

The remote calibration of instrument transformers

S. Rens

 **orcid.org/0000-0001-8428-3893**

Dissertation submitted in fulfilment of the requirements for the
degree *Master of Engineering in Electrical and Electronic
Engineering* at the North-West University

Supervisor: Prof. A.P.J. Rens

Co-supervisor: Prof. J.E.W. Holm

Graduation ceremony: May 2019

Student number: 23509333

ABSTRACT

Successful operation and control of a power system is dependent on the accurate measurement of field data. Each measurement received is the result of a chain of instrumentation and data handling processes, and with each process a certain amount of uncertainty is introduced in the measurement result.

Instrument transformers, additional transducers, analog-to-digital (A/D) converters, scaling and conversion procedures, synchrophasor recorders and communication equipment all contribute to the uncertainty in measurement. Errors in this measurement chain can either be systematic, random or installation errors.

Instrumentation transformers convert (and isolate) primary power system current and voltage waveforms into standardised instrumentation circuit values (i.e. 110 V and 5 A) for more convenient measurement purposes. Nominal conversion ratios, specified on nameplates, may differ from the actual conversion ratios due to manufacturing, drift over time and environmental conditions. To eliminate biased measurements received from instrument transformers, calibration of instrument transformers should be performed periodically. Traditionally this has been done by means field work creating an out-of-service condition. It is time-consuming, expensive and labour intensive.

An opportunity exists due to the increased availability of synchronous data for the idea of remote calibration of instrument transformers. This idea estimates a ratio correction factor (RCF) for the instrument transformers using synchrophasor data over a transmission line. It has been researched and verified through various computer-based simulation studies.

In this dissertation the opportunity of remote calibration is investigated through the introduction of real-life measurements using synchrophasor recorders over an emulated transmission line. A measurement model is created within a Matlab[®] Simulink environment to verify to methodology presented in literature and verified by emulating the waveforms using an Omicron[™] 256Plus[™].

It was concluded that measurement uncertainty contributed by using real-life synchrophasor recorders does not defy the original ideas of how synchrophasor data can be used to do much more than small-signal stability analysis such as remotely improve the calibration data of instrument transformers. Other contributions to measurement uncertainty should still be investigated in future research aiming at a pragmatic engineering solution to be used by operators of real power systems.

Keywords: Instrument transformers, measurement uncertainty, ratio correction factor (RCF), least square estimate (LSE), synchronous data, time-stamping, transmission line parameters, phasor measurement units (PMUs).

TABLE OF CONTENTS

Chapter 1: Introduction

1.1	Introduction.....	1
1.2	Why accurate instrument transformers are needed.....	2
1.2.1	Considerations on instrument transformer accuracy	3
1.3	Remote Calibration of instrument transformers: An opportunity brought about by synchrophasors	4
1.4	Is the term “calibration” acceptable for remote calibration?	5
1.5	Contributions to measurement uncertainty	7
1.6	Benefits of Remote Calibration in Power Systems	7
1.7	Research Goal	7
1.8	Conclusion	8

Chapter 2: Theoretical principles of Remote Calibration

2.1	Introduction.....	9
2.2	The evolution in power system measurements.....	9
2.2.1	State estimation.....	9
2.2.2	Phasor Measurement Units	12
2.3	Considerations on metrology	15
2.4	Selected topics from the theory of metrology	16
2.5	Instrument transformers.....	19
2.5.1	Measurement accuracy	20
2.5.2	Standard methods for calibration of instrument transformers	22
2.5.2.1	Classification of calibration methods	23
2.5.2.2	Calibration methods of current transformers	24
2.5.2.3	Calibration of voltage transformers	28
2.5.2.4	Special considerations	33
2.6	Transmission Line Parameters.....	33
2.6.1	Transmission line theory.....	34

