TEXAS A&M UNIVERSITY

77th Annual Conference for Protective Relay Engineers
March 25-28, 2024

# REQUIREMENTS FOR AND PRACTICAL EXPERIENCE ON PARTICULAR GENERATOR PROTECTION FUNCTIONS

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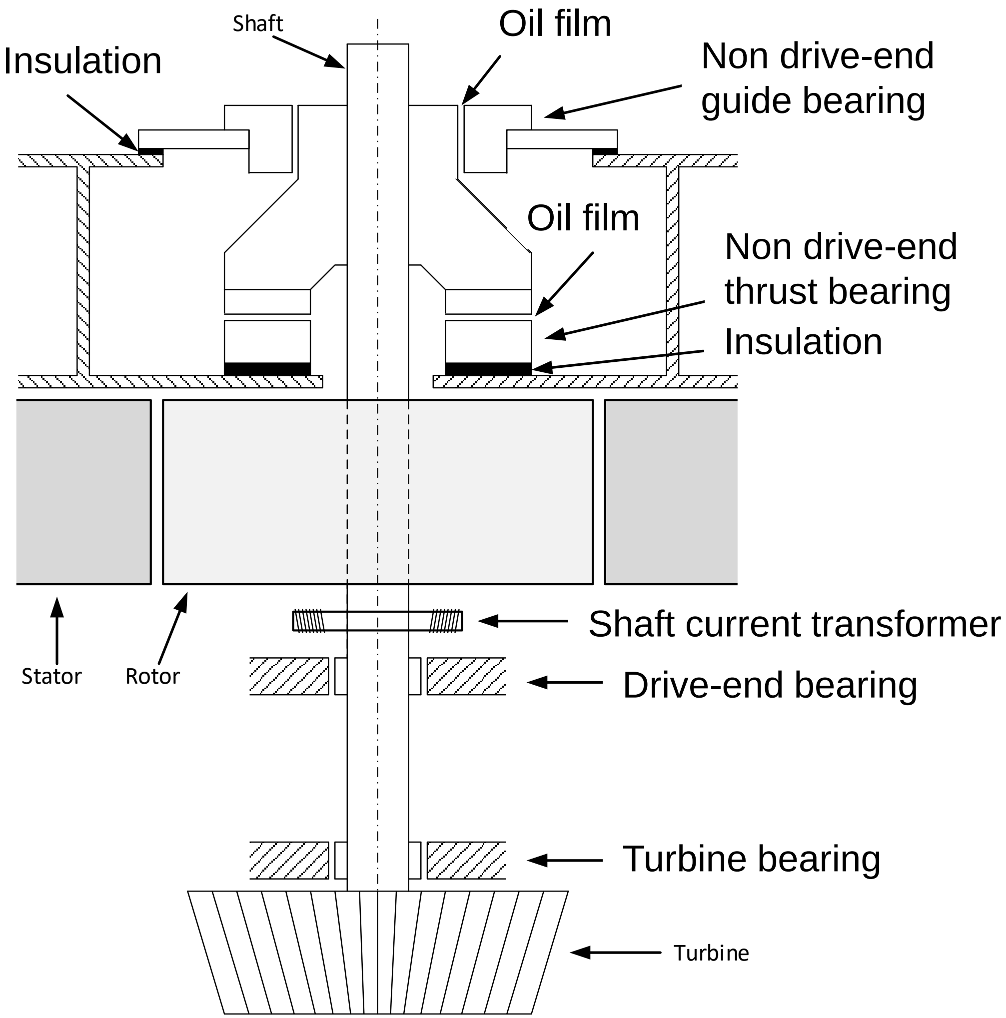
# Introduction

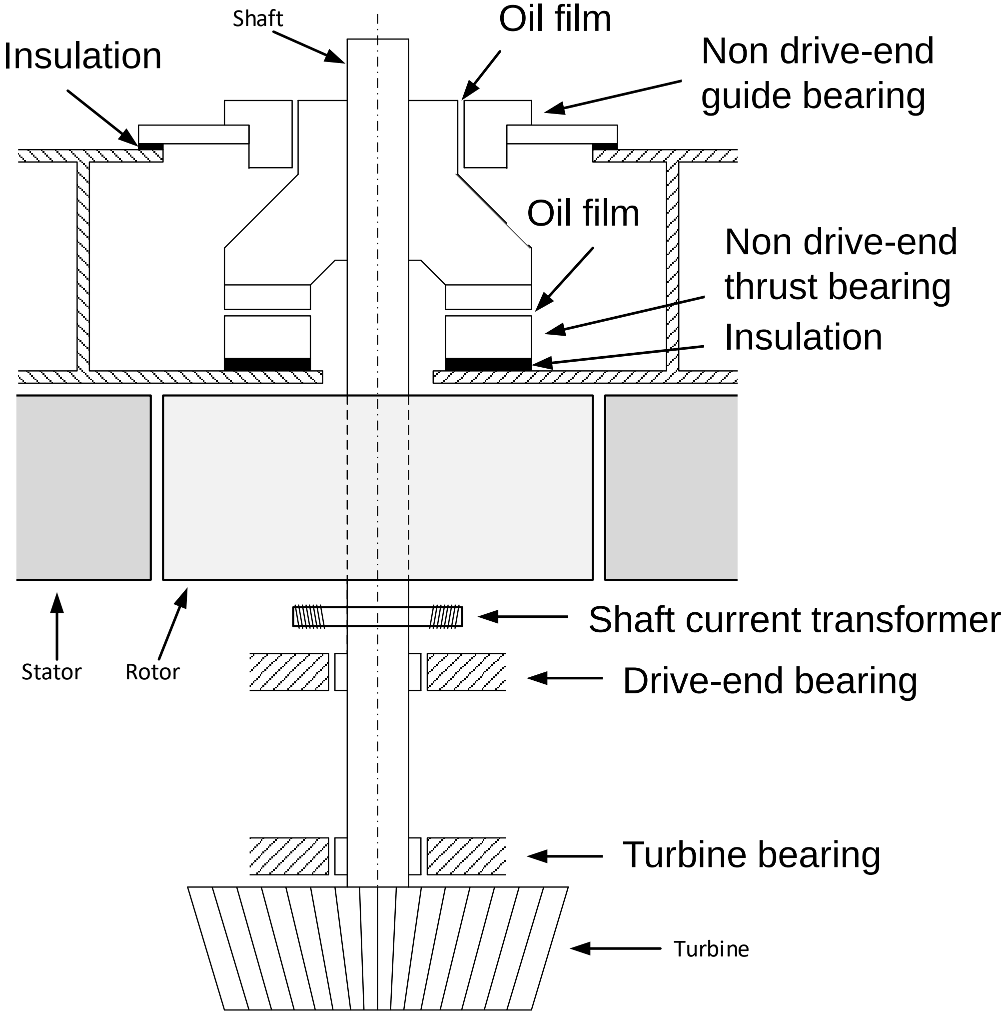
- Statkraft
  - owns and operates
    - ≈ 90 hydro power plants in Norway
    - > 340 hydro power plants globally
- Generator protection
  - includes differential, impedance-based, overcurrent functions
  - includes also functions specific for generator protection
    - presentation overview
      - shaft overcurrent protection
      - injection-based 100% stator ground fault protection
      - generator out-of-phase synchronizing
      - hydro generator islanding operation

