A METHODOLOGY FOR PERFORMANCE AND COMPATIBILITY EVALUATION OF AN ALL-DIGITAL SUBSTATION PROTECTION SYSTEM

A Thesis

by

LEVI PORTILLO URDANETA

Submitted to the Office of Graduate Studies of
Texas A&M University
in partial fulfillment of the requirements for the degree of

MASTER OF SCIENCE

December 2006

Major Subject: Electrical Engineering

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Approved by:

Chair of Committee,	Mladen Kezunovic
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ABSTRACT

A Methodology for Performance and Compatibility Evaluation of an All-Digital Substation Protection System. (December 2006)

Levi Portillo Urdaneta, B.S., Universidad del Zulia

Chair of Advisory Committee: Dr. Mladen Kezunovic

A power system protection system consists, at least, of an instrument transformer, a protective device (relay), and a circuit breaker. Conventional instrument transformers bring currents and voltages from power network levels to much lower scaled-down replicas that serve as input signals to protective relays. The relay's function is to measure input signals (or a relationship among them in some cases) and compare them to defined operating characteristic thresholds (relay settings) to quickly decide whether to operate associated circuit breaker(s). Existing protection systems within a substation are based on a hardwired interface between instrument transformers and protective relays. Recent development of electronic instrument transformers and the spread of digital relays allow the development of an all-digital protection system, in which the traditional analog interface has been replaced with a digital signal connected to digital relays through a digital communication link (process bus). Due to their design, conventional instrument transformers introduce distortions to the current and voltage signal replicas. These distortions may cause protective relays to misoperate. On the other hand, non-conventional instrument transformers promise distortion-free replicas, which, in turn, should translate into better relay performance. Replacing hardwired signals with a communication bus also reduces the significant cost associated with copper wiring. An all-digital system should provide compatibility and interoperability so that different electronic instrument transformers can be connected to different digital relays (under a multi-vendor connection) Since the novel all-digital system has never been implemented and/or tested in practice so far, its superior performance needs to be evaluated. This thesis proposes a methodology for performance and compatibility evaluation of an all-digital protection system through application testing. The approach defines the performance indices and compatibility indices as well as the evaluation methodology.

To Aiskell, for Her Love and Support

ACKNOWLEDGMENTS

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CHAPTER I

INTRODUCTION

A. Background

The purpose of an electrical power system is to provide a continuous generation, transmission and distribution of energy to consumers [1]. A graphical representation of the power system in the form of an one-line diagram is shown in Fig. 1 [1]. The energy generated and transformed in power plants is transported via transmission lines to the different distribution centers. The protection system as a part of the power system makes sure that faults caused by abnormal operating conditions are detected and the affected part of the system is quickly removed from operation. In a traditional protection system, instrument transformers (ITs) provide protective relays with a scaled-down replica of the power system currents and voltages. In this system, instrument transformers interface relays through hardwired copper cabling.

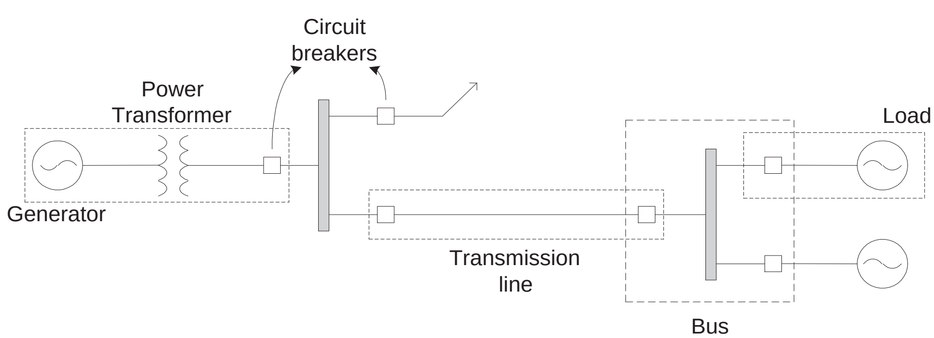

Fig. 1. One-line representation of the power system

Besides transforming the signal energy levels between the protective or metering

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This thesis follows the style of *IEEE Transactions on Automatic Control*.

device connected to their secondary side and the power system current and voltage signals connected to their primary side, ITs also provide electric isolation. A simple protective relaying system for protection of a transmission line is shown in Fig. 2 [1]. This is almost the simplest relaying system, consisting of, a pair of current and voltage transformers, a distance relay, and a circuit breaker. When a fault occurs in the protected line the distance relay will estimate the impedance by using the current and voltage signals provided by both IT. Once the relay detects the fault a trip command is issued to open the associated circuit breaker. A similar configuration is located at the other end of the line to operate the breaker at that end.

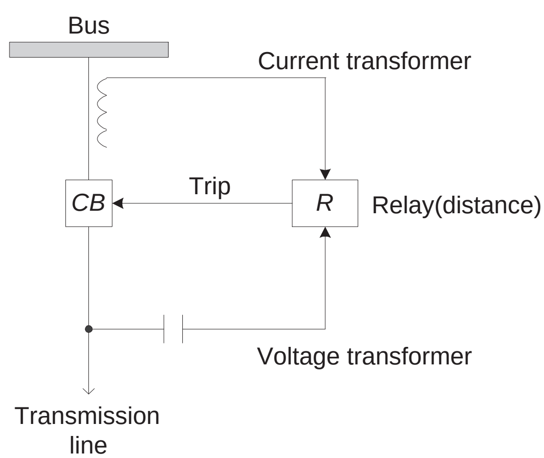


Fig. 2. Relaying system for transmission line protection

B. Definition of the Problem

Digital microprocessor-based relays (also called Intelligent Electronic Devices or IEDs) have been widely used in substation protection systems for almost 20 years. They became increasingly popular as soon as digital computers became more powerful (higher processing speed) and cheaper [2]. They offer several advantages over analog relays: self checking capability, possibility to integrate different protection functions into

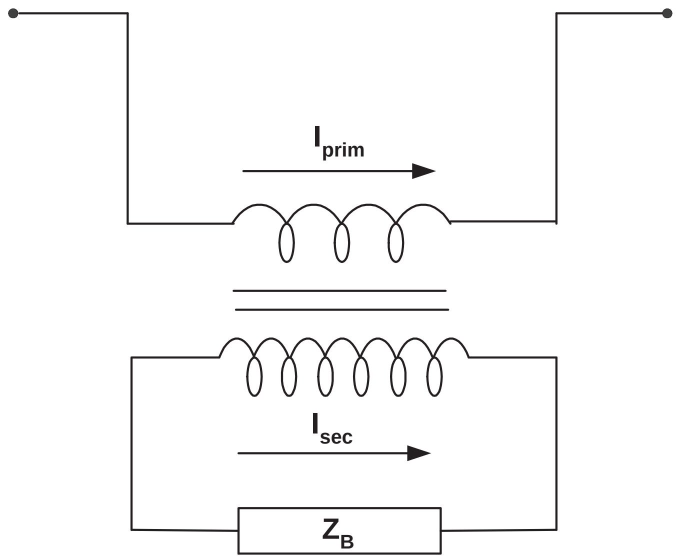


Fig. 3. Equivalent circuit of CT

one device and functional flexibility to perform other non-protection substation tasks such as metering and control. Although they are digital in nature, a hardwired connection has been maintained to interface digital relays and conventional instrument transformers.

Most instrument transformers in use today are conventional. They are based on electromagnetic coupling between their primary side (connected to the power system) and their secondary side (connected to protective and metering devices). This magnetic coupling may introduce signal distortions that are not present in the power network but are created within the transformer. Instrument transformers are classified into current and voltage transformers. Current transformers (CTs) are usually constructed by passing a single primary turn of copper or aluminum cable through a well-insulated toroidal core wrapped with many turns of wire. CTs differ from Power Transformers in their size and the fact that their primary side is connected in series with the electrical circuit (see Fig. 3). Saturation of the core is the main cause of

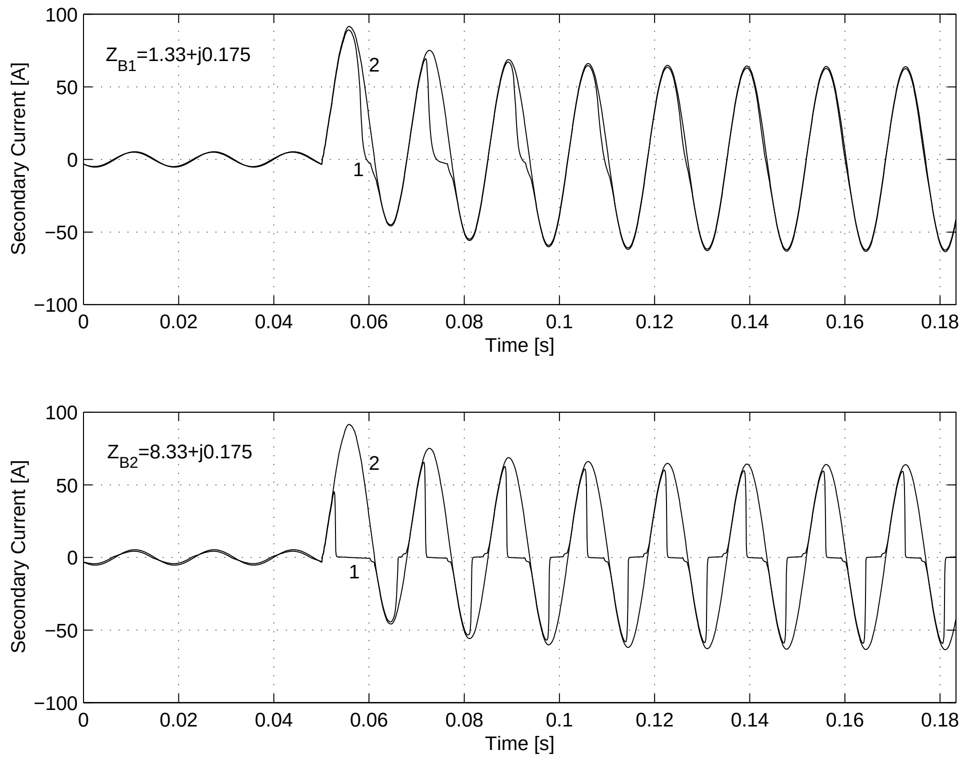


Fig. 4. Saturation of secondary current during a fault

distortions for CT. It is caused by the non-linear characteristic of the core and it is particularly affected by factors such as: physical parameters derived from transformer design such as the core's saturation curve and the magnitude of the secondary burden. Fig. 4 [3] shows how the level of saturation can be affected by the secondary burden connected to the CT.

There are two main types of conventional voltage transformers (VT): electromagnetic voltage transformers (EVTs) and coupling capacitor voltage transformers (CCVTs). EVTs are just like small power transformers but specially designed to provide high accuracy (dependant on whether it is used for metering or protection purposes) over a specified range. CCVTs work basically as capacitance potential dividers and they are preferred over EVTs for high voltage applications due to their

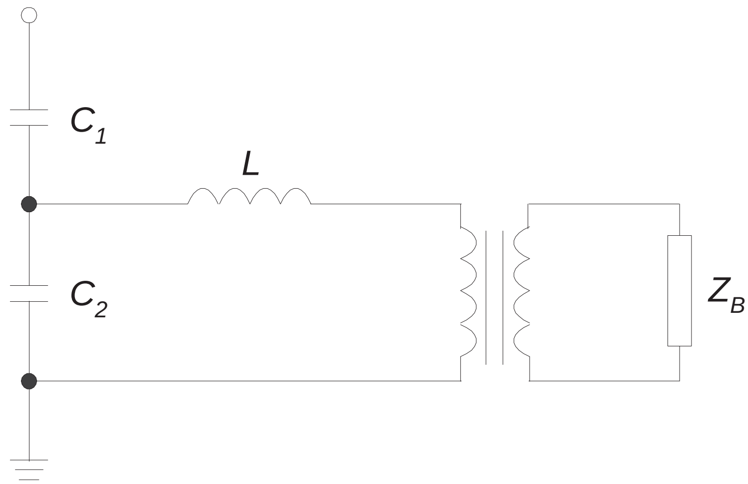


Fig. 5. Equivalent circuit of CCVT

reduced size and cost when compared to EVTs (see equivalent circuit in Fig. 5).

In the case of the CCVTs, a sudden drop in the primary voltage (could be originated by a fault on the system) will cause internal oscillations within the CCVT (this is often referred to as *subsidence transient*). These oscillations (distortion of the actual primary signal introduced by the CCVT due to the presence of non-linear elements in its design) can be fast (frequencies between 0.2 and 2.5 kHz for faults characterized by small voltage drops or slow oscillations (less than 60 Hz) for zero or close-to-zero voltage faults. Fig. 6 shows examples of a CCVT subsidence transient for different burdens.

IED are sensitive to distortions originated within the IT and could operate incorrectly under certain fault conditions. Conventional instrument transformers output consists of analog signals that are hardwired from the IT's location in the substation switchyard to the relay's location in the substation's control room. Therefore, two types of problems originate from this traditional protection system using conventional IT and IED with an analog interface:

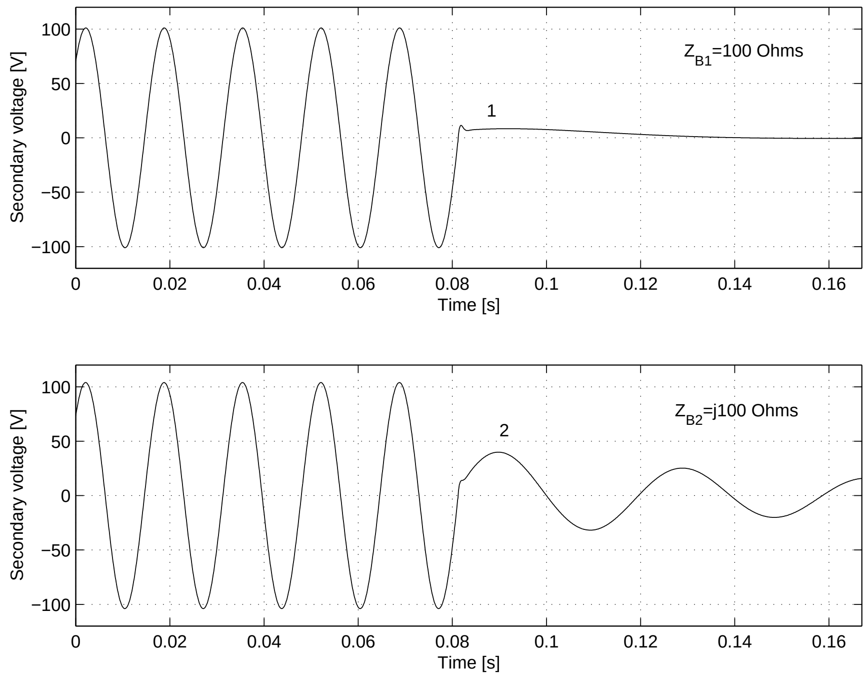


Fig. 6. CCVT subsidence transient

- Problems related to conventional IT design and characteristics:

  1. Signals distortions created by ITs (inherent to their design, hence, their effect can only be minimized but not totally suppressed) may cause protection IED to misoperate. Saturation in the case of CT and subsidence transients in the case of CCVT are the two most common signal distortions
  2. The input signal accuracy requirements of protection relays are different from power quality metering devices. Consequently, there is usually a need for different instrument transformers to provide high accuracy metering of certain power system parameters and/or conditions and different ones for relaying.

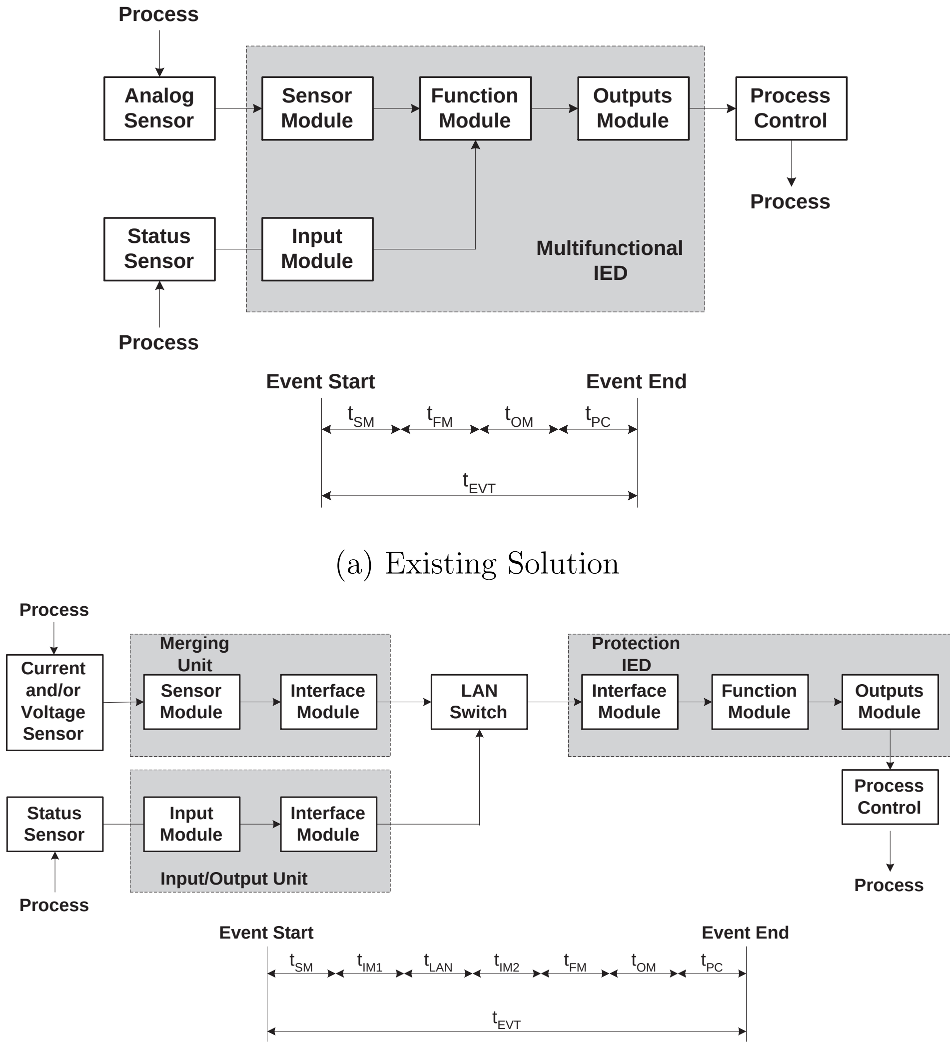
- Problems related to the analog interface:

1. Long cabling will cause a higher burden to be connected on the secondary side of the instrument transformer. The value of the secondary burden may create a distorted secondary current under maximum fault conditions [4].
2. The cost of parallel wiring (copper cabling) used to connect three phase signals) between instrument transformers at the process level (switchyard) and protection IED at the bay level (control house) represents a substantial portion of the total installation cost. It also eliminates the need for auxiliary transformers in protective relays, which are needed to convert high power signals coming from conventional ITs.

