Schweitzer 7132 Substation Instrument Transformer Early Failure Detection Owner's Manual

Schweitzer

Substation Instrument Transformer Early Failure Detection Using Time-Synchronized Measurement

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7132 Substation Instrument Transformer Early Failure Detection

Abstract—Instrument transformers in power systems are prone to failure as a result of aging, insulation

degradationelectrical stress, mechanical damage, and other factors. Failure othese transformers can have severe consequences including relamis-operation, damage to other equipment, and safety risks. Athe power grid ages, a large number of instrument transformersin service will inevitably fail, leading to significant undesireconsequences. The lack of economical conditioning monitorinsolutions for these instrument transformers often results in thembeing run until they fail.

This paper presents a real-world abnormality of an extra-higvoltage (EHV) coupling-capacitor voltage transformer (CCVTthat caused a 765 kV-bus relay mis-operation and equipmentdamage from an overvoltage transient. The paper examinevoltages recorded by different intelligent electronic devices (IEDsconnected to the same station bus within the substation, showingthe abnormality of the single CCVT. By examining past evenrecords triggered by the relays connected to the voltagtransformer, we show abnormal voltage measurements datinback months.

The paper proposes three methods to address the need for earldetection of instrument transformer abnormalities before theybecome catastrophic failures. These methods use timesynchronized measurements among IEDs to cross-check anverify the integrity of measurement and provide early warning oany measurement mismatch, which indicates potential instrumenttransformer failure. The first method uses the built-in capabilitof a digital relay that can process synchrophasor measuremenfrom as many as two other digital relays connected to the saminstrument transformer. The paper discusses algorithms that are

implemented to detect power system signal magnitude and angmismatches to provide early warning and protection supervisionand avoid relay mis-operation. This method is economical andoes not require additional devices. The second method uses dedicated synchrophasor data processor that implements similaor more sophisticated algorithms to detect instrumentransformer abnormalities. The third method uses IEC 61850GOOSE messaging for power system signal measuremenexchange among IEDs. The paper discusses the pros and cons oeach method and how each method can be used in differentscenarios.

INTRODUCTION

Power system instrument transformers, which include current transformers (CTs) and voltage transformers (VTs), play an essential role in the operation, control, and protection of electrical power systems. Instrument transformers provide input to metering and protective relays, allowing for accurate monitoring of power system states and quick isolation of failed power system components. Undetected instrument transformer failures pose significant safety risks, including fires and explosions, that can lead to personnel injuries or fatalities and damage to nearby equipment and infrastructure. Depending on the failure mode, some failed instrument transformers may be properly isolated by the protection system without causing cascading failure. Some failed instrument transformers will provide incorrect measurements to protective relays and cause relay mis-operations to isolate major power system assets such as a substation or power lines.

Most of the existing work focuses on using measurements from different instrument transformers to detect single-phase abnormalities. Synchrophasor voltage measurements (magnitude and angle) at the same location are used to detect instrument transformer abnormalities [1] [2]. These methods apply advanced algorithms to improve security and dependability. A linear state estimator has been implemented using measurements from different instrument transformers within a substation to detect abnormalities within a substation [3]. The proposed synchrophasor-based methods are implemented using a software solution to provide warnings and situation awareness to system operators. Reference [4] proposes a negative-sequence voltage-based method to detect potential coupling-capacitor voltage transformer (CCVT) failure based on the long-term negative-sequence voltage trending. Caution should be taken to differentiate an external system disturbance from a potential CCVT failure for this method.

Most instrument transformers have multiple outputs. For example, an extra-high voltage (EHV) CCVT typically has 3–5 outputs from the same capacitor stack, other than the secondaries tapped off at different positions. Similarly, bushing CTs typically support multiple secondary windings with different turns ratios. Manufacturers test and calibrate instrument transformers to meet the measurement accuracy requirements, therefore measurements from different secondary windings on the same CCVT or CT should be within the specified measurement accuracy Fig. 1 shows an actual field event during which one of the phases of a 765 kV CCVT experienced a sudden voltage surge.

Relays are connected to each of the two windings of the CCVT.

As a result of the voltage surge the relays connected to that secondary winding of the CCVT was partially damaged and resulted in a bus relay trip. The top two subplots in Fig. 1 show healthy A-phase and B-phase voltages. The third plot shows the faulted C-phase voltage. These two relay event records are aligned with GPS timestamps. The two healthy phase voltages from the same CCVT almost perfectly overlap with each other.

However, the C-phase voltage from two relays began showing some degree of deviation in magnitude before the sudden voltage surge in one of the windings. It is reasonable to assume that the voltage deviation between two windings has existed for some time before this event. If there were measures in place to closely monitor the voltage deviation between two relays, this bus tripping event could have been prevented.

