REQUIREMENTS FOR AND PRACTICAL EXPERIENCE ON PARTICULAR GENERATOR PROTECTION FUNCTIONS

Z. Gajić	R. Goin, R.J. Muñiz	M. Kockott
Hitachi Energy	Statkraft Energi	Hitachi Energy
Sweden	Norway	USA

Keywords: GENERATOR PROTECTION, SHAFT OVERCURRENT, STATOR EF, OUT OF PHASE SYNCHRONIZING, ISLANDING

Abstract

Generator protection is the most complicated part of protective relaying. It includes both impedance based and differential based protection functionality. However, in addition it often requires very specific protection functionality which is not present at all in any other parts of the power system. The goal of this paper is to present and explain end user requirements and possible practical solutions for such specific generator protection functionality.

1 Introduction

Generator protection schemes [1] contain many protection functions. Some of them are quite specific for the generator protection only. Some of these specific protection functions will be described in more detail in the paper.

Statkraft is Europe's largest renewable energy producer. The history started in 1895 when the Norwegian state acquired its first ownership rights to a waterfall. The total energy production in Statkraft is 65 TWh. 92% of this is renewable, and the majority of this is hydropower. Statkraft owns and operates over 340 hydropower plants globally. In Norway Statkraft operates approximately 90 hydropower plants. Statkraft is 100% owned by the Norwegian state.

2 Shaft overcurrent protection

A special, and not so well known, generator protection function is shaft overcurrent protection. When a generator is excited it can induce a voltage along the shaft. This induced voltage is caused by an unsymmetrical stator core. Specially for larger generators with a stator core made of several parts that are jointed together this induced voltage can be quite high. How high the induced voltage magnitude will be is also dependent on the specific stator construction details. The expected shaft voltage may be calculated for a particular machine design. If the shaft voltage is higher than one volt (1V), shaft overcurrent protection (or other types of mitigations) should be considered.

Normally there are three bearings on a hydro generator, as shown in Figure 1: turbine guide bearing, drive-end guide bearing and non-drive-end bearing. The latter is combined thrust- and guide bearing. The turbine guide bearing, and drive-end guide bearing are normally grounded. The non-drive-end bearing is normally isolated. All bearings are slide bearings.

If we look at the non-drive-end bearing, between the shaft and the bearing there will be an oil film and between the bearing and ground there will be insulation. Normally the shaft voltage will be present between the bearing and ground. If the bearing insulation is broken due to a fault, the shaft voltage will be present between the shaft and the bearing, thus over the oil film. If this voltage is too high the oil will lose its electric insulation ability and a current will start to flow between the shaft and ground through the oil film. If this shaft current is too high, the oil film will lose its lubrication abilities and the bearing may be destroyed. A current magnitude of 1A is considered to be the maximum allowed current.

The magnitude of the current through the shaft is dependent on the shaft voltage and the resistance in the current path through the generator metallic parts, such as enclosure, and the grounding system. If the current path is low ohmic the shaft current magnitude will be large even if the shaft voltage magnitude is low. In Statkraft installations shaft currents of up to 70A approximately have been measured, but normally the shaft current is lower than 10A.

Traditionally shaft current protection is solved by a magnetic core current transformer mounted around the shaft between the drive-end bearing and the rotor (see Figure 1). Normally the shaft current transformer has between 500 and 1000 secondary turns, so the measured secondary current is quite low. The secondary winding is connected to an overcurrent protection relay with special filtering considering the harmonics. Figure 1 shows a principle drawing of the bearing system and the shaft current transformer for a hydro machine. If the insulation of the non- drive-end bearing is broken, there is a possibility for breakdown of the oil film and a current path will go from the turbine via the shaft through the oil film and the bearing with broken insulation.