C. New Solution

Recently, non-conventional instrument transformers (NCITs) have been developed and tested in field applications. While conventional instrument transformers are based on electromagnetic coupling using a magnetic core, NCITs are based on the transformation of the measured current and voltage quantities using optical methods [5]. NCITs need an electronic interface for its operation. One of the key advantages of NCITs is the possibility of supplying digital current and voltage samples to protection IED. NCITs also promise to deliver accurate (virtually perfect) signal replicas of currents and voltages to protection, metering and power quality IED alike. A digital interface that replaces the copper wiring with a single fiber optic communication bus means a significant reduction in engineering and material cost.

Even though NCITs promise to solve many (if not all) of the problems inherent to conventional IT design mentioned in the previous section, some new difficulties may arise with the implementation of this new technology within an all-digital protection system. Fig. 7 [6] shows a comparison of the existing solution (analog IED interface)



(a) Existing Solution

(b) New Solution

Fig. 7. Comparison of the existing vs new solutions

versus the new solution (digital IED interface). In the case of the existing solution, the sensor module inside the conventional IED has an analog input module (A/D converter) and a DSP that will process the signal coming from the conventional IT. Then, the function module (containing the decision making algorithm) makes a decision based on what it is programmed to do, allowing the relay to operate its outputs (output module) to perform the required control action over the process. In the case of the new solution, the processing of the signal (coming from NCITs in this case) is performed by the Merging Unit (MU), which generates synchronized sampled values of the current and voltages coming from the NCITs. The new solutions requires interface modules inside the MU and the IED (these interfaces are often referred to as network interface cards) to format and receive communication messages sent through the substation LAN (process bus). As it can be seen from Fig. 7, there are a few extra steps in the new solution which could affect the performance (by increasing the overall event time t_{EVT}) of the novel system. Besides the time response, other distortions may occur such as loss of synchronization and common errors.

The IEC standard for communication networks and systems in substations [7] defines the standard for substations communication. Part 9-2 of the standard defines the protocol for transmission of sampled values from instrument transformers at the process level to metering, control and protection IED at the bay level [8]. The recent development of NCIT and the spread of digital relays permit the development of an all-digital protection system. In such a system, the output of NCIT is a digital signal, which can be connected to digital relays through an IEC 61850-9-2 digital process bus [8]. All the different components of the all-digital protection system have to meet the compatibility and interoperability requirements so that the system performs the function it is designed for. In practice, this all-digital protection system has not been previously investigated in detail due to relatively new development effort. Comprehensive study is needed for making conclusions with respect to whether the novel digital protection system is required for improved protection relay performance, and whether there is cost-benefit to substitute the conventional protection system with the novel digital one.

The introduction of NCIT and the new standard IEC 61850-9-2 are giving rise to a new question: whether the novel system needs to replace the existing one to achieve a better overall protection system performance. The following questions summarize the associated uncertainties:

1. What is the difference in performance between an all-digital protection system using NCIT digitally interfaced to protection IED vs the conventional protection system?

2. How the difference in performance may be measured and evaluated?

This thesis aimed at giving answers to these questions.

D. Existing Evaluation Approaches

Two main evaluation approaches can be found in the literature:

1. Compatibility and interoperability evaluation through conformance testing

2. Protection system evaluation through performance testing

Although neither of the approaches provides answers to both questions posed in the previous section, they will be reviewed and commented over the next paragraphs to serve as a preliminary assessment of the problem.

Compatibility and interoperability are among the main driving forces behind the creation of IEC 61850. Many interoperability tests have been performed in the past few years. Through these tests, the bay level interoperability and the IEC 61850-9-1 interoperability at the process level have been verified. Evaluation of the all-digital protection system containing NCITs connected to digital relays by an IEC 61850-9-2 process bus was not described in details in the literature yet.

Compatibility and interoperability evaluation of the all-digital protection system requires two kinds of test, namely conformance and performance test. IEC 61850-10 gives guidance for the conformance tests [9]. The conformance tests are only the first step to verifying the interoperability since they deal with individual components. On the other hand, performance tests belong to application tests, which aim at verifying the behavior of the protection system under various power network conditions. When compared with conformance tests, performance tests allow more extensive assessment and can be used to determine the performance characteristics of the overall system. Thus, performance tests are as important as conformance tests and they complement each other [10]. Fig. 8 summarizes classification of these tests.

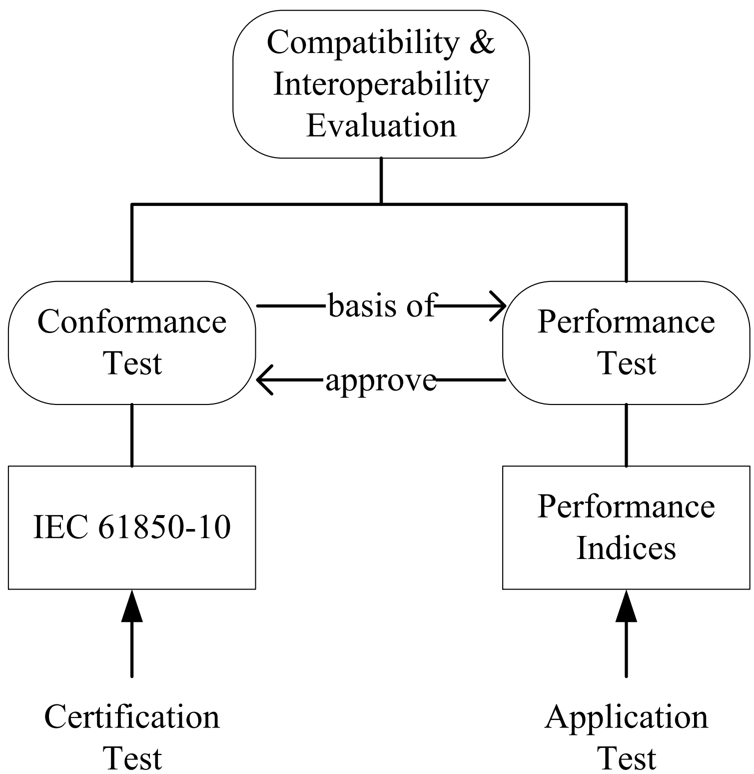


Fig. 8. Compatibility and interoperability test classification

Performance testing of the protection system by itself is not a new topic [11], [12], [13]. These previous investigations are within the scope of conventional protection systems. The evaluation criteria and methodology proposed in these papers are purely for performance evaluation purposes, not for compatibility and interoperability evaluation use.

This thesis will propose a methodology for compatibility and interoperability evaluation for the all-digital protection system through application testing. The proposed methodology will be used for evaluation of the all-digital process bus configuration assembled in Texas A&M University's Power Engineering Lab. The following sections provide further details of the methodology for evaluation.

E. Objectives

The objective of this thesis is to investigate the performance of an all-digital protection system using electronic non-conventional instrument transformers (NCIT) directly interconnected through an IEC 61850-9-2 digital process bus with digital relays. To accomplish this, the proposed research study aims at the following tasks: a) outlining a methodology for evaluation of an all-digital protection system. A methodology for compatibility and interoperability evaluation through application testing is proposed; b) defining a set of performance and compatibility indices for evaluation as well as a test approach to calculate these indices, and c) developing a hardware architecture and open software implementation for facilitating the evaluation. An open software solution will provide the flexibility to use different power network models and multiple performance evaluation criteria without altering the overall software structure and control flow of the tested system.

F. Thesis Contribution

Several thesis contributions are expected:

1. Theoretical contribution to the problem study by defining a methodology for

performance and compatibility evaluation of all-digital protection systems, as defined in the previous section. The methodology can be regarded as the first one proposed in the literature for evaluation of all-digital systems based on the IEC 61850 communications standard. It provides answers to the following questions:

- Why the evaluation of an all-digital protection system is necessary and important?
- How the difference in performance between an all-digital protection system and a conventional one can be identified?
- What are the means to quantify (measure) the difference?
- What is the best procedure to obtain quantitative measure of the difference?

2. Practical contribution is the development of the simulation and testing environment for evaluation of novel and conventional protection system. Such testing environment improves the existing evaluation practices. It combines the flexibility of modeling and simulation of various power networks and power system condition through software implementation with a hardware architecture comprised of an all-digital protection system based on IEC 61850-9-2 compliant devices.

G. Conclusion

The thesis explores viability and practicability of an all-digital protection system, examines how the digital interface realized by means of a IEC 61850-9-2 process bus can impact the overall system performance, and defines a methodology for evaluation of this novel digital protection system that complements previously defined methodologies for the conventional hardwired architecture. The new methodology for evaluation is defined based on three things: 1) establishing the need for such evaluation, 2) defining the steps that need to be taken and 3) providing means to understand the outcome of the evaluation.

The main conclusion after reviewing existing methodologies is that they are a very good starting point but none of them offers the means for both performance and compatibility evaluation, hence, the need for a new solution is clear. Availability of recently developed non-conventional instrument transformers and protection IED with a digital interface permits testing of this new solution and the enhancement of the practical application of the novel system.

The approach followed by this study is summarized as: first, characteristics of non-conventional instrument transformers and their options to interface IED will be discussed. Full benefits available from new sensing technologies are expected to be obtained only used as a part of fully digital substation. Details about the implementation of the digital interface between novel sensors and IEC 61850-9-2 compatible IED will be investigated next. Once the motivation for evaluation of the all-digital system is clear, the criteria and methodology for evaluation will be defined. Finally, methodology will be applied via software implementation and the hardware architecture for the digital interface implementation. Results of the simulation and lab testing will then be presented and analyzed.

CHAPTER II

THE ALL-DIGITAL PROTECTION SYSTEM

A. Introduction

The purpose of instrument transformers is to supply the protection system with accurate scaled down replicas of power system current and voltage waveforms. Due to their design and functioning principle, based on electromagnetic coupling between their primary and secondary sides, conventional instrument transformers may introduce distortions to the original waveforms. These distortions may influence the behavior of protective devices, causing them to make incorrect decisions, such as erroneously separating certain sections and/or power system components, or failing to issue a trip command when a fault condition is present.

The advancement of optical sensing and microprocessor based technologies has fueled the research on alternative and non-conventional current and voltage transducers for power system applications, also referred to as non-conventional instrument transformers (NCIT). Inherently different than conventional instrument transformers, NCIT are generally based on optical sensing of the primary current and/or voltage to create a digital version of the measured quantity, and they promise a better accuracy, frequency bandwidth and higher dynamic range than what is accomplished by conventional technology.

This chapter summarizes the different available NCIT designs, the physical principles under which they are conceptualized and their associated electronics for signal processing and interoperability with protective and metering IED. It also describes the implementation of the digital interface between the primary sensing equipment (electronic transducers) and the protection system IED (i.e, protection relays, power quality meters and energy metering systems). This digital interface has been defined in the context of the IEC-61850 standard for communications networks and systems in substations - Part 9-2: Specific communication service mapping (SCSM) - Sampled values over ISO/IEC 8802-3.

B. Electronic Transducer Designs

1. Current Transducer

There are mainly two available designs of electronic current transducers. The Faraday or magneto-optic current transducer described in [14], and the in-line Sagnac current transducer presented in [15]. Both designs will be explained next:

The magneto-optic current transducer uses a "Faraday" primary sensor which is sensitive to the magnetic field produced by the current flowing to a conductor. The sensor is based on two physical properties:

- The Faraday effect or the magneto-optic effect
- The Ampere theorem

The magneto-optic effect, discovered by Michael Faraday in 1845, describes how a magnetic field produced by current flowing through a conductor can rotate the plane

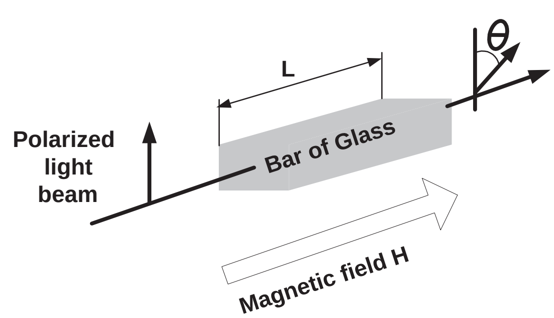


Fig. 9. Description of the Faraday effect

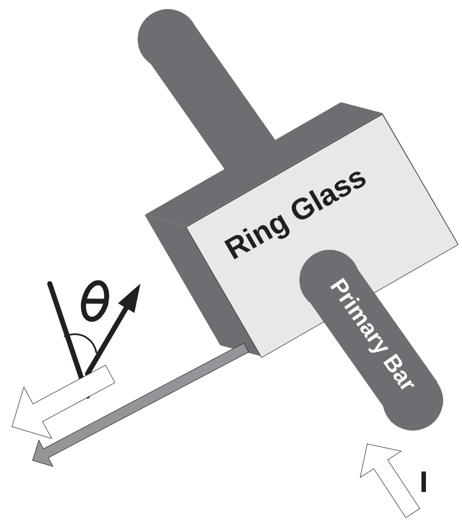


Fig. 10. Description of the Ampere theorem

of polarized light on a path (transparent optical medium) surrounding the conductor. The magnetic field alters the electron path composing the medium, which acquires a circular birefringence and affects the polarization of a monochromatic light beam propagating in the same direction as the magnetic field [14]. Fig. 9 [14] provides an illustration of the effect. Here, a bar of glass with length dL is exposed to a magnetic field aligned with a linearly polarized light beam, causing the polarization plane of this light to rotate according to equation 2.1:

$$d\theta = V \bullet (\vec{H} \times d\vec{L}) \tag{2.1}$$

where V is the verdet constant of the glass (different for each material), H is the magnetic field, dL is the length of the bar of glass, and $d\theta$ is the rotating angle of the polarization of the light.

The Ampere theorem, depicted in Fig. 10 [14] describes how the sensor becomes sensitive to the current since there is a quantitative relationship between the strength of the magnetic field and the electric current, obtained by integration on a closed loop around the conductor.

$$\theta = \oint V \bullet (\vec{H} \times d\vec{L}) = V \bullet I \tag{2.2}$$

where I is the current flowing in the bar through the optical element, V is the Verdet constant, H is the magnetic field, dL is the length of the bar of glass, and θ is the rotating angle of the polarization of the light.

An optical solution using a ring glass has been used for the sensor described in [14]. It is described as a solid element drilled for the conductor with machined and polished edges on the perimeter for reflecting the light internally in a loop around the measured conductor. This choice of ring glass appears to offer a good temperature response.

The Faraday polarization modulation is transformed to light intensity by adding a polarimetric system, including two polarizers oriented at 45 degrees from each other. The light intensity is then converted to an electric signal by photodiodes. This is shown if Fig. 11 [14]. The complete process is summarized next:

1. The LED from an electronic module emits a quasi-monochromatic light.
2. The light is transmitted by an optical fiber cable and is coupled into the optical probe, made with a Faraday sensitive element (ring-glass) placed between two polarizers.
3. This light beam is modulated by the magnetic field generated by the current flowing in the busbar crossing through the probe (ring glass).
4. The modulated light returns to the electronic module by a second optical fiber cable.

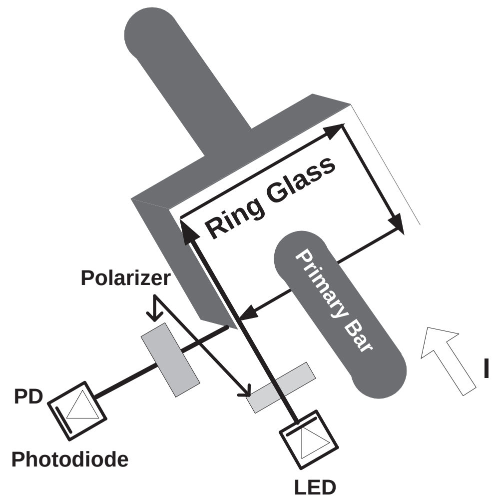


Fig. 11. Conversion of Faraday polarization to light intensity

5. The light intensity is then converted into an electric signal by the photodiode of the electronic module.

6. An analog/digital converter, associated with a microprocessor for the signal processing, performs the necessary computing to synthesize a proportional value of the current. A digital signal processor performs the following calculation [14]:

$$I(t) = \frac{1}{2V} \bullet \arcsin[\frac{2Ps(t) - Po}{Po}] \tag{2.3}$$

where *I(t)* is the current flowing in the bus bar, V is the Verdet constant, Po is the input light power, and Ps is the output function of time.