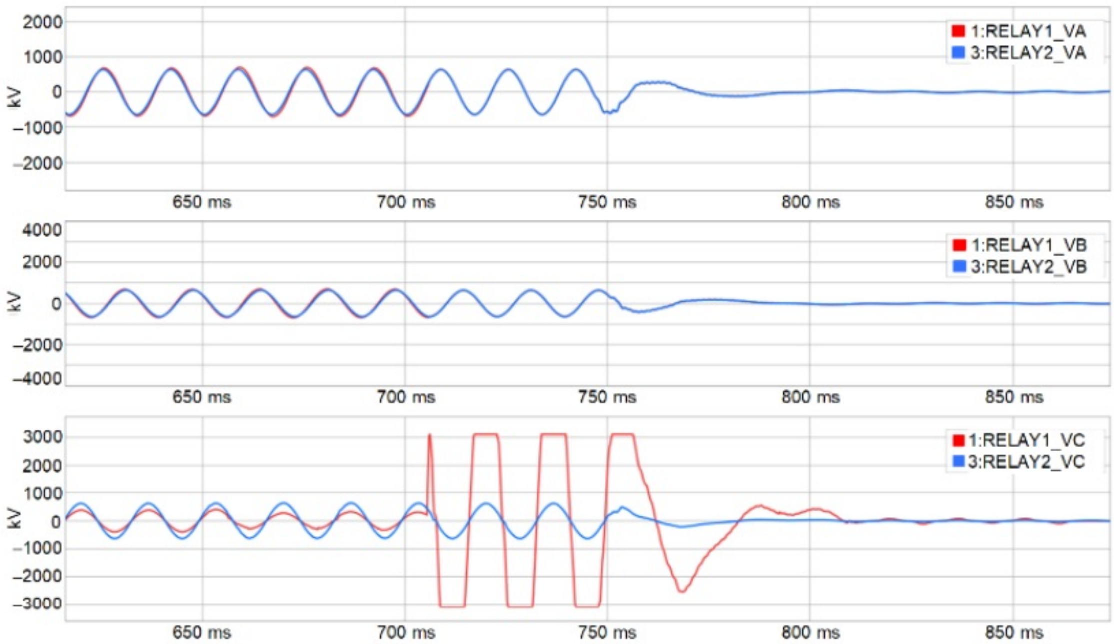

Fig. 1 CCVT winding failure field event

Considering the reliability of the instrument transformer, NERC PRC-005-2 requires maintenance for voltages and current-sensing devices that do not have real-time monitoring to be on a 12-month calendar year cycle [5]. If voltage- and current-sensing devices connected to microprocessor relays are continuously verified by comparison of sensing input value to an independent alternating current (ac) measurement source, with alarming for unacceptable error or failure, no periodic maintenance is required. Most modern substations are equipped with multifunctional microprocessor relays that have protection functions, such as overcurrent protection and distance protection, and support various industry standard communication protocols such as synchrophasor measurement and IEC 61850 GOOSE messaging [6] [7]. American Electric Power (AEP) is moving toward microprocessor relay comparison to reduce maintenance burdens and be proactive, rather than reactive, to instrument transformer/microprocessor failures.

In this paper, we report three economical methods of monitoring the status of an instrument transformer and providing an early warning and failure detection method using synchrophasor measurement or GOOSE messaging. The first and third methods do not require any additional hardware if the relays include the required features and functions.
A. Direct Synchrophasor Data Exchange Between Relays A commercially available relay family supports a built-in phasor data concentrator (PDC) function for advance synchrophasor-based applications (e.g., inter-area oscillation detection). The built-in PDC function allows the relay to directly receive synchrophasor measurements from other relays through a serial-to-serial port connection and makes these measurements available to relay programmable protection and automation functions to enable instrument transformer failure detection at a fast and deterministic speed. This feature can be used for instrument transformer condition monitoring at a minimal cost.

B. Centralized Synchrophasor-Based Method
In this approach, an external device such as a Real-Time Automation Controller (RTAC) is used to collecsynchrophasor measurement data through a built-in PDC function. This external device provides broader instrumenttransformer condition monitoring within a substation instead ofmonitoring an individual instrument transformer.
C. IEC 61850 GOOSE Message-Based Detection Method IEC 61850 GOOSE messaging is gaining popularity in modern digital relays. Although GOOSE messaging does not add a time stamp to the analog measurement at a fixed interval, its fast rate, for example 4 ms in this case, alleviates the measurement time stamp alignment requirement based on the reasonable assumption that the current and voltage magnitudes do not change significantly within a brief time window.
To test the validity of the three methods, we use a relay test set to generate voltage and current signals

simultaneously for the two microprocessor relays under test. Both relays support synchrophasor and GOOSE messaging. Fig. 2 illustrates the
testing system setup. GOOSE messages are routed between relays though an Ethernet switch. Synchrophasor data are routed through a direct serial-to-serial communication and through an Ethernet switch to the RTAC. Both relays are connected to IRIG-B time sources to provide an accurate time stamp in the message and facilitate performance comparison. To simulate the former instrument failure, we altered the magnitude or the phase of one of the relay input signals to test the system response. Relay event records were collected to generate the performance analysis shown in the following sections.