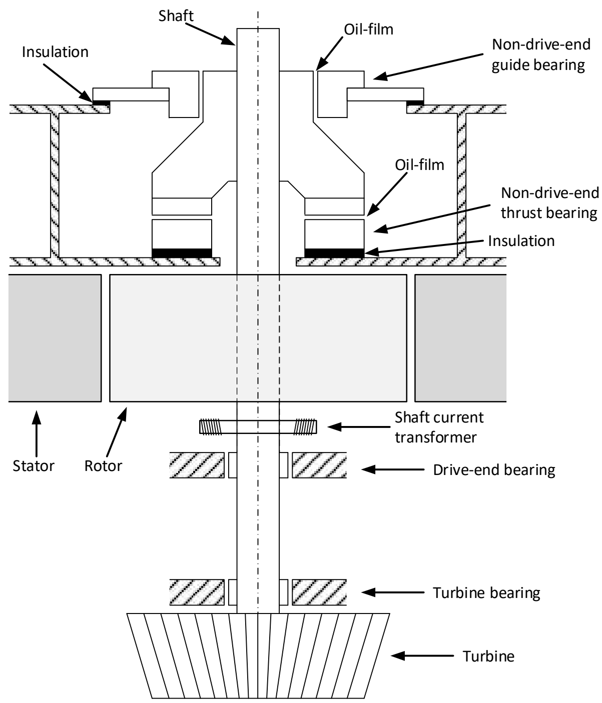

Figure 1: Principle drawing of a bearing system

It can be added that for Pelton turbines a grounding brush is mounted on the shaft near the turbine bearing.

Traditional solution has a lot of practical problems regarding positioning and mounting of the shaft CT due to its weight and limited space available around the shaft. A modern solution utilizing a Rogowski Coil for shaft overcurrent protection will be presented [2]. It has been in successful operation for several years in several of Statkraft's hydro power plants and several new installations of such scheme are on its way.

The Rogowski coil based protection scheme consists of:

1. Detachable Rogowski Coil for shafts of up to one meter in diameter. Its output is a voltage signal proportional to the rate of change of the shaft current.
2. Analogue integrator having 10m long coaxial cable for connection to the Rogowski coil. Its output is a voltage signal proportional to the shaft current.
3. Amplifier of the output voltage from the integrator.
4. VT input into a generator protection IED.
5. High precision filter to extract the phasor with a settable centre frequency within the IED.
6. Overvoltage protection having two stages (e.g. alarm and trip stage) within the IED.
7. Auxiliary supply for the equipment.

One such protection scheme arrangement is shown in Figure 2. The Rogowski coil, which shall be mounted in the same location as the shaft CT, will produce voltage output signal proportional to the first derivative of the shaft current (i.e. di/dt). The integrator will integrate this signal and produce a voltage signal proportional to the shaft current magnitude (e.g. 200mV for 1A shaft current).

Figure 2: An actual installation of Shaft OC Protection

The amplifier raises this integrated voltage signal 40 times to a level suitable for the IED VT input. Precise filtering is required within the IED to filter out the required frequency component (typically either fundamental or third harmonic component). The overvoltage function will provide two triggering levels with suitable time delays for the alarm and trip signals respectively. Typical settings used by Statkraft are 0.25A primary (i.e. pickup current level through the shaft) for alarm and 0.8A for trip.

Note that the wall-mounted box with electronic equipment shown in the bottom-right-hand side in Figure 2 is actually located approximately 10m apart from the Rogowski coil. That is necessary in order to minimize any stray flux influence from the stator winding onto the electronic equipment. The output of the amplifier is then connected by a cable (i.e. 1.5mm^2 twisted pair) to the VT input on the IED which is located in the control room.

The entire shaft OC protection scheme can be either secondary or primary tested as described in reference [2]. In Figure 3 the captured voltage waveform during such primary testing under commissioning of one machine is shown. Such test is done with a resistor connected between the shaft and the ground, so the shaft current is lower than for an actual fault.

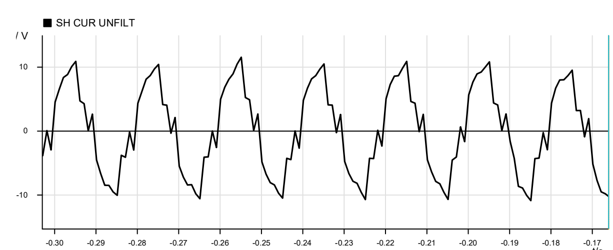

Figure 3: Measured voltage by the IED during primary testing

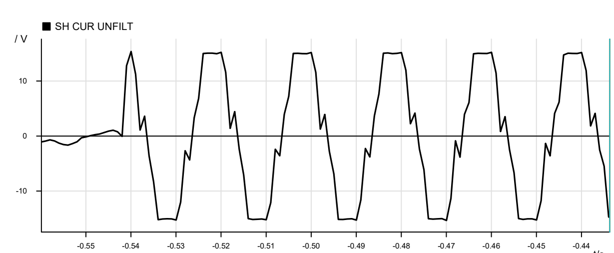

Figure 4: Measured voltage by the IED during an actual fault

A real problem with the bearing has happened on the same machine later. Recorded voltage signal proportional to the shaft current captured by the IED during a real fault is shown in Figure 4.

