WECC White Paper on Understanding Frequency Calculation in Positive Sequence Stability Programs

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June 26, 2018

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The Calculation of Frequency in Positive Sequence Programs and Its Implications

The frequency of a wave form is defined as the rate at which a cyclic signal repeats every second. In the context of power systems, the steady-state waveforms of voltage and current are sinusoidal and repeat sixty (60) times every second and thus the nominal system frequency is 60 Hz[2]. This is the basic concept of frequency; however, actual system frequency is never constant but is continually varying. The typical changes in system frequency are seemingly small in the steady-state, usually in the range of a few milli-hertz (mHz). Furthermore, actual system voltage and current in various parts of the network are imperfect sinusoids and typically contain a small level of harmonics, that is, higher order frequency components. Harmonic wave distortion is outside the scope of this document. The primary focus of this paper is to foster understanding of the nature of the fundamental system frequency (60 Hz in the US) and variations in the fundamental frequency as a result of system events. These system events include generation/load loss, loss of imports/exports from a balancing area, and electrical faults on the transmission system.

Since the power system is still primarily a synchronized system dominated by synchronous generation, when the system is in steady-state the frequency is uniform throughout the entire interconnected power system. However, when a system event occurs there will be some differences in local frequencies at various points of the network. (i.e. close to the event and far away) These will propagate extremely quickly throughout the system. The speed of frequency propagation has been estimated by some to be of the order of 1000 km/s[3].

Frequency is calculated with measuring equipment in the field and is used for various controls and protection functions. Most relevant to the current discussion is its use in determining when equipment may need to be tripped due to extreme off-nominal fundamental frequency conditions that could expose equipment to potential damage. As an example, large steam-turbines have modes of blade vibration that can be excited by off-nominal frequencies. If the unit operates for a prolonged period at certain off-nominal frequencies excessive stress and potential damage and/or loss of life to the mechanical parts in the turbine may occur[4]. As a result, most conventional generation has under/over frequency relays that will trip the unit at extreme frequency conditions. In the case of renewable energy systems like wind turbine generators, the turbines are protected from extreme speed conditions by overspeed protection that ensure mechanical components are not subjected to excessive shaft speeds. In general, however, for inverter-based generation in which the interface to the grid is a power electronic inverter, the main limitation is the dynamics of the phase-lock loop(PLL) (i.e. the band-width, pull-in and pull-out dynamics of the PLL), so there is a much wider band in which the equipment can operate. In the end, all generation equipment in North America connected to the bulk power system must satisfy NERC PRC-24. In addition, under-frequency load-shedding relays and remedial action schemes will also use calculated frequency for executing protective actions. Relay equipment typically calculate frequency by using various signal-processing techniques, with appropriate filtering, to extract the fundamental frequency.

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[2] In many other countries in the world the nominal system frequency is 50 Hz.

[3] https://arxiv.org/pdf/1108.1804.pdf

[4] IEEE Task Force Report, Interconnected Power System Response to Generation Governing: Present Practice and Outstanding Concerns, PES TR13, August 2007. http://resourcecenter.ieee-pes.org/pes/product/technical-publications/PESTR13

Such algorithms are applied to the measured sinusoidal grid voltage and can calculate frequency in a few cycles. In addition, the major vendors of relay protection systems have a voltage disable on the frequency relays such that the relay is stopped from triggering a trip for severe under-voltage conditions (e.g. IEEE Standard C37.117 indicates the relay should be disabled typically for voltage levels below 50 to 70percent of nominal voltage). The purpose of this low-voltage disabling function is to avoid false tripping of the load/generation due to spikes and spurious results from the frequency calculation within the relay under significant depressed voltage conditions caused, for example, by a nearby transmission fault.

Furthermore, a PLL also calculates the fundamental system frequency as it is the function of a PLL to lock into the grid phasor. PLLs are applied in inverter-based generation systems. However, *the calculated frequency from a PLL is not of adequate fidelity for use in relaying and protection functions*.

Finally, there is the issue of simulating all this in positive-sequence power system simulation tools (GE PSLF, Siemens PTI PSS®E, PowerWorld Simulator, PowerTech Labs TSAT™, etc.), which are used for power system planning and operational studies throughout North America and elsewhere around the world. The key issue here is that in a positive-sequence power system simulation tool, the only means of calculating frequency at a given bus in the network is to calculate the derivative of the voltage-angle. The problem with such a calculation is that when a sudden change occurs in the voltage angle – such as for example a nearby transmission fault – this results in essentially a very large spike (infinite derivative due to the step change in angle). This is resolved in the software tools by imposed filtering within the code and other numerical smoothing functions. Still, the result is a fictitiously large transient in frequency at the bus, which decays as a function of the filtering that is imposed.