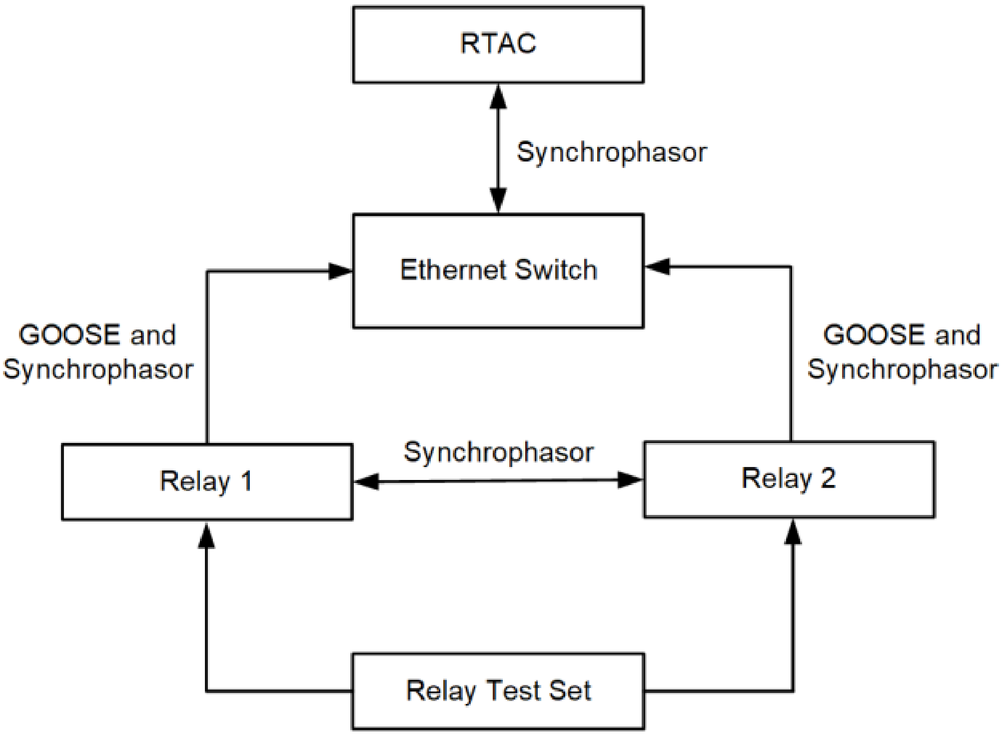

Fig. 2 Test system setup

DIRECT SYNCHROPHASOR DATA EXCHANGE BETWEEN RELAYS

While many commercially available microprocessor-based protective relays support the transmission of synchrophasor data to a remote terminal, one widely used family of devices allows as many as two serial channels to receive synchrophasor data from other devices. Protective relay Systems 1 and 2 monitor the same equipment on the power system using independent CT and VT windings. By exchanging synchrophasor magnitude and angle information for the secondary current and voltage observed by each system, a data comparison can be made to detect an issue within the instrument transformers, secondary wiring, or relay CT and PT circuitry within the protective device analog-to-digital (A/D)converter. Many microprocessor-based protective relays will employ self diagnostics that can detect system failures beyond this point, providing monitoring for the entire instrument transformer system.

To employ synchrophasors in a microprocessor-based protective relay, a high-accuracy time signal must be provided to the relay. With each device time-synchronized, phasors are created at a fundamental frequency that uses a specific point in time as a phasor reference. While magnitudes of voltages and currents can be exchanged and compared easily between devices, comparison of phase angles relies on a common reference for all devices to be effective. The common time reference provided by Synchrophasor Protocol allows for direct phase comparisons for each of the voltage and current phasors exchanged between devices.

Synchrophasor Protocol defines a fixed message rate and time stamp. This means that all selected magnitudes and angles are updated at a deterministic interval. Time alignment also allows for a local analog value to be compared to the remote analog value with certainty that any calculated error is a system issue and not caused by a channel alignment, phasor reference differences, or defined communication deadbands. The requirement is that a dedicated Synchrophasor Protocol communication channel must be in place between each relay and the peers it is working in with.

Elements are programmed into custom logic to compare each analog magnitude as a ratio of Relay 1 to Relay 2 and can compare this ratio to a threshold used for alarming. This method can be applied to each phase voltage and current that is set to be transmitted over the synchrophasor channel. A small signal cutoff should also be implemented to ensure at least one of the devices detects the phase current or voltage magnitude above a pre-determined threshold. Selecting a difference of 0.05 pu between Relay 1 and Relay 2 magnitudes and a small signal cutoff of 5% of nominal can be implemented using the logic shown in Fig. 3.

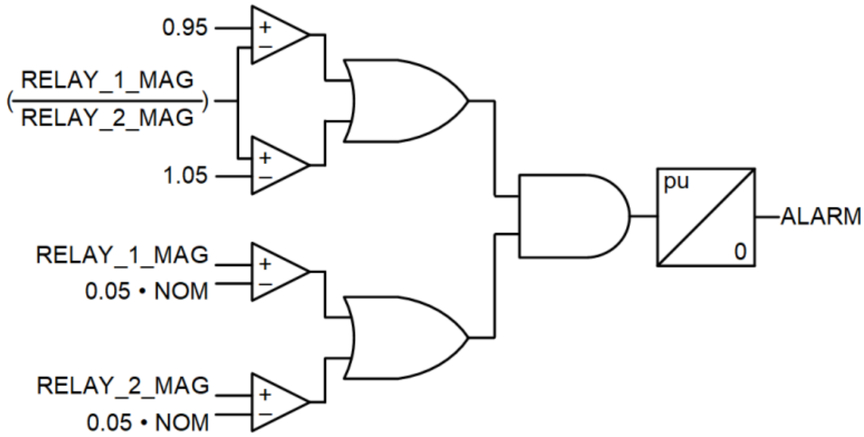

Fig. 3 Relay-to-relay synchrophasor magnitude comparison method

Because phase angles can vary greatly in value, the alarm logic for angle comparison should use the difference between the Relay 1 angle and Relay 2 angle as an operate quantity. This value can be compared to a static angle threshold to determine if an alarm should be issued. As with phase magnitudes, this logic should also be secured with a signal cutoff threshold to ensure that an alarm condition is not declared for conditions when primary equipment is out of service or minimal load flow is present. This logic with a 10° alarm threshold can be implemented as shown in Fig. 4.

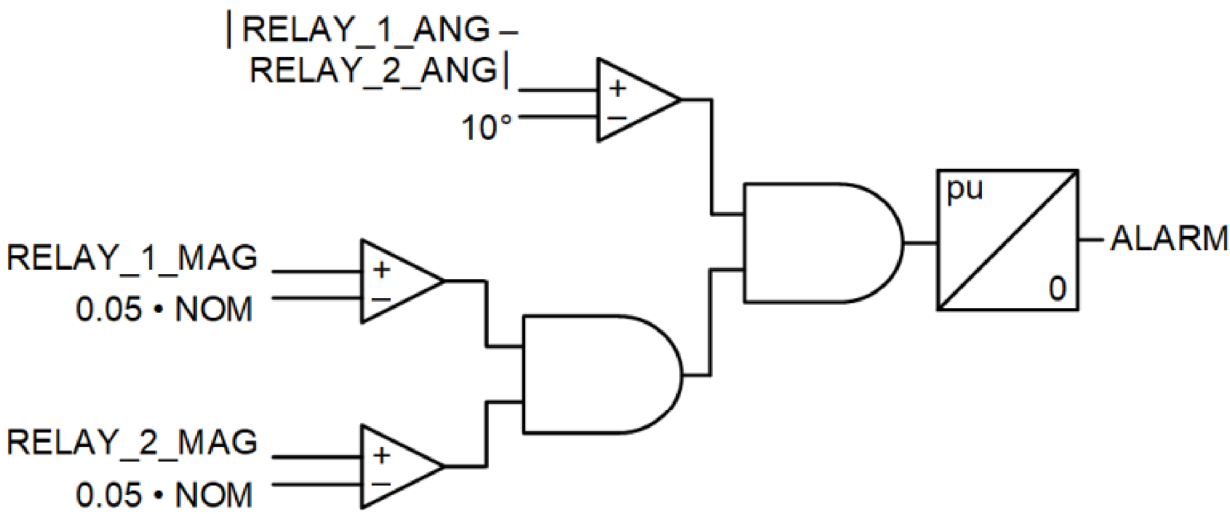

Fig. 4 Relay-to-relay synchrophasor angle comparison logic method

An additional consideration is that synchrophasors provide a phase angle within a range of –179.99°–180.00°. Should a phase angle of any phasor fall close to these boundaries, there is a chance that the reported value from one relay may be a negative angle while the other is positive, creating a large difference between them. When using a small alarm threshold such as 10° difference between Relay 1 and Relay 2, custom logic can be implemented to ensure that the smaller of the two angles between System 1 and System 2 phase angle measurements is being used to alarm while maintaining reliability. This logic is implemented as shown in Fig. 5.