The presented secondary voltage signal level of 10V on the above two figures corresponds to a shaft current of 1.25A. For this installation frequency for the filter is set to 50Hz (i.e. machine rated frequency). As can be seen from these two figures the shape of the two current waveforms are similar (only the magnitude of the current is bigger for the real fault).

3 Injection-based 100% stator earth fault

To detect stator earth faults, the basic method is to measure the fundamental frequency voltage or current component at the stator winding neutral point. If a ground fault occurs, this current/voltage will appear. However, these methods cannot detect faults in the vicinity of the neutral point. Consequently, such protection schemes are often referred to as "95% stator EF protection" as they typically cover only 95% of the stator winding, depending on the selected settings. Thus, the last 5% of the stator winding closest to the star point is not protected with such method.

An earth fault close to the stator winding neutral point can not cause any direct harm to the machine due to quite limited voltage at the fault point. But it can become a serious threat if a second earth fault would appear in any other point of the stator winding. Thus, it is of utmost importance to detect such faults for large machines. A possibility to detect a fault close to the star point can be achieved by measuring the 3rd harmonic voltages generated by the machine. As this method is dependent on the 3rd harmonic voltage magnitude, which is generated by the machine itself, it can only be active when the machine is excited and if it produces sufficient amount of third harmonic. It is often considered valuable to detect a ground fault even when the machine is at standstill. Therefore, injection method is preferred.

The Norwegian renewable energy producer Statkraft uses injection-based 100% stator earth fault protection for generators with rated power of 150MVA and larger. The size 150MVA is not randomly chosen. It is merely the size that separates medium sized and large generators in Statkraft. The above mentioned 150MVA limit is not a fixed limit. Also, for generators with lower rating, injection based 100% stator earth fault protection can be used if the condition of the stator winding requires such protection functionality. Some years ago, only hydro generators with water cooled stator windings had injection based 100% stator earth fault protection. Other smaller generators used 3rd harmonic based 100% stator earth fault protection or only 95% stator earth fault protection. However, due to not so good operational experience with 3rd harmonic based 100% stator earth fault protections, Statkraft has now decided to only use the injection-based principle when such protection functionality is required.

In order to be able to operate, any injection based 100% stator earth fault protection method shall provide its own injected (i.e. test) signal and therefore can always be active, even at machine standstill. To inject a test signal into the machine, some provisions in the primary circuit and additional hardware are usually required.

The main technical challenge, for any stator injection equipment, is that it shall inject the test signal through almost a short circuit. This can be best understood in cases when a distribution transformer with secondary NGR is used for stator grounding, as shown in Figure 5. In case of very large turbo machines the NGR value can be as low as 0.05Ω (e.g. typical NGR values are less than 1Ω). Thus, theoretically an ideal current source shall be used in order to be able to inject any power into the stator winding through almost a short circuit. On the other hand, all used equipment in such a scheme also has its thermal ratings that consequently limit the amount of current which can be injected in practice.

Note also that in case of an actual EF at the stator terminal a large voltage (e.g. around 100V at rated frequency) will be pushed back onto the injection equipment for several seconds. Therefore, injection equipment must be accordingly designed in order not to burn-out under such circumstances.

