. One example application calls for sending an alarm when the volts/Hz ratio is 105 percent and tripping in 2 seconds at the volts/Hz ratio of 118 percent [10]. On examination of Fig. 14, it can be concluded that the function will operate reliably even in the event of severe overexcitation.

Another element that is commonly employed for ground faults is the neutral overvoltage function (64G1 or 59N). This element is tuned to the fundamental frequency and set to provide coverage of about 95 percent of the stator [10]. This results in a setting in the range of 5 V (secondary), depending on the neutral grounding transformer ratio. For a fault at the generator terminals, the neutral voltage rises to the line-neutral value. However, because the generator voltage is reduced in proportion to the frequency, the neutral grounding transformer always operates in its linear region. However, because the pickup setting is fixed, coverage is reduced.

In summary, due to the impacts of various factors—some hurting and others helping—it is difficult to make definite conclusions about the performance of instrument transformers at off-nominal frequencies. Manufacturers can test individual functions and provide plots of metrics, such as accuracy or speed versus frequency. This provides protection engineers with information on the protective relay itself. However, the primary instrument transformer, generator operation, and fault current characteristics must also be considered when determining the effectiveness of the complete protection system.

IV. Traditional Approaches to Frequency Excursions in Protective Relays

A. Frequency Spectrum Requirements for Various Protection Elements

Various protection elements work on various frequency components in their input signals. Fig. 15 provides an illustration of three simple examples.

First, consider an inverse-time overcurrent element (ANSI 51) applied to provide thermal protection. The element should respond equally to all the frequency components in the current signal because all frequency components in the current cause heating. In other words, information that is used by the element is contained in the entire frequency spectrum, as shown in Fig. 15a.

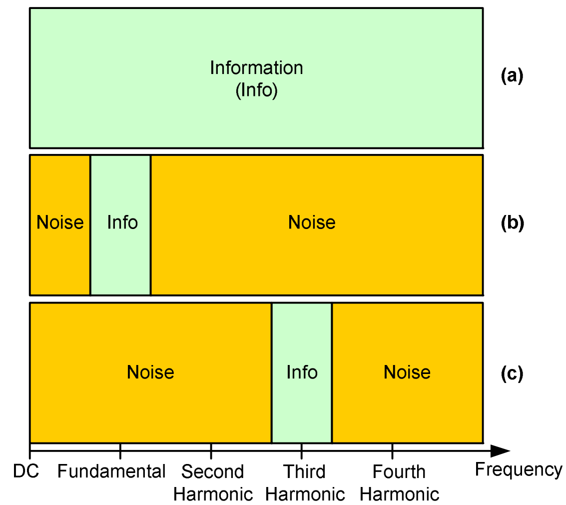

Fig. 15. Frequency spectrum of useful information for various types of protection elements ([a] thermal protection, [b] short-circuit overcurrent or undervoltage and overvoltage protection, and [c] third-harmonic ground fault protection).

Next, consider a time-delayed undervoltage element (ANSI 27) applied to protect a generator from a prolonged undervoltage condition. Ideally, this element should respond to the fundamental frequency component in the input voltage, and it must be quite accurate given the tight setting margins. To achieve high accuracy, it should not respond to harmonics and other signal components. In other words, information that is used by the element is contained in a narrow frequency band around the fundamental frequency, as shown in Fig. 15b.

Finally, consider a third-harmonic undervoltage element (ANSI 27T) applied for stator ground fault protection. This element measures the third harmonic in its input signal and must filter out not only other high-frequency components but also the standing fundamental frequency component (which is normally tens of times higher in magnitude than the third harmonic). In other words, information that is used by this element is contained in a narrow frequency band around the third harmonic, as shown in Fig. 15c.

Protective relay designers attempt to recognize the requirement that each particular protection function may need to respond to a different part of the frequency spectrum of useful information. The following two aspects should be addressed:

- If required, a relay should filter unnecessary frequency components while responding only to the frequency spectrum of interest.
- As the fundamental frequency changes, especially in applications for generators, a relay should maintain accuracy of pickup and its filtering properties despite the shift in the fundamental frequency.

To illustrate this better, consider the third-harmonic undervoltage element (27T). As the fundamental frequency moves from 60 to 65 Hz, the third harmonic shifts from 180 to 195 Hz. A properly implemented 27T element should respond to the 195 Hz component and filter out the 65 Hz component after the fundamental frequency changes to 65 Hz.

The stated frequency spectrum requirements have been very difficult to meet with the electromechanical and static relay technologies but can be easily met in microprocessor-based relays.

The following subsections discuss the frequency dependence of various relay generations and explain in more detail the frequency impact and compensation (tracking) in microprocessor-based relays.

B. Electromechanical Relays and Signal Frequency

In general, the response of electromechanical relays is difficult to characterize. Plunger-type overcurrent electromechanical relays respond to the rms value of the signal by their principle of operation (the torque equation involves an averaged, squared instantaneous current) unless special precautions are taken to provide some extra filtering, especially with respect to the decaying dc component. Decaying dc components can be removed by so-called mimic filters. Extra band-pass filtering can be accomplished by assembling passive filters and tuning them to resonate at the desired frequency of maximum sensitivity.

Electromechanical relays working with a voltage signal use a high-impedance coil to obtain the ampere turns required to activate the mechanism with a small current drawn from the voltage circuit. Therefore, their input impedance is naturally highly inductive and proportional to frequency. As a result, the coil current is inversely proportional to frequency, causing these relays—unless compensated—to increase their pickup values at higher frequencies. Table II shows the pickup accuracy values for sample uncompensated voltage relays.

TABLE II
TYPICAL FREQUENCY RESPONSE OF UNCOMPENSATED ELECTROMECHANICAL VOLTAGE RELAYS [11]

Relay Type	Pickup (in % of 60 Hz value)		
	30 Hz	60 Hz	90 Hz
Plunger/solenoid	50	100	150
Induction disk	160	100	90
Diode bridge rectifier	100	100	100
Hinged armature auxiliary	50	100	150

Electromechanical voltage relays can be compensated by inserting a resistor in series with the coil (while increasing the sensitivity of the relay itself to compensate for the lower coil current). In this way, the input impedance becomes less inductive and therefore less dependent on frequency. Band-pass filtering can also be added using RLC filters.

Electromechanical relays working with both current and voltage (e.g., impedance, power, and directional relays) exhibit some dependence on frequency. Note that torque can be produced only by the same frequency in voltage and current. Therefore, both voltage and current coils must pass a given frequency before this frequency can contribute to the total torque.

Note that even when compensated for frequency, electromechanical relays provide relatively poor filtering (typically no frequency filtering is implemented) and do not adjust their filters when the fundamental frequency shifts. Therefore, relay accuracy information with respect to frequency (such as that shown in Table II) has been of importance in applications for generator protection.

C. Static Relays and Signal Frequency

Static relays use small form-factor RLC elements, diodes, transistors, and operational amplifiers to shape their operating characteristics. As a result, relay designers could have provided for much better filtering compared with electromechanical relays. However, adjusting the filters to follow the changing fundamental frequency was very difficult and was not typically done.

Fig. 16 and Fig. 17 present sample pickup accuracy curves for a static voltage relay and a current relay, respectively, with intended application for generator protection.