# Shaft overcurrent protection



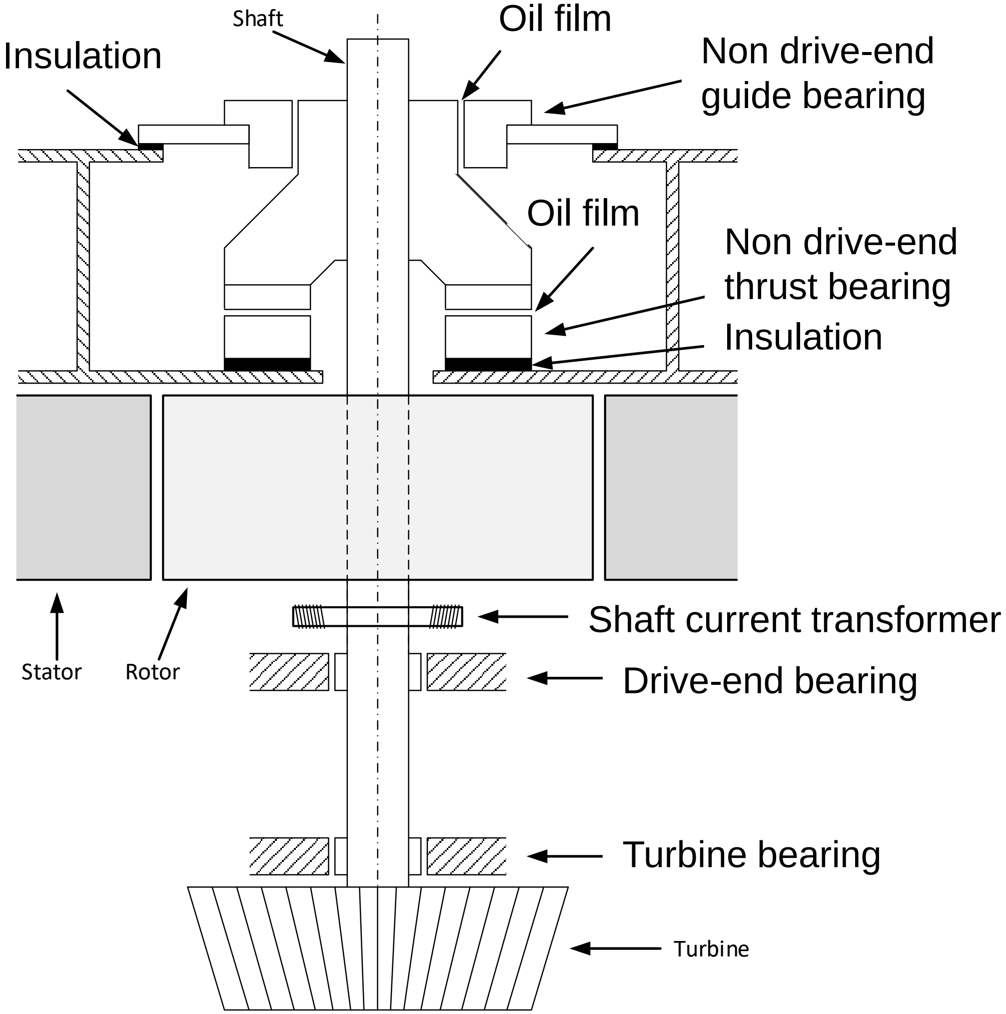

- When a generator is excited it can induce a voltage along the shaft
- This induced voltage is caused by asymmetry in the stator core - how high the magnitude of this will be depends on the stator construction
- If the shaft voltage is higher than one volt (1V), shaft overcurrent protection (or other types of mitigation) should be considered

# Shaft overcurrent protection



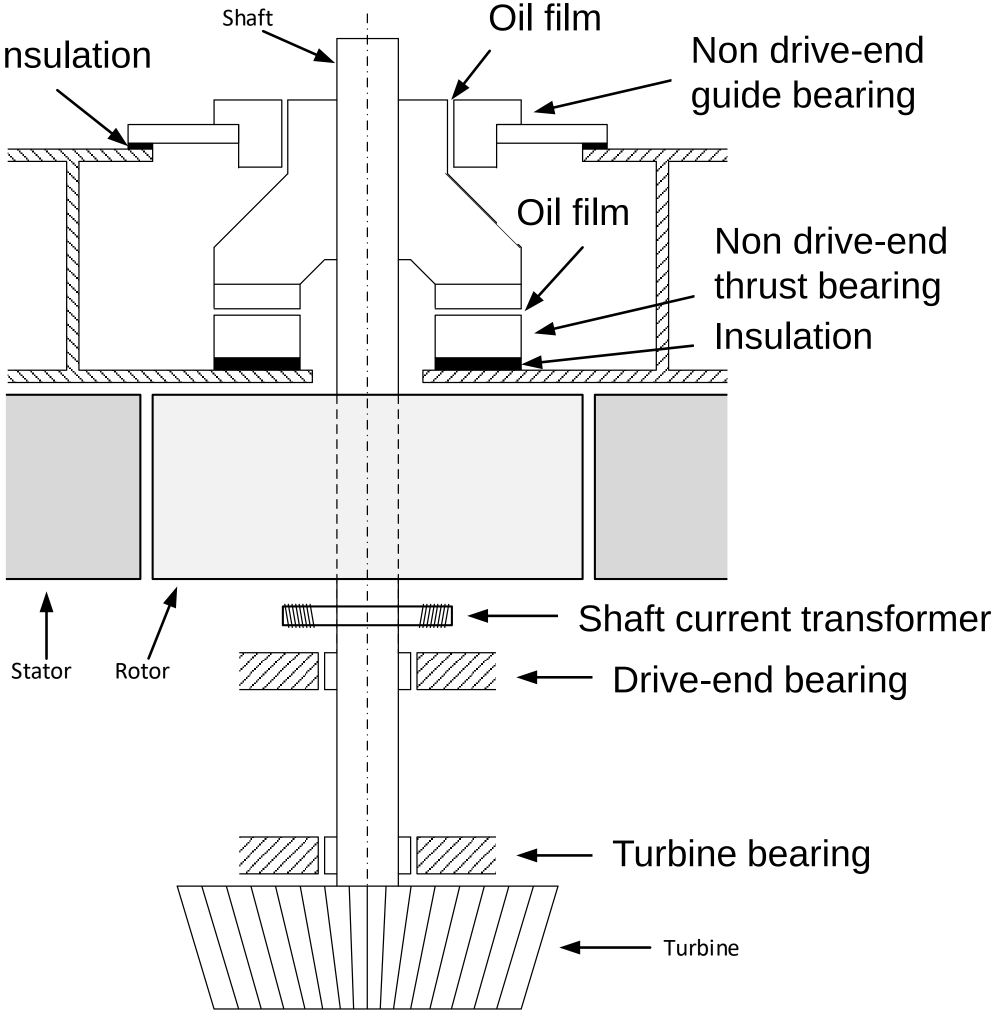

- Turbine and drive-end bearings are normally grounded
- Non drive-end bearings are normally isolated
- Non drive-end bearings
  - there is an oil film between the shaft and the bearing
  - there is insulation between the bearing and ground
  - normally the shaft voltage will be present between the bearing and ground
  - if the bearing insulation is broken due to a fault, the shaft voltage will be present between the shaft and the bearing, i.e. over the oil film