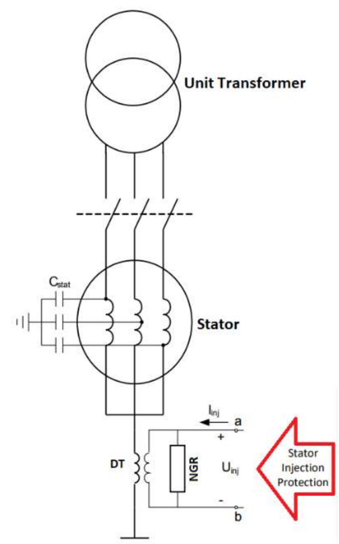

Figure 5: Typical injection scheme for secondary NGR & DT

In Norway a primary NGR is mainly used, and the stator injection using a dedicated Signal Injection Transformer (i.e. SIT) is arranged, as shown in Figure 6, in order to overcome all these technical challenges [1,3]. Note that a SIT can be used, as indicated in Figure 6, as long as the stator winding star point is accessible, regardless of the actual stator winding grounding arrangement. By properly designing the SIT and the level of the injected signal on its secondary side a reliable 100% stator EF protection can be achieved for almost all installations. This is achieved by ensuring that sufficient amount of the injected test signal is actually transferred into the stator primary circuit. The injection based 100% stator earth fault protection detects change in the measured impedance from a reference value obtained during commissioning in order to detect presence of an EF in the stator winding. Such a SIT-based injection scheme is in operation in several Statkraft stations, including the largest hydro generator in Norway.

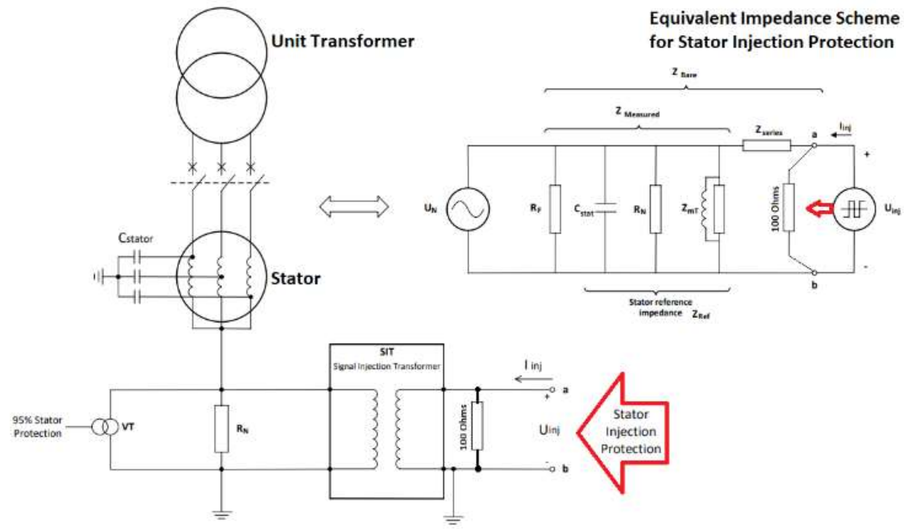

Figure 6: Injection arrangement when SIT is used

4 Generator out-of-phase synchronizing

"Bad synchronizing" or out-of-phase synchronizing (OOPS) is an event that may cause damage to the generator, the shaft and the circuit breaker. It will also cause voltage dip and high currents in the connected grid. OOPS may cause higher forces than a short circuit, and generators may not be dimensioned to handle these kinds of forces. The forces are of course dependent on how big the phase angle displacement was between generator and grid voltages. For the generator several components are exposed, but the stator windings and the damper (amortizer) windings are the components that get the highest forces compared to the dimensional criteria. The shaft is often considered to have high forces compared to what the dimensioning criteria is, but due to low torsional stress on the turbine due to no-load and normally a conservatively dimensioned shaft, this is normally not a problem in practice.

Closing of a circuit breaker during an OOPS event is not a problem. However, any trip by protection relays during an OOPS event opens the circuit breaker and exposes it to difficult operating conditions. The generator can be wrongly synchronized to the grid both with the generator circuit breaker, and with the high voltage circuit breaker (high voltage side of the generator step-up transformer). If an OOPS happened with the high voltage circuit breaker the forces on the generator are less than if it happened with the generator circuit breaker. This is due to the transformer impedance. This should favour synchronizing with the high voltage circuit breaker over the generator circuit breaker, but of course there are other issues to consider.

If installed, the generator circuit breaker (GCB), placed between the generator and the step-up transformer (GSU), is normally used to synchronize the generator to the grid. To avoid high inrush currents when energizing the GSUs from the grid, many of Statkraft's power plants are synchronized using the high voltage breaker instead. This is also the case for power plants where no generator circuit breakers are installed.

4.1. The effect of OOPS on circuit breakers

The circuit breaker and the generator are the components in the system exposed to the highest stresses due to an OOPS. Depending on the OOPS angle, the recovery voltage (RV) and the transient recovery voltage (TRV) between the primary contacts of the circuit breaker may be among the highest a circuit breaker may experience. The larger the OOPS angle, the larger the RV, the TRV, and the OOPS currents. For GCBs closing with an OOPS in full phase opposition, the OOPS current may be even higher than the rated system-source short-circuit current [5]. Also, the large DC time constant of the generator leads to relative slow decay of the DC component of the current during an OOPS event. This, together with the fast decrease of the AC component leads to delayed current zero crossings in one of the phases.

