Leveraging Digital Relays for Protection of Pumped Storage Hydro

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***Abstract*—Currently the U.S. has about 20 GW of pumped storage hydro. An additional 30 GW of new capacity has been proposed for support of renewable sources. This paper describes the challenges associated with protecting these units and how digital protective relays provide simpler and more effective protection.**

Switching from generator to pump mode impacts elements that use sequence components. A second impact occurs if the differential zone includes a reversing switch. A third item is a bad status signal from the reversing switch. The paper describes how a digital relay can address these issues.

Protecting units that start as induction motors requires protection for the damper winding, which was typically provided by an overcurrent relay or even a simple timer. An alternate method uses a motor thermal model. The paper discusses the merits of this solution and offers some setting guidelines. In the past, units that started while connected to a variable-frequency source used overcurrent and overvoltage relays with wide frequency responses to supplement the differential and neutral overvoltage elements. If a digital relay with tracking frequency is used, these supplemental functions are no longer required. In early electromechanical schemes, out-of-step protection took the form of an inverse-time overcurrent relay. This paper discusses the advantages of power and impedance-based elements present in digital relays that can provide a superior method for protecting against out-of-step conditions. Regarding the generator step-up transformer (GSU), if it is downstream from the reversing switch, then the transformer effectively changes its vector group. A second issue can occur if the tap from the GSU is used to implement low-voltage starting, which effectively changes the turns ratio of the GSU. The paper discusses how both of these issues can be addressed in a digital relay. When shutting down a hydro machine, it must be quickly brought to a standstill to avoid bearing damage. Dynamic braking is an effective way to stop these machines but introduces challenges for protection.

I. Overview of Pumped Storage Hydro

During the last two decades, renewable energy projects have gained momentum, and at present, a large installed base of wind and solar energy sources exists worldwide. These sources are intermittent, and maintaining grid stability requires bulk energy storage.

Pumped storage hydro (PSH) units are hydro units that can operate in generating or pumping mode, moving water either from the upper reservoir to the lower reservoir or vice versa, as shown in Fig. 1.

The current round-trip energy efficiency of PSH exceeds 80 percent [1], and primarily for this reason, PSH units have historically been the only practical method to store and manage large amounts of grid energy. Therefore, they play a vital role in the operation of power systems with a large ingression of renewable energy sources.

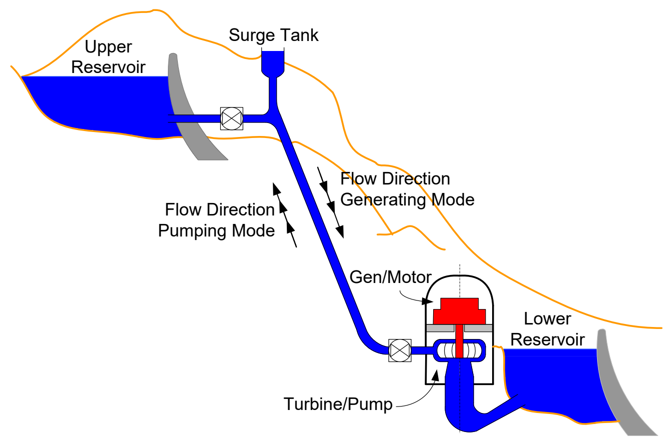

Fig. 1. Pumped Storage Hydro Scheme

PSH units can be categorized by prime mover type and by electric machine type. Three basic types of prime mover designs have been employed:

- Units are configured as either dedicated generator/turbine units or dedicated motor/pump units within the same installation. This configuration is often found in high-head installations. The design and operation of each unit is straightforward; however, the use of dedicated units adds significantly to the overall cost of the installation.
- Units are configured with a turbine, pump, and generator/motor mounted on the same shaft. These are known as ternary units. They can quickly switch from generator to motor operation without stopping the unit. Starting in pump mode is simplified since the turbine can bring the unit up to synchronous speed. However, the hydraulic system is more complex, making these units more expensive to build.
- Units are configured to operate alternately where the generator also operates as a motor and the turbine also operates as a pump. Switching from generator to motor operation requires disconnecting the unit from the power system, bringing the unit to a standstill, switching the phasing (ABC to ACB) of the primary electrical connections, and putting the unit back into service. Changing the phasing changes the direction of the machine's rotation, which in turn reverses the flow

of water. This is an efficient design, well suited for installations that are operated as generators or turbines during the day and motors or pumps at night.

Two types of electric machines have been employed.

- Variable-speed units typically employ a doubly fed induction generator (DFIG). Variable-speed operation has several advantages:
  - Higher operating efficiency than fixed speed synchronous machines,
  - Frequency regulation in generation and pump mode,
  - Regulation of real power when in pump mode,
  - No additional equipment requirements for starting in pump mode, and reactive power regulation is possible while at a standstill, i.e., the DFIG can act as a static var compensator.

  The disadvantage of a variable-speed unit is the additional costs associated with the power electronics.
- Fixed-speed units employ a synchronous machine. Consideration must be given to starting the unit in pump mode. Over the years, a wide range of schemes have been used for PSH starting. These can be roughly categorized, especially for the discussion of protection, into three main categories:
  - Units started as induction motors,
  - Units started using a variable-frequency drive, such as a line-commutated inverter (LCI),
  - Back-to-back starting (one machine acts as a generator and the other machine acts as a motor).

In this paper, we focus mainly on fixed-speed units that operate alternately as a generator/turbine or as a motor/pump.

Fig. 2 shows a typical PSH protection scheme for an alternate generator/motor configuration using electromechanical (E/M) relays. The primary circuit contains a set of parallel, interlocked switches between the generator breaker and the generator. On the blade-side of the switch (that part of the switch facing the machine) the phasing is swapped. Depending on which switch is closed, G (generating) or M (motoring), the downstream phasing changes from ABC to ACB. For the remainder of the paper, we call this pair of switches the reversing switch. Note that the reversing switch introduces the possibility of a phase-to-phase fault at the machine terminals for the case that both Switches G and M close simultaneously.

Note that the reversing switch is included in the overall unit differential zone (87U). A set of auxiliary contacts in the 87U secondary wiring replicates the position of the reversing switch. These switches transpose the secondary wiring in the same manner as the reversing switch to maintain the correct phase relationship for the 87U. A similar situation exists for the protection elements fed from the machine neutral CT. Some of these elements, for example the machine unbalance element (ANSI 46), respond to a negative-sequence current component. Therefore, a second set of auxiliary contacts are required to ensure that the phase sequence of the currents is correct. A third set of auxiliary contacts ensures the correct phase relationships between the secondary voltages and currents.