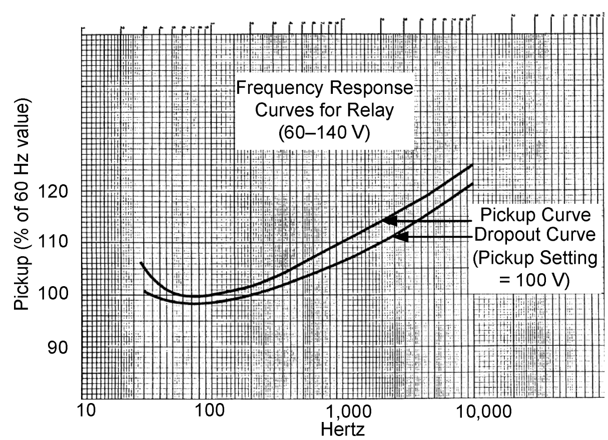

Fig. 16. Pickup and dropout accuracy versus frequency plot for one static voltage relay.

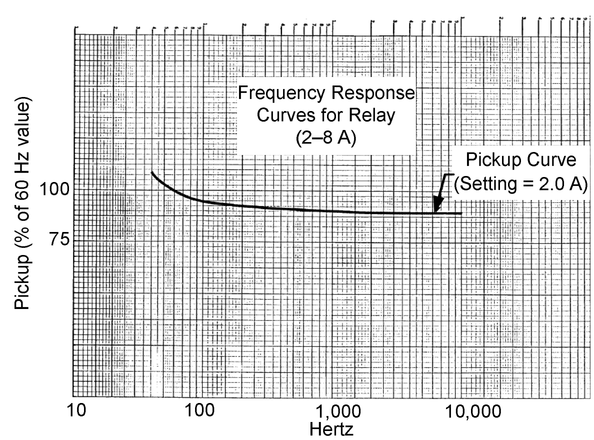

Fig. 17. Pickup accuracy versus frequency plot for one static current relay.

These sample relays do not apply any intentional filtering and exhibit frequency dependence of the pickup in the order of 5 to 20 percent for frequencies near the nominal.

We shift our attention now to microprocessor-based relays: their signal processing and methods of addressing excursions in the fundamental frequency.

D. Signal Processing in Microprocessor-Based Relays

With reference to Fig. 18, current and voltage analog signals are sampled by the analog-to-digital converter (ADC) at a variable sampling frequency (f_{SAM}). The sampling frequency is equal to the signal frequency multiplied by the constant, N, the number of samples present in 1 cycle at the rated frequency. Historically, N has been equal to 12, 16, 32, or 64 samples per cycle. These typical numbers are multiples of four for the ease of delaying the signals by 0.25 cycles, as required by the cosine filter described later. When sampled, the current and voltage signals can also be time-stamped for use in the built-in digital fault recording and synchrophasor functions.

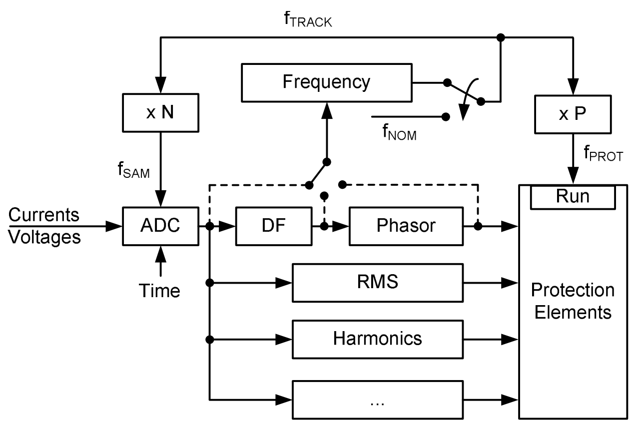

Fig. 18. Simplified diagram of a microprocessor-based relay in the context of impact of system frequency on accuracy.

The digitized current and voltage signals can be optionally filtered with a digital filter (DF) prior to passing them to a phasor estimation algorithm for calculation of magnitudes and angles. Other calculations include true rms values, harmonics, and any special quantities that are required by the protection elements of the relay.

Protection elements, relay logic, user logic, and outputs are run at a certain protection scan frequency (f_{PROT}). This frequency is typically selected as an integer multiple of the signal frequency (Multiplier P). Typically, P is 4, 8, or 16 protection scans per cycle. For example, a relay with $P = 8$ executes its protection elements every 2.08 milliseconds if the frequency is 60 Hz. This frequency dependence of the protection scan is not ideal (as explained in the following subsection) but is chosen for ease of implementation.

In Fig. 18, both the sampling (f_{SAM}) and protection scan (f_{PROT}) frequencies are controlled by the signal frequency (f_{TRACK}). Two solutions can be applied with this respect.

In one solution, the f_{TRACK} frequency is set to the system nominal frequency (f_{NOM}). As a result, the relay expects the fundamental frequency to be at or near the nominal frequency of the system. In other words, the relay does not adapt its filters to follow the actual system frequency.

In another more common solution, the relay measures the fundamental system frequency (typically using a selected three-phase or single-phase voltage signal) and adjusts its sampling and protection scan frequencies to follow (or track, hence the name) the actual system frequency. Tracking is performed to keep the accuracy and filtering intact should the fundamental frequency change. The frequency itself can be measured from raw samples, filtered samples, or phasors (more information is available in Section VI).

Frequency tracking is a convenient way to make all measurements accurate (digital filtering, phasors, harmonics, rms, and so on). Frequency compensation is a possible alternative to tracking, but it has some disadvantages. Frequency compensation uses extra equations to correct measurements performed on nontracked samples. This not only requires more processing power, but the equations are different, and they could get quite complex for different types of measurements.

Software resampling, shown in Fig. 19, is a hybrid solution between constant sampling and frequency tracking. This scheme samples the signals at a constant (typically high) rate for the benefit of digital fault recording (e.g., at 8 kHz) to resample to a lower and frequency-tracked rate (e.g., 32 samples per cycle, for example) by means of interpolation.

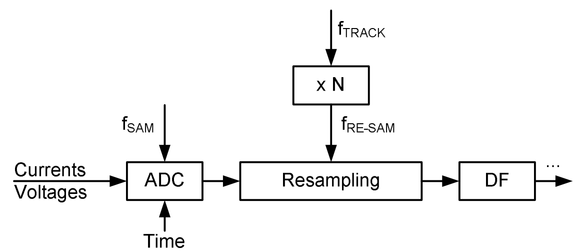

Fig. 19. Illustration of the concept of software resampling.

E. Phasor Estimation in Microprocessor-Based Relays

Most relays use phasors for the vast majority of provided protection elements. Two primary methods of phasor estimation algorithms are in use: the Fourier filter and the cosine filter, which is a subclass of the Fourier filter. Most often, a full-cycle implementation where the filter data window is equal to 1 cycle is used. The full-cycle cosine and Fourier algorithms are used in this subsection to illustrate issues with frequency.

A finite impulse response (FIR) full-cycle digital filter is defined as follows:

$$x_{OUT(k)} = \sum_{p=0}^{p=N-1} h_{WIN(p)} \bullet x_{IN(k-p)} \quad (3)$$

where:

k is the sample index.

N is the number of filter coefficients.

The filter characteristic is dictated by the shape of its window, h_{WIN}.

The cosine part of the full-cycle Fourier filter is defined by the following data window:

$$h_{COS(p)} = \frac{2}{N}\cos\left(\left(p + 0.5\right) \bullet \frac{2\pi}{N}\right), p = 0...N-1 \quad (4)$$

The sine part of the full-cycle Fourier filter is defined by the following data window:

$$h_{SIN(p)} = \frac{2}{N}\sin\left(\left(p+0.5\right)\bullet\frac{2\pi}{N}\right), p = 0 \ldots N-1 \qquad (5)$$

where:

N in (4) and (5) is the number of samples in a full cycle.