Synchronizing with the generator circuit breaker

GCBs are not required to be dimensioned to interrupt full out of phase opposition current (for angle of 180°). According to the standard [7], the GCB will have OOP breaking capacity of 50% of the rated system-source short circuit breaking current. That may only correspond to a 90° out of phase angle, although higher angles are likely to occur in practice due to wiring errors, wrong settings of synchronization apparatus during commissioning or after maintenance. An OOPS angle of 180° might give a much higher current, up to 80% larger, than in the case of an OOPS at 90° angle. According to [4] an OOPS current should be interrupted within a timeframe of 80-100ms after closing of the GCB, before the AC-component becomes too low (causing a delay in the zero-crossing) in order to ensure a successful interruption.

Synchronizing with the high voltage circuit breaker

According to the standard [8], the high voltage circuit breaker shall have OOP breaking capacity of 25% of the rated short circuit breaking current. For transmission circuit breakers, an out of phase angle of 180° gives a 40% larger OOPS current than an angle of 90°; and a 40% larger steepness of the TRV

(RRRV) [5]. The TRV peak values due to an OOPS are the highest mentioned in the HV circuit breaker standards.

According to [4] there is a time window in which the high voltage circuit breaker will not be able to force the OOPS current to zero. On the other side, depending on the breaking medium, a generator circuit breaker will most likely force the current to zero and lead to a successful interruption.

4.2. Real OOPS cases

Two recorded cases of OOPS are shown in Figure 7 and Figure 8. In both cases the synchronizing has occurred with the HV-side breaker.

In Figure 7 the trip signal is sent almost instantaneously after the breaker closing. In this case the current was so high that the overcurrent protection on the HV-side of the GSU tripped on its instantaneous step. In Figure 8 the trip signal is sent 533ms after the OOPS. In this case it was the transformer differential protection that sent the trip signal. In theory the transformer differential should not trip during an OOPS event, but due to saturation of current transformers the differential current reached the trip level after some time.

These two examples show that it is not predictable which protection functions will trip and that the trip time is also quite uncertain. In some cases, an OOPS can even happen without a trip from any protection function. The difference in the trip times in these examples can therefore be explained by the lack of a dedicated OOPS protection function, causing other protection functions to trip only when their conditions are fulfilled. This will also mean that it is possible that some protection functions send the trip signal in a timeframe which is unfavourable for the interruption of the OOPS currents, leading to higher arc times than acceptable and causing the destruction of the circuit breaker.