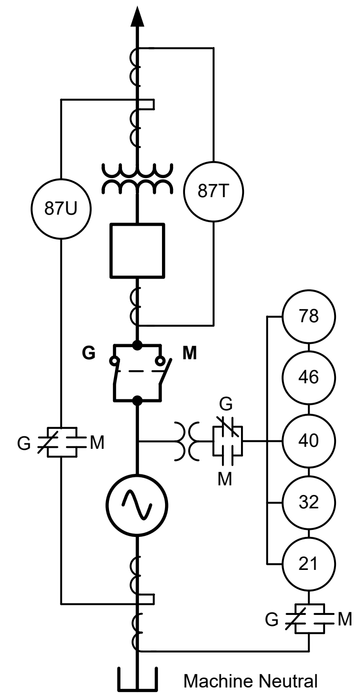

Fig. 2. E/M Relays and CT/PT Secondary Switching

II. Impact of the Reversing Switch on Protection Functions

From Section I, we see that the reversing switch can change the phase relationship within the 87U zone and the phase sequence of the protection elements supplied by the machine neutral CTs. The phase relationship change can be addressed by inserting auxiliary contacts that transpose the secondary CT wiring. However, most protection engineers would prefer to avoid inserting auxiliary devices within the CT secondary circuit since it introduces complexity and a point of potential failure in the scheme. Furthermore, failure of the auxiliary device could result in the CTs open circuiting and creating a safety hazard for personnel.

In the following examples, we show how using digital protective relays addresses the above problems and concerns without switching the secondary wiring of the CTs and PTs.

A typical digital relay has the following capabilities:

1. The differential zone can be dynamically reconfigured to add and remove an input (terminal) to the zone.
2. The phase-rotation setting of the relay can be changed dynamically from ABC to ACB. (This setting determines how sequence quantities are calculated internally.)

The first example, shown in Fig. 3, uses separate breakers to operate the machine as a generator or a motor. The primary phasing downstream of Breaker G is transposed, as denoted with a **T**. The transformer differential element (87T) is secure since transposition occurs outside of its zone; however, transposition of the secondary wiring of the generator differential element (87G) is required (also shown by a **T**). Since both Breakers G and M employ dedicated CTs, no CT switch (external or internal) is required. The generator relay protection elements (excluding the 87G) are denoted by an asterisk (*). The generator relay needs to dynamically change its phase rotation (denoted by a **P**) based on a status indication of Breakers G and M in order for the differential element to remain stable and correctly calculate the voltage and current sequence quantities.

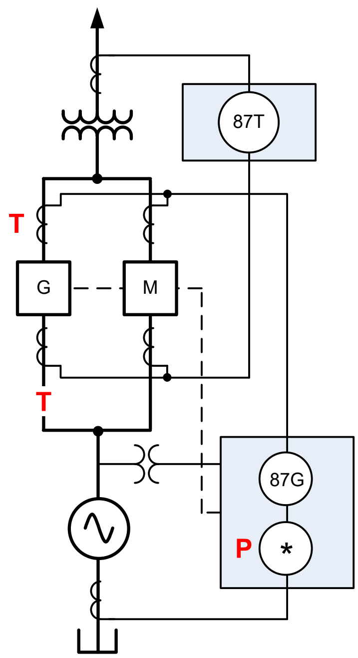

Fig. 3. Individual Breakers and CTs

The second example, shown in Fig. 4, uses a single breaker and a reversing switch, like the E/M example of Fig. 2. CTs are located at the generator terminals.

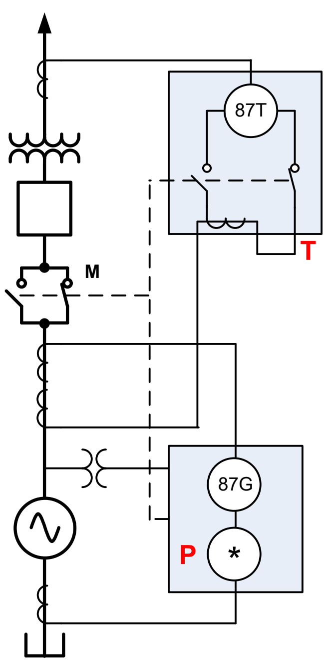

Fig. 4. CTs at the Generator Terminals

The 87T is a three-terminal differential element with dynamic switching for two of the terminals. The current supplied from the CT downstream of the reversing switch is connected to two separate input terminals on the transformer relay. However, on the second terminal, the wiring is transposed with respect to the first terminal. The combination of the internal dynamic switching and the secondary wiring transposition ensures the 87T remains stable during both generator and motor operating modes.

The third example, Fig. 5, is similar to the second example except that breaker CTs are used instead of generator terminal CTs. In this example, the reversing switch is inside the generator zone instead of the transformer zone. Dynamic terminal switching occurs in the generator relay. If the 87T were replaced with an 87U (as in Fig. 2), then dynamic switching would be required for both differential elements (87U and 87G).

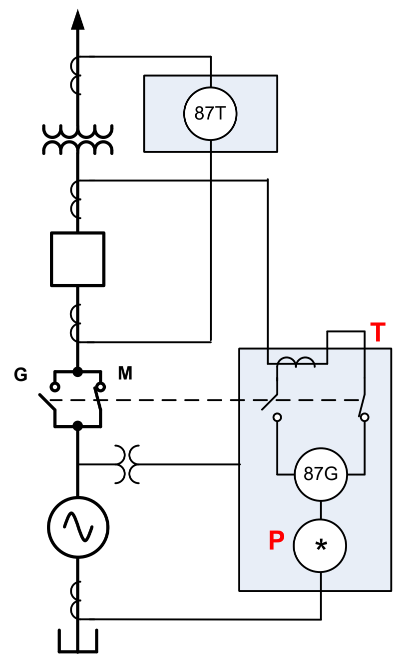

Fig. 5. CTs at the Generator Breaker

An alternative strategy to provide protection for PSH is shown in Fig. 6. In this instance, a digital relay provides protection for both the generator and the generator step-up transformer (GSU). The digital relay has the capability to transpose each current and voltage input in the relay. In this sense, it is analogous to the E/M scheme shown in Fig. 2. The pumped storage logic in a particular digital relay uses several settings to configure the logic. These settings specify:

- *The terminal current and voltage inputs to be transposed.* The current and voltage terminals that require transposition are downstream from the reversing switch.
- *The phase pair to be transposed AB, BC, or CA.* This setting transposes the corresponding voltage and current phase pair in software. The software phase transposition occurs early in the data acquisition sequence so that the transposition is transparent to the differential element and sequence calculations. This setting obsoletes the dynamic phase-rotation setting.