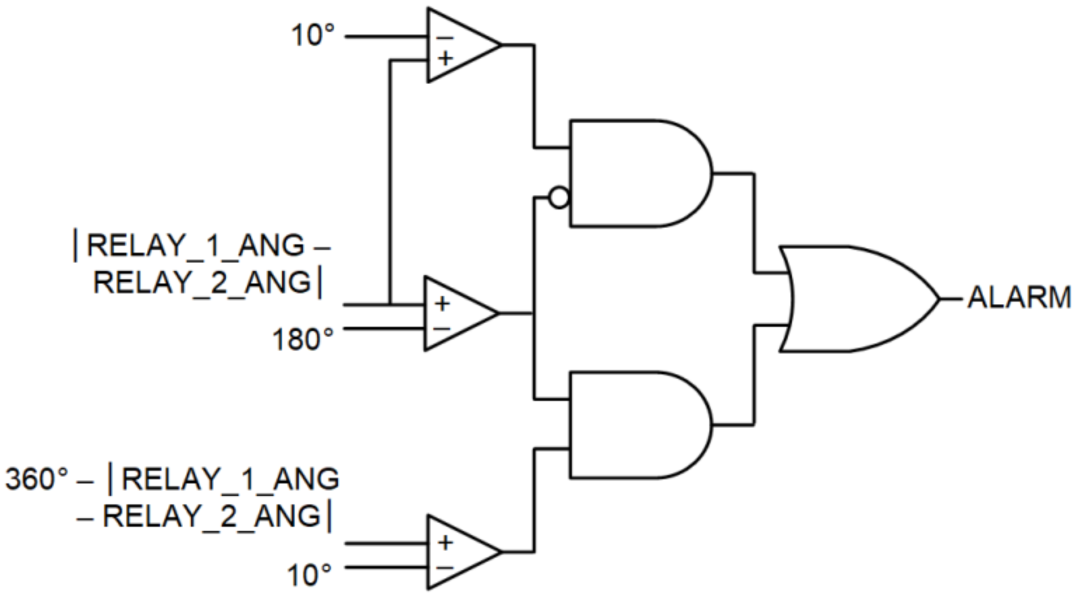

Fig. 5 Synchrophasor angle wrapping for comparison

While synchrophasors provide a deterministic message rate that can be applied to produce consistent timing for alarms that operate closer to protection speeds than other methods, there are several user-defined options within Synchrophasor Protocol that can affect the response time of these elements. While IEEE C37.118-2011 defines message rates as high as 120 messages per second, many devices do not support rates that high or may become overburdened at high rates. A lower message rate may be selected to meet desired delay specifications within the operating parameters of the selected hardware. IEEE C37.118-2011 also defines two classes of synchrophasors: protection and measurement. The standard outlines specifications for both classes including latency,

filtering, accuracy, over- and undershoot, as well as other parameters. Each class should be reviewed thoroughly to determine which provides characteristics that will meet the desired application specifications.

Lab tests provided the results shown in Fig. 6 using two microprocessor-based relays of the same family, each publishing a synchrophasor stream on one serial port while receiving the stream from the other device on a second serial port. The synchrophasor channels were set to send P class information with a wide bandwidth filter at a rate of 30 messages per second. Both relays are configured with a 300:1 CT ratio, 3000:1 PT ratio, and a nominal secondary VL-L of 115 V.

Simulating a case where the A-phase voltage on Relay 2 experiences a 10% magnitude step reduction produces the results in Fig. 6.

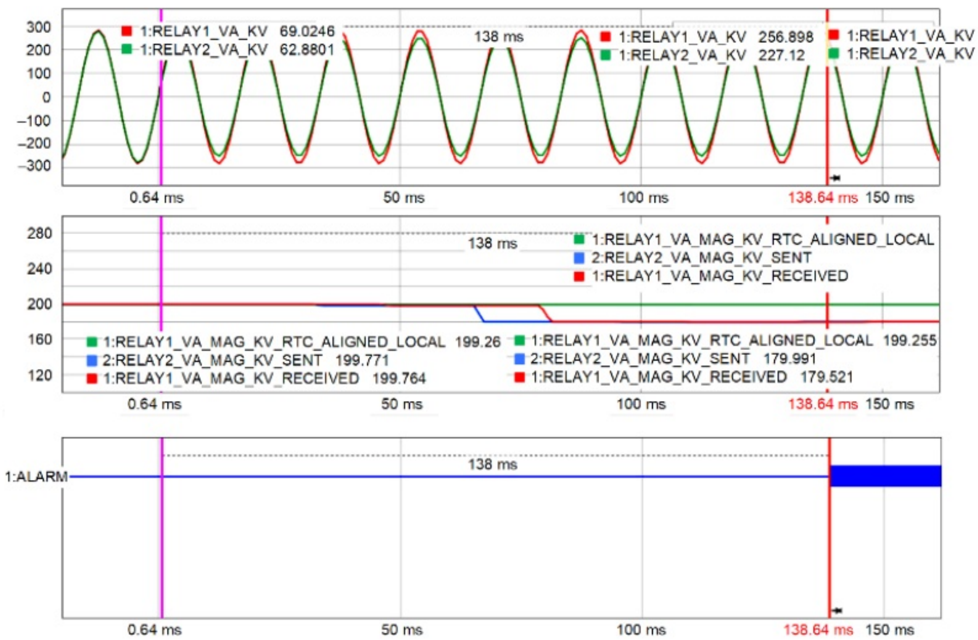

Fig. 6 Synchrophasor-based magnitude discrepancy detection

With the magnitude step change initiated at t = 0 ms, it can be observed that Relay 2 has a delay of 67 ms, or approximately 4 cycles, before synchrophasor data are sent showing the reduced magnitude. Relay 1 receives these data 14 ms later, and begins timing its alarm 57 ms later. This is a total of 138 ms of delay from magnitude step change to Relay 1 alarm pickup. Simulating a case where the A-phase voltage on Relay 2 experiences a 15° angle step change produces the results in Fig. 7.