# Shaft overcurrent protection



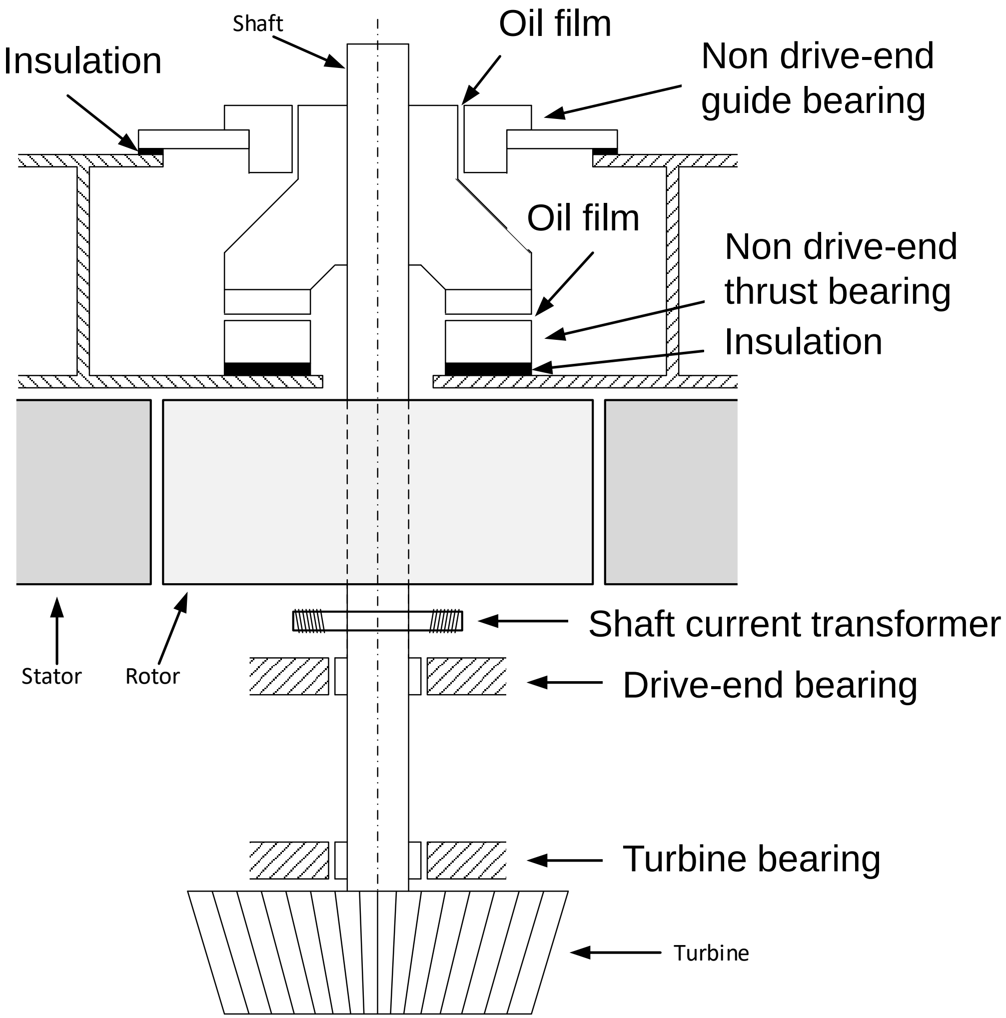

- If this voltage is too high
  - the oil will lose its electric insulation ability and a current will start to flow between the shaft and ground through the oil film
  - if this shaft current is too high
    - the oil film will lose its lubrication abilities and the bearing may be destroyed
- Statkraft installations – shaft currents of up to ≈70A have been measured, but normally the shaft current is lower than 10A
- Statkraft practice
  - 1V induced voltage is the limit to install shaft overcurrent
  - 1A shaft current is considered to be the max allowed

# Shaft overcurrent protection



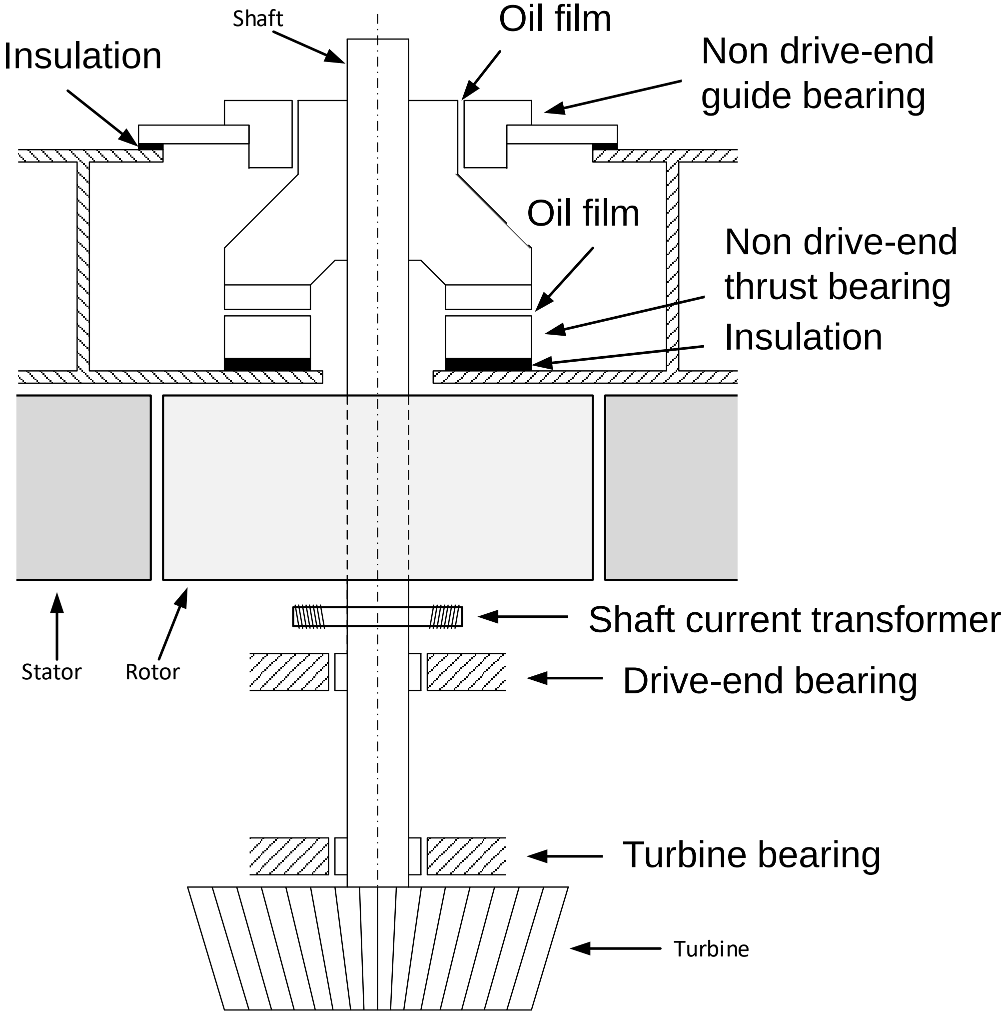

- Old Solution
  - use magnetic core CT to measure the shaft current
  - split core but still bulky and heavy
  - very difficult to mount in a confined space
  - requires specialized magnetic material
  - very low secondary current (500-1000 turns)
  - secondary winding connected to overcurrent protection
  - difficulties to produce it in recent years

# Shaft overcurrent protection



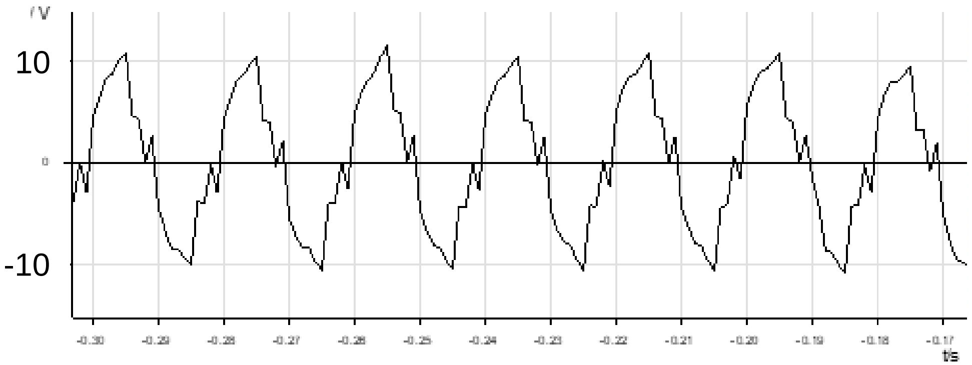

- New Statkraft solution
  - Rogowski coil – output is a voltage signal proportional to the rate of change of the shaft current
  - wall-mounted box containing electronic equipment
    - located 10m away from the Rogowski coil to minimize any influence from stray flux - coaxial cable connection
    - analog integrator – output is a voltage signal proportional to the shaft current magnitude, e.g. 200mV per 1A shaft current
    - amplifier to amplify the output voltage from the integrator (40x)
      - connected to the IED in control room (via 1.5mm$^2$ twisted pair)