2.6.2	Estimation of transmission line parameters.....	38
2.7	Conclusion	38

Chapter 3: Remote Instrument Transformer Calibration

3.1	Introduction: Where the initial idea originated.....	39
3.2	Remote calibration of instrument transformers by synchronised measurements.....	41
3.2.1	“Advanced System Monitoring with Phasor Measurements” – M. Zhou	42
3.2.2	“Synchronised Phasor Measurements Applications in Three-phase Power Systems” – Z. Wu	47
3.3	Literature review on remote calibration of instrument transformers.....	52
3.3.1	Comparative analysis of different remote calibration approaches	52
3.3.1.1	Comparison of assumptions needed	52
3.3.1.2	Comparison of solver method of methodology	53
3.3.2	Comparison on how the methodology was verified/validated	54
3.3.2.1	PMU measurement error contribution	54
3.4	Conclusion	54

Chapter 4: The opportunity for remote calibration

4.1	Introduction.....	55
4.2	How to derive the RCF for a remote instrument transformer	55
4.3	Accurate measurement of transmission line parameters.....	56
4.4	System equations.....	57
4.5	Estimation of RCFs.....	59
4.5.1	Least-squares estimation.....	59
4.6	Conclusion	61

Chapter 5: Verification of methodology

5.1	Introduction.....	62
5.2	Transmission line data	63
5.2.1	Resistance of the transmission line.....	65

5.2.2	Capacitance.....	65
5.2.3	Inductance.....	67
5.3	Simulation model	68
5.3.1	Dynamic load change	69
5.4	Collection of synchrophasor data.....	70
5.5	Estimation of RCFs.....	70
5.6	Analysis of estimation results	70
5.7	Conclusion	71

Chapter 6: Validation of opportunity to use synchrophasors to improve calibration data of instrument transformers

6.1	Introduction.....	72
6.2	Validation of the results obtained by simulation	72
6.3	Analysis of uncertainty contribution	75
6.4	Equipment used for emulation	77
6.4.1	Omicron™ CMC256plus™.....	77
6.4.2	Synchrophasors recorders.....	77
6.5	RCF estimation with measured synchrophasors	78
6.6	Results Analysis	82
6.7	Conclusion	82

Chapter 7: Conclusion and recommendations

7.1	Is the opportunity for remote calibration viable?	84
7.2	Future Work.....	85

LIST OF TABLES

Table 2-1: Standard accuracy class limits of TCF [1]	21
Table 2-2: Maximum uncertainty for ratio and phase angle [1]	23
Table 3-1: System load conditions for each simulation for three different cases	47
Table 3-2: Summary of assumptions	53
Table 3-3: Summary of solver methods used	53
Table 3-4: Validation Methods	54
Table 5-1: Transmission line data	64
Table 5-2: Resistance over transmission line	65
Table 5-3: Capacitance calculations	66
Table 5-4: Inductance calculations	68
Table 5-5: Simulation results – Deviation in size from nominal	70
Table 5-6: Simulation results – TVE	70
Table 6-1: RCFs estimated from using one synchrophasor recorder	80
Table 6-2: RCFs estimated from using two synchrophasor recorders	80
Table 6-3: Deriving the RCFs using one synchrophasor recorder compared to using simulation results (Scenario 1)	81
Table 6-4: Deriving the RCFs using two synchrophasor recorders compared to using one synchrophasor recorder (Scenario 2)	81
Table 6-5: Deriving the RCFs using two synchrophasor recorders compared to the nominal values found by computer simulation (Scenario 3)	81
Table 6-6: Emulation results – TVE	82