Fig. 20 presents the frequency response of the cosine and sine filters. As we can see, these filters are band-pass filters, providing a gain of 1.000 for the selected fundamental frequency (60 Hz in this example). They notch out the harmonics and the constant dc offset and provide moderate attenuation for interharmonics. Compared with electromechanical and static relays, protection elements based on this kind of filtering exhibit much better immunity to signal components away from the fundamental frequency.

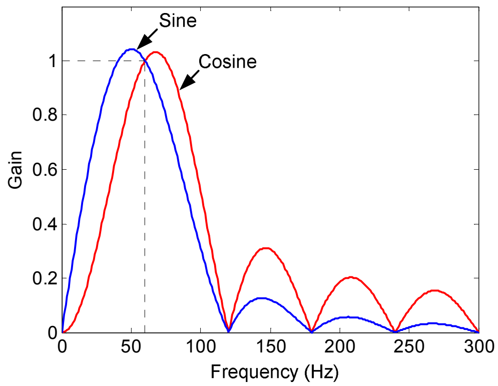

Fig. 20. Frequency response of the full-cycle sine (blue) and cosine (red) filters designed for a 60 Hz system.

The cosine filter phasor estimator uses only the cosine part of the Fourier filter and calculates the magnitude as follows:

$$X_{(k)} = \sqrt{\left(x_{COS(k)}\right)^2 + \left(x_{COS\left(k-\frac{N}{4}\right)}\right)^2} \qquad (6)$$

The Fourier phasor estimator calculates the magnitude as follows:

$$X_{(k)} = \sqrt{\left(x_{COS(k)}\right)^2 + \left(x_{SIN(k)}\right)^2} \qquad (7)$$

where:

k is the sample index.

N is the number of samples in a full cycle.

The cosine filter is very good in rejecting the decaying dc component often present in the fault current. The Fourier filter requires an additional mimic filter to achieve similar performance. The cosine filter has the additional implementation advantage of reduced processing requirements because the output of the sine portion of the processing is replaced by the cosine output delayed by 0.25 cycles. This is evident when (6) and (7) are compared.

Fig. 21 shows a frequency response of the cosine-based magnitude estimator. The shaded area indicates oscillations in the estimated magnitude for a given frequency. For example, at 60 Hz, the magnitude does not oscillate and the estimator gain is a perfect 1.000, as expected. Injected with a 90 Hz signal when sampling is still tracked to 60 Hz, the calculated magnitude oscillates between about 40 and 110 percent of its true value.

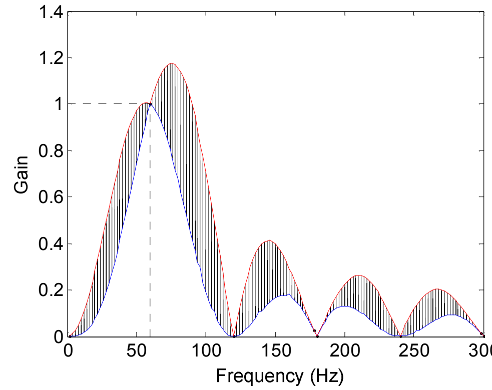

Fig. 21. Frequency response of a cosine filter magnitude estimator (for any given frequency, the magnitude oscillates between the blue and red envelopes).

Fig. 21 shows that the magnitude estimator is still a band-pass filter. However, the magnitude exhibits oscillations for off-nominal frequencies and the band-pass filtering is slightly worse that the cosine filter itself. This is due to the fact that the 0.25-cycle time delay in (6) is not exactly $\frac{N}{4}$ if the frequency is different than the nominal. The frequency response of the Fourier algorithm is similar to the cosine filter estimator and slightly better.

We now examine the frequency dependence of the cosine-filtered magnitude in more detail for frequencies close to the nominal (see Fig. 22).

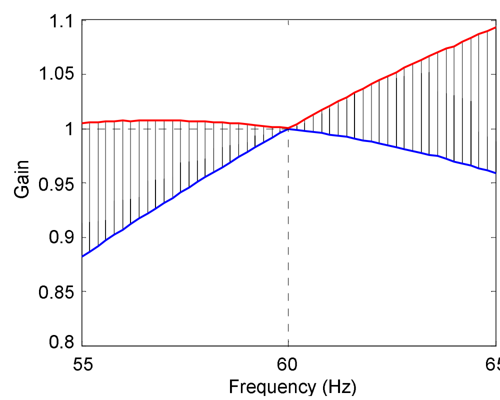

Fig. 22. Frequency response of a cosine filter-based magnitude estimator near the nominal system frequency (without frequency tracking).

As expected, when injected with a 60 Hz signal, the measured magnitude is 100 percent of the actual value and it does not oscillate.

When injected with a 55 Hz signal, the magnitude oscillates between about 88 and 101 percent of the actual value.

This means, for example, that an overcurrent element picks up solidly when the magnitude is $\frac{1}{0.88} = 114$ percent of the setting. Therefore, a time-overcurrent element with an instantaneous reset in a relay without frequency tracking or compensation times out only if the magnitude is 114 percent of the setting (i.e., a 14 percent underreach).

Assume next an instantaneous overcurrent element with no internal security delay. This element picks up at the magnitude of $\frac{1}{1.01} = 99$ percent of the setting and shows a 1 percent overreach if implemented in a relay without frequency tracking or compensation.

When the frequency is at 65 Hz, the magnitude oscillates between 96 and 108 percent of the actual value, potentially resulting in an 8 percent overreach and a 4 percent underreach in a relay without frequency tracking or compensation.

Actual protection implementations use security counts (short internal delays) for pickup and dropout comparators and/or hysteresis. These implementations have frequency errors smaller than the sample theoretical values derived from Fig. 22.

In any case, the errors due to minor frequency deviations are quite small (1 to 2 percent per each hertz of frequency error) and often can be neglected. This explains why some relays do not track frequency.

F. Effect of Frequency Tracking

We now discuss the frequency response of phasor estimators and the impact of frequency tracking as generally applied in relays. Consider the effect of frequency tracking, either by using a variable sampling rate (see Fig. 18) or software resampling (see Fig. 19). Assume $N = 32$ samples per cycle. At 60 Hz, the relay samples at 60 Hz • 32 = 1,920 Hz or every 0.5208 milliseconds. When the fundamental frequency changes to 55 Hz, the relay samples at 55 Hz • 32 = 1,760 Hz or every 0.5682 milliseconds so that the data window of 32 samples still covers exactly one power system cycle of $\frac{1}{55}$ Hz or 18.2 milliseconds. This change in the sampling frequency repositions the frequency characteristic of Fig. 22, as shown in Fig. 23. Sampling in harmony with the 55 Hz signal simply moves the point of unity gain from 60 Hz to 55 Hz, resulting in perfect measurement accuracy for the 55 Hz frequency signal.

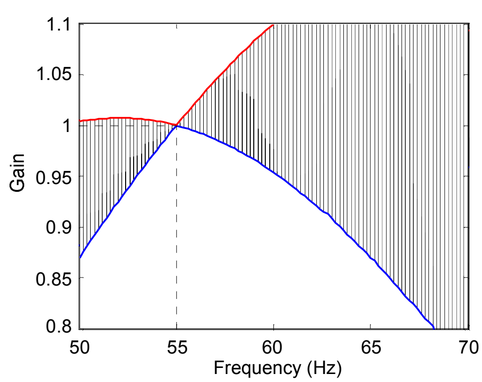

Fig. 23. Frequency response of a cosine filter-based magnitude estimator near the nominal system frequency (tracking to the 55 Hz frequency).