This is most effectively illustrated by a simple example, as shown in Figure 1. As can be seen:

1. The positive-sequence model does a rather poor job of representing actual frequency variations during and immediately following the fault.
2. The PLL also is not very effective in estimating frequency immediately after the fault clears and takes some time to lock into the network frequency following the fault.
3. The digital-signal processing type algorithm does the best job of estimating system frequency almost immediately after the fault clears. However, it too fails to calculate any sort of stable frequency during the fault, since there really is none, or at the very least the calculation is quite distorted during the fault. This identifies the reason why frequency relays are disabled/blocked during a severe voltage dip per the IEEE Standard C37.117.

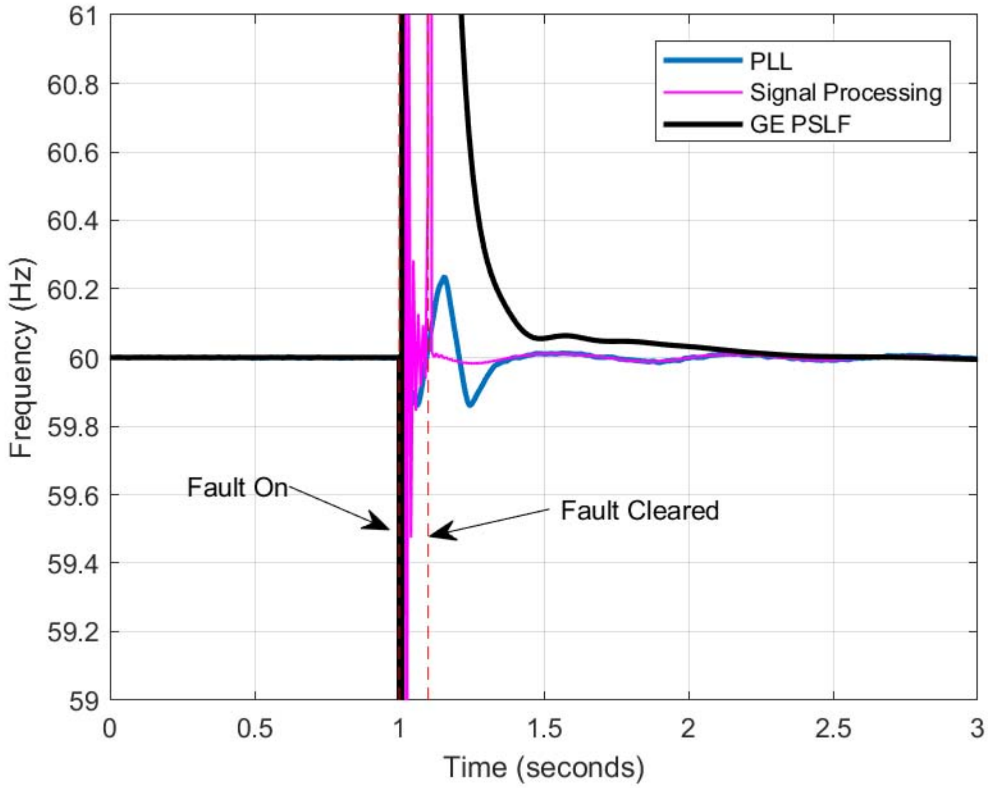

Figure 1: Simulation of a 3-phase fault to ground near a generator. The frequency is calculated at a network bus. The simulation was done in both a positive-sequence program and a 3-phase model. Then three methods were used to calculate frequency: (i) within the positive-sequence program (black line), (ii) using a digital signal processing method as might be applied in a relay (magenta line), and (ii) using a PLL (blue line).

Proposed Actions

The conclusion that may be drawn from the above explanation is that that the calculated frequency positive-sequence tools cannot be trusted as a good indication of actual frequency during and immediately after the simulation of a close-by fault. Thus, actions taken based on such frequency calculations in a positive-sequence simulation tool will not be accurate during or immediately following a close-by simulated fault. The best course of action is to introduce a new feature into frequency relay models where the model is put into a "monitor only" mode on a bus by bus basis. This model would report to the user if an over-/under-frequency trip would have occurred and at what level of frequency deviation. Then subsequent to the simulations the user can review these results and easily identify those items that are superfluous (which are the majority) and can be ignored. For example, if a frequency trip relay at a wind generator plant indicates that the plant would have tripped almost immediately after a fault due to an over-frequency of 61 (or more) Hz, this is clearly a superfluous result of the type shown in Figure 1. Another course of action is to always ensure that there is some time delay (e.g. at least 50 ms) associated with any under/over frequency trip settings in positive-sequence simulation models, and the relay model is momentarily disabled during severe voltage dips, in order to mimic similar behavior of actual equipment. However, such augmentations to the model will not guarantee correct action in all possible cases, since as shown in Figure 1 the fictious frequency spike, even after filtering, can last for a significant amount of time. Thus, the “monitor only” option with post processing by the user might be the most effective.