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System Level Tests of Transformer Differential Protection Using an IEC 61850 Process Bus

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***Abstract*—The IEC 61850 family of standards for substation communication systems were released in the early 2000s, and include IEC 61850-8-1 and IEC 61850-9-2 that enable Ethernet to be used for process-level connections between transmission substation switchyards and control rooms. This paper presents an investigation of process bus protection performance, as the in-service behavior of multi-function process buses is largely unknown. An experimental approach was adopted that used a Real Time Digital Simulator and 'live' substation automation devices. The effect of sampling synchronization error and network traffic on transformer differential protection performance was assessed and compared to conventional hard-wired connections. Ethernet was used for all sampled value measurements, circuit breaker tripping, transformer tap-changer position reports and Precision Time Protocol synchronization of sampled value merging unit sampling. Test results showed that the protection relay under investigation operated correctly with process bus network traffic approaching 100% capacity. The protection system was not adversely affected by synchronizing errors significantly larger than the standards permit, suggesting these requirements may be overly conservative. This 'closed loop' approach, using substation automation hardware, validated the operation of protection relays under extreme conditions. Digital connections using a single shared Ethernet network outperformed conventional hard-wired solutions.**

***Index Terms*—Ethernet networks, IEC 61850, IEEE 1588, industrial networks, performance evaluation, process bus, protective relaying, smart grid, substation automation**

I. Introduction

WIDESPREAD adoption of non-conventional instrument transformers (NCITs), such as optical or capacitive transducers, by electricity utilities and large industrial customers has been limited due to the lack of standardized interfaces and multi-vendor interoperability. Low power analog interfaces, such as IEEE Std C37.92, are now being replaced by IEC 61850-9-2 digital interfaces that use Ethernet networks for communication [1]. These "process bus" connections achieve significant cost savings by simplifying connections between switchyard and control rooms [2], [3]. The in-service performance when these standards are employed is largely unknown, and the technology is considered to be some years away from maturity [4], however some process bus substations are now in service [5], [6]. Trials are continuing, including a large multi-vendor installation in Mexico with promising results [7].

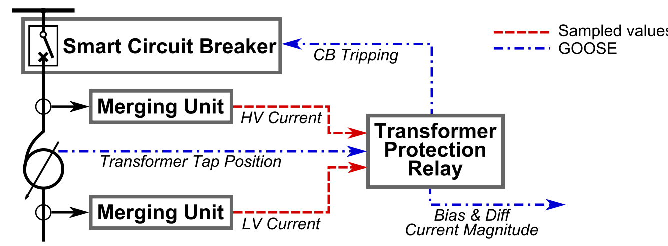

Fig. 1. Single line diagram of a digital process bus for transformer protection, including the primary plant and protection system.

The performance of IEC 61850-9-2 sampled value protection schemes has been evaluated by a number of researchers, using event based simulation with tools such as OPNET and OMNeT++ [8], [9], real-time simulation [10], [11], replay of power system simulations [12] and secondary injection protection test sets [13]. Transmission line distance protection [11], [12] and current feeder protection [13] schemes have been used as protection test cases in previous investigations. The performance of Generic Object Oriented Substation Event (GOOSE) [14] messages for circuit breaker trip commands have been studied by a number of researchers [15]–[17], however this work extends this through the use of sampled values, time synchronization and GOOSE on a shared Ethernet network.

The research presented in this paper uses transformer differential protection which introduced the need for synchronization between merging units, but was not dependent on a communications path that could influence performance. This test bed enabled the performance of Ethernet switches, PTP clocks, merging units and protection relays to be assessed while introducing controlled network traffic and network impairment. Fig. 1 illustrates the power system representation of the test case, with sampled values conveying current measurements. GOOSE was used for circuit breaker tripping, tap changer position reporting and transduced differential current measurements.

The authors' previous research has examined the performance of sampled value process bus networks [18], [19], the interaction between sampled values and GOOSE [20] and the suitability of PTP for sampled value synchronization [21], [22]. This paper "closes the loop" with system-level tests that evaluate the influence of network performance and time

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synchronization on protection response with commercially available hardware. Test methods are presented that identify sources of variation in protection response for a variety of connection types. The effect of Ethernet network delays and background traffic on the response of a transformer differential relay is presented, and shows that performance requirements can be met with process bus connections under strenuous operating conditions.

Section II defines the performance requirements of protection systems, based on IEC 61850 and grid codes from Australia and the United Kingdom (UK). A description of the test methods and network topologies is presented in Section III. The results of this testing are given in Section IV, along with discussion of the significance in Section V. Conclusions are presented in Section VI.