# Shaft overcurrent protection

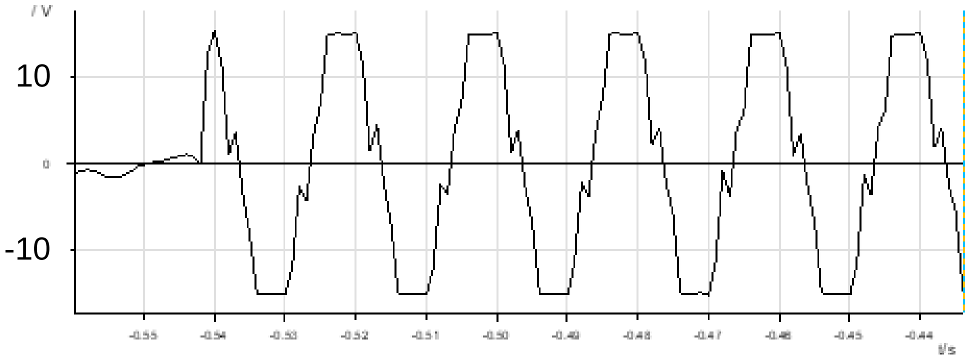



- New Statkraft solution
  - amplifier output connected to the voltage input of a generator protection IED
  - precise filtering filters out the required frequency component (typically either fundamental or 3rd harmonic)
  - overvoltage protection having two stages (e.g. alarm and trip stage) within the IED
    - alarm: $0.25A_{pri}$
    - trip: $0.8A_{pri}$

# Shaft overcurrent protection




Measured voltage by the IED during primary testing

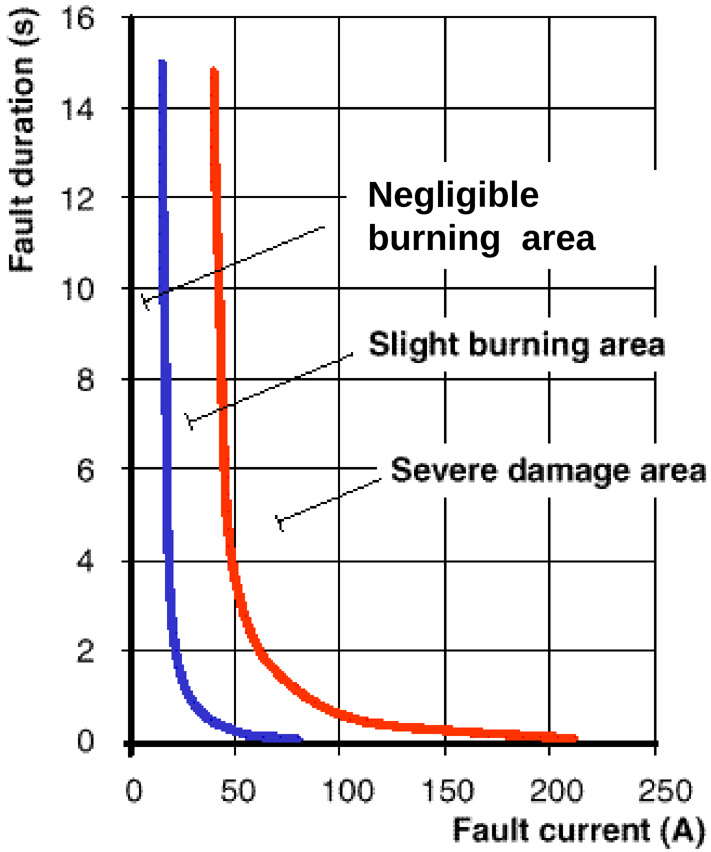



Measured voltage by the IED during an actual fault (2021)

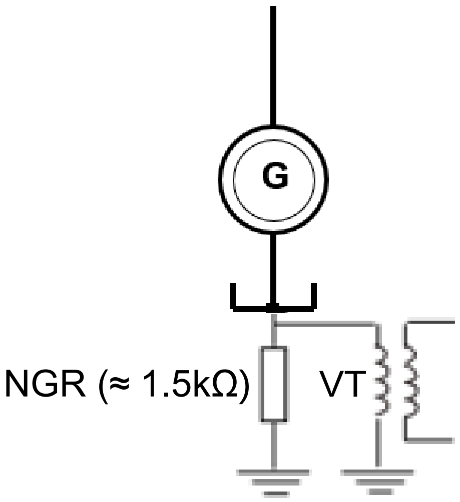
- 10V corresponds to a shaft current of 1.25A
- filter set to 50Hz

- The Rogowski scheme has been in successful operation in several Statkraft hydro stations for several years
- Several new sites/installations are in the pipeline

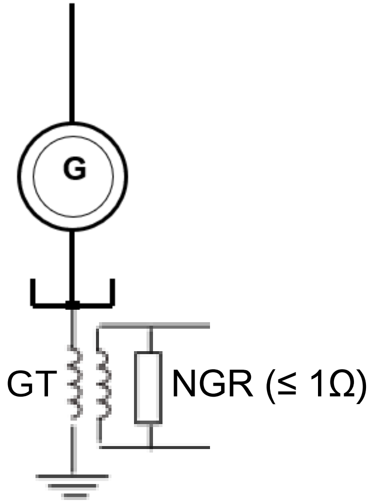
# Stator ground fault protection




- Grounding methods




Primary Neutral Grounding Resistor (NGR) + Voltage Transformer (VT)



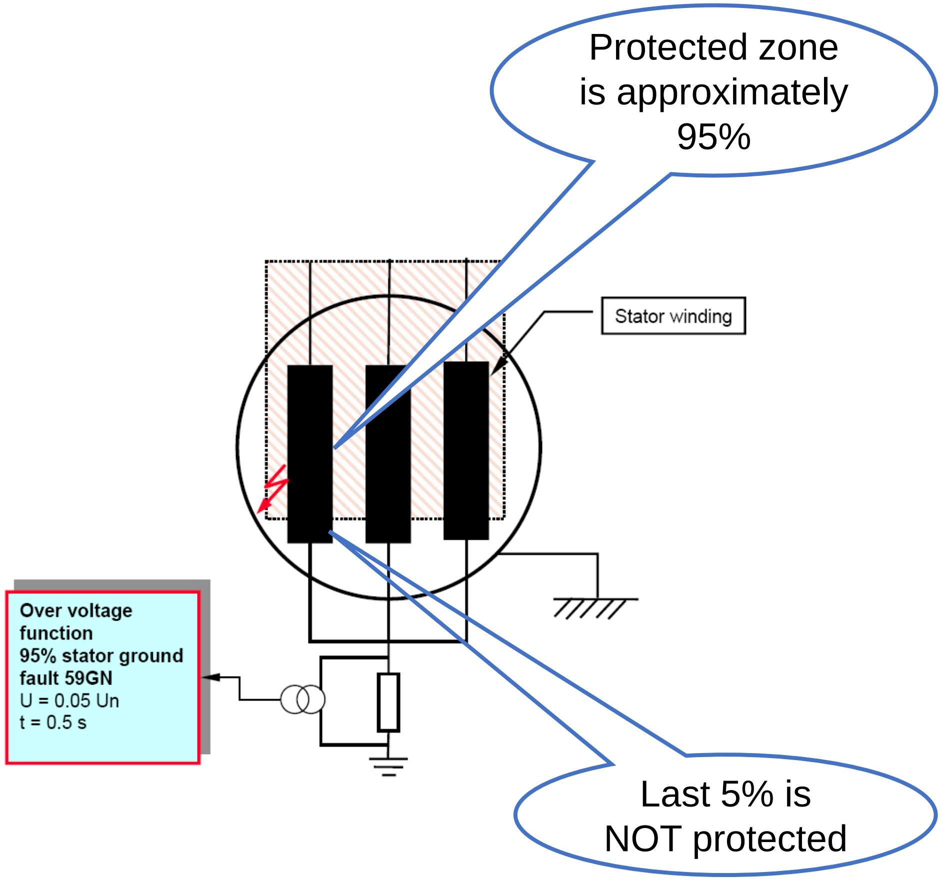

Grounding Transformer (GT) + secondary Neutral Grounding Resistor (NGR)