- *When to transpose the current and voltage inputs.* This setting is driven from a digital input, which in turn is driven from the reversing switch.

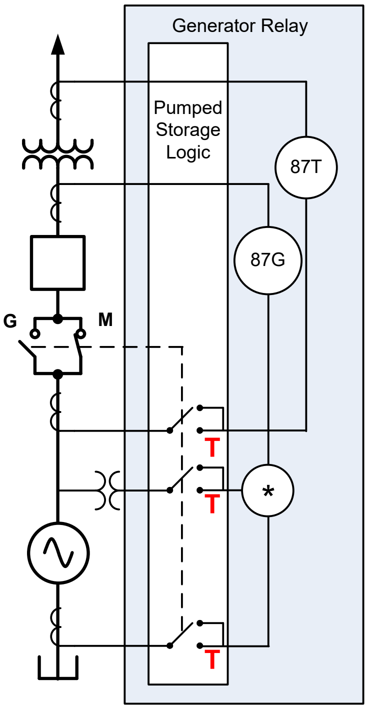

Fig. 6. Relay With Integrated Pumped Storage Logic

All the schemes discussed thus far, including the E/M schemes, make use of the reversing switch status to adapt the protection for each mode of operation. Clearly, the security of the entire protection scheme depends on the integrity of the status indication. Consequently, we recommend, at a minimum, that dual status indications be used to derive the operating mode. Since the operating mode cannot change when the unit is online, machine current can be used to further secure the element. One example that can be implemented in a digital relay is shown in Fig. 7.

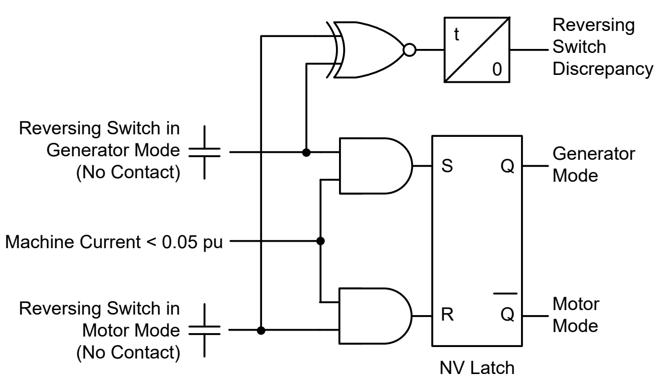

Fig. 7. Operating Mode Logic

The logic used to derive the status of the reversing switch shown in Fig. 7 allows the machine to be only in either generator or motor mode. However, should a discrepancy occur due to a problem with respect to the generator or motor breaker auxiliary contacts, it may be possible for both the set (S) and reset (R) inputs of the flip-flop to assert simultaneously. If this should occur, the logic shown in Fig. 7 issues a reversing switch discrepancy alarm. This alarm can be used to take the following corrective actions depending on the magnitude of the machine current.

- If the machine current is above 0.05 pu, the output of the flip-flop will not change state. As such, simply notifying maintenance personnel of the issue is sufficient.
- If the machine current is below 0.05 pu, the output of the flip-flop may toggle—one input typically has priority over the other in the event that both inputs assert simultaneously. Therefore, the case may exist where the wrong operating mode is selected. In this event, the following can be done:
  - Allow the differential and other sequence elements to trip the machine in the event that the incorrect operating mode is selected and the machine begins to draw current.
  - Block the differential and other sequence element. Once the phase current increases above 0.05 pu of the rated machine current, calculate the positive- (I_1) and negative- (I_2) sequence current magnitudes. If $|I_1| >> |I_2|$, then the selected or present mode of operation is correct and the differential and other sequence elements can be re-enabled. If $|I_2| >> |I_1|$, then the selected mode of operation is incorrect. In this situation, the protective relay can select the correct operating mode and re-enable the differential and sequence elements, or the differential elements and sequence elements can remain blocked until the discrepancy is corrected by maintenance personnel.

III. Protection Considerations During LCI or Back-to-Back Starting

Several different methods have been employed for starting the unit in motor mode [2]. Several of these methods entail connecting the machine to a source with a frequency that is ramped from zero to nominal. The field is applied to the unit while the frequency is ramped. Consequently, we need to consider the protection performance at off-nominal frequencies. The E/M relays that were applied in the past for PSH protection generally suffered from poor sensitivity at low frequencies. This led to the application of a supplementary overcurrent element for phase fault protection and a supplementary neutral overvoltage element for ground fault protection. Often plunger-type relays were chosen.

In the case of ground fault protection, the supplementary relay had no capacity to tune out the third harmonic. The relay pickup had to be increased accordingly. Modern digital relays are capable of tracking over a wide range of frequencies. Some generator relays can track to less than 10 Hz. Thus, there is no degradation in the accuracy of the protection operating signals except when the frequency is very low. At this point, the internal relay magnetics will begin to saturate. In a digital generator relay, the primary ground fault protection element is the fundamental neutral overvoltage element. This element will operate correctly over the frequency tracking range; however, since the generator voltage is ramped with the frequency to maintain a constant flux, the coverage provided by this element decreases with frequency. For instance, consider an element with a pickup setting that provides 90 percent coverage at nominal frequency. At 20 percent of nominal frequency, the same pickup setting will only provide 50 percent coverage. Subharmonic injection has gained popularity for detection of stator ground faults; therefore, solutions are now available that provide 100 percent ground fault protection throughout the entire starting process. Since the field is applied throughout the starting process, it is possible that a problem with the generator controls could result in serious overfluxing of the generator. Therefore, it is important that volts/hertz protection is available during starting. Digital relays provide accurate volts/hertz protection over their entire tracking range.

IV. Protection Considerations During Induction Motor Starting

One method of starting the synchronous machine when in motor mode is as an induction motor. Since the rotor of a PSH machine is laminated, the damper winding current produces the starting torque of the machine. In contrast, for solid rotor machines (not typically used in PSH applications), the starting torque is developed by the eddy currents, induced on the surface of the pole shoes.