The output of this transducer is digital to allow for the possibility to communicate with digital IED through a digital interface. For conventional applications, a digital/analogue converter (DAC) is used to produce low level voltage signals or amplified signals, proportional to the primary current.

On the other hand, the transducer described in [15] uses the in-line Sagnac design

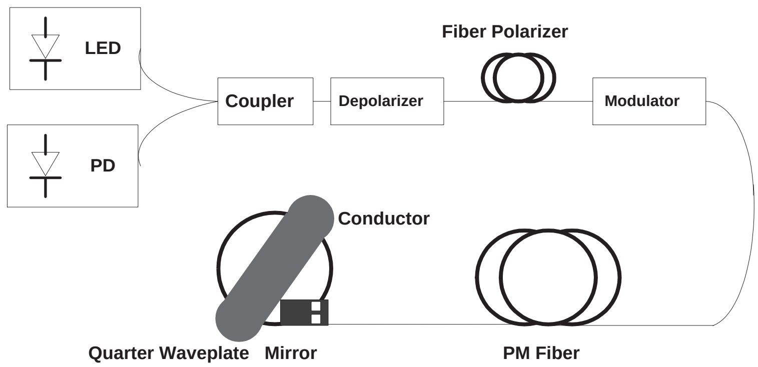


Fig. 12. In-line Sagnac interferometer current sensor

shown in Fig. 12 [15]. Here, the current-induced light intensity change in the Faraday method is replaced by a phase shift. Polarized light is split into two orthogonal polarization modes (being converted to right and left hand circularly polarized light waves before entering the sensing region) and the phase shift between these two beams when they go back over the sensing fiber is that caused by the magnetic field in the sensing region. The phase shift is four times the single-pass Faraday rotation as described in equation 2.4:

$$d\theta = 4VNI \tag{2.4}$$

where V is the Verdet constant of the fiber glass, N is the number of turns of the optical fiber wound around the wire and I is the current in the wire.

2. Voltage Transducer

Electronic voltage transducers fall into two main categories: optical voltage transducers and non-optical voltage transducers. Most practical optical voltage sensors follow to fundamental properties:

- The electro-optic effect or ”Pockels Effect”, which is a characteristic effect of some crystals (only crystals which lack a center of symmetry may show this effect)

- Measurement of a potential difference by applying two potentials to the input and the output of the crystal

The Pockels effect is an electro-optic effect describing the production of birefringence in an optical medium (transparent crystal) under the influence of an electric field (birefringence will be proportional to the field). Substances such as KDP (Potassium Dihydrogen Phosphate), KD*P (Deuterated KDP) and LiNbO3 (Lithium Niobate) show significant Pockels effects.

The Pockels effect is used to make Pockels cells, which are voltage-controlled wave plates. An electric field can be applied to the crystal either longitudinally or transversely to a monochromatic light beam. Atom clusters in the crystal become small dipoles orienting themselves according to the electric field lines. Non-homogeneity of the density induces a linear birefringence which alters the polarization of the light.

As shown in [14], for a class 43m cubic crystal, with length dL and mean refractive index n used in longitudinal configuration, the phase displacement value ($d\Gamma$) between its neutral lines is:

$$d\Gamma = \frac{2\pi}{\lambda} \bullet n^3 \bullet r_{41} \bullet (\vec{E} \times \vec{DL}) \tag{2.5}$$

where r_{41} is an electro-optical coefficient.

To measure the potential difference, it is necessary to apply two potentials on the two crystal faces to integrate the electric field along the optical path A to B:

$$\Gamma = \frac{2\pi}{\lambda} \bullet n^3 \bullet r_{41} \bullet \int_A^B (\vec{E} \times \vec{DL}) = K \bullet U_{AB} \tag{2.6}$$

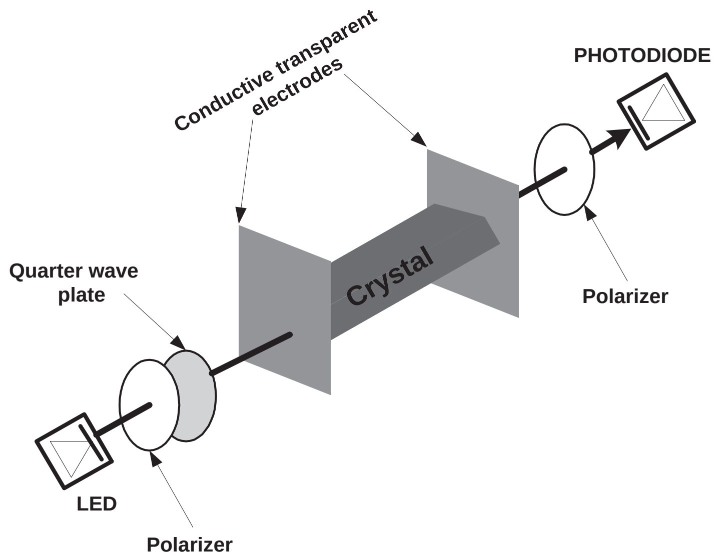


Fig. 13. Pockels cell voltage sensor

where U_{AB} is the electric potential (voltage) between the input and the output faces of the crystal, and K a constant for the specific application. For a very high voltage (200- 765 kV), a voltage divider is used to reduce the voltage to an acceptable value on the crystal. This can be a capacitive or resistive divider, or a capacitive/resistive divider isolated with SF_6 gas pressure.

Just like in the case of the optical current transducers, the Pockels polarization modulation becomes a light intensity modulation by adding a polarimetric system made of two polarizers and a phase quarter wave plate. Equation 2.7 shows how the light intensity leaves the crystal modulated by the applied voltage. The process is illustrated in Fig. 13 [14].

$$Ps(t) = \frac{1}{2} Po \bullet [1 + sin(K \bullet U_{AB}(t))] \tag{2.7}$$

Another type of electronic voltage transducer, usually preferred over optical voltage sensors for gas insulated substations, is the electronic capacitive/resistive divider (also referred to simply as electronic capacitive divider). The basic principle for this transducer has been presented in [16], and it is based on the measurement of the current flowing through a very stable high voltage capacitor. The basic circuit for the transducer is shown if Fig. 14 [16]:

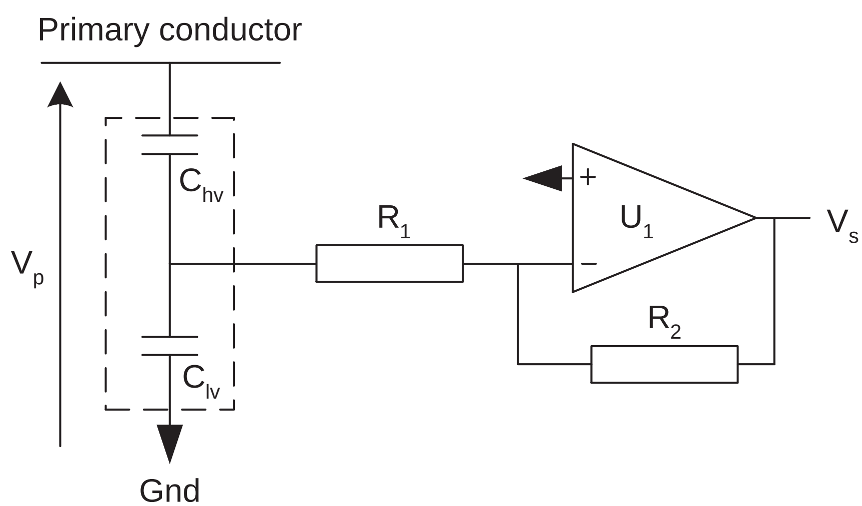


Fig. 14. Capacitive/resistive voltage sensor

The sensor (shown in the dotted line) is immersed into pressurized SF_6 gas enclosure. At the fundamental frequency, R_1 behaves as short circuit compared to the low voltage capacitor C_{lv}. Then, the current flowing through the high voltage capacitor C_{hv} will also flow through R_2 (high stability resistor), resulting in a secondary voltage V_s as a measurement of the current, which in turn is representation of the derivative of the primary voltage V_p. At high frequencies, C_{lv} acts as a short circuit compared to R_1, and current will flow through C_{hv} and C_{lv}, performing as a voltage divider and limiting the level of transmitted high frequencies. The process is described by equation 2.8 [16]:

$$V_s = -R_2 \cdot C_{hv} \cdot \frac{\partial V_p}{\partial t} - R_1 \cdot (C_{hv} + C_{lv}) \cdot \frac{\partial V_s}{\partial t} \quad (2.8)$$

The secondary voltage V_s is converted to a digital signal under the requirements of the IEC 61850 standard through dedicated boards in the opto-electronic rack.

C. Physical Connection to IED

While it is generally accepted that NCIT should provide IED with an ideal digital signal given their inherently digital nature of the signals they produce, it is required that optical electronic transducers interface with the existing analog substation infrastructure. This is providing the user the required flexibility in their design. Typically, there are three available options to interface electronic transducers with IED: high energy analog outputs, low energy analog outputs and digital outputs. Different options for analog output signals are shown in Table I.

The digital output from an electronic transducer, representing the primary quantity of interest, has been defined in the IEC standard 60044-8 [17]. The standard defines the signal that will come out from the merging unit (MU). The MU will be described in details in the next section. Fig. 15 shows the block diagram of a single phase electronic current transducer as defined in [17]. The arrangement for electronic voltage transducer is similar to the one shown in Fig. 15 but only substituting the

Table I. Analog interface options for optical electronic transducers

Analog Interface Type	**Current Transducers**	**Voltage Transducers**
Low Energy Analog	4 V_{rms} metering, 200 V_{rms} protection	4 V_{rms}
High Energy Analog	1 A_{rms} or 5 A_{rms}	69 V_{rms} or 120 V_{rms}

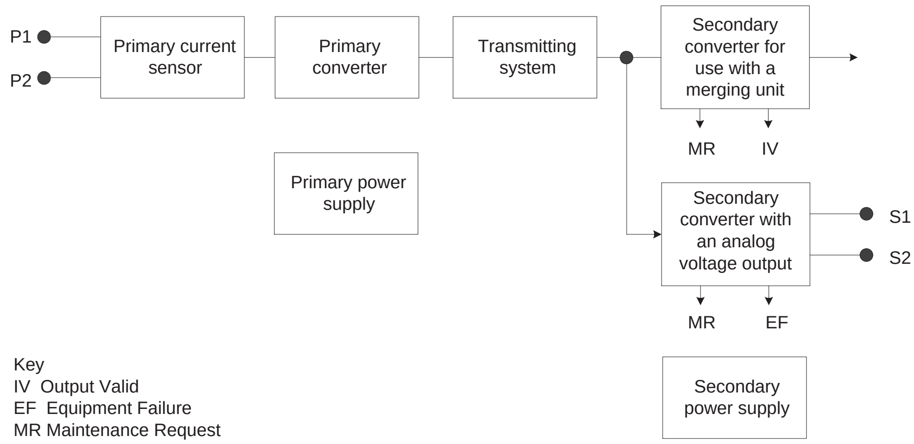


Fig. 15. Block diagram of a single-phase electronic current transducer

primary current sensor with a primary voltage sensor.

Since the main focus of this research is to evaluate the performance of the protection system when a digital interface between NCIT and IED is used, the design requirements for such digital interface is presented next, as it has been described in the standard [17]. In the case of optical electronic transducers, the optical signals (from sensors located in the substation switchyard) are transmitted through fiber-optic cables to the opto-electronic rack (typically located in the control house). A typical configuration is shown in Fig. 16.

The interface between the sensing device and the opto-electronic module is specific to each manufacturer and not subject to standardization. Table II shows available

Table II. Digital interface options for electronic transducers

Physical Link	**Specification**
Fiber Optic	IEEE 802.3 100Base FX is preferred, with an option of 10Base-FL for sampling rates lower than 48 samples/cycle
Copper	Twisted-pair medium according to IEEE 802.3 10Base-T with appropriate EMC protection

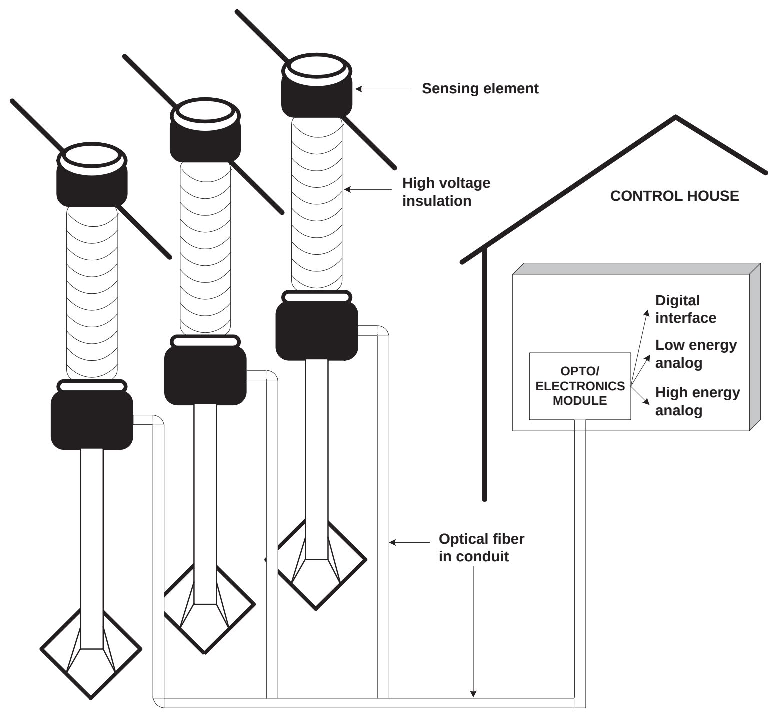


Fig. 16. Interface options for optical electronic transducers

physical links for the digital output.

D. Merging Unit

A merging unit is defined in [17] as a physical unit to do the time-coherent combination of the current and/or voltage data coming from the secondary converters. The MU's function is to collect information from different current and voltage sensors. The MU receives the digital output from several optical sensors (each OCT's manufacturer will have a different MU that will receive this data at a proprietary bit and sample rate), converts it to standard format and outputs the standardized data in such a way that several input channels are merged into one stream of sampled measurement values. All merging units in a given location will sample signals at the same synchronized rate. When conventional instrument transformers are used for the same application, it is possible to use a secondary converter to integrate these signals to the MU.

The block diagram of an electronic transducer with a digital output is given in Fig. 17. Here, the secondary converter (SC) of an electronic current or voltage transducer is utilized. Up to 9 data channels are grouped together using one merging unit and a data channel carries a single stream of sampled measurement values from an electronic transducer.

E. Time Synchronization of Digital Output

In order for the MU to do a time-coherent combination of the sampled data, synchronization of all measurements (3 voltages and/or 3 currents) is required. For this purpose, the MU uses its internal clock to supply the synchronization signal to the A/D converters within the Opto-electronics module. For some applications, it is necessary to combine signals from different MU into one IED in a time-aligned fashion so that most protection functions can operate properly (some protections functions

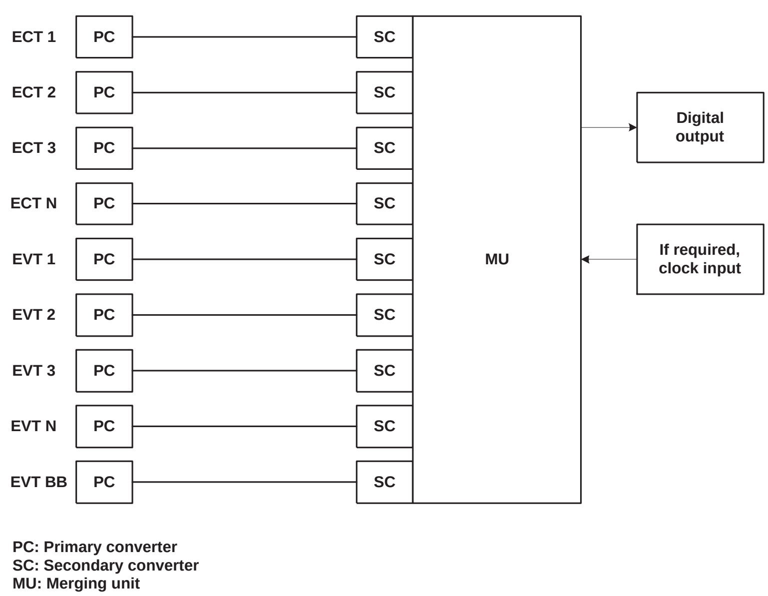


Fig. 17. Block diagram of an electronic transducer with digital output

require signals from different switchyard bays with synchronized current and voltage samples).

Two means to accomplish this synchronization are presented in [17]: interpolation of the values from several MU or the use a station-wide clock (see Fig. 17). In the case of interpolation, the different known time delays in the different protocols are used to calculate the samples at a decided instance using interpolation between the samples from the different protocols. In the case of the use of common clock, each MU must have a clock input and means to provide the secondary device (IED) with a digital stream made of samples taken at a time instance given by the signal at the clock input. This is illustrated in Fig. 18.