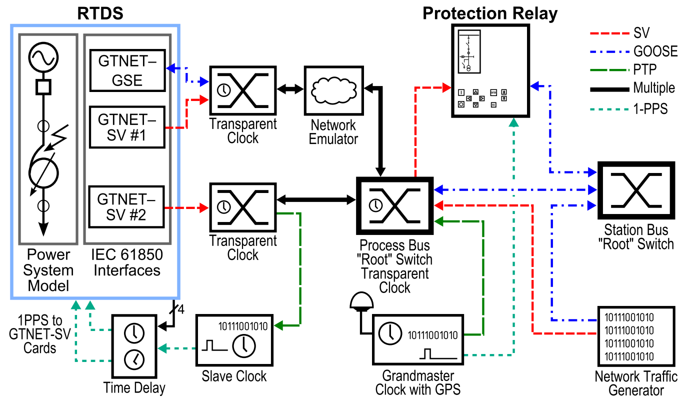

Fig. 2. Schematic of process bus test bed equipment for transformer differential protection testing.

II. Performance Requirements

Protection clearance times, taking into account protection response time (fault inception to transmission of a trip command) and circuit breaker operating times, are generally mandated in grid codes to ensure power system security. The National Electricity Rules in Australia [23] and the UK Grid Code [24] specify the maximum permitted fault clearance times for their respective electricity networks. Australia and the UK both have clearance times that range from four to six power frequency cycles, depending on operating voltage. The operating time of high voltage circuit breakers generally range from two power frequency cycles (400 kV and some 275 kV breakers) to three cycles (some 275 kV and most 110/132 kV breakers). As a result, protection relay response times must be less than 40 ms at 400 kV and be less than 60 ms for other operating voltages.

Section 13.7 of IEC 61850-5 specifies the maximum transfer time for various message types [25]. The transfer time is the sum of the processing times at the sender and receiver and the network transmission time. Overall performance classes P2 and P3, defined in [25], apply to transmission substations (with >100 kV operating voltage) and determine the applicable transfer time for each message class. GOOSE messages that "trip" plant (type 1A) and sampled value "raw data messages" (type 4) both have transfer time requirements of 3 ms. The conformance testing requirements in IEC 61850-10 specify that network latency is allocated 20% of the transfer time, with 40% allocated to the communication processing time at both the sender and receiver [26]. This gives a network transfer time limit of 600 µs for sampled value and GOOSE tripping messages.

III. Method

A model substation automation system, based on a Real Time Digital Simulator (RTDS), was used for this research [3]. This process bus test bed incorporated power system communication using IEC 61850-9-2 sampled values and IEC 61850-8-1 GOOSE [14], and time synchronization using the Precision Time Protocol (PTP) [27] with the PTP Power System Profile [28]. The RTDS had three GTNET cards fitted to provide IEC 61850 functionality. Two cards (referred to as GTNET-SV #1 and #2) published sampled values and one (referred to as GTNET-GSE) published and subscribed to GOOSE messages. The GTNET-SV cards acted as merging units and used the dataset and protection messaging rate (80 samples per power cycle) specified in the UCAIug "9-2LE" Implementation Guideline [29]. The transformer differential protection relay used for this testing was an ABB RET670 with 9-2LE (sampled value) and conventional copper (CT/VT) inputs. This allowed a performance comparison between conventional inputs and sampled value inputs to be performed. The protection relay communicated to other devices with digital inputs, dry contact outputs and IEC 61850-8-1 GOOSE messages.

Fiber optic cables connected the two locations to simulate the network connections between a switchyard and a substation control room. A Simena NE1000 network emulator created artificial latency between the merging units and the core switch. Sampled value and GOOSE network traffic was generated by an Endace DAG7.5G4 precision Ethernet card [30]. Controlled synchronizing errors were introduced with custom hardware controlled by the RTDS. Fig. 2 shows the equipment in the test bed, however each test used a subset of the equipment.

The simulated transformer was a 375 MVA 275/110 kV auto transformer. The protection settings were the factory default settings applicable to this model of transformer, and the restraint curve is shown graphically in Fig. 3. Unrestrained operation was set to 10 per unit (p.u.) differential current (I_D). The performance of the RET670 was assessed by simulating a fault in the RTDS and measuring the elapsed time from fault inception to the receipt of a differential protection operation indication. This indication was via a GOOSE message or a state change on an RTDS digital input connected to a relay contact on the RET670. The conformance testing guidelines in section 7.2.2 of [26] were followed, with 1000 faults applied and the response of each recorded.