# Stator ground fault protection

- 95% stator ground fault protection
  - stator ground faults cause a displacement of the generator neutral-point voltage – the magnitude of the neutral-point to ground voltage depends on where the ground fault occurs

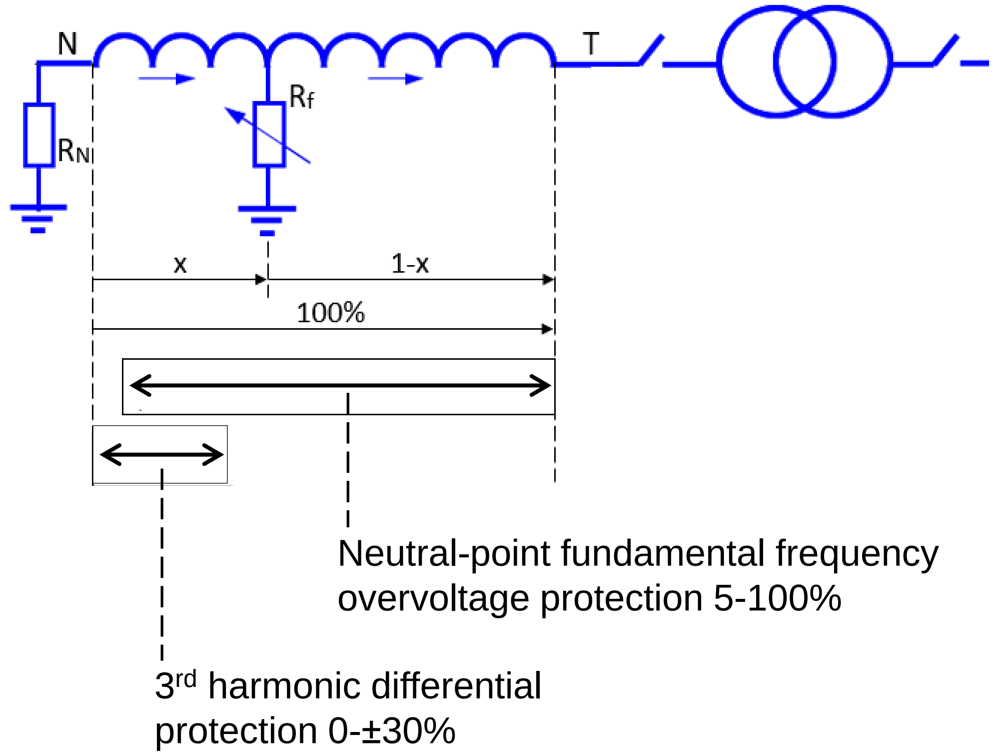
    = zero for a ground fault at the neutral-point

    = the rated generator Ph-G voltage for a ground fault at the terminals
  - to detect, measure the voltage between the generator neutral-point and ground
    - even when healthy, a small amount of zero-sequence current will flow – the neutral-point therefore has a non-zero voltage
    - a 59N function will not remain selective if set too low
    - typical setting: pickup 5% of rated Ph-G voltage → 95% stator ground fault protection



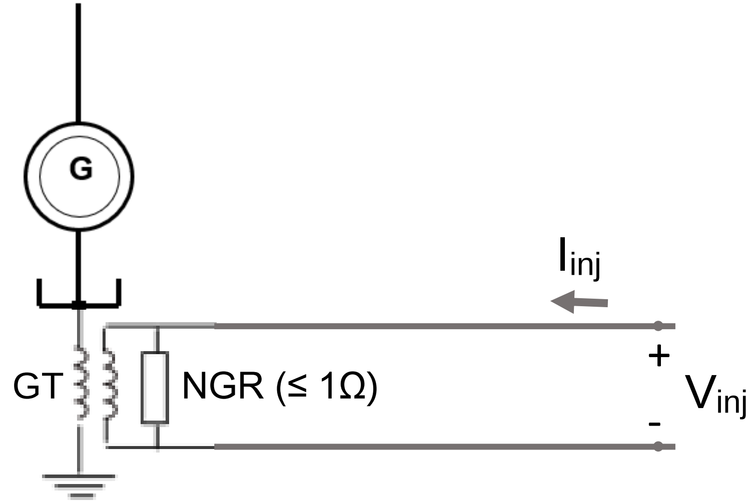
# Stator ground fault protection

- 3rd harmonic-based 100% stator ground fault protection (100% together with 59N / 51N)
  - based on measurement of the 3rd harmonic voltages generated by the machine
  - provides stator ground fault protection for the so far uncovered last 5%
  - reason to cover the last 5%: a ground fault at or near the neutral-point shunts the high resistance, and so poses a serious threat should a second ground fault occur elsewhere in the stator winding
  - drawbacks
    - requires machine to be excited and able to generate sufficient 3rd harmonic voltage
    - cannot detect a ground fault when the machine is at standstill