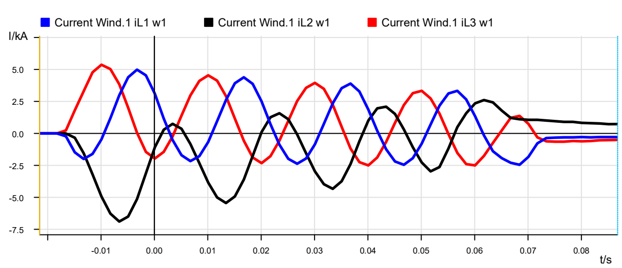

Figure 7: OOPS event No 1

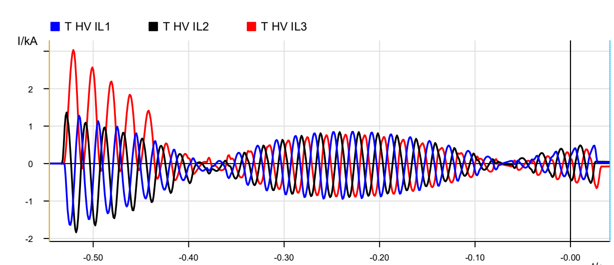

Figure 8: OOPS event No 2

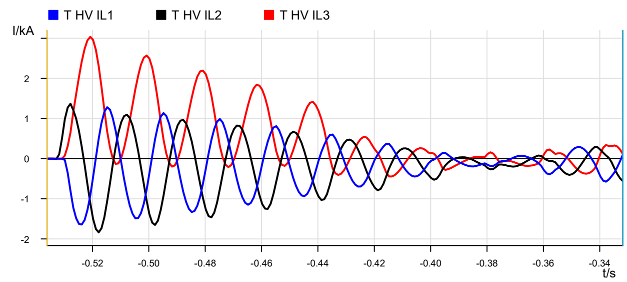

Figure 9: OOPS event No 2, first 200ms of the event

In Figure 9 only the first 200ms of the same OOPS event given in Figure 8 is shown. This figure shows that there is a period of time when the AC part of the current is very low which gives a very high relative DC current. The figure also shows that the red phase waveform (phase L3) is affected by CT saturation after the fifth peak, which explains the differential trip.

Simulated OOPS cases

Simulations of OOPS with HV breaker and GCB have been performed. Due to limited space only one such simulated OOPS scenario when the HV breaker is closed for a voltage phase displacement of 90° with a protection trip delay of 0.1s is shown in Figure 10. The breaker internal arcing begins at a very unfavourable moment where the AC component of the current is very low, and the current in one of the phases is almost pure DC. If no OOPS protection is installed and another protection sends the trip signal with this delay of 0.1s, or near to that, the arcing time will be so long that the circuit breaker will most likely be destroyed. Note that the arc voltage in the circuit breaker will also contribute to force the zero crossing and reduce the arcing time. The value of the arc voltage will depend on the used breaking medium.

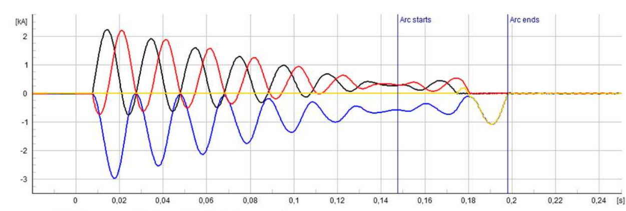

Figure 10: OOPS HV breaker 90° delayed 0.1s - arc time 51ms

If the protection would have operated with a longer time delay (e.g. >0.2s) the DC component of the OOPS current would be much lower, and current zero crossings would occur, leading to much shorter arcing time.

4.3. The OOPS and protection relays

First, one can clearly state that OOPS should not happen and that reliable generator paralleling devices should be used. However, even if the best paralleling equipment is used, due to technical problems and/or human errors, one must realize that OOPS incidents will happen in practice. In Statkraft OOPS or accidental energizing (AE) happens almost every year (please have in mind that the number of generators in Statkraft is much higher than the number of hydro power plants which is 340). If an OOPS has occurred it is likely that some protection will trip, most likely the differential protection, but also the overcurrent protection. Dependant on several parameters the trip by protection may be instantaneous or in some cases it can be delayed as already shown.

In Statkraft the philosophy is that after an OOPS event the generator and especially its damper windings, shall be inspected. But how do we know that there's been an OOPS event? We could analyse the disturbance records manually but that involves special competence to download disturbance records from the protection relays, and special competence to analyse these records. It is also a prerequisite that there's been a trip, or else no one would consider to analyse anything.

Another way to detect such event is to have a special OOPS logic. This logic can give a fault signal only to the SCADA and dispatch centre, or the logic can also activate a trip. To detect that an OOPS has occurred a special logic has been made as shown in Figure 11. In a way it is a similar logic to that used for standard accidental energizing protection, but the main difference is that the logic is disarmed by a small amount of current which is expected to start to flow through the stator winding in case of a proper synchronising. If the stator current instead has large magnitude the OOPS condition is detected.

Statkraft have used this kind of logic for a few years now, but only on the largest generators. The logic only sends a fault signal to SCADA (i.e. no trip is given to the breaker). The idea behind this is that it is not likely to gain something by tripping the generator. If the forces are high enough, we may have a differential trip, or other protection trip anyhow. Another argument for not tripping is that a trip after an OOPS event may be harmful for the circuit breaker. The third argument is that we only have limited operational experience with this logic, so we would need more experience to trust the security of the proposed OOPS logic.