A. Measurement validation

The first series of tests validated the measurement system and assessed the variation in response time under ideal network conditions. The performance of the RTDS was cross-checked

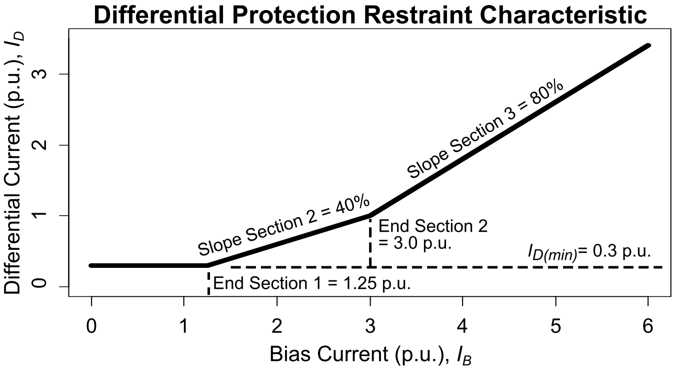

Fig. 3. RET670 three-section restraint curve with factory settings.

with an OMICRON CMC256-6 protection test set that had IEC 61850 and conventional signaling capabilities. This gave six test configurations for comparison purposes: three with relay contact trip signaling and three with GOOSE trip signaling. Each set of three comprised the RTDS with sampled values, the OMICRON with sampled values and the OMICRON with analog outputs.

High fault current (20–25 p.u.) three phase faults on the high voltage (HV) terminals of the transformer and medium fault current (3–4 p.u.) line to ground faults on the low voltage (LV) transformer terminals were used to test unrestrained and restrained operation of the RET670.

1) Protection Function Response: The response of the RET670's transformer differential protection element was assessed by applying 100 unrestrained and 100 restrained faults. The protection response time was recorded by the RTDS for comparison purposes. After each set of 100 faults was complete the disturbance records were downloaded from the RET670 in COMTRADE format [31]. The time elapsed from fault inception to the assertion of the protection operate signal in the relay logic was calculated. This assessed the internal variability in the RET670.

2) GOOSE Subscription Timing: The network traffic on the process and station buses was captured with a 4-port Ethernet card while 200 faults (100 restrained and 100 unrestrained) were applied to the RET670. The RTDS and CMC256-6 were both configured to transmit a zero voltage value until the fault was applied (which did not affect the transformer differential protection). A custom *LUA* script, written by the authors, was executed by the Wireshark network analysis tool [32] to calculate the elapsed time between the onset of fault (non-zero voltage) to the publication of the GOOSE trip indication. The GOOSE subscription time was the difference between the relay response time calculated from the network captures and the time calculated by the test instrument (OMICRON or RTDS).

B. Network Loading and Impairment

The results of the measurement validation tests, presented in Section IV-A, showed that high fault currents that resulted in unrestrained trips gave the least variation in response time. Three phase faults on the high-voltage side of the transformer were used for the network loading and network impairment tests.

1) Sampled Value Network Load: Artificial sampled value traffic was generated to load the process bus to near capacity. Previous research has shown that a 100 Mb/s network can support 20 merging units publishing 4000 frames per second (a 50 Hz power system) [19]. Three sets of synthetic sampled value traffic were created:

1) A unique source address and a unique multicast destination address for each "stream".
2) A unique source address and the same multicast destination address used by the RTDS.
3) The same source address and multicast destination address used by the RTDS.

The three addresses were used to determine how the RET670 filtered sampled value traffic. The Endace DAG card transmitted the background traffic continuously while the RTDS applied the faults to the protection relay. This presented a maximum network load of 20 merging units (two "real" GTNET-SV streams and 18 "synthetic" background streams) to the protection relay.

2) Station Bus Network Load: GOOSE traffic was injected into the Station Bus to assess whether GOOSE subscriptions by the protection relay would slow protection response. The RTDS published a GOOSE message with the transformer tap position based on its model of the power transformer, and asserted a signal when a fault was applied. The RET670 subscribed to this message to enable transformer tap compensation to be applied to the differential protection function. The ability of the protection relay to filter GOOSE messages was tested by varying the multicast destination address, GOOSE application ID, source address and GOOSE dataset name in the background traffic. The simulated GOOSE messages had the same dataset contents as the messages published by the RTDS, and were transmitted at 1000, 2000, 5000 and 10 000 messages per second. This was the equivalent of 2.1–21 Mb/s of traffic. The GOOSE traffic flows opposite to the sampled value traffic, and therefore there is no contention [20]. It is not expected that this level of GOOSE traffic would be present on a process bus.