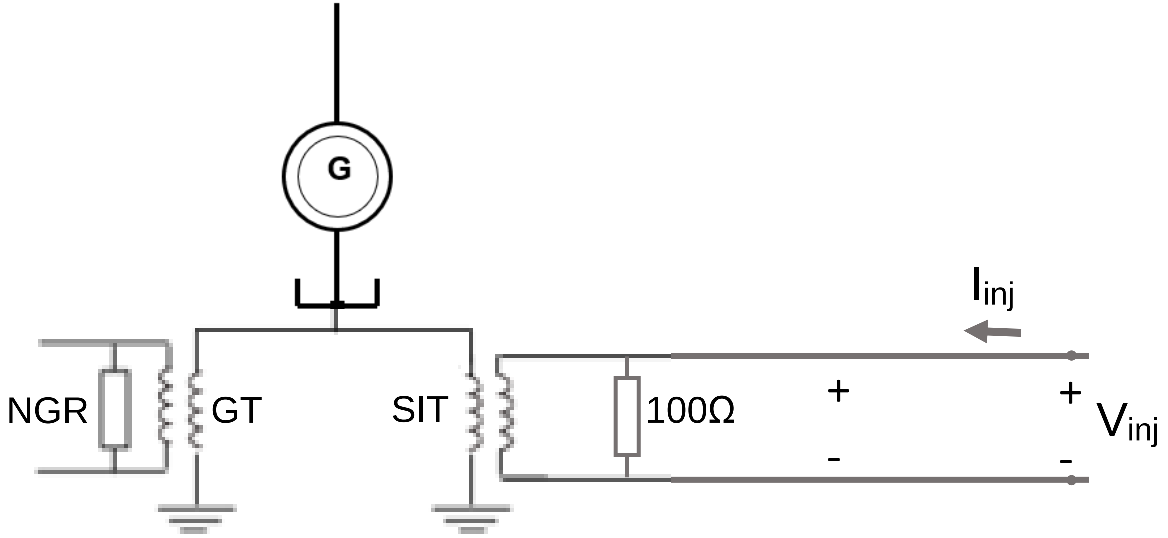
# Stator ground fault protection

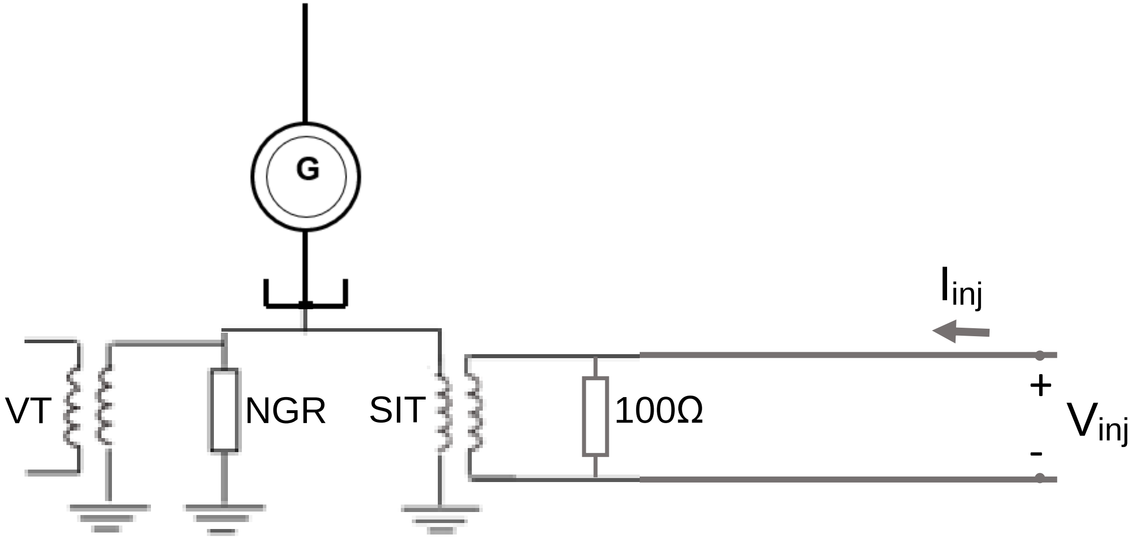
- Injection-based 100% stator ground fault protection
  - main challenge
    - injection is done through almost a "short circuit"
      - e.g. in the case when a GT with secondary NGR is used for stator grounding
      - for very large turbo machines, the NGR can have a value as low as 0.05Ω (typically ≤ 1Ω)
      - limited sensitivity as not much of the injected signal power is being transferred to the stator (thermal rating of injection equipment limits the amount of current which can be injected)
    - for a ground fault at the stator terminal a voltage will be pushed back onto the injection equipment, which must be designed to handle this



# Stator ground fault protection

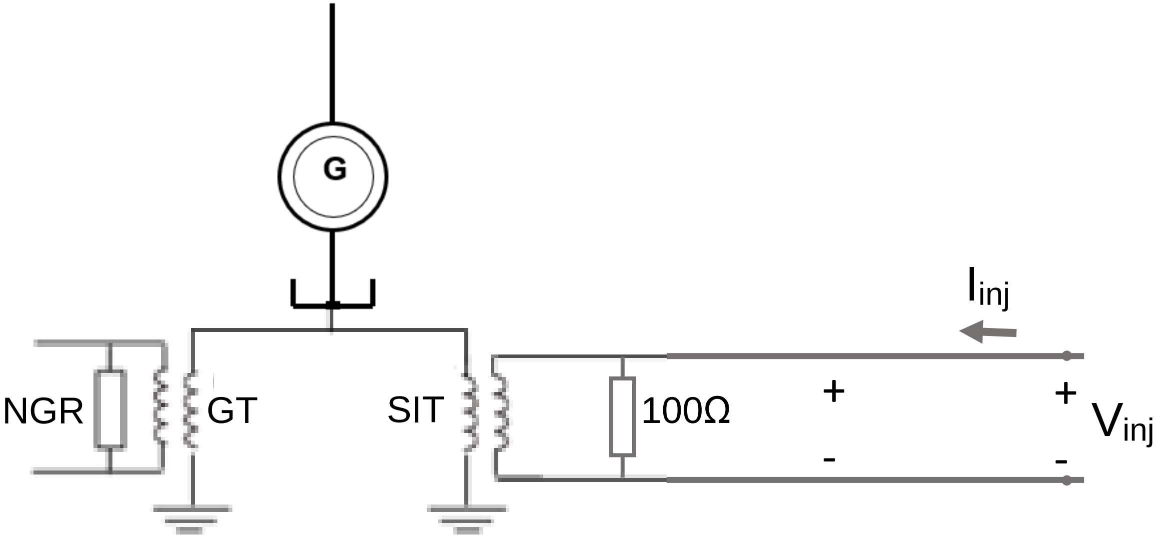
- Injection-based 100% stator ground fault protection
  - incorporate a dedicated Signal Injection Transformer (SIT) → universal way to inject into the stator regardless of the actual grounding arrangements
  - the generator neutral-point must be accessible
  - reliable 100% stator ground fault protection can be achieved by proper SIT design and the level of the injected signal – i.e. by ensuring that a sufficient amount of the injected signal power is transferred into the stator primary circuit
  - detects a change in the measured impedance from a reference value obtained during commissioning

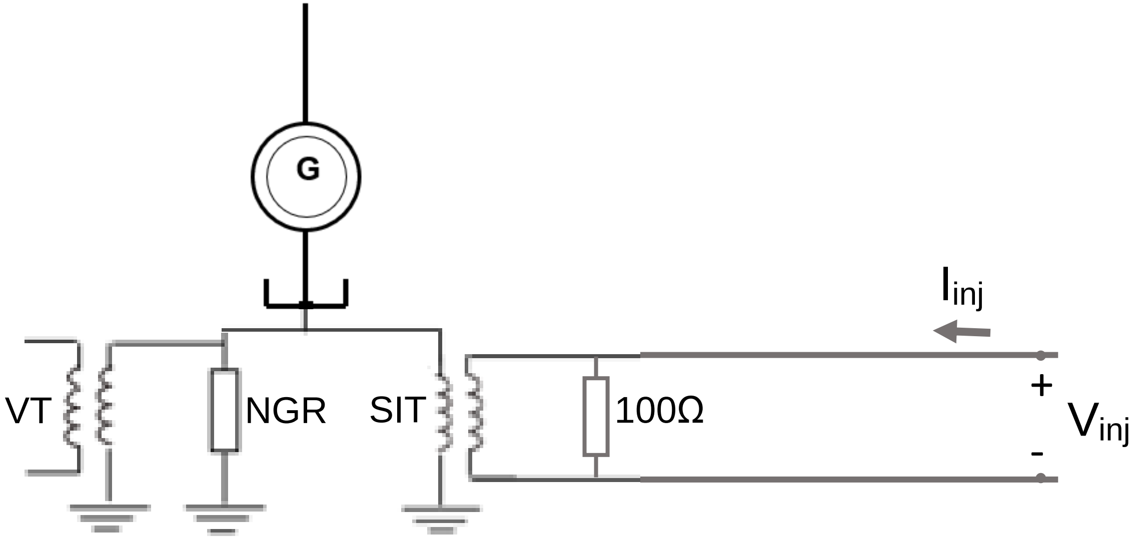


# Stator ground fault protection

- Injection-based 100% stator ground fault protection
  - at Statkraft
    - mainly use primary NGR
    - injection-based scheme is in successful operation on the largest hydro generator in Norway as well as at several other installations



# Generator out-of-phase synchronizing (OOPS)

- An OOPS incident is hazardous (high forces and currents that can cause damage) to
  - stator windings; rotor damper (amortisseur) windings; shaft; circuit breaker (if it is tripped)
- The forces depend on how big the phase angle was between the generator and grid voltages
  - the larger the OOPS angle, the larger the OOPS forces (currents)
- From the perspective of the CB
  - closing for an OOPS is not a problem
  - opening (trip by protection) following an OOPS exposes the CB to difficult operating conditions
    - the large DC time constant of the generator leads to a relatively slow decay of the DC component of the current
    - fast decrease of the AC component