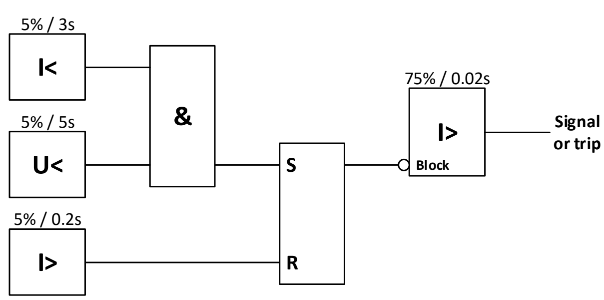

Figure 11: Proposed OOPS logic

However, it must be added that there haven't been any unwanted operation of this OOPS logic in Statkraft either. This idea/philosophy is of course a subject for further discussion. If an OOPS occurs the generator should be inspected. If the generator doesn't trip, is it then safe to operate it until the next planned outage? On this we do not have any definitive answer yet, but the discussion is ongoing within Statkraft.

5 Generator islanding operation

In Norway islanding operation of a certain part of the grid is quite common. As well under such circumstances the generation shall remain in operation (i.e. shall not be disconnected as required in some other countries). For this reason, there are grid requirements for generators, as well as for the associated line protection on the HV side of the generator transformer, to withstand and operate for large frequency deviation from the rated frequency of 50Hz. For example ±10Hz, but in some parts of the grid a frequency excursion of up to 70Hz for 10s is also possible. Such islanding conditions are even tested live in order to study behaviour of the whole system during such events.

The grid code in Norway (NVF 2021) [6] has certain requirements that the hydropower plants must satisfy. In the NVF from 2021 it is stated that the operating area of the synchronous generator shall not be unnecessary limited. The TSO suppose that hydro power plants can be operated normally within the area 45-60Hz, and normally even wider. Table 1 is used as a guideline to ensure successful transition to islanding operation.

Normally in Norway hydro power generators connected to the transmission grid have the following under-frequency protection; 45Hz (prior to NVF) and 42.5Hz (according to NVF). The scope of the under-frequency protection is to have a lower limit of the frequency in such a way that restoration of the power system can be done easier. Over-frequency protection is normally not used. Over-frequency protection is allowed, but the frequency and time setting must be higher than under the full load rejection condition.

In areas where islanding operation is likely to happen, and there is a distribution grid and energy-intensive industry, successful transition to islanding operation is an important requirement. In such areas setting of frequency protection can be even more challenging because of different demands from the end customers and the transmission grid. In some areas live tests have been performed in cooperation between TSO, DSO, power generators and industry. These tests have given valuable information on how the power system behaves in different islanding scenarios. From one of such test, Table 2 is suggested with over- and under-frequency protection pickup settings and associated time delays for some of the generators in that area.

Table 1: Allowed frequency deviation for network in Norway [6]

Frequency region	Duration of required operation
45.0 Hz – 47.5 Hz	60 seconds
47.5 Hz – 49.0 Hz	30 minutes
49.0 Hz – 51.0 Hz	Unlimited
51.0 Hz – 53.0 Hz	30 minutes
53.0 Hz – 57.0 Hz	20 seconds
57.0 Hz – 60.0 Hz	10 seconds

Table 2: Proposed settings for under- and over-frequency protection

Generator rating	**f<< Time delay**	**f< Time delay**	**f> Time delay**	**f>> Time delay**
240 MVA	43Hz 0.1s	45Hz; 30s	57Hz 30s	70Hz 0.1s
130 MVA	43Hz 0.1s	45Hz 30s	55Hz 30s	65Hz 0.1s
22 MVA	43Hz 0.1s	45Hz 30s	55Hz 30s	65Hz 0.1s
14 MVA	43Hz 0.1s	45Hz 30s	53Hz 30s	57Hz 0.1s
6,0 MVA	43Hz 0.1s	45Hz 30s	53Hz 30s	55Hz 0.1s
5,2 MVA	43Hz 0.1s	45Hz 30s	53Hz 30s	55Hz 0.1s

As we can see from Table 2 the frequency range is quite wide, and it consequently requires protection relays to work correctly in a wide frequency range. This does not pose much problem for the generator protection which is fully capable to track and adapt to the actual power system frequency [1].

However, this is equally applicable for the distance protection installed on the HV lines in the vicinity of this hydro power plant. For the associated HV line protections and especially for the distance protection such wide frequency excursions can be a real challenge.

One such unwanted operation of a distance protection is shown in Figure 12. Note that in Figure 12 the distance protection voltage and current magnitudes are presented in secondary volts and amps respectively. The distance protection function mal-operated when the frequency became bigger than 60Hz in the 50Hz power system over a short period of time of approximately 1.75 seconds.