3) Network Impairment: A Simena NE1000 network emulator was used to introduce additional latency into sampled value and GOOSE messages, which allowed the effect of network latency on protection response to be examined. Latency was selectively introduced to GTNET-SV #1 and GTNET-GSE. The network connection from GTNET-SV #2 to the process bus root switch was not impaired.

The network emulator had a 1 ms resolution for latency. Latencies of 2 ms, 5 ms, 8 ms and 10 ms were applied to sampled value messages, which is an extreme case to demonstrate the latency/response time relationship. Latencies of 5 ms, 10 ms, 15 ms and 20 ms were applied to GOOSE messages. The "wireline" mode where the emulator passes frames without any impairment was used as the reference for sampled value and GOOSE testing. 1000 unrestrained faults were applied with each latency and the protection response times recorded.

C. Sampled Value Synchronizing Accuracy

The effect of errors in the one pulse per second (1-PPS) signal used to synchronize the sampling of GTNET-SV merging units was evaluated by introducing RTDS-controlled delays into the synchronizing input of one GTNET-SV card with a microcontroller. The time delays were verified with a digital oscilloscope to have a mean error of 65 ns with a standard deviation of 0.2 ns (n=1000 for each delay from 2–1000 μs).

Two sets of tests were conducted. The first was to evaluate the impact of synchronizing error on the differential current, I_D, reported by the RET670 when there was no fault. Any synchronizing error manifested as a phase error in the merging unit output, which in turn resulted in "spill current" (erroneous differential current) in the differential calculation. The second series of tests involved "walking" the restraint characteristic (shown in Fig. 3) while a series of synchronizing errors were applied. Spill current from the synchronizing error changed the point at which the relay tripped. The characteristic was mapped by applying 65 bias (I_B) currents in 0.1 p.u. steps from 0.5–7.0 p.u. and 60 differential currents (I_D) from 0.8 p.u. below to 0.4 p.u. above the expected curve in 0.02 p.u. steps. Where $I_D < 0.8\,\text{p.u.}$ the "walk" started at 0.0 p.u., resulting in 3589 faults being applied (from a maximum of 3900 faults) for each synchronizing error.

IV. Results

The majority of tests were conducted with 1000 faults applied, as per the requirements of IEC 61850-10. "Box and whisker plots" have been used to show the statistical distribution of multiple measurements in a compact form. Outlying results are significant for protection systems, and these are not captured by the mean and standard deviation. The "box" represents the Inter-Quartile Range (IQR), which is the 25th to 75th percentile, and the bar is the median value of all observations. The "whiskers" extend to the minimum and maximum values, provided these are within two times the IQR from the upper or lower limits of the box. Any points beyond this are outliers, and are shown as hollow circles.

A. Measurement System Validation

Fig. 4(a) shows the protection response time for three phase faults on the HV side of the transformer, which resulted in a fault current of 24 p.u. (approximately 19 kA). Fig. 4(b) is the corresponding LV phase to ground fault response time, with fault currents of approximately 3.5 p.u. (7 kA).

The responses show that the response times cluster into two groups: GOOSE fault indication and relay contact fault indication. GOOSE tripping was, on average, 3.4 ms faster for the RTDS and 3.9 ms faster for the OMICRON CMC256-6. HV faults were selected for network and synchronizing tests due to the reduced variability. The similarity of RTDS and OMICRON response times for HV faults gives confidence that the measurement system is accurate. GOOSE tripping was used for the remaining tests, as this replicated the functionality of a smart circuit breaker using a process bus for trip signaling.

The response time of the differential function in the RET670 to 100 restrained and 100 unrestrained faults is shown in

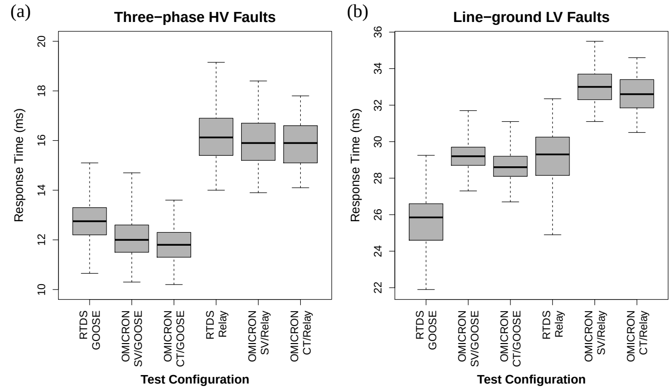

Fig. 4. Comparison of protection response times for the RTDS and OMICRON CMC256-6 with (a) HV three phase (unrestrained) faults and (b) LV phase to ground (restrained) faults.