Prior to starting, the field winding is short-circuited via an external resistor to protect the insulation of the field winding and slip rings from abnormally high voltages that are generated in the field before the rotor reaches near synchronous speed [3]. During the machine starting period, the largest portion of the acceleration torque is developed by the damper winding (induction motor effect). This torque accelerates the machine (rotor) to about 95 percent of synchronous speed. At this speed, either the reluctance torque will pull the rotor into synchronism, or more commonly, the field voltage is applied, which will then pull the rotor into synchronism.

In some cases, the supply voltage is reduced during starting. This lowers the starting current, which in turn, reduces the starting torque by the square of the current reduction. This leads to a longer machine starting time. The decrease in the starting current also results in a reduction of the voltage dip in the power system during starting. The voltage reduction is achieved by a specifically designed GSU, as discussed in Section VI.

The damper winding is designed to have a high resistance and a low reluctance to obtain the highest ratio of torque to apparent power (MVA) [4]. Not only do the damper windings produce the highest torque during starting, they also experience the greatest thermal increase. Should starting last too long, the damper windings will experience thermal damage. Normally, no water exists in the turbine during starting, but if this is not the case, the load torque could be quite substantial. Therefore, it is important to protect the damper windings of the machine during the starting period. The stator current is relied upon to mimic the heating effect in the damper windings since it's not possible to directly measure the current in the damper windings.

When E/M relays were applied to PSH units, starting protection was provided either by using a timer interrupted by a speed switch or an overcurrent element with a long timing characteristic [2]. The motor thermal model implemented in digital relays has several advantages over these earlier methods. The thermal model provides thermal protection for both the rotor windings during the starting mode and the stator windings when in the running mode. The thermal model can be configured to account for both the heating and cooling characteristics of the machine. Advanced thermal models derive the slip (s) from the terminal measurements. Using the slip of the machine provides a more accurate heat calculation for high-inertia systems.

In the absence of thermal parameters for the machine, the settings from the existing overcurrent element can be translated into settings for the thermal model. Should the machine's locked rotor current (LRA) and locked rotor time (LRT) be available, we can use these parameters. In this case, the thermal limit can be described by (1).

$$\int I^2 dt = LRA^2 \cdot LRT \quad (1)$$

A. Rotor Thermal Model

The rotor thermal model integrates the motor starting current over time to estimate the thermal capacity used (TCU). For each processing interval (k), a digital relay computes the rotor TCU using (2).

$$TCU[k] = TCU[k-1] + \Delta TCU[k] \quad (2)$$

where:

$$\Delta TCU[k] = 100 \cdot \frac{\Delta t \cdot I^2[k]}{LRA^2 \cdot LRT}$$

k = present processing interval

$k-1$ = previous processing interval

Δt = time between two consecutive processing intervals

Note, if the current remains at the LRA magnitude for a duration of LRT, TCU will reach 100 percent after a time equal to LRT. Multiplying and dividing (2) by the rotor resistance (R_r), we obtain (3), the slip-independent thermal model, which we refer to as the I^2t model.

$$\Delta TCU[k] = 100 \cdot \frac{\Delta t \cdot I^2[k] \cdot R_r}{LRA^2 \cdot LRT \cdot R_r} \quad (3)$$

where:

$LRA^2 \cdot LRT \cdot R_r$ = the maximum energy that the rotor can absorb before experiencing thermal damage.

$\Delta t \cdot I^2[k] \cdot R_r$ = the amount of incremental energy accumulated in the rotor during the processing interval.

The slip-dependent thermal model takes into account that R_r is a function of s. To include the dependence of R_r on s, we rewrite (3) as follows:

$$\Delta TCU[k] = 100 \cdot \frac{\Delta t}{LRA^2 \cdot LRT} \cdot \frac{I^2[k] \cdot R_r(s[k])}{R_r(1)} \quad (4)$$

where R_r is a function of s and, $R_r(s)$ is given by:

$$R_r(s) = R_1 s + R_0(1-s) \quad (5)$$

where:

$R_1 = R_r$ when $s = 1$

$R_0 = R_r$ when $s = 0$

$R_1 \geq R_0$ and $s[k] \in [0,1]$

Substituting (5) into (4), we obtain (6).

$$\Delta TCU[k] = \frac{100 \cdot \Delta t}{LRA^2 \cdot LRT} \cdot \frac{I^2[k] \cdot \left(R_1 s[k] + R_0(1 - s[k])\right)}{R_1} \quad (6)$$

The ratio of $R_1 s[k] + R_0(1 - s[k])$ to R_1 is 1 when $s = 1$, and $0 < \frac{R_0}{R_1} \leq 1$ when $s = 0$. The result now includes the dependence of R_r on s. This allows for a longer starting time than (3), which does not account for the dependence of R_r on s. Fig. 8 compares the slip-independent thermal model to the slip-dependent thermal model where:

$$\frac{R_0}{R_1} = \frac{1}{3}$$

From Fig. 8, we can see as the slip approaches zero, the slope of the slip-dependent TCU goes down, allowing for two additional seconds of start time. Fig. 8 was obtained by maintaining a constant current magnitude and assuming that the slip decreases linearly during the motor starting period, resulting in a linear TCU for the I^2t model.

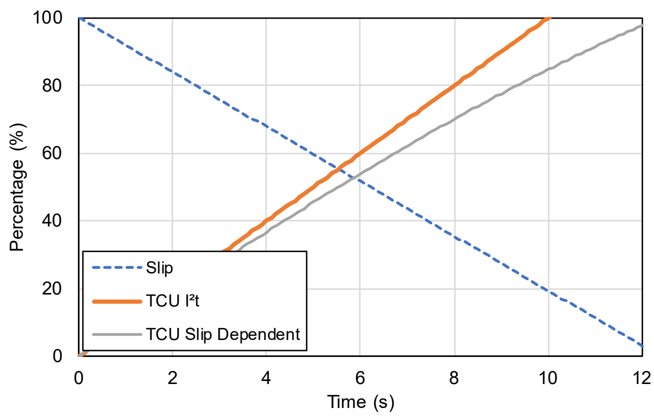

Fig. 8. Slip-Dependent vs I^2t Thermal Model Assuming Constant Current Magnitude

In Fig. 9, we use actual data from a 20 MW synchronous motor. Note that while the I^2t model would trip the motor at about 7 seconds, the slip-dependent TCU only reaches a value of 85 percent.