Similarly, at 65 Hz, the relay samples at 2,080 Hz or every 0.4808 milliseconds. This results in the shift of the characteristic to the right so that the 65 Hz signal benefits from the perfect gain of 1.000 (see Fig. 24).

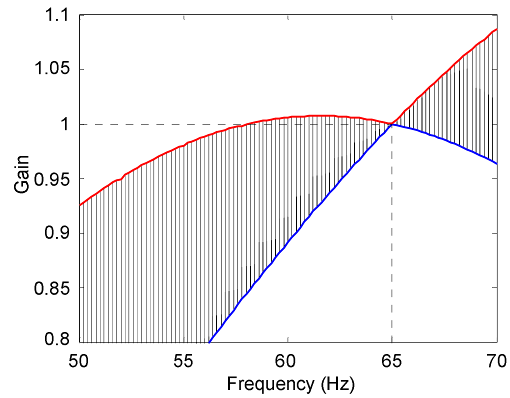

Fig. 24. Frequency response of a cosine filter-based magnitude estimator near the nominal system frequency (frequency tracking to 65 Hz).

When sweeping the phasor estimator that uses frequency tracking, we would discover the effective characteristic, as shown in Fig. 25. When the frequency changes between 55 and 65 Hz (the assumed range of tracking), the phasor estimator is perfectly accurate, exhibiting a gain of 1.000. The algorithm retains the filtering properties, too. For example, all of the harmonics are notched out, even when the fundamental frequency (and its harmonics) shifts.

Interestingly, frequency tracking is even more important for measuring harmonics. For example, assume the fundamental component moves by 2 Hz, from 60 to 62 Hz. This is a minor problem for the fundamental frequency magnitude measurement (there is an expected error of 1 to 2 percent). However, the third harmonic moves from 180 to 186 Hz. This is a departure of 6 Hz, causing more error for the third-harmonic measurement. At the same time, if no tracking is applied, the third-harmonic filter is set to notch out 60 Hz while the actual fundamental frequency is at 62 Hz. This results in the fundamental frequency leaking into the third-harmonic measurement.

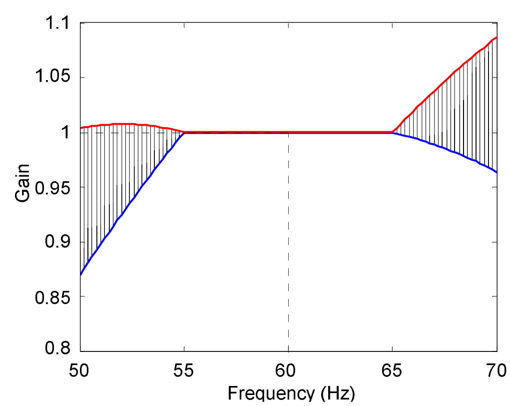

Fig. 25. Frequency response of a cosine filter-based magnitude estimator near the nominal system frequency (with frequency tracking in the 55 to 65 Hz range).

G. Requirements for Frequency Measurement When Tracking

Frequency tracking requires measuring the fundamental signal frequency. This measurement should be biased toward security at the expense of accuracy or speed. If the relay tracks to a wrong frequency by a large margin, it exhibits large errors. If the relay tracks to a frequency that is off by a fraction of a hertz, the errors are small and acceptable. As a result, practical frequency measuring algorithms for tracking apply multiple logical checks to make sure the measured frequency does not have a large error. Such checks are required regardless of the particular method used for frequency compensation. They also apply smoothing and nonlinear filtering (such as removing the highest and lowest values before averaging) to increase accuracy at the expense of lagging the actual frequency as it ramps. Security checks and smoothing create a small lag between the actual and measured frequencies when the actual frequency changes, but this small lag creates relatively small errors in relay measurements.

Section VI provides more information about frequency measurements.

V. Novel Approach to Wide Frequency Excursions in Microprocessor-Based Generator Relays

The approach described in the previous section works well in transmission relays that are specified to measure accurately under moderate frequency excursions, typically ±5 Hz from nominal.

Generator relays specified for a very wide frequency range, such as from 5 to 120 Hz, could use a better approach to overcome some of the following challenges.

First, when tracking to 120 Hz and using protection scans tied to the system frequency, the relay has half the time to finish processing as compared with operation at 60 Hz. For example, at P = 8 protection scans per cycle, the processing time shrinks from 2.08 milliseconds at 60 Hz to 1.04 milliseconds at 120 Hz. This not only requires an extra processing power margin but also exposes internal processes of the relay to large variations in the execution rate, which is not desirable for embedded systems such as microprocessor-based relays. By contrast, a relay that tracks in the 55 to 65 Hz range varies its 8 protection scans per cycle protection scan between 2.27 and 1.92 milliseconds—a much narrower and acceptable range.

Second, when tracking at 5 Hz, the relay samples and processes information very slowly. For example, sampling at 32 samples per cycle, the relay only takes a new sample every 6.25 milliseconds. Processing at 8 protection scans per cycle, the relay only runs protection elements every 25 milliseconds. Although it requires the same number of cycles to acquire a phasor at any frequency, the impact of running protection at a rate tied to tracking frequency produces a large variation in the internal processes of the relay. All of this would make protection substandard because the damage from the fault current is proportional to time and not to any arbitrary relay processing interval.

Third, modern generator relays support a large number of ac inputs that can be used to measure a number of currents and voltages around the generator. Sources of voltage and current can include the machine itself, high-voltage breakers, auxiliary power transformers, and so on.

Consider the example shown in Fig. 26.

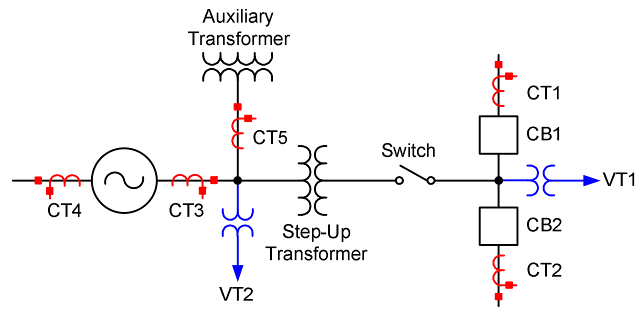

Fig. 26. Generator protection application with a multitude of current and voltage measurements.

In this application, the generator protection system can use CT4, CT5, CT1, and CT2 to provide overall stator and step-up transformer differential protection, CT4 and CT3 to provide stator differential protection, CT1 and CT2 to provide breaker failure for the high-voltage breakers, VT2 to provide overexcitation protection for the generator and the step-up transformer, and so on. Normally, all of these apparatus are connected together and operate at a single common frequency. However, during start up and other conditions, the relay can work with signals that belong to two or more frequency islands, as defined by the state of various isolating devices.

For example, the machine can be static-started or on a turning gear (the first frequency island) while the high-voltage breakers in a breaker-and-a-half bus are closed and carry 60 Hz currents (the second frequency island). It would be beneficial to measure signals within each frequency island accurately.

This section presents a novel solution to the challenge of tracking frequency over a very wide range. It has the following advantages:

- Processing is not frequency dependent, making the internal relay processes robust and allowing for fast response even if the machine is operated at a very low frequency.
- The relay can track multiple frequencies simultaneously, providing accurate and fast protection for parts of the system that operate at drastically different frequencies during special conditions.
- Phasors calculated in two different frequency islands are coherent (i.e., their angles can be meaningfully compared).

With reference to Fig. 27, the relay samples its input signals at a constant sampling rate (such as 8 kHz). The relay estimates frequency and applies software resampling to obtain a data window of precisely N samples per cycle (such as 32 samples per cycle). The protection scan is not frequency dependent but constant. For example, protection elements are run every 2 milliseconds or 500 times a second, irrespective of system frequency (e.g., for 5 Hz, 50/60 Hz, or 120 Hz).