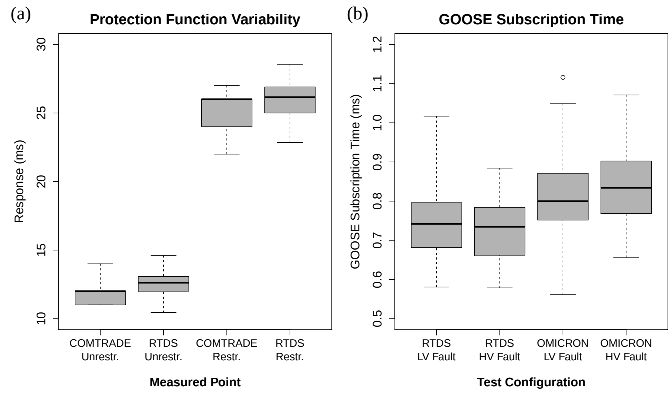

Fig. 5. Sources of variation in protection response. (a) Comparison of protection response determined by COMTRADE records and RTDS measured response. (b) Delays introduced by GOOSE subscription in the RTDS and OMICRON.

Fig. 5(a), along with the corresponding overall protection response times measured by the RTDS. The mean response for restrained faults was 25.1 ms and for unrestrained faults was 11.9 ms. The variation in the unrestrained response was half that of the restrained response, with a standard deviation of 0.71 ms. Second harmonic blocking, which avoids tripping due to transformer in-rush current, was the dominant restraint signal.

These results show that the variation in response measured by the RTDS is mostly due to response variation in the time required for the differential protection function to detect the fault rather than variation in the time required for the RTDS to process the GOOSE message. Fig. 5(b) shows the difference in protection response time measured by the RTDS or OMICRON and that calculated based on network captures. These results show that the RTDS and OMICRON introduce less than 0.5 ms of variation into the protection response time, and therefore these devices are suitable for detecting subtle changes in protection response.

B. Artificial Network Load

Fig. 6(a) shows that the relay operates correctly with 20 merging units sharing the network, with no adverse ef-

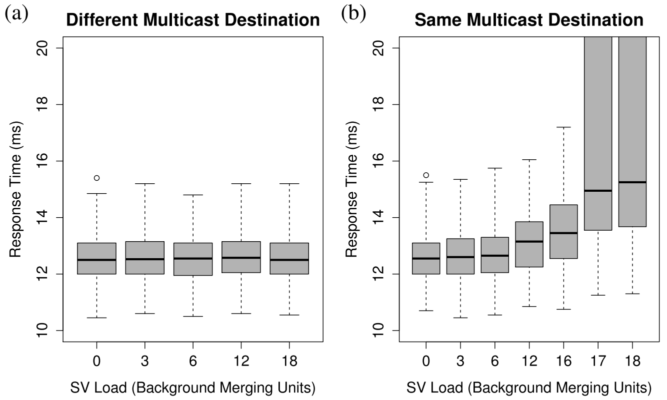

Fig. 6. Protection performance with varying background sampled value traffic levels with (a) different multicast addresses and (b) the same multicast address as the RTDS.

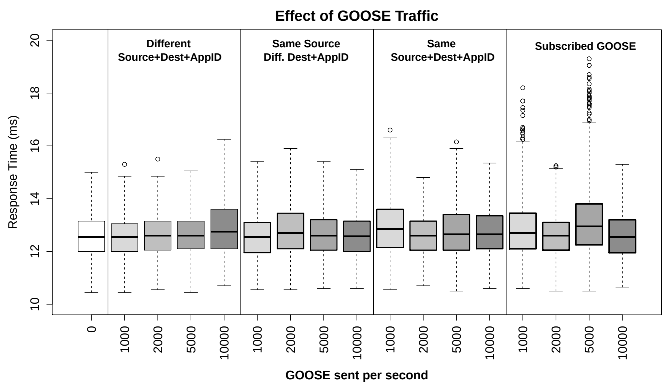

Fig. 7. Protection performance with varying background GOOSE traffic levels with differing multicast addresses. "Same" represents the multicast addresses used by the RTDS for tap position messages that the RET670 subscribed to.

fects when different multicast destination addresses are used. Fig. 6(b) shows that if the same multicast destination address is used response time starts to degrade at 14 merging units (two desired and 12 background), and is unacceptable at 19 merging units in total. The response with the source address set to that of the RTDS was the same as Fig. 6(b), which suggests that only the multicast destination address is used for filtering.