With the angle step change initiated at t = 0 ms, we observed that Relay 2 has a delay of 80 ms, or approximately 4.8 cycles, before data are sent showing the full value of the changed angle.

Relay 1 receives these data in the same channel delay of 14 ms later, and begins timing its alarm 57 ms after receipt of the new angle measurement. This is a total of 160 ms of total delay from the step angle change to remote relay alarm pickup.

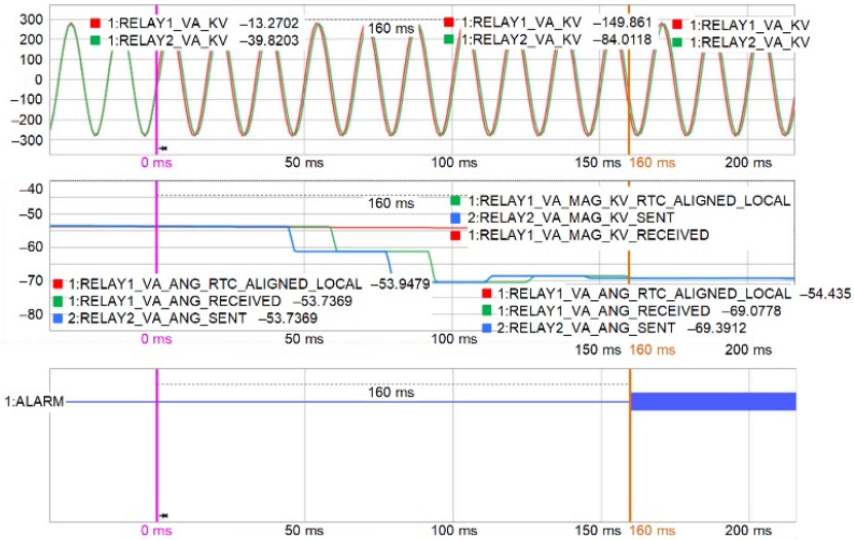

Fig. 7 Synchrophasor-based angle discrepancy detection

This testing shows that the method described can be implemented for both phase magnitude and phase angle comparisons with a deterministic implementation using microprocessor-based relays both as synchrophasor servers and clients.

CENTRALIZED SYNCHROPHASOR-BASED METHO

This section describes a method to provide Asset Health Monitoring (AHM) for instrument transformers and redundant microprocessor relays using Synchrophasor Protocol and an RTAC with a built-in PDC function. AHM for instrument transformers and intelligent electronic devices (IEDs) can be accomplished by comparing PMUs of similar specifications. The PMU from redundant instrument transformers should produce equivalent measurements, allowing for some margin because of manufacturing tolerances.

Additional RTAC hardware is needed for this approach.

RTACs are widely deployed in substations for data management, AHM, and deterministic mission-critical control applications such as power system stability monitoring. For many substations with an existing RTAC, there is no significant additional hardware cost when implementing AHM for instrument transformers and relay systems. There are several advantages to using an RTAC for this application:

- One RTAC device is typically sufficient to cover the instrument transformer condition monitoring application for the entire substation.
- RTACs have a built-in powerful deterministic logic processor that allows for more flexibility and sophisticated failure detection logic, including comparing more than two synchrophasor measurements from the same instrument transformer.
- The modular design of the instrument transformer monitoring function can be easily replicated, creating multiple instances to monitor more instrument transformers.
- RTACs have a built-in human-machine interface (HMI), including a substation one-line diagram, that visualizes the condition of each instrumenttransformer and seamlessly provides SCADA communications related to

instrument transformer condition monitoring.

Within RTAC implementation, more synchrophasormeasurements from different relays connected to the sameinstrument transformer windings can be used to provide moresensitive failure detection. The decision logics shown in Section II for point-to-point connection are modified as shownin the following equations: Alarm If 1.05 > (Max(Relay_Mags) / Minimum(Relay_Mags> 0.95 AND (Minimum(Relay_Mags) > 0.05)

Alarm If Max(ABS(Relay_Ang_x – Relay_Ang_y)) > 10° AND(Minimum(Relay_Mag) > 0.05) For magnitude comparison, the maximum value and minimum value of the phasor magnitudes are used for the decision logic. For phase angle comparison, the angledifference between each pair of synchrophasor measurementsis calculated and the maximum of the phase angle difference isused for abnormality detection.
Fig. 8 and Fig. 9 illustrate the instrument transformemonitoring function diagram that shows normal condition andalarm condition, respectively, under different testing conditionsas used in the previous sections.

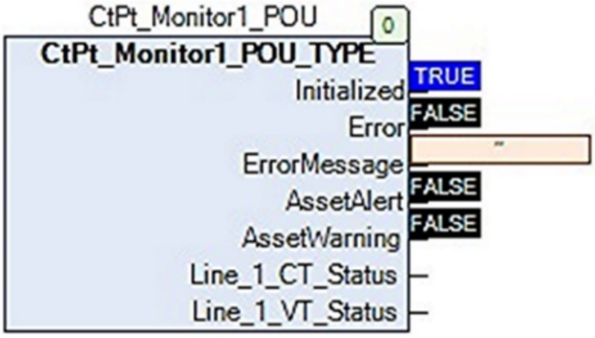

Fig. 8 Instrument transformer monitoring (normal condition)