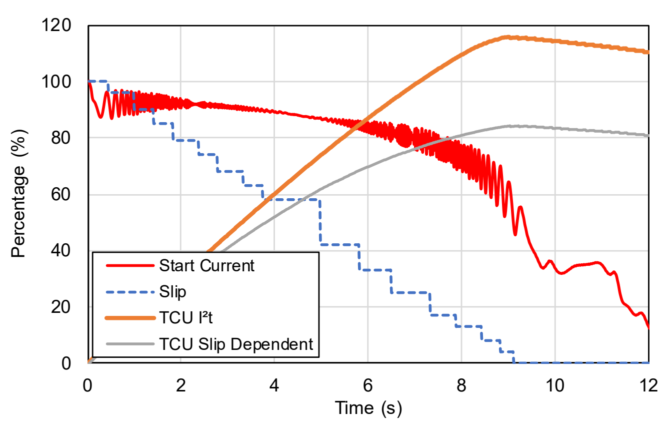

Fig. 9. Slip-Dependent vs I^2t Thermal Model

V. Out-of-Step Protection

If the mechanical load on a synchronous machine that is operating as a motor exceeds its electrical input power, the machine will begin to slow down and will pull out of synchronism if the condition persists. This condition is often referred to as a pullout, out-of-step, or loss-of-synchronism (LOS) condition. During an LOS condition, the interaction between the magnetic fields of the stator and rotor causes damaging mechanical stress and vibrations. Further, increased induced currents cause rapid heating of the rotor damper windings that can only be maintained for the locked rotor time of the machine. LOS conditions must be detected quickly to allow for resynchronization or to trip the machine to avoid thermal overload and damage to the machine. The three main causes of LOS are [5]:

- Mechanical load increase,
- Stator voltage dip leading to reduced electrical torque,
- Excitation voltage dip or decrease leading to reduced electrical torque or total loss of excitation.

LOS due to reduced or complete loss of excitation is dependably detected using protective elements such as positive-sequence mho elements and field undercurrent or field undervoltage elements. These loss-of-field (LOF) elements are simple to set using the machine parameters [6][7][8].

When PSH units are protected using E/M relays, LOS protection is typically provided using an overcurrent element with a long timing characteristic. Synchronous machine protective relays often include two dedicated methods to determine LOS conditions. One method consists of monitoring the power factor of the motor and declaring an LOS condition when it lags exceedingly. The other method monitors the trajectory of the positive-sequence impedance on the impedance plane and uses a set of blinders to determine oscillations caused by the LOS conditions. Synchronous machine protective relay elements, such as reactive power and phase overcurrent, are often used to protect machines on slowly changing loads like fans, pumps, and compressors. Reference [8] gives guidelines for the use of these elements on LOS applications.

Other methods have been used in the industry to detect LOS conditions but are now less common, for example, field ac overcurrent elements activated by the oscillations created as the machine slips poles and notching relays that count the number of times the field current or the reactive power changes direction in a given time interval [5].

Reference [2] addresses the performance of the power factor and the impedance plane elements during an LOS condition caused by a sudden increase in load and a decrease in the stator voltage. The conclusion that can be drawn by [2] is that both methods adequately provide protection for the machine during an LOS condition. Additionally, it can be concluded that in applications where power factor and impedance plane elements are available, the power factor element can be set to boost the field voltage in an attempt to avoid an LOS condition. In addition, the impedance-based distance elements can be set more securely to trip the machine and load upon an LOS condition.

The improvement described in Section III with regard to the performance of digital relays during off-nominal frequency extends to the LOS functions. This allows the impedance-based distance element to be set to detect an LOS event if two machines lose synchronism when offline during a back-to-back starting operation. Since both machines are typically the same size, they will have similar impedances, and the swing center will pass between the impedance of the two machines. If the machines are swinging slowly with respect to each other, the impedance calculated by the distance element will be in the range of (X'd + X'q)/2. For faster swings, the impedance will be closer to (X"d + X"q)/2.

VI. GSU Considerations

A. Reversing Switch Upstream of the GSU

If the reversing switch is on the GSU high-side and is part of the differential zone, as shown in Fig. 10, then during pumping mode, the secondary currents from the downstream CT need to be transposed. The vector group setting also needs to be adjusted to balance the overall differential. This is represented as a **V** in Fig. 10. For instance, if the transformer connection is Yd1 (YDAC) when the phase rotation is ABC, it becomes Yd11 (YDAB) when the reversing switch changes the high-voltage side (HV) phasing to ACB.

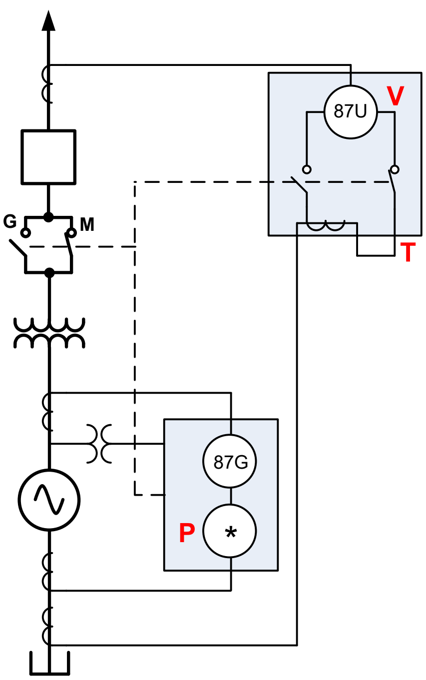

Fig. 10. Reversing Switch Upstream of the GSU

If the reversing switch is further upstream and not part of the differential zone, the GSU high-side currents also need to be transposed. Another option is to not transpose any CTs but simply adjust the transformer vector group accordingly.

B. Effect of Reduced-Voltage Starting

Units that are started as induction motors often employ reduced-voltage starting. This is done to reduce the starting current of the machine, which in turn reduces the voltage dip on the power system when starting the machine. Reduced-voltage starting is achieved by tapping the secondary winding of the GSU, as shown in Fig. 11.