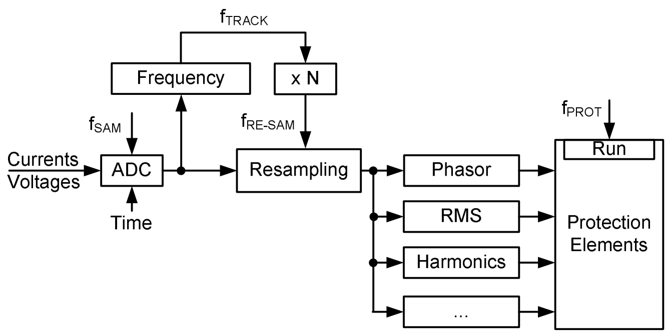

Fig. 27. New method for frequency tracking suitable for generator relays with a very wide frequency tracking range.

Note that the phasor, rms, harmonics, and other derived signals are required only when the protection elements are executed. As a result, these calculations are not tied to the incoming data stream (i.e., the output from the ADC physical sampling) but to the downstream process (i.e., the protection scan). Therefore, prior to running protection calculations, the input signal data windows are created by resampling the physical samples. The created samples are placed in such a way that the newest sample is aligned with the protection scan time marker, the previous sample is delayed by $\frac{1}{(N \cdot f_{TRACK})}$, and so on.

This approach naturally supports frequency tracking for multiple frequency islands, as shown in Fig. 28. In this scheme, resampling has an upstream process of physical sampling and a downstream process of consuming the frequency-tracked data.

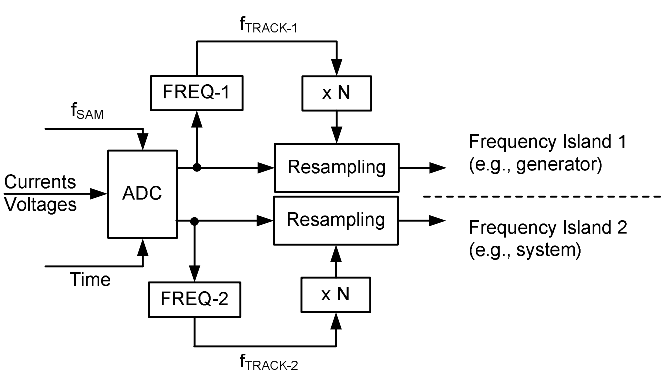

Fig. 28. Principle of tracking to multiple frequencies.

The upstream process pushes the data in at a constant rate (such as 8 kHz). The downstream process consumes the data at a constant rate (such as every 2 milliseconds). As a result, the resampling process is not coupled with either the upstream or downstream process, and consequently, we can have more than one resampling process to cover more than one frequency island in the measurements.

Fig. 29 illustrates the process further by showing two signals of different frequencies and their physical samples (blue dots) as well as resampled frequency-tracked samples (red dots). For better visibility, Fig. 29 assumes 2 kHz physical sampling and 16 samples per cycle after frequency-tracked resampling. The protection scan runs every 2 milliseconds.

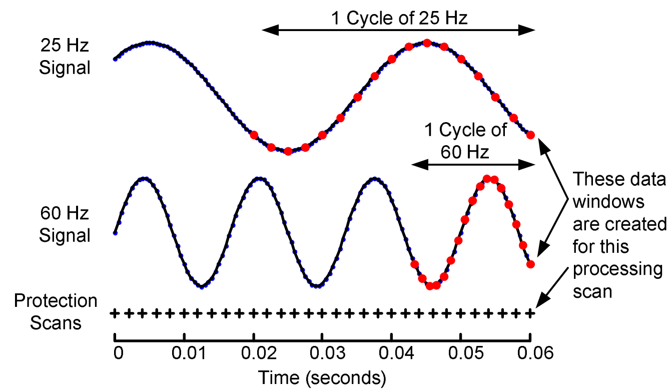

Fig. 29. Illustration of the data window creation.

The 25 Hz signal in Fig. 29 could be a generator terminal voltage during static starting. The relay correctly tracks this signal and is ready to respond to abnormal conditions in the 25 Hz subsystem, checking the trip conditions every 2 milliseconds. The 60 Hz signal in Fig. 29 could be a current through a closed high-voltage breaker in a breaker-and-a-half bus. The relay correctly tracks this signal and is ready to respond to abnormal conditions in the 60 Hz subsystem, checking the trip conditions every 2 milliseconds.

Fig. 29 also illustrates two important aspects of the new approach.

First, each time the protection scan is executed, an entire data window must be recreated rather than only adding new samples that were created past the time mark of the last protection scan. Repopulating the entire data window requires additional processing, but this is a minor problem that is easily solved.

Second, when the two signals become the same frequency, the two data windows are placed identically with respect to time, resulting in a correct angle measurement between the two signals despite the fact that the two frequency sources are used to track the two signals.

The second aspect can be appreciated better when considering a synchronism-check element. In the new approach, the two voltages are measured accurately even when their frequencies are drastically different. Their angles are measured correctly, too, and they show one voltage rotating faster than the other. When synchronism is reached, the two voltages measure identically. In contrast, a traditional synchronism-check function may track to one voltage, and when the two frequencies are different, the magnitude of the other voltage is measured with an error and it oscillates. This does not result in misoperation because the frequency difference condition (or slip) prevents the element from asserting, but it can create some confusion for operators using relay measurements. In the new method, the two voltages are measured with good accuracy at all times even when their frequencies are very different.

VI. Frequency Measurement

In theory, frequency can be measured from the voltage or the current. However, voltage is preferable to current for frequency tracking purposes. Its magnitude is relatively constant at all levels of loading, and it has fewer artifacts during transients.

A linear combination of the voltages, such as the alpha or the Clarke component, is usually applied in order to improve the availability of the tracking source.

$$V_\alpha = V_1 - \frac{V_2}{2} - \frac{V_3}{2} \tag{8}$$

where:

V_1, V_2, and V_3 can be phase-to-neutral or phase-to-phase voltages.

V_α is the alpha component.

These components are available during most faults and abnormal conditions. The performance requirements for frequency measured for tracking differ somewhat from those used in protection functions. In a protection application such as load shedding, measurement accuracy and speed can be critical. However, the function is called on to operate only when the frequency and voltage magnitudes are still relatively close to nominal. In contrast, for frequency tracking in a generator application, the magnitude and frequency of the tracked signal vary over a wide range.

For example, in combustion gas turbine and pumped storage starting, effective protection is desired at frequencies as low as is practical. At this point, the voltage magnitude can be only a few volts secondary. The starting process for these machines can take as long as 30 minutes. At the other end of the extreme, hydrogenerators can overspeed to 90 Hz at a rate exceeding 10 Hz per second. On the other hand, the requirements for measurement accuracy are not excessive because, as noted in Fig. 21, small errors in tracked frequency result in only a slight degradation in phasor estimates. A failure to track frequency has serious consequences for protection. Therefore, the measurement must be robust.

Harmonics (see Fig. 30) and commutation notches (see Fig. 31) generated by converters can produce additional zero crossings.