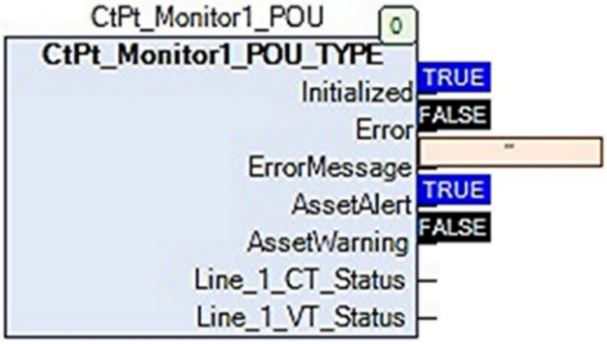

Fig. 9 Instrument transformer monitoring (alarm condition)

Modern RTACs have deterministic processing times as fast as tens of milliseconds. The real-time condition status output for the instrument transformer can be programmed as a Sequence of Events (SOE) with a more elaborate message, as illustrated in Fig. 10. This status output can be incorporated into different protection and control applications as a supervisor or sent to HMIs to alert operators.

Time Stamp	Category	Message
2023-08-11 16:07:40.190	CtPt Monitoring - Alerts	Asset Alert : EXPIRATION : VT1_VA_Mag,VT2_VA_Mag
2023-08-11 17:49:46.690	CtPt Monitoring - Alerts	Asset Alert : EXPIRATION : VT1_VA_Ang,VT2_VA_Ang

Fig. 10 RTAC-based instrument transformer condition change SOE

GOOSE MESSAGING BETWEEN RELAYS

This method takes the current/voltage magnitude and angle signals received from the System 1 relay through GOOSE messaging and compares them to the current/voltage magnitude and angle signals in the System 2 relay. The System 1 and System 2 relays see the same current parameters but from different CTs. The System 1 and System 2 relays see the same voltage parameters but from different windings on a CCVT or PT. This method not only monitors the instrument transformers, but the relay wiring and relay internal current and voltage input circuitry as well. The System 1 relay will send the current/voltage magnitude and angle data using analog GOOSE messaging. The System 2 relay will subscribe to these data and perform logic comparing the System 1 data to the current and voltage magnitude and angle data directly measured by the System 2 relay.

The data signals from the System 1 relay are transmitted to the System 2 relay using IEC 61850 analog GOOSE messaging. Care must be taken with these data because the signal is not necessarily continuous. These data are transmitted to the System 2 relay under supervision of an IEC 61850 MMXU deadband setting. For the current magnitude signals, a 0.001% change was chosen and must occur before a new data value is transmitted from the System 1 relay. For the voltage magnitude signals, a 0.1% change was chosen and must occur before a new data value is transmitted from the System 1 relay. For the current and voltage angle signals, a 0.1% change was chosen and must occur before a new data value is transmitted from the System 1 relay.

For a 345 kV system with a CCVT ratio of 3000:1 and a CT ratio of 300:1, the deadband will translate as follows:

- Voltage magnitude deadband: 825 V primary
- Voltage angle deadband: 0.36°
- Current magnitude deadband: 0.69 A primary
- Current angle deadband: 0.36°

The set points chosen for comparison are 5% for magnitude and 10° for angle. Therefore, if the difference between the System 1 and System 2 data exceeds these set points, an alarm will be generated. A 60-second delay is also introduced to avoid any false larming because of sudden system changes. These sudden system changes could result in momentary error exceeding the set points because of GOOSE deadband and time delay to transmit and receive the data. This method is not intended to provide fast detection to disable protection and avoid a false trip; its mission is to monitor steady-state conditions and provide alarming.

The System 2 relay, which processes the data from the System 1 relay, must have a supervision level such that if the System 1 data are less than this supervision level, data comparison will be blocked. This supervision reflects the System 1 data and the deadband associated with them. In addition, the comparison set point plays a part in the selection of this supervision value. With a 0.001% deadband level and a magnitude set point selection of 5%, (1) determines a good setting for this supervisory set point:

$$X = \frac{Y \bullet Z}{C(1-Y)}$$

where:
X = Supervisory set point factor
Y = Mismatch set point
Z = GOOSE deadband in primary amperes
C = CT ratio
The current supervision is calculated from the following

parameters:

- X = 0.95(0.69 A)/(300(1 – 0.95)
- X = 0.0437
- Multiply by 2 for security. Round up.
- The chosen supervision set point is 0.1 A secondary.
- Translated to primary amperes, X = 0.1(300) = 30 A.

Note that regardless of the CT ratio, the supervisory set point factor will compute to the same value. Only the

primary ampere value will change per the CT ratio.
Care was taken for the method of angle comparison. One item is time alignment. The GOOSE messaging method will not be time stamp aligned. For example, if the System 1 relay transmits a value of 10° and the phasors are rotating at a slip frequency where the System 2 relay is indicating 15° at the moment of comparison, this will be a problem. Therefore, a method must be applied that would allow for this. AEP also has two relay systems. Each system is a different relay manufacturer. Manufacturer 1 defines angle 0° to be equated to the A-phase voltage. Manufacturer 2 defines angle 0° to be equated to the positive-sequence voltage. This introduces alignment error between the two systems. Testing by comparing the individual phase-to-ground angles will not work.
We determined that instead of testing the phase-to-ground angles, the phase-to-phase angles should be tested to eliminate alignment errors. To reiterate, the goal with this method is not to provide fast detection, only to detect errors during steady state.
Fig. 11 illustrates detection and timing data taken from lab tests for magnitude comparison. The comparison was made between two different relay manufacturers.