F. The Process Bus

In order to take advantage of the digital output offered by non-conventional instrument transformers while guaranteeing interoperability between devices from different manufacturers, a standard protocol to digitize the primary current and voltage signals and transmit them to the substation LAN is required. Part 9-2 of the IEC 61850 standard (see [8]) deals with this need by specifying the mapping of samples values

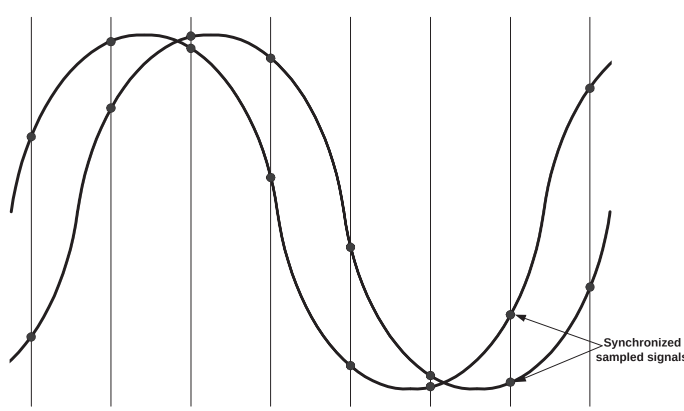


Fig. 18. Samples from two different switchyard bays synchronized by a common clock

over ethernet (ISO/IEC 8802-3) and the implementation of the Process Bus.

As described in chapter II, the interface between the transducer and the MU is a proprietary link. IEC 61850-9-2 specifies the transmission of the digital signal coming from the MU by defining a configurable data set that can be transmitted on a multi-cast basis from one publisher to multiple subscribers [18].

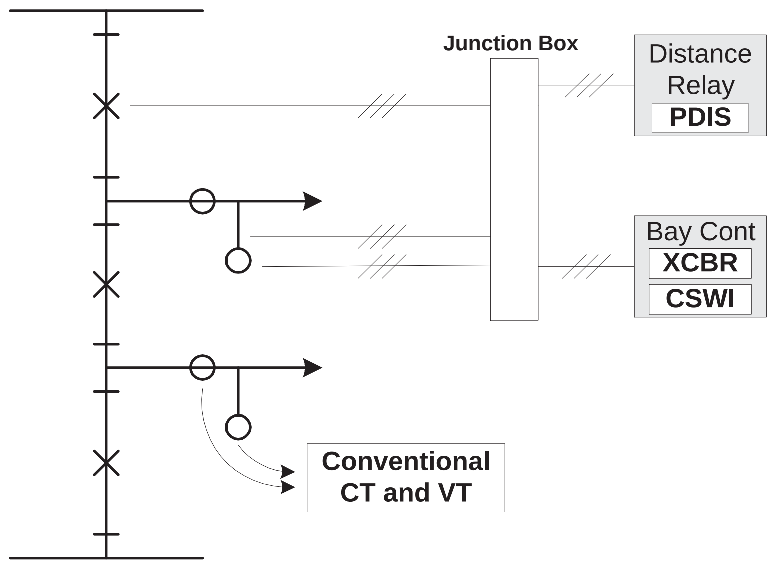
Fig. 19 shows the basic concept of the process bus versus the conventional hard-wired architecture. In the conventional case, all connections between the process level equipment (CT and VT) and the bay level devices (distance protection and associated circuit breakers) are made through copper cabling, which may require hundreds of wires for one bay depending on the application. In the process bus implementation, the merging unit converts sample data from non-conventional instrument transformers into a IEC 61850-9-2 stream and multicasts the data (data is transmitted to multiple destinations at the same time) to several protection and control devices (IED) through an ethernet switch. Switched ethernet has been chosen due to the following reasons:

- Ethernet has been used in the office and business environments for many years and has dominant position in the industrial local area network field. Hence, implementation remains at a very competitive price when compared to alternative solutions.

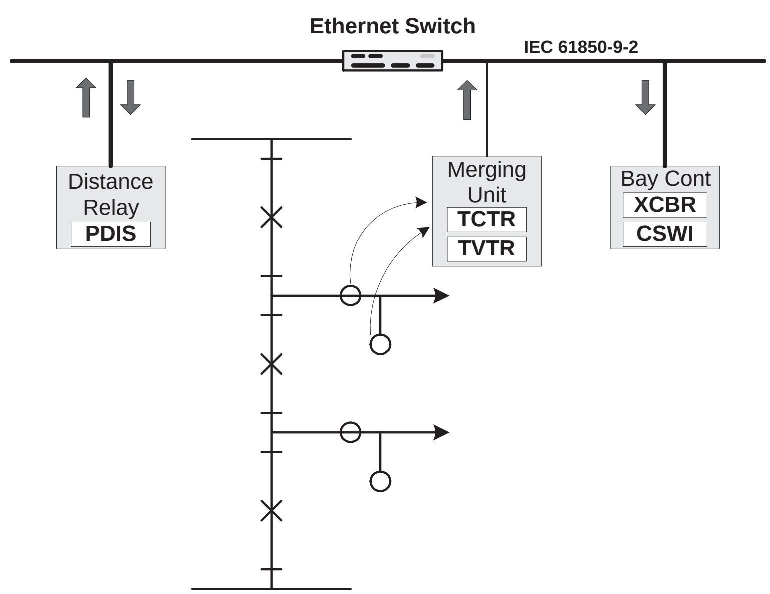
- Switched ethernet (an extension of classical ethernet) can work in full duplex mode which means that a connection can transmit and receive different packets simultaneously by queuing packets to be sent one after the other without creating collisions.

- An ethernet switch can also handle mission-critical data with priority (over non-critical data) by using traffic class prioritization (a Quality of Service feature of ethernet).

The process bus implementation allows for the use of the current and voltage samples coming from the MU for different devices and applications: protection re-



(a) Conventional connection



(b) Process bus concept

Fig. 19. Comparison of the analog vs digital interface

lays, power quality meters, phasor measurement units (PMU) and energy metering systems.

G. Conclusion

This chapter reviews typical electronic transducer designs, some of their characteristics and their available interface options with IED. Typical electronic current transducer designs (magneto-optic and in-line Sagnac interferometer) and voltage transducer designs (Pockels cell transducer and electronic capacitive/resistive divider) were described from the standpoint of protection system applications.

Three options for interfacing electronics transducers with IED - low energy analog, high energy analog and digital output, were discussed. It was shown how all the different options are implemented to provide a simple way to interconnect conventional (old and existing IED) and novel equipment (non-conventional instrument transformers). Special attention was focused on providing details on the implementation of a digital interface. The merging unit plays a very important role in the correct representation and conversion of sampled currents and voltages to the IEC-61850 standard protocol.

An understanding of the functioning principle and design characteristics of electronic transducers is critical so that users can take full advantage of the benefits of the new technology. Even though the novel sensing devices presented in this paper can interface with the existing substation infrastructure through analog outputs, the transition to a complete digital substation is possible now that all the components to build a digital protection system are available and digital interface protocols have been defined. Some details on this digital communication standard protocol have also been presented in this chapter.

CHAPTER III

EVALUATION METHODOLOGY FOR AN ALL-DIGITAL PROTECTION SYSTEM

A. Introduction

Evaluation of the all-digital system performance is necessary in order to recognize all possible conditions when protection system may miss-operate, or operate with unacceptable performance (reduced selectivity, increased operating time, etc). Identifying these abnormal situations is important for two reasons: a) recognizing possible conditions for incorrect operation, b) proving that the novel implementation will not translate in degrading protection system performance.

This chapter defines a set of criteria that can be used for numerical evaluation of the all-digital protection system performance. Instrument transformers (also referred to as transducers) and protection relays (IED) are elements of the protection system. Therefore, criteria will be defined separately for the mentioned elements.

A methodology for evaluation is presented in this chapter. The ultimate goal is to answer the fundamental questions raised in Chapter I. Currently, methodologies for performance evaluation of instrument transformers and protection relay focus on conventional IT and IED [3], [12]. A methodology for compatibility and interoperability evaluation of a conventional protection system is not required due to the inherent property of the design where simple copper wires are used. With the introduction of open communication protocols to interface these protection system elements, there is a need to define a set of criteria for numerical evaluation of compatibility between different devices. The new methodology presented here adapts previous methodologies, to meet the needs of the all-digital protection system.

B. Shortcomings of the Existing Performance Criteria

Criteria for performance evaluation of the protection system is not a new topic and has been investigated in different research efforts [11], [12], [13]. Although they have proven to be effective to evaluate the performance of conventional protection system, their scope is limited since they only focus on performance evaluation. Since compatibility evaluation is a necessity introduced by the implementation of a digital protection system, the criteria need to be extended to be applicable for all-digital systems.

There are two known criteria to evaluate the performance of protection systems:

1. Criteria presented in [19] defines protective relay performance as:
   - Correct operation
   - Incorrect operation
   - No conclusion
2. Criteria presented in [12] evaluates protective relay performance as follows:
   - Based on the measuring algorithm
   - Based on the decision making algorithm

Even though both performance characterizations can be useful, they suffer from certain shortcomings when applied to the all-digital system:

- In the case of criteria number 1 presented above, classes are too broad and they do not provide a complete assessment of the overall performance of the protective relay. There are no means to differentiate performance of two different relays with respect to specific performance characteristics such as: operating time, correct fault type identification, fault locator accuracy, etc.

- Criteria number 2 do provide to some extent means for a complete assessment of protection performance. However, the evaluation of the measuring algorithm only fits conventional relays. Relays compliant with digital process bus are not required to have a measuring algorithm which will trace the analog signals since the inputs are inherently digital.

The above shortcomings make these criteria insufficient to evaluate performance of a process bus based protection system. In order to evaluate the performance of this novel system, a new methodology needs to be defined.

C. Referent Models

In order to evaluate how the performance of the all-digital protection system measures up to the performance of the conventional protection, the concept of referent transducer system and protective relay is introduced. A comparison of performance and compatibility index values is necessary. A difference in the values of performance and compatibility indices between:

1. Referent protective relay exposed to signals supplied by a referent instrument transformer

2. A process bus compliant protective relay exposed to signals supplied by novel electronic transducers

serves as an indicator of the overall performance of a particular protection system (with specific electronic transducer and protective relay) when compared to the performance of the referent protection system.

The referent instrument transformer can be regarded as an ideal one that delivers exact signal replicas from the primary side. Even though this can not be achieved with actual instrument transformer designs, for practical purposes, this referent instrument transformer can be any transformer with a accurate, known and proven performance in field application. The referent protective relay is a software simulation model that accurately represents the behavior of a given protective relay. Several protective relay models with different operating principles such as overcurrent and impedance have been realized [20] [21].

D. Performance Indices

Performance evaluation aims at verifying the behavior of the protection system, accuracy and operating times under various power network conditions. Two sets of performance indices will be presented in this thesis: **relative** performance indices and **absolute** performance indices. Relative indices are dependent on a comparison between the protection system under study and a referent protection system. On the other hand, absolute indices are calculated by considering only the behavior of the protection system under study.

1. Relative Indices

A number of performance indices for evaluation, design and setting optimization of measuring algorithms, operating principles, complete relays and protective systems are defined in details in [12]. This thesis will adapt some of the performance indices that can meet the needs of the all-digital protection system. The evaluation methodology is described in Fig. 20. The following definitions summarize the relative performance indices proposed in this thesis:

Definition 1 *: A single exposure E is a disturbance which triggers a protection system P to perform certain operations or other signals if called upon [12]. The exposures*

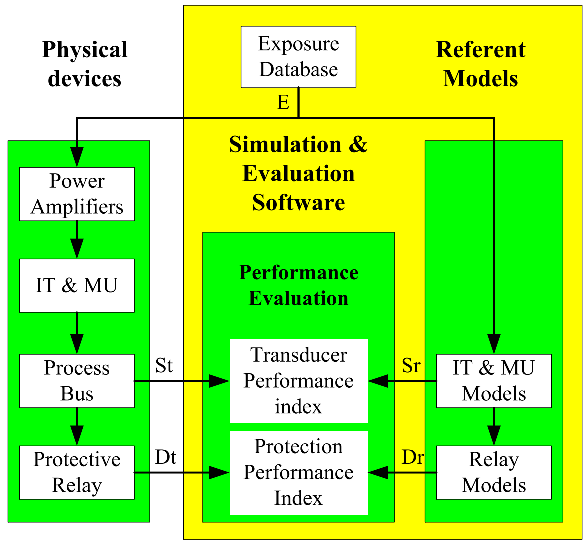


Fig. 20. Performance indices calculation

database EB is a database of exposures collected from the actual system or using simulators. Signal S^t, S^r denote the digital output of the tested and referent transducer system respectively. Decision D^t, D^r denote the decision of the tested and referent protection system respectively.

Definition 2 *: The performance index of transducer T when fed by exposure E is denoted by TPI_T^E, $E = \{e_1, e_2, e_3, ..., e_n\}$. The average performance index of transducer T is defined as:*

$$TPI_T = \frac{1}{N} \sum_{E \in EB} TPI_T^E \tag{3.1}$$

where N is the number of exposures in the database.

There are two primary types of transducer performance indices calculation methods, namely the time domain method and frequency domain method respectively. For the time domain:

$$TPI_T^E = \sqrt{\sum_{i=1}^{n} (S_i^t - S_i^r)^2 / \sum_{i=1}^{n} (S_i^r)^2} \tag{3.2}$$

For the frequency domain:

$$TPI_T^E = \sqrt{\sum_{j=1}^{m}(F_j^t - F_j^r)^2 / \sum_{j=1}^{m}(F_j^r)^2} \tag{3.3}$$

where F_j^t, F_j^r stand for the FFT coefficients of S_i^t, S_i^r respectively.

Definition 3 *The performance index of protection system P when fed by exposure E is denoted by PPI_P^E. The average performance index of protection system P is defined as:*

$$PPI_P = \frac{1}{N}\sum_{E \in EB} PPI_P^E \tag{3.4}$$

where N is the number of exposures in the database.

There are two types of protection performance indices calculation methods, namely the trip decision method and trip time method respectively. For the trip decision method:

$$PPI_P^E = |D^t - D^r| \tag{3.5}$$

where:

$$D^t, D^r = \begin{cases} 1 & \text{if relay trips} \\ 0 & \text{otherwise} \end{cases}$$

For the trip time method:

$$PPI_P^E = D^t - D^r \tag{3.6}$$

where D^t, D^r stand for the trip time of the tested and the referent protection system respectively.

2. Absolute Indices

References [4] [22] [23] define **security** of protection IED as the ability of the IED to refrain from unnecessary operations. Conversely, **dependability** is the ability of the IED to operate for a fault or abnormal condition within its zone of protection, and they can be define in mathematical terms as:

$$d = \frac{N_1}{N_{1t}} \tag{3.7}$$

$$s = \frac{N_0}{N_{0t}} \tag{3.8}$$

where d is dependability, s is security, N_{1t} is the total number of events for which protection IED should operate, N_1 denotes number of correct trip signals issued, N_{0t} is the total number of events for which IED should restrain from operation and N_0 denotes number of correct trip restraints. These two indices can be combined into the **selectivity** index (see reference [24]) defined as:

$$s = \frac{N_1 + N_0}{N} \tag{3.9}$$

where N is the total number of exposures.

Other performance indices used in this thesis are:

- Operating time: average, standard deviation
- Fault location accuracy: defined as the percent difference between the known (simulated) fault location and the value calculated by the relay

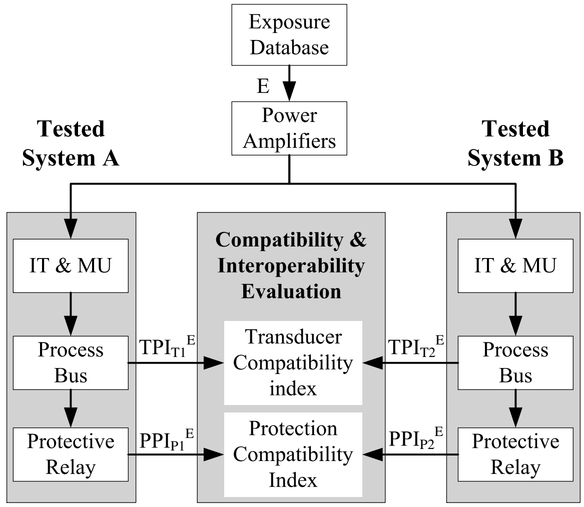


Fig. 21. Compatibility indices calculation

E. Compatibility Indices

In the context of the all-digital protection system, compatibility means the ability of two or more IEDs to perform their intended functions while sharing the IEC 61850 common communication standard [7]. Interoperability according to IEC 61850 means the ability of IEDs from different manufacturers to execute bi-directional data exchange functions, in a manner that allows them to operate effectively together [7]. The compatibility evaluation methodology is described in Fig. 21. It will be explained by the following definitions.

Definition 4 *The compatibility index of transducer $T1$ and $T2$ when fed by the same test signal E is defined as:*

$$TCI^E_{T1,T2} = |TPI^E_{T1} - TPI^E_{T2}| \tag{3.10}$$

The average compatibility index of transducer $T1$ and $T2$ is defined as:

$$TCI_{T1,T2} = \frac{1}{N} \sum_{E \in EB} |TPI^E_{T1} - TPI^E_{T2}| \tag{3.11}$$

The transducer system includes the NCIT and its associated interface electronics (usually referred to as merging unit). By definition, the smaller TCI, the better compatibility and interoperability.