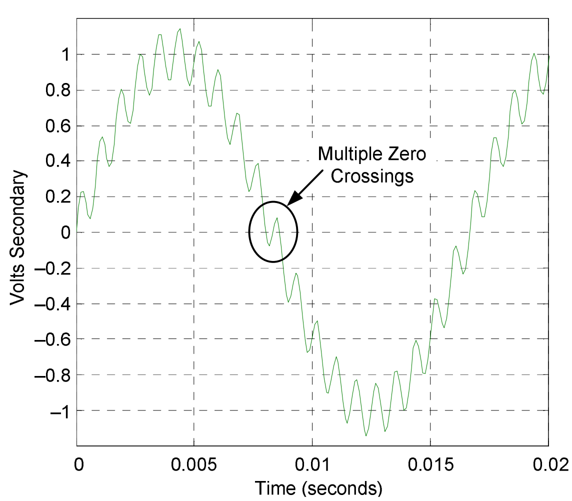

Fig. 30. Voltage rich in harmonics.

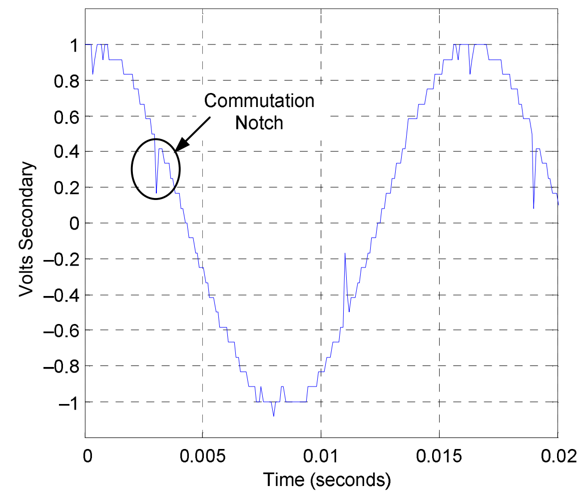

Fig. 31. Voltage waveform during LCI starting.

Subharmonics (see Fig. 32) and dc offsets can cause zero crossings to move. If left unmanaged, these artifacts can produce erroneous frequency measurements.

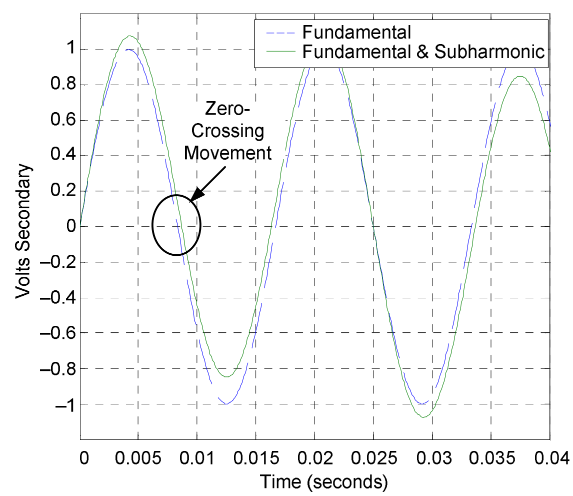

Fig. 32. Subharmonic component can periodically move the zero-crossing times.

In addition, for generators operating at very low frequencies and thus low signal levels (to keep the volts/Hz limited), 60 Hz signals induced from adjacent control cables can become significant (0.5 to 1.0 V) when compared with the low magnitude of the voltage to be tracked at very low frequencies.

The zero-crossing method and the phasor rotation-based method are commonly applied to track frequency. The zero-crossing method typically employs prefiltering to remove high-frequency components. Next, the zero crossings of the waveform are measured from the samples. It is highly unlikely that the waveform will be sampled exactly at zero. Therefore, the method searches for two consecutive samples that have opposite signs. Using the magnitudes and time stamps of these samples, the zero-crossing time can be computed more accurately using interpolation. Frequency can then be calculated as the reciprocal of the difference between successive zero-crossing measurements. Comparing only positive crossings with positive crossings and negative crossings with negative crossings reduces errors due to dc offset. Due to the nature of the measuring technique, the accuracy of the zero-crossing method is frequency dependent to some degree—better at high frequencies and worse at low frequencies.

The phasor method relies on the fact that when a phasor is extracted using the Fourier or cosine filters (see Section IV), successive estimates have angles that increase at the rate of $\frac{360^\circ}{N}$, where N is the number of phasor calculations per cycle, as shown in Fig. 33. The phasor can be stabilized by multiplication with a unit phasor rotating clockwise at the same rate [12].

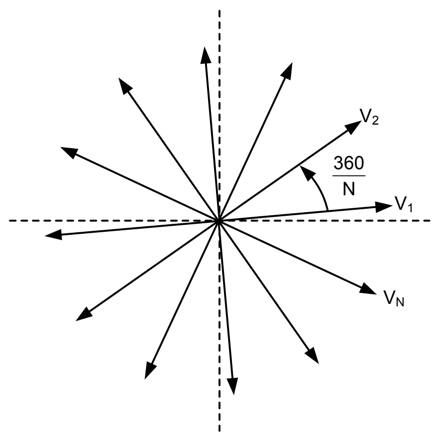

Fig. 33. Rotating phasor ($N = 12$).

Once stabilized, a change in frequency is exhibited as a movement in consecutive phasor measurements. Referring to Fig. 33, the measured frequency is given by:

$$f_{(k)} = \frac{f_{SAM}}{N} + \frac{\operatorname{atan}\left[\frac{\operatorname{imag}(V(k))}{\operatorname{real}(V(k))}\right] - \operatorname{atan}\left[\frac{\operatorname{imag}(V(k-1))}{\operatorname{real}(V(k-1))}\right]}{2\pi M} \quad (9)$$

where:

f_{SAM} is the sampling frequency.

M is the number of frequency measurements per cycle.

Typically, for either method, some form of postprocessing is carried out to produce the final frequency measurement. This can involve rejecting outliers and averaging previous measurements. Postprocessing increases the accuracy of the measurement at the expense of the introduction of a delay. Fig. 34 and Fig. 35 illustrate the impact of postprocessing on an increasing frequency ramp (representative of a hydrogeneration machine overspeeding upon load rejection) and also show the resulting degradation of the phasor estimation for a signal with a magnitude of 100. Note that the tracking frequency follows the signal frequency with a small lag. This lag results from the extra smoothing applied to the raw frequency measurements. Because the signal frequency is higher than the tracking frequency (the frequency increases and tracking lags), the cosine-based magnitude estimator tends to overestimate the actual magnitude slightly (compare with Fig. 22). As the frequency increases, the small lag in tracking frequency becomes a smaller portion of the actual frequency and the magnitude estimation accuracy actually improves.

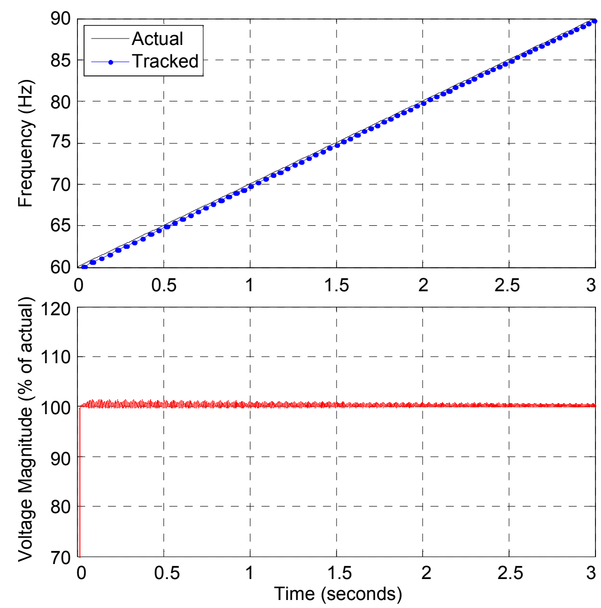

Fig. 34. Frequency increase of 10 Hz per second tracking to 90 Hz: signal frequency, tracking frequency, and estimated signal magnitude.