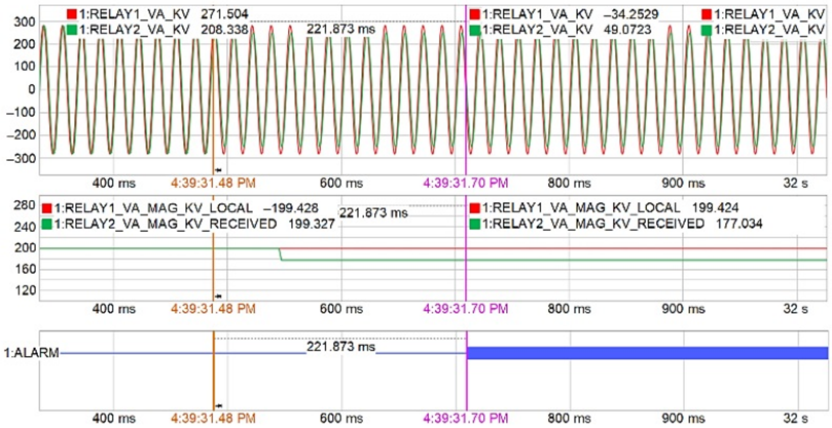

Fig. 11 GOOSE-based magnitude discrepancy detection

The data show the response to a voltage magnitude change of 11% on one of the relays. The diagram shows that from the time of the change until the algorithm detects the change, approximately 222 ms have expired.Fig. 12 illustrates detection and timing data taken from lab (1) tests for angle comparison. The comparison was made between two different relay manufacturers.

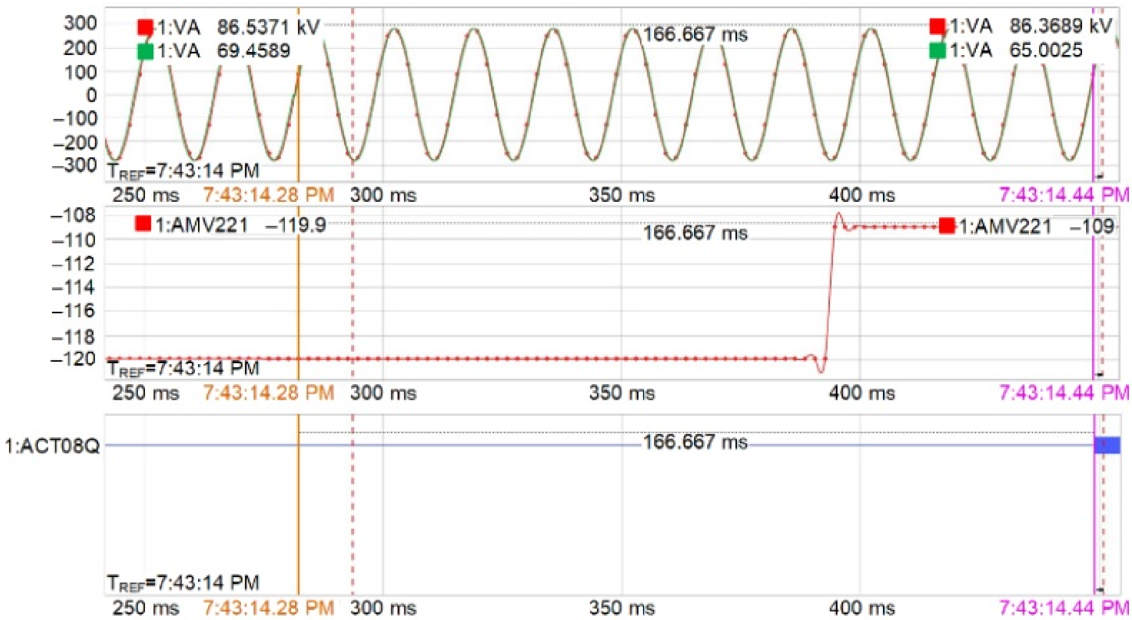

Fig. 12 GOOSE-based angle discrepancy detection

The data show the response to a phase angle change of 10° on one of the relays. The diagram shows that from the time of the change until the algorithm detects the change, approximately 167 ms have expired.

The data shown in Fig. 13 are from field-connected devices protecting a transmission line. These data show the angle data captured from the System 1 and System 2 relays, as well as the validity of the GOOSE data from the System 1 relay versus the measured data from the System 2 relay. The data were recorded in the System 2 relay.

VAFM	VAFA	RA015	VBFM	VBFA	RA016	VCFM	VCFA	RA017
20.630	8.830E-02	0.000	20.745	-119.990	-120.000	20.653	119.904	119.800
20.635	9.874E-02	0.000	20.755	-119.995	-120.000	20.658	119.896	119.800
20.637	0.104	0.000	20.753	-120.010	-120.000	20.651	119.898	119.800
20.633	9.775E-02	0.000	20.746	-120.003	-120.000	20.649	119.906	119.800
20.653	9.482E-02	0.000	20.762	-120.009	-120.000	20.669	119.909	119.800
20.646	0.101	0.000	20.752	-120.025	-120.000	20.656	119.914	119.800

LIAFM	LIAFA	RA018	LIBFM	LIBFA	RA019	LICFM	LICFA	RA020
216.163	-38.652	-38.400	222.111	-160.755	-160.000	211.998	78.742	79.400
216.514	-38.873	-38.400	222.286	-160.735	-160.000	212.980	78.690	79.000
215.349	-38.940	-38.400	221.757	-160.868	-160.000	212.142	78.466	79.000
216.574	-38.827	-38.400	222.406	-160.823	-160.000	212.692	78.689	79.000
215.050	-39.054	-38.400	221.632	-161.140	-160.400	211.189	78.167	78.600
212.586	-38.973	-38.400	220.169	-161.014	-160.400	209.546	78.027	78.600

Fig. 13 System 1 (top) and System 2 (bottom) relay data

- VAFA: System 2 A-Phase Voltage Angle
- RA015: System 1 A-Phase Voltage Angle
- VBFA: System 2 B-Phase Voltage Angle
- RA016: System 1 B-Phase Voltage Angle
- VCFA: System 2 C-Phase Voltage Angle
- RA017: System 1 C-Phase Voltage Angle
- LIAFA: System 2 A-Phase Current Angle
- RA018: System 1 A-Phase Current Angle
- LIBFA: System 2 B-Phase Current Angle
- RA019: System 1 B-Phase Current Angle
- LICFA: System 2 C-Phase Current Angle
- RA020: System 1 C-Phase Current Angle

This magnitude comparison has been in service at AEP for about 14 years. The angle comparison has been in service at AEP for about one year. This is a real-time system, i.e., this system observes data in real time rather than after the fact. Initially, the test was magnitude only. Recently, angle comparison was added to the line protection schemes. The test has also been added to bus differential schemes. It is slated to be added to transformer schemes on future standard updates. In addition, the monitored data are being recorded in each relay for post-event analysis.