Definition 5 *The compatibility index of protection system $P1$ and $P2$ when fed by the same test signal E is defined as:*

$$PCI^{E}_{P1,P2} = |PPI^{E}_{P1} - PPI^{E}_{P2}| \tag{3.12}$$

The average compatibility index of protection system $P1$ and $P2$ is defined as:

$$PCI_{P1,P2} = \frac{1}{N} \sum_{E \in EB} |PPI^{E}_{P1} - PPI^{E}_{P2}| \tag{3.13}$$

The protection system includes the transducer system, the process bus (the Ethernet LAN) and the protective relay. By definition, the smaller the PCI, the better compatibility and interoperability. Table III lists all possible cases for compatibility and interoperability evaluation given that at least 2 different sets of transducers (T), process bus (B) and protective relays (R) are available. To calculate the PCI, we combine the T, B, and R in different protection systems. The possible cases fall into three categories:

Table III. Test cases and combinations of protection systems

T	**B**	**R**	**P**
T1	B1	R1	P1
T1	B1	R2	P2
T1	B2	R1	P3
T1	B2	R2	P4
T2	B1	R1	P5
T2	B1	R2	P6
T2	B2	R1	P7
T2	B2	R2	P8

1. In the case where compatibility between transducers and relays, and interchangeability between transducers is evaluated, the following compatibility indices can be calculated: $PCI_{P1,P5}$, $PCI_{P2,P6}$, $PCI_{P3,P7}$ and $PCI_{P4,P8}$

2. In the case where interoperability between transducers and IEDs is evaluated, the following compatibility indices can be calculated: $PCI_{P1,P2}$, $PCI_{P3,P4}$, $PCI_{P5,P6}$ and $PCI_{P7,P8}$

3. In the case where interchangeability between ethernet switches and/or performance of the protection system with different traffic loads is evaluated, the following compatibility indices can be calculated: $PCI_{P1,P3}$, $PCI_{P2,P4}$, $PCI_{P5,P7}$ and $PCI_{P4,P6}$

It is important to note that all compatibility indices presented in this section can be regarded as relative indices. In other words, values of these indices by themselves serve as an indicator of the difference in compatibility between different systems.

F. Conclusion

This chapter introduced criteria for evaluation of an all-digital protection system. First, the motivation for defining a methodology that fits the specific needs of an all-digital protection system were discussed. Separate criteria was defined for different evaluation purposes (performance and compatibility indices) as well as for different elements of the protection system (instrument transformers and protective relays).

The conclusion of this chapter is that proposed criteria can be used as a valuable and effective tool to quantitatively determine the performance, compatibility and interoperability of the novel protection system. The key elements of the methodology are summarized next in the form of questions and answers:

Why the evaluation of an all-digital protection system is necessary and important? The recent development of optical instrument transformers and the advent of microprocessor-based protective relays permits the development of an all-digital protection system based on the IEC 61850 substation communications standard. The performance of the all-digital system has not been investigated in details in the past. Evaluation of the novel digital system should be a significant step towards developing confidence in the application of the new technology in field implementations.

How the difference in performance between an all-digital protection system and a conventional one can be identified? The difference in performance can be measured by defining criteria in the context of transducer and protection system functions. The evaluation can be accomplished by comparing performance of the functions in two cases: 1) functions in the context of a conventional protection system composed of referent instrument transformers and referent protective relays (see section C), 2) functions in the context of an all-digital protection system comprised of electronic transducers and 61850 compatible protective relays.

What are the means to quantify (measure) the difference? A set of well-defined absolute and relative performance indices have been defined in sections D and E. Relative index values are indicators of the mentioned difference, alternatively, absolute index values are NOT indicators of the difference in performance; rather, the DIFFERENCE in values is the indicator.

CHAPTER IV

MODELING, SIMULATION AND LAB TESTING

A. Introduction

The compatibility indices, defined in the previous chapter, should be calculated by analyzing output signals of transducers and IED from different manufacturers combined into two or more test systems. At least 2 sets of transducers and 2 different protective relays are required. Only one complete test system (from one manufacturer) was available for testing. Availability of a complete test system still allows for calculation of all performance indices defined in chapter III.

Performance indices can be obtained by analyzing the transducer and relay response. Their response is generated by certain input signals. Input signals can be generated from two different sources:

1. Signals obtained from field-recorded data

2. Signals obtained from simulations

As mentioned in the previous chapter, exposure signals representing various power system conditions are desirable. Given the typical failure rate of most power system components, it would take many years to collect all the field-data required for this investigation. Hence, simulation is a much more practical approach.

This chapter describes evaluation through modeling, simulation and lab testing. First, simulation approach will be presented. Second, the power network and protective relay models will be described. Next, simulation scenarios used for generation of all exposure signals will be defined. Finally, details about the hardware architecture as well as the software implementation will be explained.

B. Simulation Approach

As mentioned in the introduction, power system responses are triggered by simulated signals corresponding to various power network conditions, such as faults and disturbances. A set of three phase current signals and three phase voltage signals constitutes an exposure. Fig. 22 shows an example of an exposure. The fault type for which this exposure has been recorded is phase-B-to-phase-C-to-ground (BCG) fault, for a fault located at 20% of the transmission line, without phase-to-phase-to ground resistance. First 8 cycles of the exposure correspond to steady state signals and last 6 cycles are transient post-fault waveforms.

The purpose of the simulation and lab testing procedures is to supply the tested

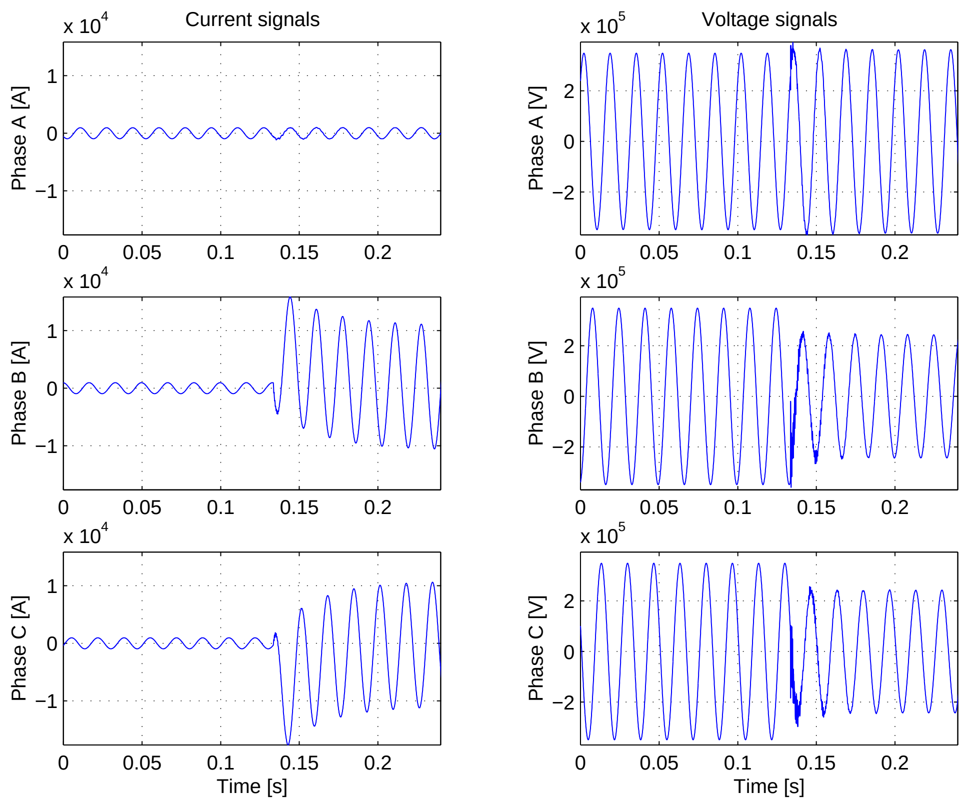


Fig. 22. Exposure signals for a BCG fault

protection systems with a large number of exposures and record the transducer and protective relay responses. This process can be summarized as follows:

1. Database of exposures is created by simulating different events using a power network model

2. Exposures are replayed into:

    - All-digital system build in Texas A&M Power Engineering Lab

    - Referent system modeled using referent instrument transformers and protective relays

3. Output signals from instrument transformers and protective relays are recorded

The steps are illustrated in Fig. 23. Models and scenarios used in simulation are described in the next sections.

C. Simulation Models

1. Power Network Model

The power network model used for simulations is a representation of an actual power system section, the model was developed according to specifications given in [25]. The model offers the flexibility for simulation of various power system conditions and

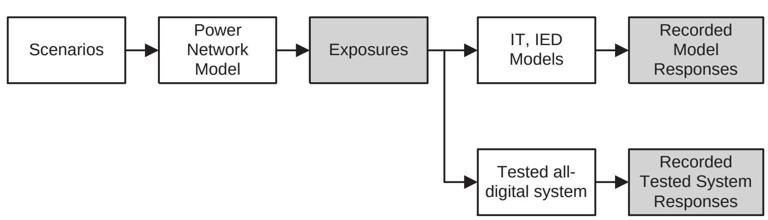


Fig. 23. Steps of the simulation process

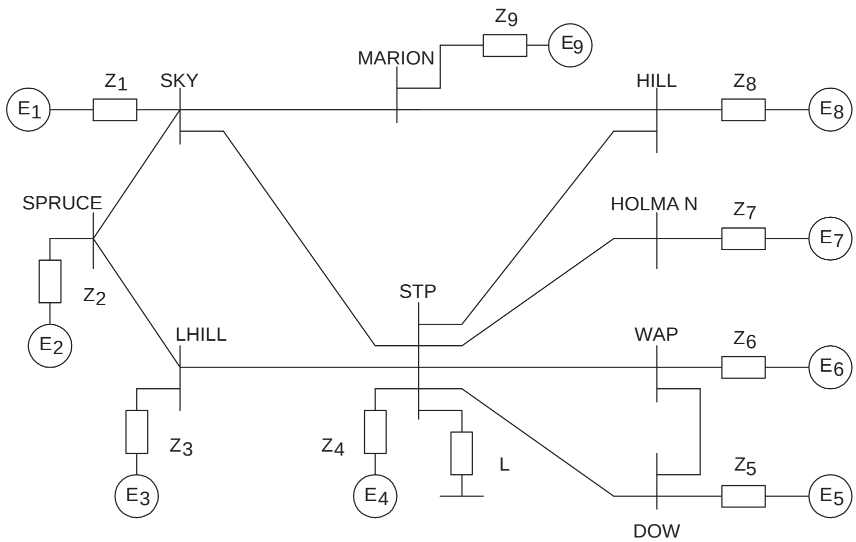


Fig. 24. Model of the power network

it has proven to effectively capture dynamic characteristics of disturbances and faults (see [24] and [25]). Remote network sections are modeled using Thevenin equivalents. Fig. 24 shows a one-line diagram of the network.

2. Relay Models

Two relay models were selected for simulation: an overcurrent relay (denoted as model A) and a distance relay (denoted as model B). Both models have been implemented in [20].

Features of the overcurrent relay (model A) are:

- Three-phase directional instantaneous overcurrent protection as primary protection
- Three-phase time overcurrent protection as backup protection
- Residual time overcurrent protection

Functional elements of the model are shown in Figure 25. Elements and their functions are:

- Measuring element extracts current and voltage phasors from the input signals supplied by instrument transformers. Extraction is performed based on Fourier analysis of input signals.

- Overcurrent element consists of 3 sub-elements. Each of the sub-elements implements a certain protection principle. The sub-elements and their functions are:

  1. Time overcurrent protection uses inverse-time characteristic to determine operating time. Time-inverse characteristic allows for fast operation in case of high-level fault currents, and for slow operation in case of low-level fault currents.

  2. Residual time overcurrent protection active only for detection of fault involving ground.

  3. Directional protection determines direction of the flow of the power to determine whether a potential fault is in the direction of protected zone. It restrains assertion of trip command in case of faults in direction opposite to protected zone.

- Logic element performs certain logic functions (AND, OR) to derive trip asserting or trip blocking command at the output of the relay model. The logic is implemented to improve security and dependability of the model.

Output signals of the overcurrent relay model (trip decision and tripping time) are recorded and stored in the database of relay responses. Settings of the model are:

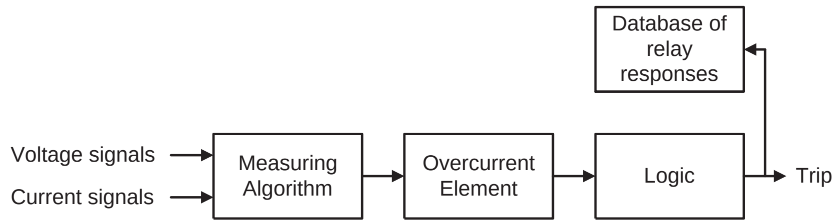


Fig. 25. Elements of relay model A

- Directional forward protection of the line Sky-STP (see Figure 24)
- Nominal input current of relay model is $I_n = 5A$
- Pickup current is set to 1.5 times the nominal value: $I_{pickup} = 7.5A$
- Very inverse time-current characteristic was used. This characteristic is defined as:

$$t_{operate} = \frac{13.5 \cdot k}{I_n - 1}$$

  Time-parameter k was chosen as: k=0.025. The plot of characteristic is shown in Figure 26.

Features of distance relay (model B) are:

- Three separate quadrilateral forward sensing zones for phase to ground faults
- One "quadrilateral" reverse sensing zone for phase to ground faults
- Undervoltage element

Functional elements of the model are shown in Figure 27. Elements and their functions are:

- Measuring algorithm extracts impedance from the input current and voltage signals using differential algorithm. Impedance from relay location to fault is calculated using expressions for six fault types: AG, BG, CG, ABC, BC, CA.

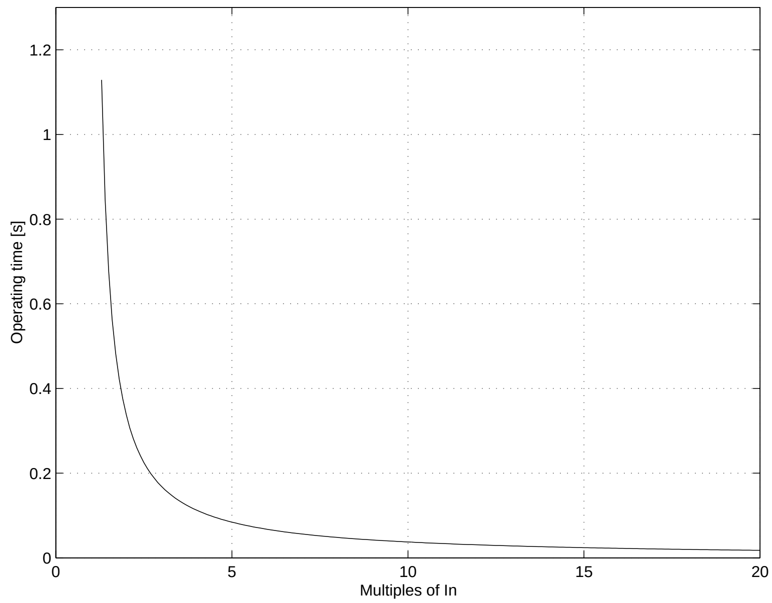


Fig. 26. Inverse time-overcurrent characteristic of relay model A

- Fault identification element determines whether calculated impedance falls into any of the user-defined zones of protection.
- Fault classification element determines fault type, based on impedance calculated for six basic fault types.
- Logic element performs certain logic functions to derive trip asserting or trip restraint command at the output of the relay model.

Output signals of distance relay model (trip decision and tripping time) are also recorded and stored in the database of relay responses. Settings of the model are:

- Line under protection is Sky-STP
- Two zones of protection are defined:
    1. First zone covers 80% of the Sky-STP line. Time-delay for this zone is set to 0ms.

2. Second zone covers 80% through 120% length of the Sky-STP line. Time delay for this zone is set to 150ms.

- Shape of zones of protection is set to quadrilateral. Coverage of protection zones and corresponding line impedance are shown in the impedance plane in Figure 28

D. Simulation Scenarios

Simulation scenarios define the power system events to be created and replayed into the modeled referent protection systems and the all-digital protection system assembled in the lab. This events are modeled by a sequence of switching of power network circuit breakers corresponding to various power system conditions. Any particular scenario is defined by two things:

- Time at which the event starts and finishes and,
- Features of the event, such as: fault location along the transmission line, associated fault resistances (line-to-ground or line-to-line resistance), fault inception angle, fault type and so on.