    → delayed zero-crossings

# Generator out-of-phase synchronizing (OOPS)

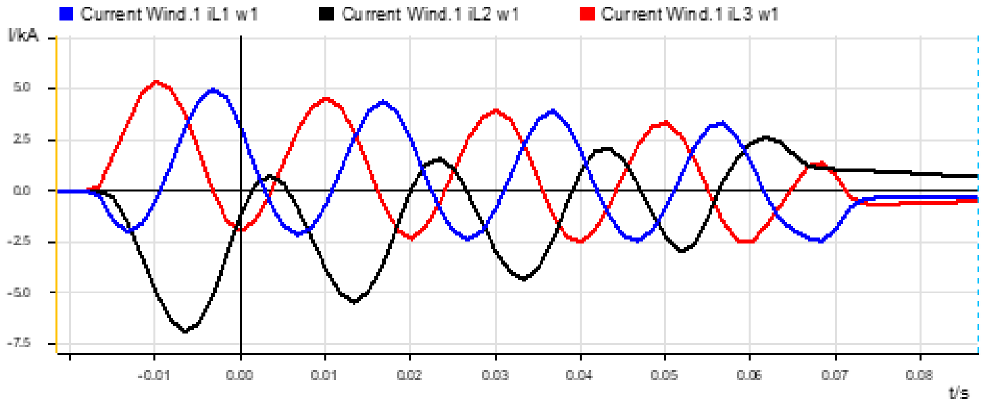
- Synchronizing the generator can occur by closing
  - the generator breaker; the HV breaker (HV-side of the GSU)
    - if an OOPS occurs when synchronizing (closing) the HV breaker, the forces on the generator will be less than if synchronizing with the generator breaker due to the GSU impedance
    - much of Statkraft's synchronizing is done via the HV breaker – avoids the high inrush currents when energizing the GSU from the grid

# Generator out-of-phase synchronizing (OOPS)

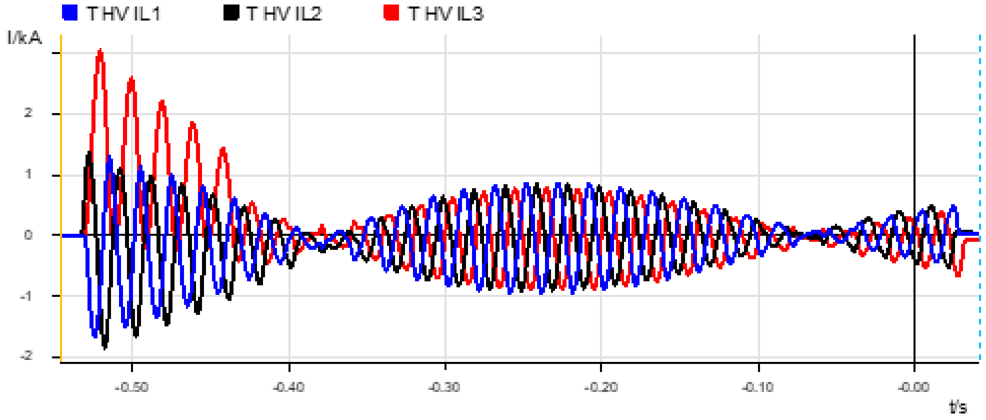
- Depending on the OOPS angle, the recovery voltage (RV) and the transient recovery voltage (TRV) may be among the highest a circuit breaker may experience
  - the larger the OOPS angle, the larger the RV, the TRV and the OOPS currents
- Synchronizing via the generator breaker
  - has an OOP breaking capacity of 50% of the rated short circuit breaking current – may only correspond to a 90° out of phase angle
    - an OOPS angle of 180° might give a current up to 80% larger than for an OOPS angle of 90°
    - an OOPS current should be interrupted within 80-100ms after closing, before the AC component becomes too low (causing a delay in the zero-crossing) to ensure a successful interruption
- Synchronizing via the HV breaker
  - has an OOP breaking capacity of 25% of the rated short circuit breaking current
    - an OOPS angle of 180° might give
      - a current up to 40% larger than for an OOPS angle of 90°
      - and a 40% increased steepness in the TRV

# Generator out-of-phase synchronizing (OOPS)

- Real OOPS events



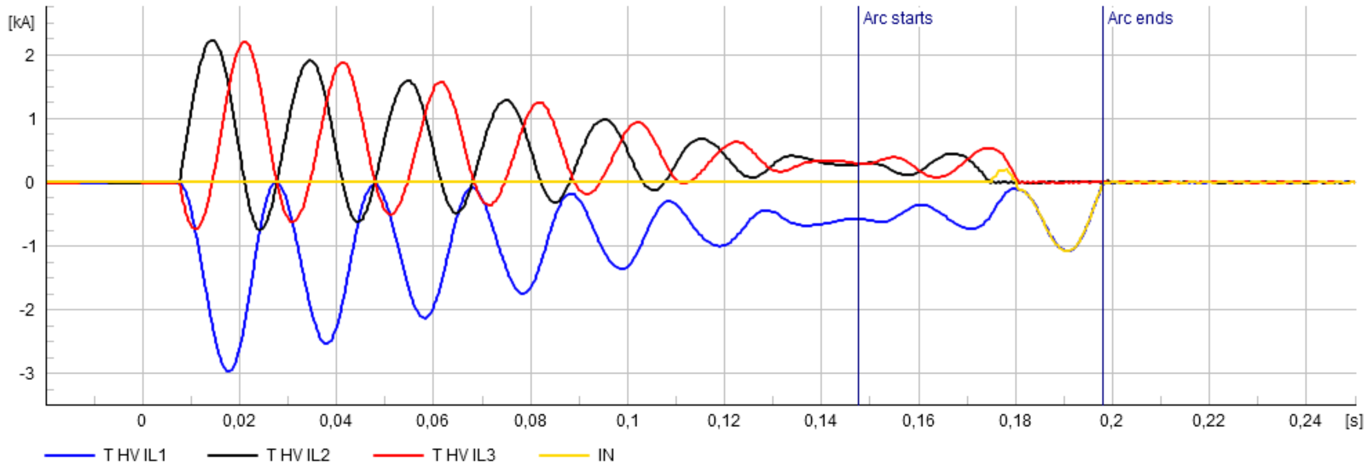

- event 1
  - synchronize (close) via HV breaker
  - instantaneous trip – GSU HV-side overcurrent




- event 2
  - synchronize (close) via HV breaker
  - trip 533ms after the OOPS – GSU differential – should not trip for an OOPS, but due to CT saturation the differential current reached the trip level after some time

# Generator out-of-phase synchronizing (OOPS)

- Simulated OOPS event



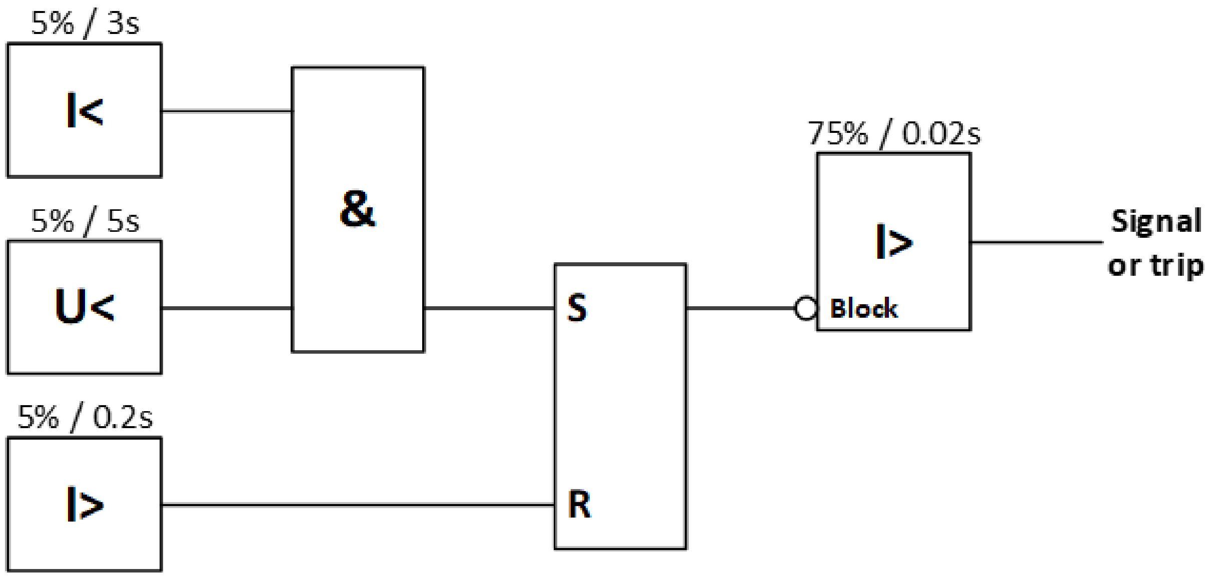

- close HV breaker, 90° out of phase, protection trip at +0.1s
  - the CB internal arcing begins at a very unfavorable moment (the AC component of the current is very low, and the current in one of the phases is almost pure DC)
  - in this case, for a trip signal with a 0.1s delay (or near to that), the arcing time will be so long (51ms) that the circuit breaker would most likely be destroyed
  - if the protection were to operate 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