For CCVTs, the GOOSE method monitors separate windings on the CCVT. If the problem with the CCVT is located in the capacitive circuit, which is common to both CCVT windings, the GOOSE comparison method will not detect this condition; both relays will see the same voltage. To detect this condition, a method of monitoring the zero-sequence voltage was implemented. This detection has two set points. The lower set point has a fixed time delay to alarm. The next set point, set higher, has a much faster time delay to alarm. The goal of real-time monitoring is to eliminate the need for manual periodic testing to satisfy NERC PRC-005-2 maintenance requirements, therefore reducing costs.

SUMMARY

Instrument transformers are pivotal components in power systems and are vulnerable to failures resulting from aging, insulation degradation, electrical stress, and mechanical damages. These failures, as highlighted by the severe consequences such as relay mis-operation and equipment damage, underscore the importance of standards such as NERC PRC-005-2. This NERC standard mandates either manual maintenance at the maximum interval of 12 years or deploying continuous monitoring solutions.

Recognizing the need to align with standards such as NERC PRC-005-2 and preemptively detect instrument transformer irregularities, the paper introduced three economical methods using synchrophasor measurement or GOOSE messaging, which are built-in functions of modern IEDs. The proposed methods for early detection of instrument transformer abnormalities offer several benefits, especially when viewed in light of the challenges associated with power system management and maintenance. The benefits of the proposed methods include the following:

Early Detection of Abnormalities: The primary advantage of these methods is the proactive identification of potential transformer failures. Early detection can prevent catastrophic events, safeguarding the integrity of the power grid and protecting expensive equipment from irreversible damage.

Cost Savings: Addressing instrument transformer abnormalities in their early stages can lead to substantial cost savings. This proactive approach can prevent more expensive repairs or replacements if the equipment fails and can also minimize downtime, thus ensuring uninterrupted power supply and revenue generation. All the proposed approaches are continuous online monitoring methods that can exempt utilities from the NERC PRC-005-2 requirements of enhanced reliability and safety.

Enhanced Reliability and Safety: Reliable instrument transformers are crucial for the safety and stability of power systems. By ensuring these transformers function optimally, the methods enhance the overall reliability of the power grid and reduce safety risks associated with equipment failures, such as fires and other hazards.

Optimal Use of Resources: The first and third methods, which use the built-in capability of digital relays, are economical and do not require additional devices. This efficient use of existing resources ensures optimal resource allocation and reduces the need for further investment.

Advanced Monitoring: Using a dedicated synchrophasor data processor, as mentioned in the second method, allows for the implementation of sophisticated algorithms. This ensures greater accuracy in detecting abnormalities, even in complex power system scenarios.

Flexibility and Adaptability: The three proposed methods cater to different scenarios, offering utilities the flexibility to choose the most suitable approach based on their infrastructure, budget, and requirements.

Enhanced Record Keeping and Analysis: By employing time-synchronized measurements, utilities can maintain a consistent log of measurements and events. This can be invaluable for post-event analysis, predictive maintenance, and for compliance with regulations like NERC PRC-005-2.

Improved Protection: By cross-checking measurements and identifying mismatches, these methods can prevent relay mis-operation, ensuring that protective mechanisms in the power grid function as intended.

Stakeholder Confidence: Regular and efficient monitoring, coupled with proactive maintenance, can boost confidence among stakeholders, including investors, regulatory bodies, and consumers. A reliable power system is foundational to modern economies, and these methods ensure consistent delivery on this front.

In conclusion, the proposed methods not only serve to enhance the reliability and safety of the power system but also position utilities to make informed decisions, optimize resources, and realize significant cost savings in the long run.

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BIOGRAPHIES

Jason Byerly received his BS from The Ohio State University in 2004 and is currently pursuing his MSEE from the University of Idaho. He joined American Electric Power (AEP) in 2004 and has supported several roles in protection and control engineering. Jason is a registered Professional Engineer (PE) in Ohio, a senior member of IEEE, contributor to IEEE PSRC, and a member of IEC 61850 WG 10.

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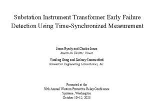
Yanfeng Gong earned his BS in electrical engineering with a focus on power systems from Wuhan University, China, in 1998. He went on to obtain his MS from Michigan Technological University in 2002 and his Ph.D. from Mississippi State University in 2005, continuing his specialization in power systems. Yanfeng worked as a research engineer at Schweitzer Engineering Laboratories, Inc. (SEL) from 2005 to 2013. He later served as a principal engineer and supervisor at American Electric Power (AEP) in the Advanced Transmission Studies & Technologies (ATST) department from 2013 to 2019.

In 2019, he returned to SEL, assuming the role of principal engineer. In addition to his professional endeavors, Yanfeng has played an active role in industry committees. He served as the past chair of the IEEE Transient Analysis and Simulation Subcommittee (TASS) and is currently the vice chair of the IEEE Analytic Methods for Power Systems (AMPS) technical committee. He has been an active contributor to several industry standardization efforts and technical working groups. Yanfeng is a senior member of IEEE and is a registered Professional Engineer (PE) in Washington.

Zachary Summerford earned his BS in electrical and computer engineering with a focus on power systems and digital logic design from The Ohio State University in 2012. He earned his ME in electrical engineering with a focus on power systems from the University of Idaho in 2022. He began working for Schweitzer Engineering Laboratories, Inc. (SEL) in 2012 and is currently a senior application engineer for protection. He is a member of IEEE and a registered Professional Engineer (PE) in Ohio.

Documents / Resources

	Schweitzer 7132 Substation Instrument Transformer Early Failure Detection [pdf] Owner's Manual 7132 Substation Instrument Transformer Early Failure Detection, 7132, Substation Instrument Transformer Early Failure Detection, Instrument Transformer Early Failure Detection, Transformer Early Failure Detection, Early Failure Detection, Failure Detection

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