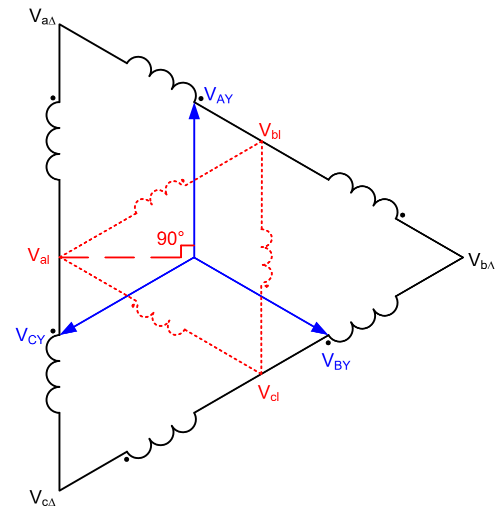

Fig. 11. Reduced-Voltage Starting Using Three Midwinding Taps

During a reduced-voltage start, the motor is connected to the midpoint taps on the low-voltage delta winding. Hence, half the nominal voltage is imposed across the machine terminals, as discussed in Section IV. When using the reduced-voltage bushings, the transformer turns ratio increases by a factor of 2 and the phase compensation changes from Yd11 (YDAB) for the full winding, to Yd9 for the reduced winding (half winding).

In some cases, a configuration using the corner of the full delta winding is used, as shown in Fig. 12. In this case, the turns ratio also increases by a factor of 2, but the winding phase compensation stays as Yd11 (YDAB). The effect on the differential can be changed by switching settings groups in a digital relay.

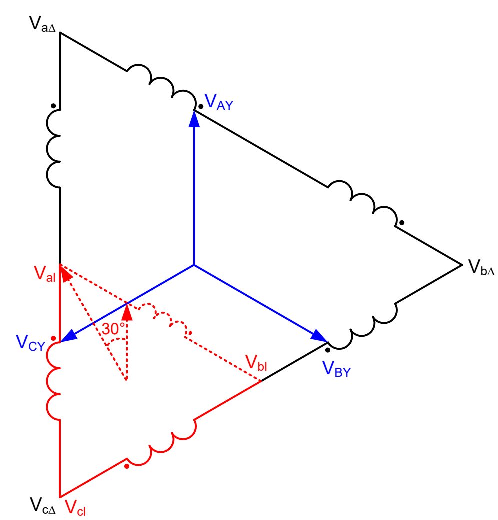

Fig. 12. Reduced-Voltage Starting Using Two Midwinding Taps

In Fig. 13, we see an example where separate current inputs are available from the starting (S), motoring (M), and generating (G) breakers. In this case, the transformer differential does not need to be adapted. The approach to the transposition for the generator differential has been described in Section II.

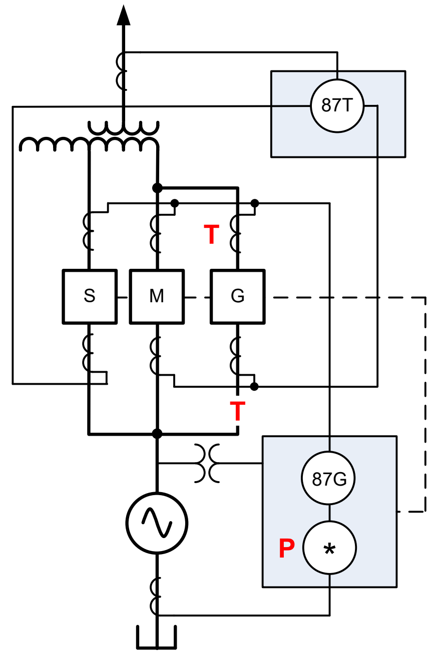

Fig. 13. Reduced-Voltage Starting With Individual Breakers

In Fig. 14, we consider an example of reduced-voltage starting with the reversing switch in the differential zone.

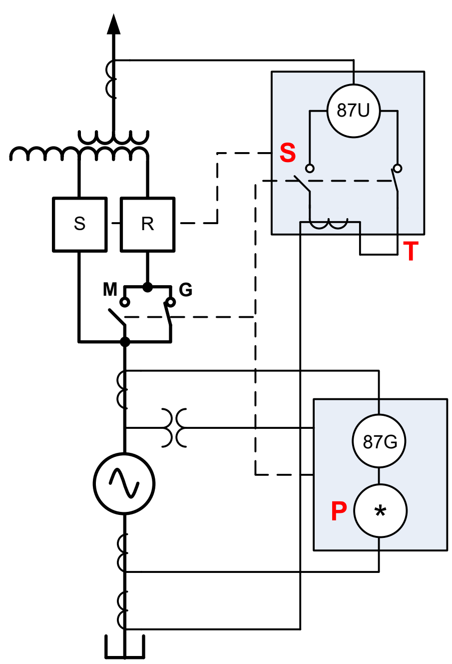

Fig. 14. Reduced-Voltage Starting With Reversing Switch

Breaker S corresponds to the machine tapped from the reduced-voltage bushings to enable starting as an induction motor. Breaker R corresponds to the connection to the full delta winding and operates either as a generator or motor depending on the position of the reversing switch.

A combination of the techniques shown earlier is used to adapt the differential:

- The transformer turns ratio needs to be doubled to compensate for the reduced voltage when Breaker S is closed. This is denoted as an **S** in Fig. 14.
- A vector group compensation change may be required depending on which bushings are used for the reduced-voltage start.
- The phases for the downstream CTs need to be transposed to compensate for the reversing switch.

All the adaptations to the differential, such as modifications to the transformer turns ratio, using alternate terminal currents, and adjusting the vector group compensation, can be achieved by changing settings groups in a digital relay.

VII. Dynamic Braking

Dynamic braking is installed to enable rapid deceleration and stopping of hydro units that are of the generator and motor combination type (reversible unit). A slow deceleration and stopping of these units results in poor to no lubrication of the bearings for a significant time while the unit decelerates. The rapid deceleration provided by dynamic braking increases bearing longevity. Furthermore, dynamic braking reduces the wobble time of the unit during deceleration. The advantages of dynamic braking over friction braking are as follows:

- Faster decelerating and shorter stopping time,
- No generation of brake dust that will settle in the stator winding and possibly lead to stator winding short circuits.