Different scenarios have been defined for the two protection functions to be tested (directional overcurrent and distance protection functions), as shown in Tables IV

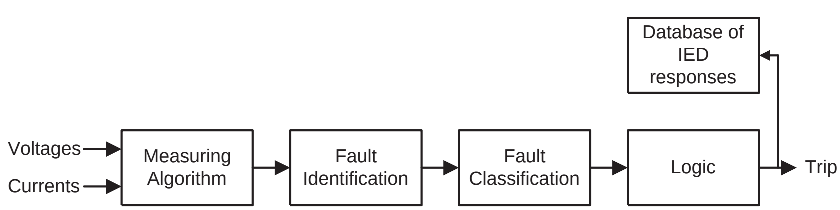


Fig. 27. Elements of relay model B

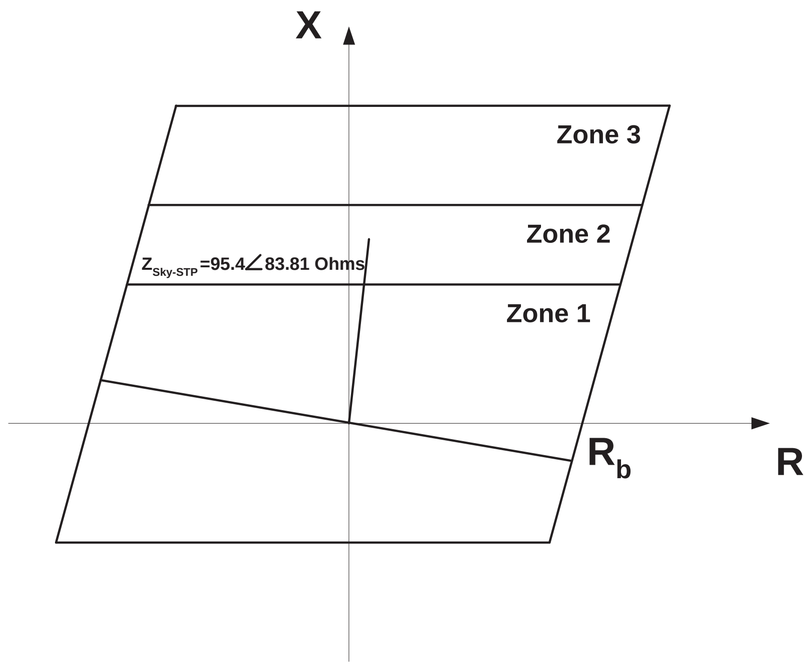


Fig. 28. Coverage of quadrilateral zones of the relay model B

and V. Simulated scenarios are selected to create those power system conditions in which correct operation of the protection system is critical. Overcurrent protection is expected to operate (issuing a trip command) for faults in the forward zone of protection and restraint from operating for faults in the backward zone of operation. Distance protection will be exposed to faults simulated in zones 1 and 2. Operation of the relay is expected to coincide with the fault being simulated, in other words, it should operate as a primary protection for faults in zone 1 and backup protection for faults in zone 2.

Four types of fault are simulated: phase-to-ground (AG), phase-to-phase (BC), phase-to-phase-to-ground (BCG) and three phase faults (ABC). In the case of the overcurrent protection testing, three locations along the transmission line are simulated: -10% (backward direction), 20% and 70%. For the distance protection testing,

Table IV. Simulation scenario, overcurrent protection

Fault type	**Fault Location [%]**	**Resistance [Ω]**	**Inception Angle [deg]**
AG	-10, 20, 70	0, 5, 10	0, 30, 60, 90
BC	-10, 20, 70	0, 5, 10	0, 30, 60, 90
BCG	-10, 20, 70	0, 5, 10	0, 30, 60, 90
ABC	-10, 20, 70	0	0, 30, 60, 90

simulated fault locations are: 20%, 50%, 70% and 90%. Number of fault-resistances varies depending on the fault type, for faults involving ground up to 5 different values are used (0Ω, 5Ω, 10Ω, 20Ω, 30Ω) whereas for balanced faults only one is required (0Ω). Finally, every fault is simulated starting at four different fault inception angles and each fault will be replayed five times into the tested systems.

A total of 120 different exposures (600 tests since each exposure will be replayed 5 times) are generated for the overcurrent protection testing. Also, a total of 224 exposures are created for the distance protection testing (1120 tests).

E. Hardware Architecture

The elements and flowchart of the hardware architecture of the tested all-digital protection system are shown in Fig. 29. Elements of the hardware architecture are:

- Simulation computer: An IBM PC compatible 32-bit personal computer with

Table V. Simulation scenario, distance protection

Fault type	**Fault Location [%]**	**Resistance [Ω]**	**Inception Angle [deg]**
AG	20, 50, 70, 90	0, 5, 10, 20, 30	0, 30, 60, 90
BC	20, 50, 70, 90	0, 5, 10	0, 30, 60, 90
BCG	20, 50, 70, 90	0, 5, 10, 20, 30	0, 30, 60, 90
ABC	20, 50, 70, 90	0	0, 30, 60, 90

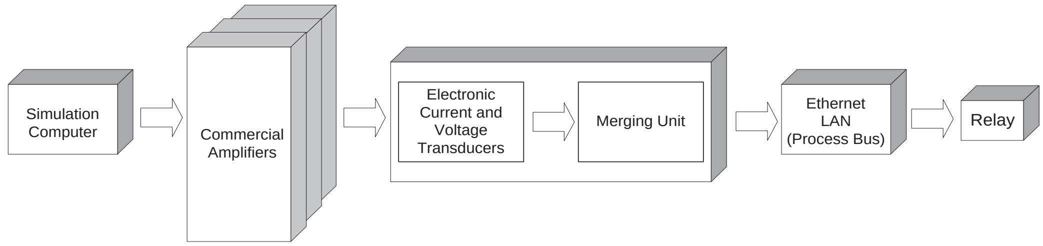


Fig. 29. Elements and flowchart of the hardware architecture

Windows operating system. Relay Assistant^{TM}, a software for open loop transient testing of protective relays [26], is installed on this computer

- Commercial amplifiers set: consists of three TECHRON TEC3600 single phase voltage amplifiers and three TECHRON TEC7780 single phase current amplifiers interconnected to the simulation computer by a TLI serial communication board (IOBox^{TM})

- Electronic current transducers set: three phases of magneto optic current sensors

- Electronic voltage transducers set: two kinds of voltage transducers were available. A set of three phases of Pockels cells transducers and a set of three phases of electronic resistive dividers

- Merging unit: for signal processing, merging and synchronization of signals coming from all electronic current and voltage transducers. It supplies the standardized 61850-9-2 digital interface

- Ethernet LAN: consists of a RuggedSwitch^{TM} with six 10/100BaseTX ports and two 2-100BaseFX. This is a managed ethernet switch specifically designed to operate in harsh environments.

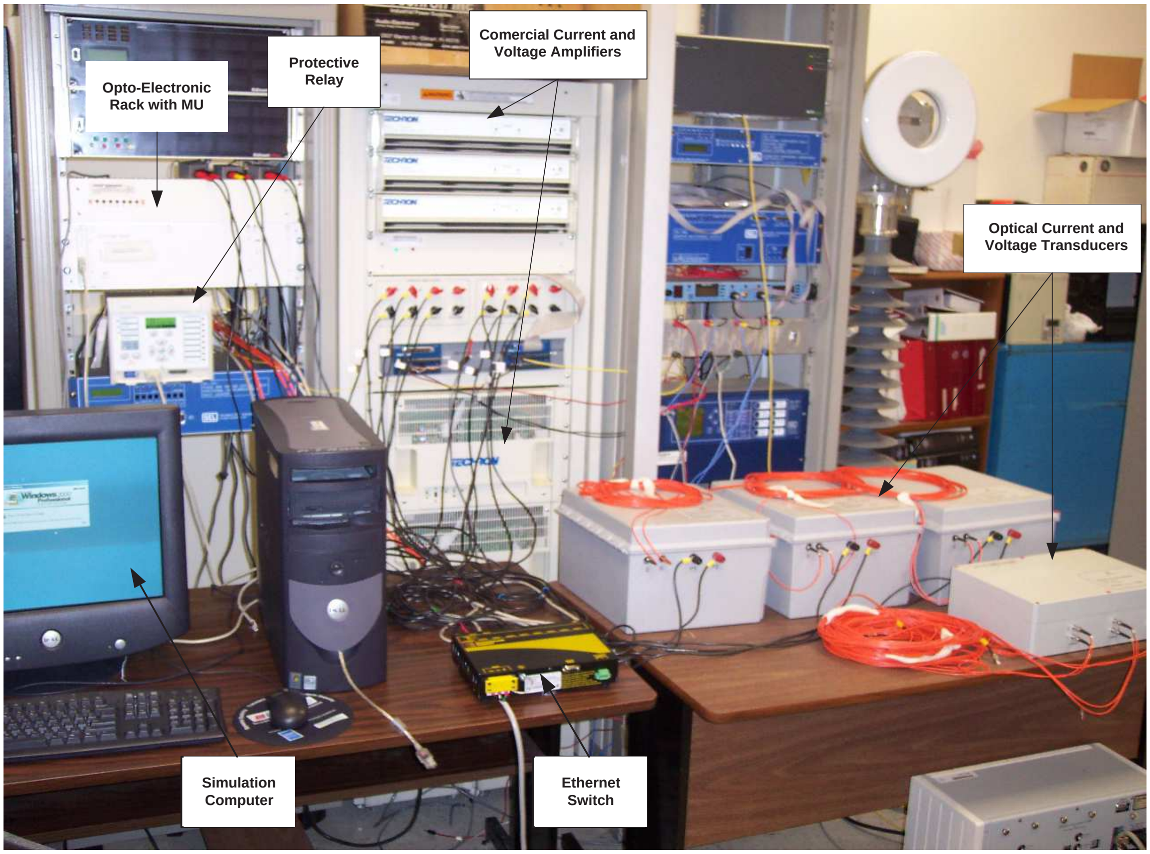


Fig. 30. Lab implementation of all-digital protection system

- Protective relay: MICOM P441 distance relay with two fault detection algorithms, a quadrilateral operating characteristic, backup directional phase overcurrent function and independently settable resistive reach per zone of protection.

The lab setup for testing purposes is shown in Fig. 30 as implemented at Texas A&M University Power Engineering Lab. Detailed description of the lab setup is given in Appendix A.

F. Software Implementation

The simulation environment along with several commercial software tools provided for this investigation support the evaluation of the tested all-digital protection system following the methodology proposed in chapter III. The simulation environment allows the user to evaluate different power network models, instrument transformers and power system conditions by setting the input_scenario.ini file shown in Fig. 31.

The input data file specifies six data classes that define all simulation scenarios and models to be evaluated, elements of the file are:

- System model: location of *.atp version of power network model
- Parameter: timeline of events, represented as the number of cycles of the fundamental frequency for the prefault and postfault portion of the simulated condition
- Fault: fault type, location, resistance and inception angle
- CT model: location of *.atp version of ct model, ct ratio, location on power system model and ct burden
- VT model: location of *.atp version of vt model, vt ratio, location on power system model and vt burden
- Relay model: relay type and location on the power system model

A batch simulation program developed in Matlab [27] has been created based on the *.atp version of power network models (models are implemented in ATP [28] and the choice of the model is made by the user). The program automatically generates a set of exposures for different simulation scenarios with settable: fault type, location, resistance and inception angle. Output waveforms can be of several formats: PL4, MAT and COMTRADE [29]. A separate visual C++ software tool has been developed to convert these exposure files from MAT files (Matlab) to RLA files (Relay Assistant).

Simulation environment permits fully automated testing of the referent protec-

```
[System model]
SysModelFile=C:\ProPerformance\models\StpPlain10kHz5sec.atp
SysModelName=Spcspr

[Parameter]
t_prefault=3
t_postfault=15
delta_t=8e-6

[Fault]
FaultType=[AG__]
FaultLoc=[0.20]
FaultRes=[30]
InceptionAngle=[45]
FaultLine=Sky,Stp

[CT model]
CTModelnode1=Sky
CTModelnode2=Stp
CTModelFile=C:\ProPerformance\models\CT02.atp
CTModelName=CT02
CTRatio=900/5
CTBurden=1.3+j*0.175

[VT model]
VTModelnode=Sky
VTRatio=345e3/112
VTBurden=100
VTModelName=VT02
VTModelFile=C:\ProPerformance\models\VT02.atp

[Relay model]
RelayType=D
RelayModelName=R1
RelayModelFile=relay01
RelayPosition=Sky,Stp
```

Fig. 31. Example of input data - input_scenario file

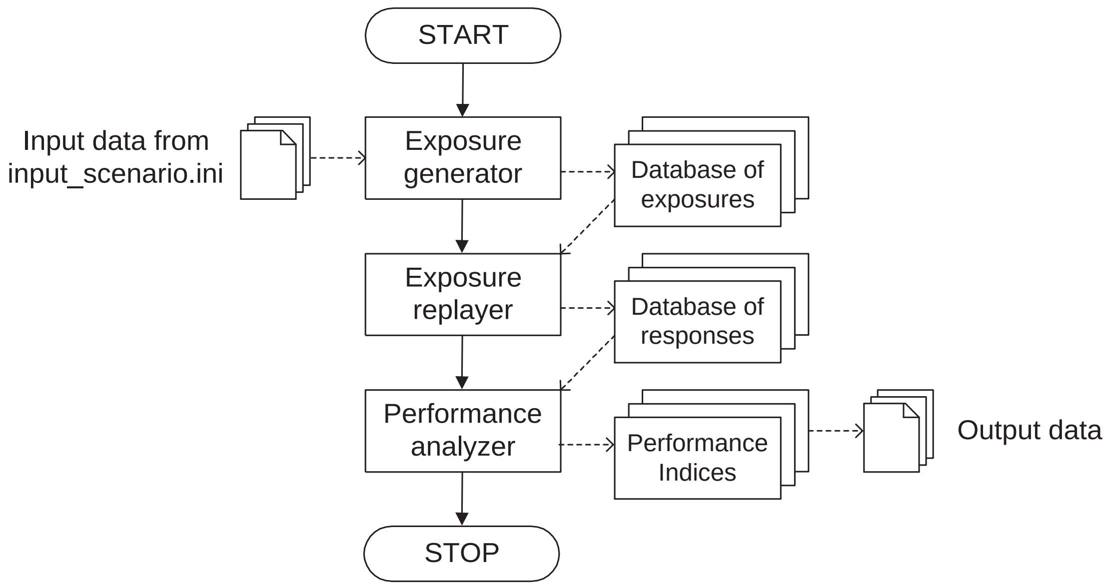


Fig. 32. Flowchart of simulation environment

tion system since software generated models of instrument transformers and protective relays are used. Main functional elements and flowchart of the simulation environment for the evaluation of the referent protection system are shown in Fig. 32. There are three elements:

- Exposure generator, which uses the input data from input_scenario.ini file to build the database of exposures

- Exposure replayer, in which waveforms from datatabe of exposures are replayed into protective IED models to build database of responses

- Performance analyzer, which uses database of responses to calculate performance indices for the tested protection system

Additional software tools are needed for testing the fully networked all-digital protection system. Simulation environment in this case is partially automated since exposure files are replayed into the tested all-digital system using the Relay Assistant

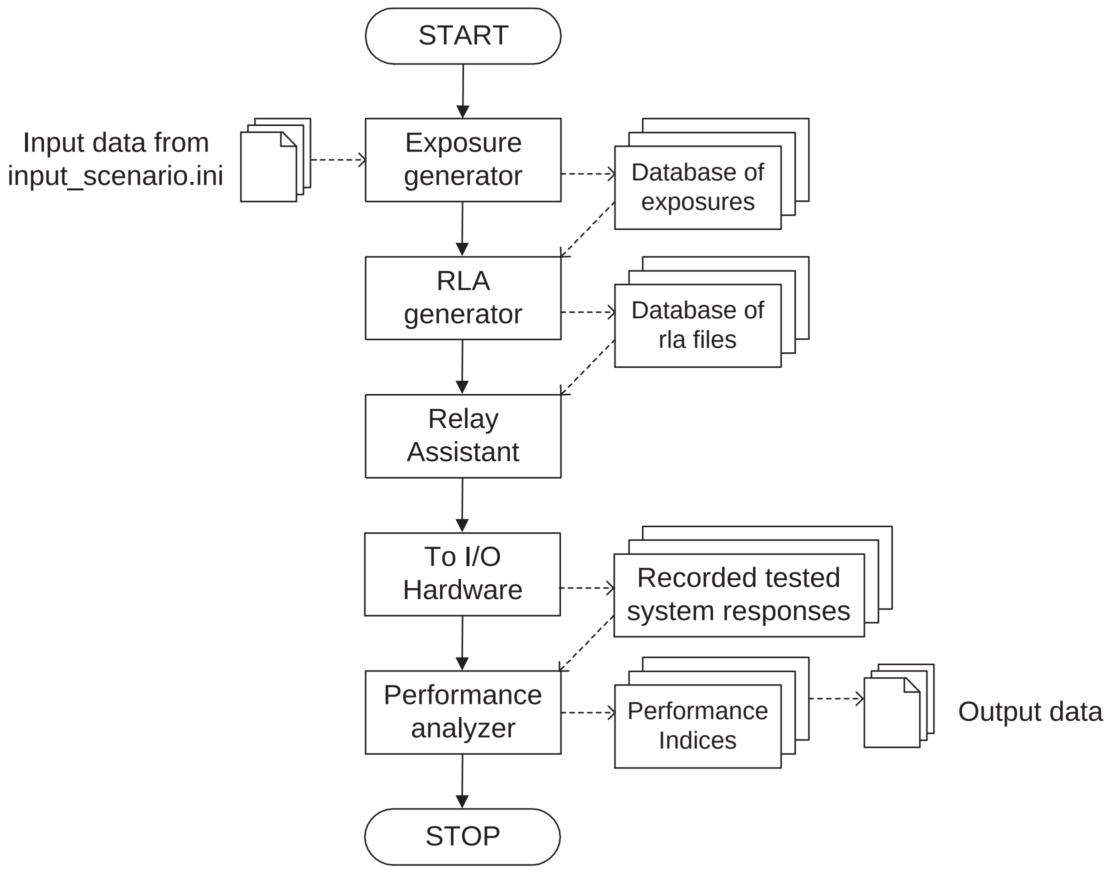


Fig. 33. Simulation environment - all-digital system

software. Also, the IEC 61850-9-2 digital stream at the process bus level is manually recorded for every test using AREVA's 61850 Digital Analyzer. This software tool allows for visualization of signals from the IEC 61850 protocol. The signals can also be recorded (with settable recording time) and saved to a file. Main elements and flowchart of the simulation environment for the all-digital protection system are shown in Fig. 33.