Background station bus traffic with additional GOOSE messages gave similar results, and these are presented in Fig. 7. Once the multicast destination was set to the same as any subscribed GOOSE message the background traffic had some influence at very high (>2000 messages/sec). The worst case was where the outgoing RTDS GOOSE message was blocked and the synthetic data set to replicate the RTDS. A bit was toggled on each transmission to elicit a response from the protection relay. This increased the response time, with the mean response increasing by 0.7 ms, and the maximum response increasing by 3.9 ms (for 5000 GOOSE messages per second).

The protection relay raised a "denial of service" (DOS) warning at 5000 messages per second, and a DOS alarm at 10 000 messages per second. When the DOS alarm was active the communications interface throttled traffic to preserve

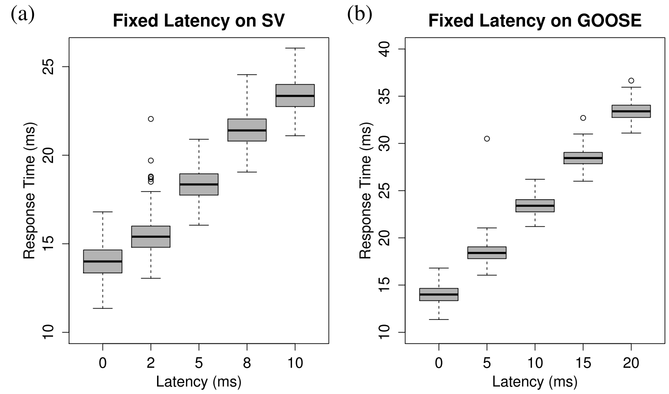

Fig. 8. Protection performance with fixed latencies introduced into (a) sampled value traffic and (b) GOOSE traffic by the network emulator.

TABLE I
RESPONSE TIME INCREASE DUE TO LATENCY.

Sampled Values		**GOOSE**	
Latency	Δresponse time	Latency	Δresponse time
2 ms	1.4 ms	5 ms	5.0 ms
5 ms	4.4 ms	10 ms	10.3 ms
8 ms	7.4 ms	15 ms	15.0 ms
10 ms	9.4 ms	20 ms	19.4 ms

the protection functions of the relay. This may explain the improvement in response when GOOSE traffic increased from 5000 to 10 000 messages per second in the "Subscribed GOOSE" panel in Fig. 7.

C. Network Contingencies

The effect of fixed network latency introduced by the NE1000 network emulator into the sampled value and GOOSE network are illustrated by Fig. 8(a) and Fig. 8(b). The measured increase in response time for each latency setting is presented in Table I. Sampled value traffic was not delayed beyond 10 ms as this resulted in the protection relay raising a "sampled value failure alarm" and blocking protection functions. Delays introduced to GOOSE traffic did not affect the operation of the protection relay, but did delay the response measured by the RTDS. This verifies that there is a linear relationship between network latency and protection performance. Network latency is therefore an important metric for predicting protection performance with a process bus.

D. Synchronizing Errors

Merging unit synchronization is of particular importance for differential protection, and therefore the effect of synchronizing error on the bias and differential currents calculated by the protection relay was assessed.

The differential current measured by the RET670 was recorded against the bias current for a range of fixed delays applied to the 1-PPS input of one merging unit and. linear regression models were fitted to the measurements.