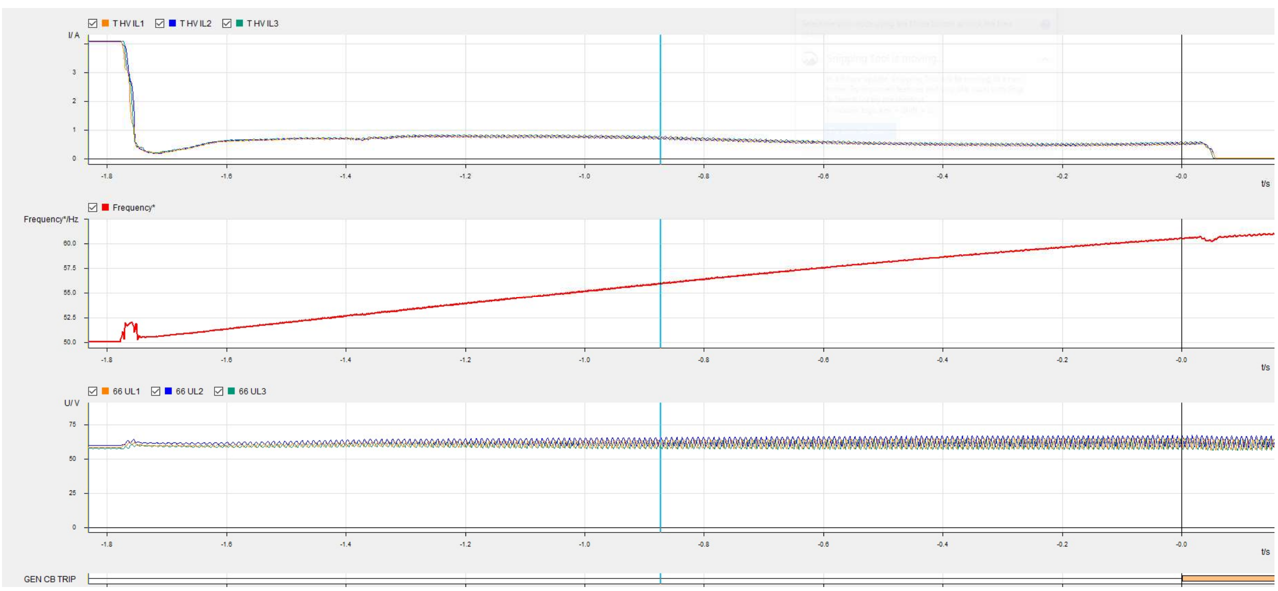

Figure 12: Maloperation of an HV-side distance protection due to large frequency excursion from the rated frequency

Even if frequency tracking is used for the distance protection its fixed X-reach in ohms will become variable with respect to the distance to fault due to the frequency excursion. As a consequence, typical set values for Zone 1 (e.g. 80% of the line length) and 120% for zone 2 will suddenly not be true anymore.

As a result, distance protection underreach may occur for such large over-frequency conditions. For such installations it is advisable to discuss this issue with a relay manufacturer to select the most suitable type of distance protection for such applications. Alternatively line differential protection can be used instead.

6 Conclusions

The paper has described several important but quite special protection functions/functionality for a generator protection. Regardless the complexity of such protection functionalities they can be implemented in a modern protection IED.

Shaft overcurrent protection using Rogowski coil as a shaft current measuring device was discussed. A field record from such shaft overcurrent protection scheme during actual bearing failure is also presented.

Injection based 100% stator earth fault protection was discussed. The basic problem of such protection schemes was described. The solution utilizing a dedicated signal injection transformer is presented. Such protection solution is successfully used on Statkraft hydro generators.

Out of phase synchronizing does happen. This phenomenon and the possible issues for the machine windings and associated circuit breaker were discussed. A dedicated logic to detect such event is proposed. What is still not completely clear is what to do when an OOPS event is detected? Give a trip command to the breaker(s) or just signal it to the SCADA system?

Large frequency variations are quite common in the Norwegian power system when it is transiting into an islanding mode of operation. Generator protection can easily cope with it by using a frequency tracking feature. However, this can be a potential issue for line distance protection installed on the HV-side of the generator transformer. Such frequency excursions were discussed and an actual record of distance protection maloperation during such an event is presented.

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