Dynamic braking is accomplished by short-circuiting the stator windings of the machine once the machine has been isolated from the power grid. The stator windings are shorted via a normal isolator switch [9]. The rotor circuit is then transferred to a separate dc power supply and excitation maintained until the machine is at a standstill. During dynamic braking, kinetic energy is taken from the rotor of the machine and dissipated as heat in the stator winding, and because the prime mover does not supply energy to the rotor, the rotor begins to slow down. The braking transformer and rectifier are rated to provide nominal stator current (1 pu) during the braking or shorting period. Excitation is maintained until the machine is at a standstill. At standstill, there is still flux in the stator winding, and because the machine is stationary, the stator current begins to decay at a rate determined by the stator L/R ratio. The decaying stator flux generates a voltage that begins to reduce the rotor current since there is an opposing voltage to the applied field voltage. This opposing voltage reduces the effective field voltage across the rotor, which in turn reduces the field current until the stator flux has completely decayed. At this time, the field current increases again. A typical dynamic braking configuration for a reversible unit is shown in Fig. 15.

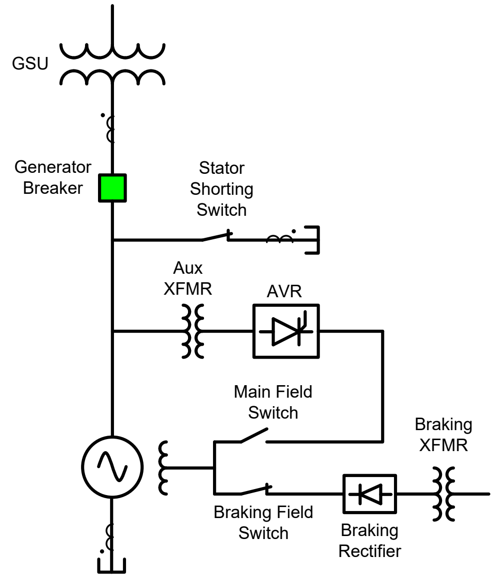

Fig. 15. Typical Configuration of a Dynamic Braking Setup for a Reversible PSH Unit

A. *Generator Stopping and Braking Sequence*

Following is the operating/switching sequence to decelerate and stop a reversible unit using dynamic braking.

1. Unit is unloaded.
2. Generator breaker opens.
3. Governor stop valve closes.
4. Main inlet valve begins to close, and the unit begins to slow down.
5. Main inlet valve closes completely; this occurs at around 50 percent of rated speed.
6. Main field switch opens.
7. If the excitation system uses a rotating exciter, a wait period is applied to allow the flux in the machine to decay. If the excitation system is static, the excitation switches off when the unit is taken off line.
8. With the main field switch and the generator breaker open, the generator terminal voltage is low; then the stator shorting switch closes.
9. Dynamic braking rectifier turns on, and the dynamic braking field switch closes.
10. Rotor current increases according to the L/R time constant of the rotor circuit.
11. Stator current begins to flow through the stator winding, generating heat due to the winding resistance. As a result, the mechanical kinetic energy stored in the rotor dissipates, and the rotor begins to slow down.

B. *Protection Implications*

The stator shorting switch creates a three-phase fault within the generator differential zone. This results in the operation of the generator differential protection. Two options generally exist to avoid the operation of the generator differential under dynamic braking.

1) *Turn Off the Generator Differential*

With this option, the generator differential protection is turned off during dynamic braking. The advantage of this method is that it is simple. However, it is not wise to turn off the main generator protection with rated stator current circulating in the stator. This is not the preferred option.

a) *Electromechanical Schemes*

In traditional E/M generator differential schemes, the current inputs short-circuit. In a high-impedance differential scheme, the bus wires short-circuit; whereas for a low-impedance differential generator neutral, the CTs short-circuit.

b) *Digital Schemes*

In a digital generator differential scheme, the operation of dynamic braking will assert a digital input that will disable the generator differential protection.

2) *Add the Shorting Switch to the Differential Protection*

Another solution is to add the current in the stator shorting switch to the differential circuit, as shown in Fig. 16. This stabilizes the differential circuit during dynamic braking; however, it does require a three-input differential scheme with extra CTs.

a) *High-Impedance Schemes*

The addition of an extra CT input in a high-impedance differential scheme is simple to implement. The extra is simply connected to the bus wires. However, most high-impedance relays use a tuned circuit in the operating element. This results in a higher operation at lower frequencies and virtually no operation at very low frequencies.

b) *Biased Differential Schemes*

E/M biased differential schemes require a three-terminal input relay. Operation at lower frequencies is dependent on the relay design. Digital relays also require a three-terminal input relay. The operation at lower frequencies is dependent on the element design. It may be necessary to disable the generator differential element at frequencies lower than 2.5 Hz.

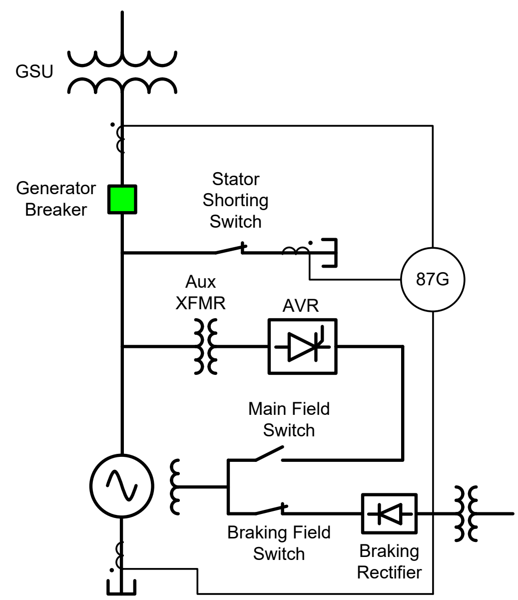

Fig. 16. Dynamic Braking Differential Protection (Dynamic Braking Equipment Not Shown for Clarity)

C. *Shorting Switch and Breaker Closed*

With the addition of the generator shorting switch, a possible new operating problem has been created. Assume the generator is online and an error causes the stator shorting switch to close. The result is a three-phase short circuit within the generator protection zone, as shown in Fig. 17. Therefore, secure and robust interlocking on the closure of the shorting switch is required. However, shorting switches have closed due to leaks in pneumatic systems. With a CT monitoring the current through the shorting switch, the generator differential protection will remain stable for such events.