G. Conclusion

This chapter described simulation approach for evaluation of the novel protection system based on an IEC-61850-9-2 digital process bus. First, motivation to combine simulation and lab testing for evaluation purposes was explained. Details on the type of data to be obtained from simulation and procedures to be used are presented. Next, power network and protective relay models are presented. Proper selection of the power system models is required to ensure that both the referent protection system and the tested digital protection system are exposed to realistic power system conditions. Also, settings and operating characteristics of relay models used for referent protection system should match those implemented on the 61850 compatible digital relay under evaluation as a part of the tested digital protection system. Selection of features for simulated scenarios was based on the idea that the protection system is best evaluated when exposed to conditions in which correct operation (and interaction) of instrument transformers and protective IED is more critical.

Overall structure of the simulation environment and its software implementation were described. Simulation environment is comprised of several software modules. The four major components of the simulation environment are: 1) exposure generator, 2) exposure replayer, 3) RLA generator and 4) performance analyzer. The main feature of the simulation environment is its adaptability to interface with some other software tools needed for the analysis of the IEC 61850 digital stream.

Conclusion is that application tests aimed at verifying the behavior of the all-digital protection system can be realized by means of a seamless interaction between the implemented simulation environment and hardware architecture. This chapter is the theoretical and practical base for the next chapter. Next chapter presents results from simulation and lab testing.

CHAPTER V

METHODOLOGY APPLICATION AND RESULTS

A. Introduction

This chapter presents application of the evaluation methodology. Results are obtained by using simulation and test procedure detailed in the previous chapter. Performance indices for the transducer and protective relays of both the referent and the tested all digital protection systems are presented in the form of average values. First section provides values of performance indices for the electronic transducers. Second section illustrates different types of test performance indices obtained for the protection system. The discussion of test results is given in both previously mentioned sections. A summary is given in the last section of this chapter.

B. Electronic Transducer Performance

Output signal from non-conventional instrument transformers can be recorded by means of an IEC 61850-9-2 analyzer software as described in the previous chapter. In order to evaluate the values of performance indices for the electronic transducers, it is necessary to define what range of values are indicative of good or "expected" performance and what range of values is indicative of bad or "unexpected" performance. From the definition of the transducer performance indices given in chapter III, the smaller the value, the better the performance. However, the following realistic expected values can be used as indication of satisfactory performance:

- TPI_i and TPI_v, which are the time domain transducer performance indices for the current and voltage transducers respectively, should be less than 0.05 (for this value, the accuracy of the transducer system can be regarded to be within

5% with respect to the referent system)

- $TPIF_i$ and $TPIF_v$, which are the frequency domain transducer performance indices for the current and voltage transducers respectively, should also be less than 0.05. In both cases the chosen values represent the preferences of the author based on the knowledge of what each index represents.

The selection of the values should be done according to the application for which the tested transducer system is being used. The chosen values guarantee accurate performance for protection purposes. Accuracy for metering and energy metering applications should be higher (expected value of both indices could be set to 1% in this case).

Values of transducer performance indices are shown in Tables VI through IX. The following conclusions can be made, based on the performance indices for the electronic transducers:

- Values of time domain and frequency domain performance indices for current transducers are an indication of good performance with the exception of values obtained for phase-to-ground faults (AG). The reason for this is the dynamic range of the Faraday sensors used in the evaluation. Faraday sensors are ideally used for sensing high currents (primary rated current ranges from 40 A to 4000 A). However, the tested Faraday sensors have been modified to measure currents as low as 5 A, which causes the sensor's accuracy to increase as higher currents are simulated (best performance is obtained for ABC faults, which is the fault type that causes higher fault currents, with an average TPI_i of 0.044 and an average $TPIF_i$ of 0.036)

- Values of time domain and frequency domain performance indices for voltage transducers are an indication of good performance for all simulated conditions.

Values for both performance indices (TPI_v and $TPIF_v$) show very small variations which indicates that they are independent of simulated fault type, location and fault resistance

Table VI. Transducer performance index, ABC fault

Fault Location [%]	**Resistance** [Ω]	TPI_i	$TPIF_i$	TPI_v	$TPIF_v$
20	0	0.039	0.027	0.031	0.006
50		0.046	0.031	0.036	0.007
70		0.046	0.031	0.036	0.009
90		0.045	0.032	0.030	0.008
Average		**0.044**	**0.030**	**0.033**	**0.007**

Table VII. Transducer performance index, AG fault

Fault Location [%]	**Resistance** [Ω]	TPI_i	$TPIF_i$	TPI_v	$TPIF_v$
20	0	0.075	0.065	0.038	0.005
	5	0.079	0.065	0.038	0.005
	10	0.073	0.065	0.028	0.005
	20	0.073	0.065	0.030	0.005
	30	0.073	0.065	0.032	0.004
50	0	0.072	0.064	0.023	0.005
	5	0.073	0.064	0.021	0.005
	10	0.078	0.065	0.043	0.005
	20	0.072	0.065	0.015	0.004
	30	0.073	0.066	0.029	0.004
70	0	0.072	0.065	0.018	0.006
	5	0.074	0.065	0.027	0.006
	10	0.073	0.064	0.016	0.006
	20	0.080	0.064	0.031	0.005
	30	0.079	0.065	0.040	0.006
90	0	0.077	0.064	0.037	0.005
	5	0.076	0.065	0.033	0.005
	10	0.075	0.066	0.026	0.005
	20	0.076	0.067	0.014	0.005
	30	0.084	0.070	0.041	0.004
Average		**0.075**	**0.065**	**0.029**	**0.005**

Table VIII. Transducer performance index, BC fault

Fault Location [%]	**Resistance [Ω]**	TPI_i	$TPIF_i$	TPI_v	$TPIF_v$
20	0	0.044	0.035	0.023	0.004
	5	0.048	0.034	0.035	0.004
	10	0.039	0.034	0.014	0.004
50	0	0.049	0.035	0.035	0.005
	5	0.044	0.035	0.021	0.004
	10	0.044	0.035	0.021	0.005
70	0	0.054	0.036	0.039	0.005
	5	0.058	0.036	0.044	0.005
	10	0.050	0.036	0.029	0.005
90	0	0.050	0.038	0.024	0.005
	5	0.053	0.038	0.034	0.005
	10	0.055	0.038	0.034	0.005
Average		**0.049**	**0.036**	**0.029**	**0.005**

Table IX. Transducer performance index, BCG fault

Fault Location [%]	**Resistance [Ω]**	TPI_i	$TPIF_i$	TPI_v	$TPIF_v$
20	0	0.044	0.036	0.020	0.005
	5	0.054	0.032	0.045	0.005
	10	0.045	0.032	0.029	0.005
	20	0.042	0.033	0.023	0.005
	30	0.044	0.033	0.028	0.005
50	0	0.057	0.033	0.040	0.006
	5	0.051	0.034	0.035	0.005
	10	0.043	0.033	0.020	0.005
	20	0.042	0.033	0.021	0.005
	30	0.045	0.033	0.027	0.005
70	0	0.049	0.035	0.026	0.007
	5	0.049	0.035	0.029	0.007
	10	0.045	0.035	0.016	0.006
	20	0.051	0.035	0.030	0.006
	30	0.082	0.068	0.029	0.009
90	0	0.051	0.037	0.024	0.007
	5	0.063	0.037	0.042	0.006
	10	0.077	0.066	0.021	0.005
	20	0.059	0.038	0.039	0.006
	30	0.050	0.037	0.021	0.005
Average		**0.052**	**0.038**	**0.028**	**0.006**

C. Protection Performance

Two types of performance indices have been defined to evaluate the performance of the protection system: relative and absolute indices (see section D in Chapter III). Results for both kinds of indices have been obtained as methodology was applied to both tested protection functions (overcurrent and distance protection). The results are presented in the following sections.

1. Interpretation of Relative Indices

The values or relative performance indices, by themselves, are an indication of the DIFFERENCE in performance between the referent protection system and the tested all-digital system. By definition, performance of the referent protection system can be regarded to be ideal, that is, performance has been proven to be accurate and stable in laboratory testing. Since the values of relative indices illustrate a difference in performance, it is necessary to define what range of values are an indication of good or "expected" difference in performance and what range of values is an indication of bad or "unexpected" difference in performance. The following values can be used for such purpose:

- The average value for PPI_d, which is the trip decision performance index, should be less than 0.02 (a value like this guarantees that trip decision between the two systems is different in less 2% of the cases)
- The average value for the PPI_t, which is the trip time performance index, should be less than 0.025s or one and a half cycles of the fundamental power system frequency (for a 60 Hz system)

It is important to note that in both cases, the chosen values reflect the preference of the author. Selection of the values was based on typical tripping times for digital relays (see [13] and [30])

2. Relative Indices for Overcurrent Protection Function

Values of protection performance indices for the overcurrent protection function are shown in Tables X through XIII.

Table X. Relative overcurrent protection performance indices, ABC fault

Fault Location [%]	**Resistance [Ω]**	PPI_d	PPI_t
10	0	0	-
20		0	0.019
70		0	0.012
Average		**0**	**0.015**

Table XI. Relative overcurrent protection performance indices, AG fault

Fault Location [%]	**Resistance [Ω]**	PPI_d	PPI_t
10	0	0	-
	5	0	-
	10	0	-
20	0	0	0.021
	5	0	0.020
	10	0	0.019
70	0	0	0.005
	5	0	-0.002
	10	0	-0.011
Average		**0**	**0.009**

Table XII. Relative overcurrent protection performance indices, BC fault

Fault Location [%]	**Resistance [Ω]**	PPI_d	PPI_t
10	0	0	-
	5	0	-
	10	0	-
20	0	0	0.021
	5	0	0.021
	10	0	0.021
70	0	0	0.019
	5	0	0.019
	10	0	0.019
Average		**0**	**0.020**

Table XIII. Relative overcurrent protection performance indices, BCG fault

Fault Location [%]	**Resistance [Ω]**	PPI_d	PPI_t
10	0	0	-
	5	0	-
	10	0	-
20	0	0	0.021
	5	0	0.021
	10	0	0.021
70	0	0	0.016
	5	0	0.014
	10	0	0.014
Average		**0**	**0.018**

The following conclusions can be made, based on the performance indices for the overcurrent protection function:

- A PPI_d of zero for all fault types shows there is no difference in the ability of the overcurrent protection function from the tested relay to properly detect the simulated faults when compared to the overcurrent relay model in the referent protection system

- Average values for the PPI_t range between 9 ms for a phase-to-ground faults

(AG) to 20 ms for phase-to-phase faults (BC). Difference in performance between the tested and referent protection systems is relatively small

3. Relative Indices for Distance Protection Function

Values of protection performance indices for the distance protection function are shown in Tables XIV through XVII. The following conclusions can be made, based on the performance indices for the distance protection function:

- As in the case of the overcurrent protection, an average value for the PPI_d of 0.009 shows that performance of the fault detection algorithm for the IEC 61850 compatible distance protective relay is very similar to performance obtained from the distance relay model. Only in two cases the tested distance relay failed to issue a trip command (fault location at 50% of the line and fault resistance of 30 Ω)

- By looking at the average values for the PPI_t (it ranges from 27 to 38 ms), it is obvious that tripping times for the tested digital distance relay differ significantly from those obtained from the distance relay model in the referent protection system. This is due in most part by larger processing times of the decision making algorithm inside the tested relay. Also, for some simulated AG faults (with fault resistance of 20 and 30 Ω) the tested distance protection issued trip commands with incorrect time delay (faults in primary zone detected as belonging to backup zone). This last factor influencing the operating time of the tested distance relay will be discussed in the next sections

Table XIV. Relative distance protection performance indices, ABC fault

Fault Location [%]	**Resistance [Ω]**	PPI_d	PPI_t
20	0	0	0.031
50		0	0.050
70		0	0.046
90		0	0.023
Average		**0**	**0.038**

Table XV. Relative distance protection performance indices, AG fault

Fault Location [%]	**Resistance [Ω]**	PPI_d	PPI_t
20	0	0	0.017
	5	0	0.015
	10	0	0.020
	20	0	0.027
	30	0	0.104
50	0	0	0.018
	5	0	0.025
	10	0	0.023
	20	0	0.116
	30	0.5	-
70	0	0	0.011
	5	0	0.011
	10	0	-0.060
	20	0	-
	30	0	-
90	0	0	0.019
	5	0	0.030
	10	0	-
	20	0	-
	30	0	-
Average		**0.025**	**0.027**

Table XVI. Relative distance protection performance indices, BC fault

Fault Location [%]	**Resistance [Ω]**	PPI_d	PPI_t
20	0	0	0.030
	5	0	0.032
	10	0	0.031
50	0	0	0.040
	5	0	0.038
	10	0	0.039
70	0	0	0.053
	5	0	0.037
	10	0	0.047
90	0	0	0.030
	5	0	0.030
	10	0	0.027
Average		**0**	**0.036**

Table XVII. Relative distance protection performance indices, BCG fault

Fault Location [%]	**Resistance [Ω]**	PPI_d	PPI_t
20	0	0	0.032
	5	0	0.029
	10	0	0.026
	20	0	0.026
	30	0	0.027
50	0	0	0.029
	5	0	0.025
	10	0	0.029
	20	0	0.027
	30	0	0.027
70	0	0	0.027
	5	0	0.025
	10	0	0.029
	20	0	0.026
	30	0	0.027
90	0	0	0.016
	5	0	0.026
	10	0	0.030
	20	0	0.035
	30	0	0.030
Average		**0**	**0.027**

4. Absolute Indices for Overcurrent Protection Function

Values of protection performance indices for the overcurrent protection function are shown in Tables XVIII through XXI. Even though general criteria and definition of absolute performance indices has been detailed in chapter III, further clarification of the indices from the overcurrent protection perspective is needed.

- s_1 is defined as:

$$s_1 = \frac{N_1}{N_{forward}}$$

- s_2 is defined as:

$$s_2 = \frac{N_2}{N_{backward}}$$

  where: N_1 is the number of correct trip assertions for faults in forward direction and N_2 is the number of correct trip restrains for faults in backward direction. $N_{forward}$ and $N_{backward}$ are the faults simulated in the forward and backward zones of protection respectively

- t is the average tripping (operating) time

- σ is the standard deviation for the recorded tripping times, which is a common measure of statistical dispersion

The following conclusions can be made, based on the results:

- Selectivity of overcurrent protection function for the tested all-digital protection system is perfect. In all of the simulated faults the relay correctly issued trip commands for faults in forward zone and restrained from operation for faults in backward zone

- A comparison of the average tripping times shown in Tables XVIII through XXI demonstrates that for all simulated fault types the reaction time of the tested relay is very close to the expected operating time given by the very inverse time-current characteristic presented in the previous chapter.