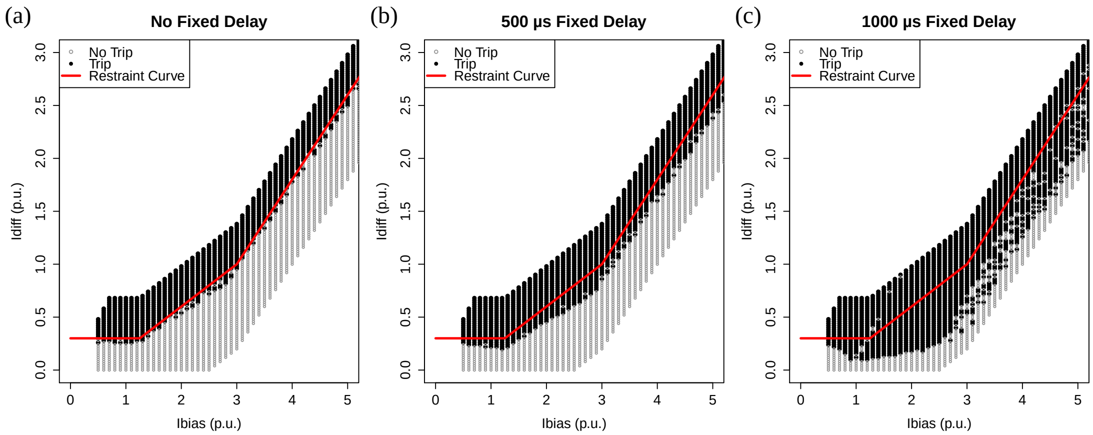

Fig. 9. Differential protection restraint curves with (a) no synchronizing error, (b) 500 µs error and (c) 1000 µs error. 'Ibias' is the bias current and 'Idiff' is the differential current, with both expressed as per unit (p.u.) quantities.

The relationship was found to be linear, with a coefficient of determination (R^2) of 1.000, a slope of $2\pi f \Delta t$ and an intercept < 0.001 for each delay from 4 µs to 1000 µs.

The synchronizing error converted the error factors (slopes) to absolute differential currents when the restraint curve was "walked". Fig. 9 shows three restraint curves, with synchronizing errors of 0 µs, 500 µs and 1000 µs applied to the LV merging unit (GTNET-SV #2). The black points are where the relay issued a trip command, and the hollow grey points are where no trip was issued. The line is the restraint characteristic set in the protection relay (from Fig. 3).

It can be seen in Fig. 9(a) that the trip/no-trip boundary matches the restraint curve, while in Fig. 9(b) and Fig. 9(c) the relay is tripping at lower I_D values than desired. It must be noted that a synchronizing error of 1000 µs is a deliberately extreme case and correct operation of the relay was not expected. Automated repetitive testing enables a comprehensive set of results to be obtained rather than using sampling.

V. Discussion

A. Measurement Consistency

The protection performance with sampled values over Ethernet was very similar to that with traditional 1 A secondary cabling when tested with the OMICRON test set. The sampled value response was, on average, 0.4 ms slower than the CT response. There was however a significant improvement in tripping performance with GOOSE messaging compared to relay contacts. This may be due to the physical limitations of relay signaling: coil energizing time and contact de-bounce in the receive circuitry. The relay "chatter" of the RET670's output contact lasted 700 µs when observed with an oscilloscope. The default de-bounce time for the OMICRON was 3 ms, which in turn delays passing the signal to the timer in the instrument. High speed solid state outputs would reduce, and perhaps eliminate the need for, the de-bounce time. The GOOSE and digital output blocks in the RET670 had a scan-time of 1 ms, giving a common sending delay. Transmission delays will be less with the relay compared to GOOSE as there is no store-and-forward delay. The minimum delay through a 100 Mb/s Ethernet switch for the 188-byte GOOSE trip message is 16.0 µs, which is equivalent to the propagation delay of 4.5 km of open wire or 3.2 km of fiber optic cable. Additional benefits of GOOSE indications are the richer set of data to be transmitted, including time-stamps and quality attributes, and the self-monitoring nature of the data connections.

The RTDS was originally configured to subscribe to nine digital GOOSE signals and eight analog GOOSE signals. This resulted in increased variability in GOOSE subscription times (of up to 4 ms) and increased the average response time. The GTNET-GSE specification for latency (with version 4.3 firmware) is 500 µs plus 50 µs per subscription. If multiple GOOSE subscriptions are required on the RTDS, it is recommended by the RTDS manufacturer that GOOSE subscriptions are shared between all available GTNET-GSE cards to reduce latency. A single subscription was used on the RTDS and on the OMICRON test set to minimize variability during the protection performance test, and allowed small changes in response time to be observed.

B. Network Loading

The effect of background traffic on protection response was shown in Fig. 6 (sampled values) and Fig. 7 (GOOSE) to be dependent on the multicast destination address of the background traffic. This reinforces the need to design a system where multicast destination addresses are allocated to minimize the traffic transmitted to a protection relay. Sampled value traffic typically generates 4.5–5.5 Mb/s of multicast traffic per merging unit. GOOSE messages range in size depending on the dataset selected, with 160–200 bytes typical for single trip message. More information on messaging rates can be found in [20].