# Generator out-of-phase synchronizing (OOPS)

- If an OOPS occurs it is likely that some protection will trip – differential, overcurrent – but an OOPS can also occur where no protection trips
  - the trip may be instantaneous, or in some cases time delayed
- For events 1 and 2, there was no dedicated OOPS protection function
  - the difference in the trip times was due to other protection functions tripping when their trip conditions were fulfilled
  - this means that the trip signal could occur in a timeframe which is unfavorable for the interruption of the OOPS currents, leading to higher arcing times than acceptable and causing possible destruction of the circuit breaker

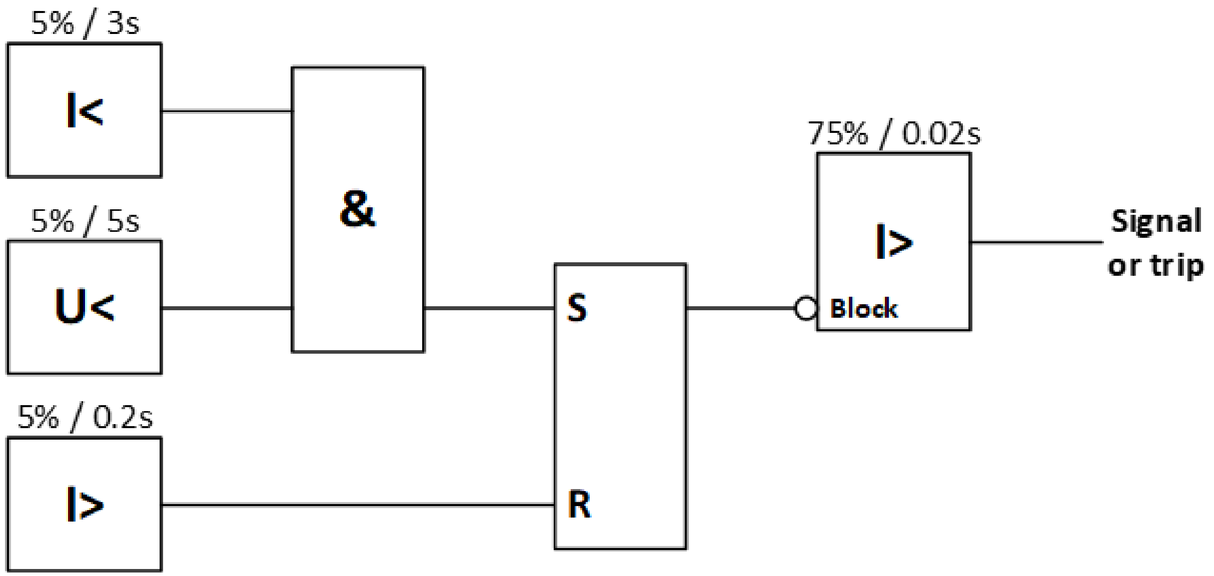
# Generator out-of-phase synchronizing (OOPS)

- The Statkraft philosophy is that the generator (especially its damper windings), shall be inspected after an OOPS has occurred
  - how to know the OOPS has occurred?
- Logic was designed to detect an OOPS incident



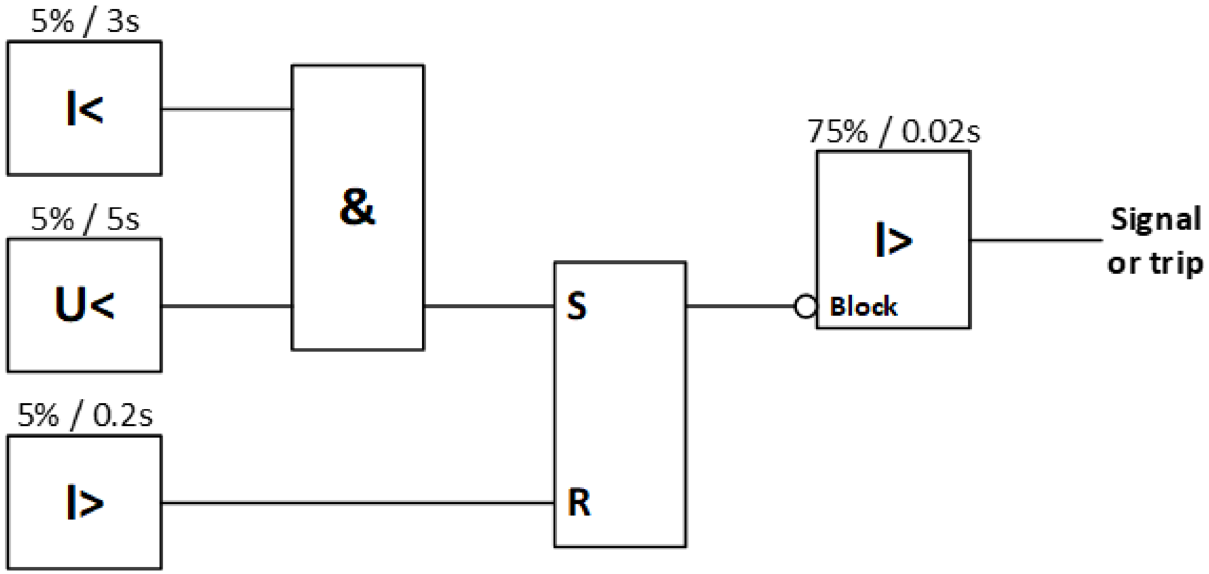
# Generator out-of-phase synchronizing (OOPS)

- Statkraft have used this logic for a few years now, but only on the largest generators
- Presently only an alarm is given to SCADA by this logic (no trip issued)
- Current thinking – no gain by tripping
  - if the forces are high enough, other protection will trip
  - after an OOPS has occurred it may be harmful for the circuit breaker to be tripped
  - operational experience with this logic is limited, so need more experience to trust in its security
    - to date there has been no unwanted operation of this logic



# Generator out-of-phase synchronizing (OOPS)

- Further discussion
  - if an OOPS occurs should the generator always be inspected?
    - if the generator isn't tripped, is it then safe to operate it until the next planned outage?
  - no definitive answer yet, but the discussion is ongoing within Statkraft



# Generator islanding operation

- In Norway islanding operation is quite common
  - the generation shall remain in service
  - required to withstand and operate for large frequency deviations from the 50Hz rated frequency (e.g. ±10Hz – in some parts even up to 70Hz for 10s is possible)
  - grid code specifies requirements hydro power plants must satisfy – expected to operate normally within 45-60Hz

*Allowed frequency deviation for network in Norway*

| 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 |

- hydro power generators connected to the transmission grid
  - underfrequency
    - <45Hz
  - overfrequency
    - normally not used, but is permitted – must withstand a full load rejection

*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 |

# Generator islanding operation

- The protection relays need to work correctly within the wide frequency range
  - poses no problem for the generator protection which is fully capable to track and adapt to the actual power system frequency
  - the distance protection on the power lines in the vicinity of the hydro power plants can be a real challenge due to the wide frequency range
    - the fixed X-reach in ohms will become variable with respect to the distance to fault due to the frequency excursion
    - line differential protection can be a possible better solution

# Conclusions

- Several important but quite special protection functions/functionality for generator protection have been described
- Regardless of the complexity of such protection functions/functionalities, they can be implemented in a modern protection IED