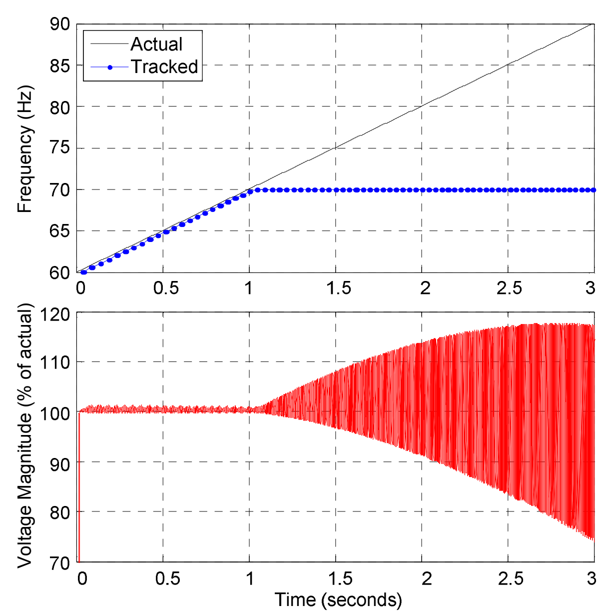

Fig. 35. Frequency increase of 10 Hz per second capped at 70 Hz: signal frequency, tracking frequency, and estimated signal magnitude.

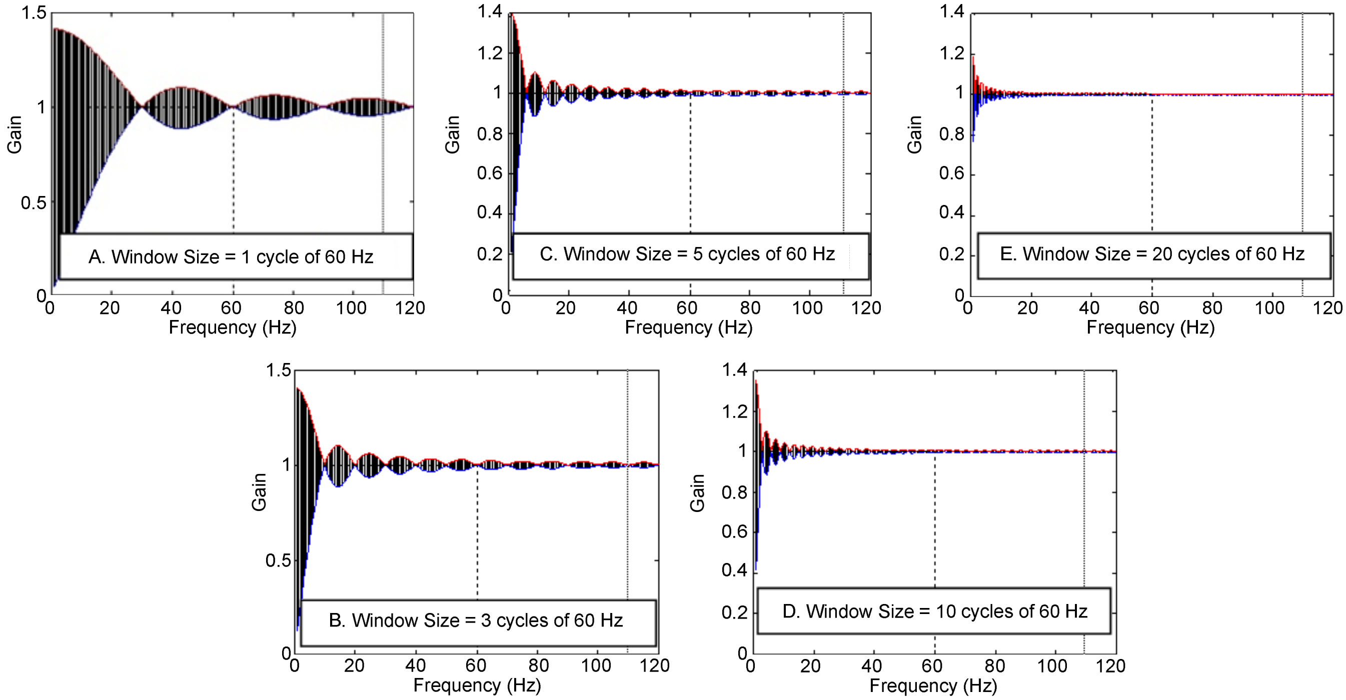

Fig. 36. Frequency response of an rms estimator for various data window lengths.

VII. Instances Where Frequency Cannot Be Tracked

The scheme described in Section V is capable of frequency compensation over a very wide range. Even so, there can still be instances when the frequency is outside the tracking range or otherwise unavailable but where protection is still required. These include the following:

- Dynamic braking of hydrogenerators where frequency tracking is not possible because the voltage at the machine terminals is zero.
- Cross-compound machines when one rotor is on turning gear and the field is applied to lock the second rotor to the first rotor and where the frequency may be 2 Hz or less.

For these cases, operating signals can be derived using a fixed sampling rate and rms calculation with a long data window, as illustrated in Fig. 36. Assuming a nominal frequency of 60 Hz, data windows of 1, 3, 5, 10, and 20 times the nominal period (16 milliseconds) are selected for comparison. Note that they all produce a gain of 1 at 60 Hz. However, off-nominal response is degraded. Off-nominal accuracy improves as the window length is increased. The impact is particularly evident at low frequencies. The disadvantage of the longer window is a proportionally longer operating time. For example, an element with a data window that is larger by a factor of three takes three times longer to operate for the same fault (see Fig. 37). Thus, window length is a compromise between speed and accuracy.

Using an rms calculation is beneficial when frequency tracking cannot be employed. Fig. 36 shows that the element responds regardless of the actual frequency and that employment of a large window produces a flat frequency response. The rms calculation provides natural averaging of the input waveform, rejecting spurious spikes and keeping the element picked up during a momentary dip. An rms calculation can be applied to an overcurrent element or to a summation of the instantaneous values of the currents making up the generator differential zone, as shown in Fig. 38.

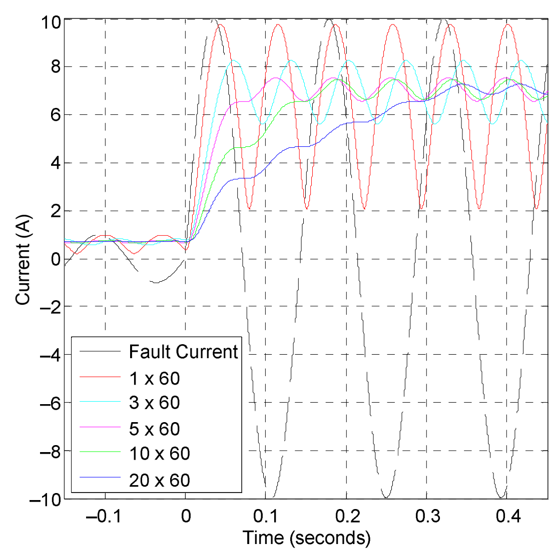

Fig. 37. Response of the rms magnitude estimator to a sample fault current at 7 Hz.