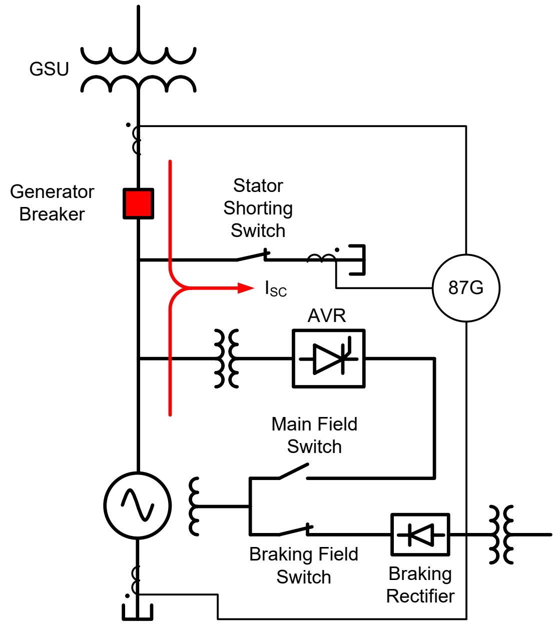

Fig. 17. Shorting Switch Applying a System Fault

To provide protection for the unit for the situation in which the generator breaker and the shorting switch are closed simultaneously, an instantaneous overcurrent element (50) is added to the protection scheme to monitor the current through the stator shorting switch, as shown in Fig. 18. The pickup of the overcurrent element is typically set at 1.5 times the rated current of the generator. During dynamic braking, the current magnitude does not exceed the rated current of the generator.

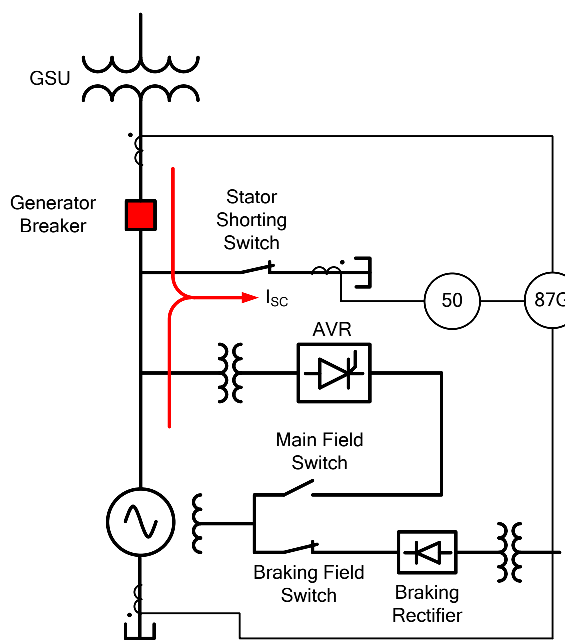

Fig. 18. Dynamic Braking Overcurrent Protection

For the situation where the generator breaker and stator shorting switch close simultaneously, the fault current through the stator shorting switch will be high enough to operate the overcurrent element (50) and trip the generator breaker. This system is the preferred protection option.

A digital differential relay can provide another option. If the generator breaker closes (52A = 1), a digital input in the relay asserts, which in turn removes the shorting switch current input from the differential element. Therefore, should the stator shorting switch close at the same time as the generator breaker, the differential element will no longer be stable and will trip the generator breaker. This is a more elegant solution.

VIII. Conclusions

Pumped storage hydro reversible units pose a challenge to electromechanical protection schemes. The schemes require either auxiliary contacts to transpose the secondary CT leads or a multiterminal differential protection device to correctly address the instance when the primary phases are transposed as the unit switches from generation into pumping mode. Furthermore, when the unit is started, either back-to-back or using a variable-frequency drive, a relay that does not track frequency cannot adequately protect the unit during the starting period. Digital protective relays track frequency over a wide range, thereby protecting the PSH unit over a wider frequency range. The flexibility and adaptability of digital relays allows them to be easily adapted to any protection scheme.

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X. Biographies

Terry Foxcroft has worked in the power industry for over 36 years. He has worked in the protection, commissioning, testing, and design fields for over 30 years. He has presented papers at many national and international conferences. Terry is also a member of the Australian CIGRE B5 Committee. Terry is responsible for protection design at Snowy Hydro.

Normann Fischer received a Higher Diploma in Technology, with honors, from Technikon Witwatersrand, Johannesburg, South Africa, in 1988; a BSEE, with honors, from the University of Cape Town in 1993; an MSEE from the University of Idaho in 2005; and a PhD from the University of Idaho in 2014. He joined Eskom as a protection technician in 1984 and was a senior design engineer in the Eskom protection design department for three years. He then joined IST Energy as a senior design engineer in 1996. In 1999, Normann joined Schweitzer Engineering Laboratories, Inc., where he is currently a fellow engineer in the Research and Development division. He was a registered professional engineer in South Africa and a member of the South African Institute of Electrical Engineers. He is currently a senior member of IEEE and a member of the American Society for Engineering Education (ASEE).

Dale Finney received his bachelor of engineering degree from Lakehead University and his master of engineering degree from the University of Toronto. He began his career with Ontario Hydro, where he worked as a protection and control engineer. Currently, Mr. Finney is employed as a senior power engineer with Schweitzer Engineering Laboratories, Inc. His areas of interest include generator protection, line protection, and substation automation. Mr. Finney holds several patents and has authored more than 20 papers in the area of power system protection. He is a member of the main committee and the rotating machinery subcommittee of the IEEE PSRC. He is a senior member of the IEEE and a registered professional engineer in the province of Nova Scotia.

Ritwik Chowdhury received his bachelor of engineering degree from the University of British Columbia and his master of engineering degree from the University of Toronto. He joined Schweitzer Engineering Laboratories, Inc. in 2012, where he has served as an application engineer and presently works as a research engineer. He has authored several technical papers on power system protection and control. His interests include the analysis and control of generators and their systems, controlled switching, and generator and line protection. He is a member of IEEE.

Marcos Donolo (S 1999, M 2006, SM 2013) received his BSEE from Universidad Nacional de Río Cuarto, Argentina (2000), and his MS degree in electrical engineering (2002), his MS degree in mathematics (2005), and his PhD in electrical engineering (2006) from the Virginia Polytechnic Institute and State University. Since 2006, he has been with Schweitzer Engineering Laboratories, Inc., where he is presently a senior research engineer. He holds several patents and has authored numerous papers related to power system protection. He can be contacted at marcos_donolo@selinc.com.

Douglas Taylor received his BSEE and MSEE degrees from the University of Idaho in 2007 and 2009, respectively. Since 2009, he has worked at Schweitzer Engineering Laboratories, Inc., and currently he is a lead research engineer in the Research and Development division. Mr. Taylor is a registered professional engineer in the state of Washington and is a member of the IEEE. His main interests are power system protection and power system analysis.

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