The RET670 was robust, accepting high levels of network traffic before performance degraded, however this cannot be assumed of other protection relays. The tests presented in this paper are a means of verifying this capability. Network loads that resulted in sampled value messages being dropped were not tested, however it has been shown that traffic that exceeds the process bus capacity significantly increases the mean time to trip [11]. Detailed network design should be undertaken to avoid overload conditions by managing the traffic flow on all Ethernet connections.

The results in the previous section demonstrate that the protection response of a transformer protection relay subscribing to sampled values and publishing trip indications over GOOSE meets the requirements of Australian and UK grid codes. The worst case response time increased by 1.6 ms with additional sampled value traffic. This, combined with the slowest LV restrained trip of 31.7 ms, is still less than the 40 ms time required at 400 kV with two cycle circuit breakers, or at 275 kV with three cycle circuit breakers.

Artificial latency introduced by the network emulated confirmed that network latency has a linear effect on protection performance. Precision capture of network traffic and differential timing, such as that described in [19], is therefore a good technique to predict how a data network will influence the performance of the overall protection system.

C. Synchronizing Accuracy

The synchronizing accuracy requirement for sampled value data (class T4) in transmission substations (protection classes P2 and P3) in IEC 61850-5 is 4 µs [25]. The restraint curve characterization tests with a controlled synchronizing error show that the restraint curve with 100 µs of error is very similar to that with no introduced error, and was also the case with 4 µs and 10 µs delays. It was only with 500 µs and 1000 µs of error that the response deviated from ideal.

The power system reference values stated for class T4 in IEC 61850-5 are that 4 µs relates to 4 minutes of angle at 50 Hz, 5 minutes of angle at 60 Hz and 1.2 km of distance (time of flight) when locating faults. The 9-2LE sampling rate is 4000 Hz (50 Hz power) or 4800 Hz (60 Hz power), and introduces significantly more error into fault location, as 250 µs (the sampling rate for a 50 Hz power system) equates to 75 km. Consideration should be made to relaxing the instrument transformer synchronizing requirements on the basis of sampling rate. In the tests conducted for this paper, a 100 µs error in the synchronization of one merging unit sampling at 250 µs did not affect the restraint characteristic. The magnitude of higher order harmonic currents, such as the fifth harmonic used to prevent false-tripping due to transformer over-excitation, is not affected by sampling accuracy. Magnetizing currents only flow on one side of the transformer (either the LV or HV side), and therefore any harmonic currents will be present in the instantaneous differential current signal, regardless of phase.

Power quality monitoring using the 256 samples per cycle option of 9-2LE (78 µs sampling rate with a 50 Hz fundamental) would require greater precision, however 40 µs rather than 4 µs may suffice.

VI. Conclusions

Network traffic management is required for a process bus protection system to operate correctly. In particular, the flow of multicast messages must be limited to reduce the computation workload of protection relays and substation computers. Subjecting the process bus and station bus to high levels of network traffic are needed to identify the capabilities and failure modes of the devices on the network. This in turn determines the robustness of the network design. The RET670 used in this study was robust, accepting high levels of network traffic before performance degraded, however this cannot be assumed of other protection relays.

Network level testing, using methods described in [19] and [20], verifies that the underpinning Ethernet network can transport process bus traffic in a timely and reliable manner. Similarly, test methods to assess PTP synchronization in [22] can be used to predict the quality of the synchronizing signal supplied to a merging unit. System tests that incorporate hardware-in-the-loop simulation provide evidence of the performance of the overall protection system and whether the grid code requirements are met. The systematic testing of a protection system presented in this paper demonstrates that protection relays can meet performance requirements under extreme conditions. Testing using real time simulation is a means of determining the limits of operation under controlled conditions without any risk to the power system.

The close coupling of Ethernet network performance and overall protection system performance, particular in process bus applications, has been demonstrated in this paper. Hardware-based network emulation, commonly used in telecommunications, should become a standard tool for IEC 61850 substation automation. These tools define the limits of performance while the precision capture of network traffic for performance assessment can be used to verify that the final substation network has latencies that meet the performance specification.

This paper has described test methods to identify and quantify the sources of variability in transformer differential protection performance, for both conventional and Ethernet-based signaling. Real-time networks and precision timing provide the underlying foundation for a process bus, and the research presented here will provide confidence to organizations considering adopting the technology that it can meet their requirements.

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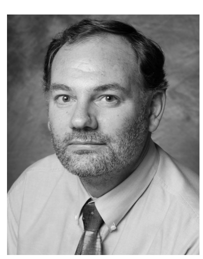

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