- Average values for the standard deviation (it ranges from 0.002 to 0.003) show that there is a high degree of certainty that the tested digital relay's operating time for any given fault will consistently follow the operating time-current characteristic with almost a negligible level of dispersion from the mean trip time (around 2 ms)

Table XVIII. Absolute overcurrent protection performance indices, ABC fault

Fault Location [%]	**Resistance [Ω]**	s_1	s_2	$t[s]$	$\sigma[s]$
10	0	-	1	-	-
20		1	-	0.052	0.003
70		1	-	0.098	0.002
Average		**1**	**1**	**0.075**	**0.002**

Table XIX. Absolute overcurrent protection performance indices, AG fault

Fault Location [%]	**Resistance [Ω]**	s_1	s_2	$t[s]$	$\sigma[s]$
10	0	-	1	-	-
	5	-	1	-	-
	10	-	1	-	-
20	0	1	-	0.076	0.002
	5	1	-	0.079	0.002
	10	1	-	0.081	0.002
70	0	1	-	0.194	0.003
	5	1	-	0.208	0.003
	10	1	-	0.230	0.003
Average		**1**	**1**	**0.0145**	**0.003**

Table XX. Absolute overcurrent protection performance indices, BC fault

Fault Location [%]	**Resistance [Ω]**	s_1	s_2	$t[s]$	$\sigma[s]$
10	0	-	1	-	-
	5	-	1	-	-
	10	-	1	-	-
20	0	1	-	0.058	0.002
	5	1	-	0.058	0.002
	10	1	-	0.057	0.002
70	0	1	-	0.109	0.003
	5	1	-	0.109	0.003
	10	1	-	0.109	0.004
Average		**1**	**1**	**0.083**	**0.003**

Table XXI. Absolute overcurrent protection performance indices, BCG fault

Fault Location [%]	**Resistance [Ω]**	s_1	s_2	$t[s]$	$\sigma[s]$
10	0	-	1	-	-
	5	-	1	-	-
	10	-	1	-	-
20	0	1	-	0.057	0.002
	5	1	-	0.057	0.001
	10	1	-	0.056	0.002
70	0	1	-	0.110	0.001
	5	1	-	0.112	0.002
	10	1	-	0.114	0.003
Average		**1**	**1**	**0.084**	**0.002**

5. Absolute Indices for Distance Protection Function

Values of protection performance indices for the distance protection function are shown in Tables XXII through XXV. Meaning of indices is explained next:

- s_1 is defined as:

$$s_1 = \frac{N_1}{N_{primary}}$$

- s_2 is defined as:

$$s_2 = \frac{N_2}{N_{backup}}$$

  where: N_1 is the number of correct trip assertions for faults in the primary zone of protection and N_2 is the number of correct trip assertions for faults in the backup zone of protection. $N_{primary}$ and N_{backup} are the faults simulated in the primary and backup zones of protection respectively

- Fault location error, FL_{err}, defined as:

$$FL_{err} = \frac{|measured - actual|}{actual} \times 100\%$$

  where: *measured* refers to the fault location calculated by the relay and *actual* refers to the known (simulated) fault location

- t_1 and t_2 is the average tripping (operating) time for the primary and backup zones of protection respectively

The following conclusions can be made, based on the results:

- Selectivity was very good for all fault types with the exception of phase-to-ground faults (AG). Selectivity for AG faults was low (0.71 for primary zone and 0.4 for backup zone) due to the relay's inability to detect high-resistance faults (relay did not trip for faults at 50% with a fault resistance of 30 Ω, faults at 70% with 20 or 30 Ω and faults at 90% with 10 - 30 Ω), or in some cases, due to trip assertions with incorrect time delay for faults in the primary zone of protection. Usually, distance relays are not sensitive enough to detect these high resistance faults, specially for phase-to-ground faults. That is why sensitive ground overcurrent protection is used in addition to the distance protection (typically, both functions are available in the same protective IED)

- Average tripping time for the primary zone of protection is within the expected values (it varies from about 2 cycles for BCG faults to 3 cycles for an AG fault). Also, considering a set time delay of 150 ms for backup zone of protection, average tripping times for the backup zone are also within the expected range (it ranges from 171 to 178 ms)

- Values for the standard deviation show that for almost all types (excluding BCG faults) the tripping times are usually far from the average tripping time. This means that for any given event, there will be little certainty to whether the relay's operating time will be close to the expected (mean) value. Furthermore, since the collected data approximates to a normally distributed population (verified through a normal probability plot), it can be assumed that about 68% of the value are within 1 standard deviation of the mean. Applying this to the BC fault type, 68% of the recorded tripping time for the primary zone should be between 29 and 71 ms. This also means that approximately 16% of the tripping times will be higher than 71ms (the actual value was 15% for BCG faults), which is an unacceptably high operating time for a trip in primary zone

- The average fault location error is tolerable (around 5%) for all simulated conditions with the exception of those obtained for BC and BCG faults located at 20% of the transmission line. In these cases, average fault location error ranges from 13 to 23%. Also, as it was previously explained, for most single phase-ground faults simulated at 20 and 50% of the line, the high fault resistance caused the distance protection to incorrectly sense faults within its primary zone of protection, as being outside of the reach. This had an effect on the fault locator's estimation and explains unexpected values for the FL_{err} in this cases

Table XXII. Absolute distance protection performance indices, ABC fault

Fault Location [%]	**Resistance [Ω]**	s_1	s_2	$t_1[s]$	$t_2[s]$	$\sigma[s]$	$FL_{err}[\%]$
20	0	1	-	0.039	-	0.019	3.07
50		1	-	0.061	-	0.031	6.83
70		1	-	0.061	-	0.031	4.65
90		-	1	-	0.171	0.028	6.58
Average		**1**	**1**	**0.054**	**0.171**	**0.027**	**5.28**

Table XXIII. Absolute distance protection performance indices, AG fault

Fault Location [%]	**Resistance [Ω]**	s_1	s_2	$t_1[s]$	$t_2[s]$	$\sigma[s]$	$FL_{err}[\%]$
20	0	1	-	0.035	-	0.012	3.99
	5	1	-	0.033	-	0.016	4.80
	10	1	-	0.039	-	0.011	7.91
	20	1	-	0.048	-	0.015	12.65
	30	0.35	-	0.123	-	0.072	18.46
50	0	1	-	0.043	-	0.010	2.78
	5	1	-	0.050	-	0.018	6.16
	10	1	-	0.049	-	0.021	9.17
	20	0.3	-	0.142	-	0.079	16.04
	30	0	-	-	-	-	-
70	0	1	-	0.045	-	0.012	4.28
	5	1	-	0.048	-	0.016	7.68
	10	1	-	0.061	-	0.028	10.98
	20	0	-	-	-	-	-
	30	0	-	-	-	-	-
90	0	-	1	-	0.168	0.026	3.83
	5	-	1	-	0.179	0.020	14.85
	10	-	0	-	-	-	-
	20	-	0	-	-	-	-
	30	-	0	-	-	-	-
Average		**0.71**	**0.4**	**0.057**	**0.173**	**0.020**	**8.69**

Table XXIV. Absolute distance protection performance indices, BC fault

Fault Location [%]	**Resistance [Ω]**	s_1	s_2	$t_1[s]$	$t_2[s]$	$\sigma[s]$	$FL_{err}[\%]$
20	0	1	-	0.038	-	0.011	13.67
	5	1	-	0.041	-	0.013	15.11
	10	1	-	0.040	-	0.014	16.89
50	0	1	-	0.051	-	0.020	3.24
	5	1	-	0.050	-	0.021	3.80
	10	1	-	0.051	-	0.014	2.39
70	0	1	-	0.067	-	0.024	4.18
	5	1	-	0.051	-	0.020	3.67
	10	1	-	0.061	-	0.029	3.89
90	0	-	1	-	0.179	0.038	4.92
	5	-	1	-	0.179	0.029	5.69
	10	-	1	-	0.176	0.021	5.91
Average		**1**	**1**	**0.050**	**0.178**	**0.021**	**6.95**

Table XXV. Absolute distance protection performance indices, BCG fault

Fault Location [%]	**Resistance [Ω]**	s_1	s_2	$t_1[s]$	$t_2[s]$	$\sigma[s]$	$FL_{err}[\%]$
20	0	1	-	0.041	-	0.010	17.08
	5	1	-	0.037	-	0.010	20.26
	10	1	-	0.034	-	0.013	22.90
	20	1	-	0.035	-	0.012	13.14
	30	1	-	0.036	-	0.012	21.39
50	0	1	-	0.040	-	0.008	3.26
	5	1	-	0.036	-	0.009	2.87
	10	1	-	0.040	-	0.008	3.08
	20	1	-	0.038	-	0.008	3.34
	30	1	-	0.038	-	0.009	4.64
70	0	1	-	0.042	-	0.008	4.19
	5	1	-	0.040	-	0.009	8.90
	10	1	-	0.043	-	0.014	4.06
	20	1	-	0.040	-	0.008	6.46
	30	1	-	0.041	-	0.013	4.32
90	0	-	1	-	0.166	0.017	5.47
	5	-	1	-	0.174	0.016	9.24
	10	-	1	-	0.177	0.016	4.79
	20	-	1	-	0.181	0.022	4.39
	30	-	1	-	0.176	0.018	4.62
Average		**1**	**1**	**0.039**	**0.175**	**0.012**	**8.42**

D. Conclusion

Results from the performance evaluation of an all-digital protection system based on an IEC-61850-9-2 process bus are presented in this chapter. Results were obtained by application of the evaluation methodology described in Chapter III. Application tests were performed on the hardware architecture (lab setup) presented in Chapter IV by means of the software implementation detailed in the same chapter. The following comments can be made, based on the results from application testing:

- Tested non-conventional instrument transducers, based on new sensing technologies, showed excellent performance for all simulated power system conditions. Values of transducer performance indices (for both, time and frequency domain) indicate that current and voltage transducers based on new sensing technologies deliver nearly distortion-free replicas of signals from their primary side. By keeping the distortion to acceptable levels, it is possible to guarantee that performance of protection system IED will not be affected or influenced by unacceptable transducer performance

- Difference in performance between the novel (all-digital) and the referent protection systems varies considerably from one protection function (operating principle) to another. Even though for the overcurrent protection function there is no significant difference in performance between the two systems with respect to trip decision and average tripping time, average operating times for the all-digital distance protection is considerably higher than those of the distance relay model. Relative indices provide a simple and effective way to measure up the overall performance of the tested system against a selected referent system. Many protective relays with a compatible IEC 61850-9-2 are expected to be commercially available in the near future and comparison of different systems will be highly desirable

- Performance of the novel system can be regarded as excellent when considering test results for the directional overcurrent protection function. Relevance of this result lies in the fact that these two principles (comparison of the measured quantity versus a threshold and distinction of current flow) are the basis for many other protection functions

- Problematic performance of the distance protection function in the tested all-digital system , with respect to the operating time, was confirmed by means of absolute performance indices. Although average operating times are within the expected values, results show there is great uncertainty with respect to what tripping time can be expected for any given event, which means calculated average tripping times are not necessarily a good prediction of the relay's reaction time

- High fault location estimation errors only for faults of a certain type and at a certain location (phase-to-phase faults that are close to the relay's location, in this case, 20% of the line) show how these behaviors can be hard to detect using traditional test procedures or field-data. A flexible and automated simulation environment combined with the available lab setup is a powerful tool to identify and correct problems during the design stage of the device

CHAPTER VI

CONCLUSION

A. Summary

In a traditional protection system, instrument transformers provide protective relays with a scaled-down replica of the power system currents and voltages. Even after the introduction of microprocessor based (digital) relays to the substation environment almost 30 years ago, and analog interface (hardwired copper cabling) was maintained to ensure interoperability with the available sensing technology. Initiatives to come up with a standard communications architecture for substations, started in the mid 1990s by the International Electrotechnical Commission, have resulted in the development of the IEC 61850 series of standards for "Communication networks and systems in substations". These efforts were fueled in most part by the advent of digital relays and recent commercial availability of non-conventional current and voltage transducer offering a digital interface option as well as the traditional analog one.

Unlike conventional instrument transformers, non-conventional transducer do not suffer from saturation and some other typical limitations imposed by intrinsic design characteristics of conventional transformers (they also provide a higher frequency bandwidth). An all-digital protection system using non-conventional instrument transformers and digital relays is expected to benefit (higher accuracy and selectivity) from this superior performance of new sensing technologies. Additional benefits that can be anticipating by the novel implementation are: a) lower sensors and wiring costs by means of a process bus with high speed communication that allows the data exchange between devices and b) reduced times and cost associated with deployment of new devices via a standardized object models and device configuration files.

This all-digital system has not been previously investigated details neither using field application cases nor laboratory test procedures. An uncertainty whether the novel system needs to replace the existing one to achieve a better overall protection system performance still exists. The following questions summarize this uncertainty:

1. What is the difference in performance between an all-digital protection system using NCIT digitally interfacing protection IED vs the conventional protection system?

2. How the difference may be measured and evaluated?

Existing approaches for evaluation of protection system performance, do not address this questions since they are only focused on the conventional protection system. This thesis proposes a methodology for performance and compatibility evaluation of an all-digital protection system. Existing approaches are intended to evaluate the protection system performance, which is reasonable, since the need for compatibility evaluation is inherent to digital interface solution.

The procedure to develop and apply the methodology for evaluation has been described throughout the different chapters of this thesis. First, electronic transducers designs, the physical principles under which they are built and their associated electronics for signal processing were addressed in Chapter II. Different options to interface novel transducers and IED were shown: analog (low and high energy) and digital outputs. The purpose of the different available choices is to provide interoperability between conventional and novel equipment.

The actual implementation of the digital interface between instrument transformers and protection system IED was also discussed in Chapter II. It was explained how such interface can be realized based on the process bus concept detailed in the

IEC 61850-9-2 standard. The object model provided by the standard is intended to guarantee interoperability between devices from different manufacturers. This is done by defining logical nodes (core objects) as the mechanism to exchange information throughout the different substation levels.

Criteria and methodology for numerical evaluation of the all-digital protection system is defined in Chapter III. Separate criteria was defined for different evaluation purposes (performance and compatibility) and for performance evaluation of different system components. Proposed criteria pursues to answer two important questions pertinent to the evaluation of the novel system: 1) Why the evaluation is necessary? and 2) How the difference in performance between the novel and conventional protection systems can be identified and quantified?

Evaluation approach through modeling, simulation and lab testing was described in Chapter IV. Simulation approach was presented, along with simulation models (power network and relay models) and different simulation scenarios. Next, details of the hardware architecture used for the process bus implementation were given. Finally, the software implementation, consisting of the developed simulation environment and several third party software tools, was discussed. It was concluded that application tests required to test the behavior of the novel digital system can be realized by means of a seamless interaction between the implemented simulation environment and hardware architecture.

Application of the evaluation methodology was presented in Chapter V. Results are definitely helpful in gaining understanding on what level of performance can be expected from the novel system, how does the measured performance compares to that of conventional systems, what elements of the novel system contribute to problematic performance and under what conditions. It was concluded that: non-conventional instrument transformers are not expected to influence the performance of protection

IED since they deliver replicas of signals from their primary side with a relatively small distortion level. Problematic behavior of certain protection functions in the all-digital system can be easily identified by analyzing numerical values of performance indices.

B. Research Contribution

Before this research venture took place, performance and compatibility of an all-digital protection system was not investigated in details. Two reasons for this are: 1) IEC 61850-9-2 compatible devices have just recently been made available for lab test purposes and 2) There was no systematic methodology to assess the feasibility and evaluate the overall performance of the novel system. Both issues have been addressed in this investigation. Major contributions of this thesis are:

- Criteria and methodology for performance and compatibility evaluation of an all-digital protection system, consisting of non-conventional instrument transformers interfaced to digital relays via an IEC 61850-9-2 digital process bus, was defined (Chapter III). In the case of performance evaluation, criteria has been defined in the form of two types of numerical indices, namely relative and absolute performance indices. The first type provides an indication of the DIFFERENCE in performance between the tested all-digital system and a referent protection system. The second type offers a quantitative indication of the performance of the tested system only.

- Feasibility of the all-digital system has been demonstrated by the successful application of the mentioned methodology to the lab setup built in Texas A&M University's Power Engineering Lab (see Chapter IV). Hardware architecture can be easily expanded to investigate some other technical aspects of interest within the novel system, such as absolute synchronization of sampled values.

- Criteria and methodology have been applied through the software implementation described in Chapter IV. It was shown that the proposed approach is a valuable tool for assessing advantages and disadvantages of the novel system. An analysis of the simulation results points out specific power system conditions under which operation of the all-digital system is most likely to fail. Manufacturers are expected to focus their efforts to correct IED's problematic performance in those situations before devices are made commercially available.

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APPENDIX A

DETAILED DESCRIPTION OF LAB SETUP

The following is a more detailed description of some of the equipment used in the lab setup for the all-digital system:

- **Current Amplifiers:** three single phase TECHRON TEC3600 current amplifiers with the following specifications:

  Maximum Output Current: 180 A pk

  Maximum Output Voltage: 140 V pk

  Minimum Output Load Constraints: 0.25 Ω @ 60 Hz

  DC Output Offset Current: ¡10.0 mA pk

  Frequency Response: DC to 10 kHz

- **Electronic Current Transducers:** 3 single phase optical (Faraday) current sensors

- **Electronic Voltage Transducers:** 3 single phase electronic resistive dividers

- **Opto-Electronics Rack:** current sensor, voltage sensor and merging unit (MU) boards. Output of MU board in the IEC 61850-9-2 format

- **Current Amplifiers:** three single phase TECHRON TEC7780 voltage amplifiers with the following specifications:

  Maximum Output Voltage: 150 V pk/ch, 300 V pk mono

  Maximum Output Current: 180 A pk/ch

Output Load Constraints: 24 Ω min, 0 to 90 degrees

DC Output Offset Voltage: ¡10.0 mV pk

Frequency Response: DC to 20 kHz

- **Ruggedized Ethernet Switch:** a RuggedSwitch^{TM} with the following specifications:

  Ethernet Ports: 6-10/100BaseTX + 2-100BaseFX (MTRJ/LC connectors)

  Reliability in Harsh Environments: Immunity to EMI and heavy electrical surges. It meets or exceeds the following standards: IEEE 1613 Class 2, IEC 61850-3, IEEE 61800-3, IEC 61000-6-2, NEMA TS-2

  Operating Temperature: -40 to +85C (no fans)

- **Protective Relay:** a MICOM P441 (AREVA) distance relay with the following characteristics:

  - Two fault detection algorithms

  - Quadrilateral operating characteristic with independently settable resistive reach for each zone

  - Four alternative setting groups

  - Backup overcurrent protection (can be set to directional or non-directional) protection

  - Disturbance recording capability

  - Available interface with process sensors : digital (IEC 61850-9-2)

- **Ethernet Physical Link:** The twisted-pair (copper) medium according to IEEE 802.3 10Base-T is used

VITA

Levi Portillo Urdaneta was born in 1979 in Maracaibo, Venezuela. He received his B.S. degree in electrical engineering from the University of Zulia in 2000.

Since September 2004, he has been a graduate research assistant in the Department of Electrical Engineering, working on non-conventional instrument transformers application in power systems and LAN-based substation protection and control systems using the IEC 61850 standard.

From 2000 to 2001 he joined COPLAN in Maracaibo, Venezuela, as a staff engineer working on construction, installation, and operational testing of industrial automation systems. In September 2001 he joined the Venezuelan state-owned petroleum company, Petrleos de Venezuela, S.A. (PDVSA), where he was a staff engineer for the High Voltage Substation Group, developing scope, cost estimates and engineering of major equipment for 69 and 115 kV substations, including transformers, breakers, controls and relays.

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