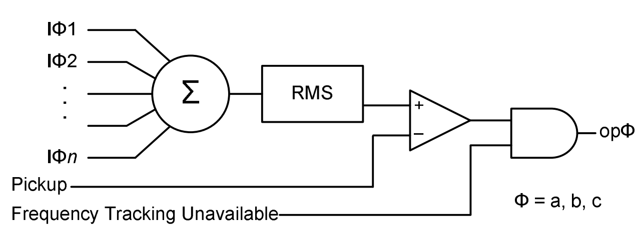

Fig. 38. Differential element using an rms calculation.

Another effective scheme for ground fault protection at very low frequencies is subharmonic injection (64S). It has become an increasingly popular method for ground fault protection in general. This scheme measures the resulting current from an injection source connected at the generator neutral. The injection source frequency is in the range of 15 to 20 Hz in order to minimize the impact of winding capacitance.

Because the element responds to its own injection source, it is capable of providing effective protection over an extremely wide frequency range (even at standstill) and also when frequency tracking is unavailable. In some designs, operation can be blocked when the generator frequency is in the same range as the injection source frequency. Other implementations do not have this limitation.

VIII. Conclusion

This paper reviews the protection requirements for generators operating at off-nominal frequencies. Although in many cases only a small subset of protection elements is required as compared with normal machine operation, these essential functions must operate securely and dependably during off-nominal frequency conditions.

The operating quantities for functions that remain in service must be accurate phasor or rms estimates of primary quantities and be free of harmonics.

Many modern microprocessor-based relays incorporate frequency tracking in order to provide accurate phasor and rms estimates. They do it, however, over a relatively limited operating frequency range. In order to accommodate the very wide frequency ranges required in some generator applications, a comprehensive approach that considers the operating requirements of each protection function is called for.

In this respect, we need to consider the failure modes of the generator at off-nominal frequencies, the specific operating configuration of the machine at the time, the anticipated values of voltage and current, the behavior of the CTs and VTs, and the other unique aspects of the particular application.

The novel approach to frequency tracking described in this paper allows for excellent implementations that are not constrained by the design approaches of typical transmission or distribution microprocessor-based relays.

IX. Acknowledgment

The authors would like to thank Mr. Terry Foxcroft of Snowy Hydro Limited for his valuable input.

X. References

[1] D. Reimert, *Protective Relaying for Power Generation Systems*. CRC Press, Taylor and Francis Group, Boca Raton, FL, 2006.

[2] R. M. Johnson, J. H. Chow, and B. Hickey, "Pelton Turbine Deflector Control Designs for Bradley Lake Hydro Units," proceedings of the American Control Conference, Anchorage, AK, May 2002.

[3] C. E. Kilbourne and I. A. Terry, "Dynamic Braking of Synchronous Machines," *Transactions of the American Institute of Electrical Engineers*, Vol. 51, Issue 4, December 1932, pp. 1007–1010.

[4] N. O. Engebretson, J. R. Boyle, H. L. Goodridge, C. H. Griffin, S. H. Horowitz, R. A. Larkin, R. E. Linton, G. D. Paradis, A. C. Pierce, B. M. Rice, W. R. Roemish, W. H. VanZee, C. L. Wagner, and S. V. Watson, "Protective Relaying for Pumped Storage Hydro Units," *IEEE Transactions on Power Apparatus and Systems*, Vol. 94, Issue 3, May 1975, pp. 899–907.

[5] W. B. Boyum, R. W. Ferguson, and J. G. Partlow, "Methods of Starting Gas-Turbine-Generator Units," *Electrical Engineering*, Vol. 73, Issue 5, May 1954, p. 419.

[6] IEEE PSRC Working Group J-2, "Protection Considerations for Combustion Gas Turbine Static Starting," August 2011. Available: http://www.pes-psrc.org/Reports/J2_ProtectionConsiderationsforCGT StaticStarting%20Final2.pdf.

[7] C. B. Meher-Homji and A. Bromley, "Gas Turbine Axial Compressor Fouling and Washing," proceedings of the 33rd Turbomachinery Symposium, College Station, TX, September 2004.

[8] T. Wagner and R. J. Burke, "Gas Turbine Efficiency (GTE) Benefits of GTE Water Wash Systems," proceedings of the ASME 2008 Power Conference, Lake Buena Vista, FL, July 2008, pp. 85–90.

[9] IEEE C37.110, IEEE Guide for the Application of Current Transformers Used for Protective Relaying Purposes.

[10] IEEE PSRC, "IEEE Tutorial on the Protection of Synchronous Generators," 2011. Available: http://www.pes-psrc.org/Reports/ IEEEGenProtTutorial_20110506.pdf.

[11] IEEE PSRC Working Group J9, "Motor Bus Transfer Applications Issues and Considerations," May 2012. Available: http://www.pes-psrc.org/Reports/IEEE_PSRC_Working_Group_J_9_Report_-_Final_Document_-_May_21,_2012.pdf.

[12] G. Benmouyal and A. D'Aversa, "Concurrent Implementation of 81 Frequency Elements Together With Frequency Tracking in Protective Relays: Issues and Solutions," proceedings of the 36th Annual Western Protective Relay Conference, Spokane, WA, October 2009.

XI. Biographies

Dennis Tierney is an electrical engineer at Calpine Corporation in Houston, Texas, where he provides electrical engineering support for Calpine's 92 operational power plants located across the United States. Before working at Calpine Corporation, Dennis worked for Mott MacDonald Group, where he provided field engineering design and support for two new power plants in Shuwaikh and Sabiya, Kuwait. Dennis worked as a senior applications engineer for relay protection at Doble Engineering Company for approximately 10 years. Prior to this position, for eleven years, Dennis worked at Salt River Project in Phoenix, Arizona, in system protection, power quality, and SCADA. Before working at Salt River Project, he worked in HVDC and communications at the Los Angeles Department of Water and Power. Dennis graduated from Arizona State University in 1982 with a bachelor's of science degree in electrical engineering.

Bogdan Kasztenny is the R&D director of technology at Schweitzer Engineering Laboratories, Inc. He has over 23 years of expertise in power system protection and control, including ten years of academic career and ten years of industrial experience, developing, promoting, and supporting many protection and control products.

Bogdan is an IEEE Fellow, Senior Fulbright Fellow, Canadian representative of CIGRE Study Committee B5, registered professional engineer in the province of Ontario, and an adjunct professor at the University of Western Ontario. Since 2011, Bogdan has served on the Western Protective Relay Conference Program Committee. Bogdan has authored about 200 technical papers and holds 20 patents.

Dale Finney received his bachelor's degree from Lakehead University and his master's degree from the University of Toronto, both in electrical engineering. He began his career with Ontario Hydro, where he worked as a protection and control engineer. Currently, Dale is employed as a senior power engineer with Schweitzer Engineering Laboratories, Inc. His areas of interest include generator protection, line protection, and substation automation. Dale holds several patents and has authored more than a dozen papers in the area of power system protection. He is a member of the main committee of the IEEE PSRC, a member of the rotating machinery subcommittee, and a registered professional engineer in the province of Ontario.

Derrick Haas graduated from Texas A&M University in 2002 with a B.S.E.E. He worked as a distribution engineer for CenterPoint Energy in Houston, Texas, from 2002 to 2006. In April 2006, Derrick joined Schweitzer Engineering Laboratories, Inc., where he works as a field application engineer. He is a member of IEEE.

Bin Le received his B.S.E.E. from Shanghai Jiao Tong University in 2005 and an M.S.E.E. from the University of Texas at Austin in 2008. He has been employed by Schweitzer Engineering Laboratories, Inc. since 2008. Bin currently holds the position of power engineer in the research and development division. He is a member of IEEE and a professional engineer registered in the state of Washington.

Previously presented at the 2014 Texas A&M
Conference for Protective Relay Engineers.

20140210 • TP6616-01