LIST OF FIGURES

Figure 1-1: Power system measurement chain	2
Figure 2-1: State estimation architecture.....	11
Figure 2-2: Estimation of system state at unobservable nodes for an observable network.....	12
Figure 2-3: Schematic of the basic PMU architecture [19].....	13
Figure 2-4: WAMS architecture	14
Figure 2-5: Limits for accuracy classes for voltage transformers for metering [1].....	21
Figure 2-6: Limits for accuracy classes for current transformers for metering [1]	22
Figure 2-7: CT accuracy test for current comparator method [1]	25
Figure 2-8: CT accuracy test for direct-null difference network [1]	26
Figure 2-9: CT accuracy test with direct-null network [1].....	27
Figure 2-10: CT accuracy test with comparative-null network [1]	28
Figure 2-11: VT accuracy test with current comparator (direct-null) – Capacitance ratio method [1].....	29
Figure 2-12: VT accuracy test (direct-null) – Capacitance divider method [1]	30
Figure 2-13: VT accuracy test (direct-null) – Resistance divider method [1].....	31
Figure 2-14: VT accuracy test (direct-null) – Pseudo bridge method [1]	32
Figure 2-15: VT accuracy test – Comparative-null method [1]	32
Figure 2-16: Two-port network for transmission line model	34
Figure 2-17: Short transmission line equivalent circuit model [15].....	35
Figure 2-18: Medium length transmission line – nominal π -circuit	35
Figure 2-19: Medium length transmission line – nominal T -circuit	35
Figure 2-20: Distributed nature of transmission line parameters	37
Figure 2-21: Equivalent π -circuit representation of long transmission line	37
Figure 3-1: One-line diagram for RMC at one substation [6]	40
Figure 3-2: Two-bus system [10]	44

Figure 3-3: Two-bus system for three-phase transducer calibration	48
Figure 4-1: Transmission line pi-network	55
Figure 5-1: Matlab® Simulink model	69
Figure 5-2: Active power and reactive power of dynamic load	69
Figure 6-1: Experimental setup using a CMC256plus to generate both the sending- and receiving end waveforms, measured by two different synchrophasor recorders	74
Figure 6-2: Matlab® .wav file creation	75
Figure 6-3: Contributions to uncertainty in the emulation setup.....	76
Figure 6-4: RMS voltage of synchrophasor (top) and angle (bottom) across transmission line.....	78
Figure 6-5: RMS current of synchrophasor (top) and angle (bottom) in transmission line	79

LIST OF ABBREVIATIONS

CT	Current Transformer
VT	Voltage Transformer
RCF	Ratio Correction Factor
MCF	Magnitude Correction Factor
PACF	Phase Angle Correction Factor
PMU	Phasor Measurement Unit
EMS	Energy Management System
WLS	Weighted Least Squares
GPS	Global Positioning System
DSP	Digital Signal Processing
SCADA	Supervisory Control and Data Acquisition
WAMS	Wide Area Measurement Systems
DFT	Discrete Fourier Transform
RAS	Remedial Action Scheme
ROCOF	Rate of Change of Frequency
TVE	Total Vector Error
FE	Frequency Error

CHAPTER 1: INTRODUCTION

1.1 Introduction

Operational requirements of a power system such as reliability and economical operation require accurate field data of current, voltage, real and reactive power. A control centre will evaluate the data and use it for monitoring the system performance. From the objectives pertaining (such as stability of voltage and frequency) control measures will be communicated back to the different assets under control in order to realise these objectives.

Success of a power system control relies on how accurate the field data are, how many nodes of interest are being measured, and a statistic significant set of data (data availability) to further a useful understanding of system technical performance. Some metadata is normally added to the measured database as additional information needed can be derived from computer applications, supporting the decision-making process (such as a system state-estimator to derive data for nodes not being equipped with measuring instruments).

Each measurement received at such a control centre is the result of a chain of instrumentation and data handling processes. Such a chain consists of:

- Instrumentation transformers that convert (and isolate) primary power system current and voltage waveforms into standardised instrumentation circuit values (i.e. 110 V and 5 A),
- Signal transducers to interface the instrumentation circuit to a measuring instrument,
- Filters to constrain spectral leakage,
- Analog-to-digital converters inside the instrument,
- Internal scaling and conversion,
- Application of a measurement standard to derive for example the phasor values of voltage and current,
- A time source to time-stamp the data,
- Communication equipment to distribute the measured field data to a control room where the visibility of power system performance is needed.

During each measurement phase, measurement errors contribute to the final result. The final result is a collective reflection of all the errors added in the measurement chain. A brief overview of the measurement chain, where possible errors are introduced, is shown in Figure 1-1.

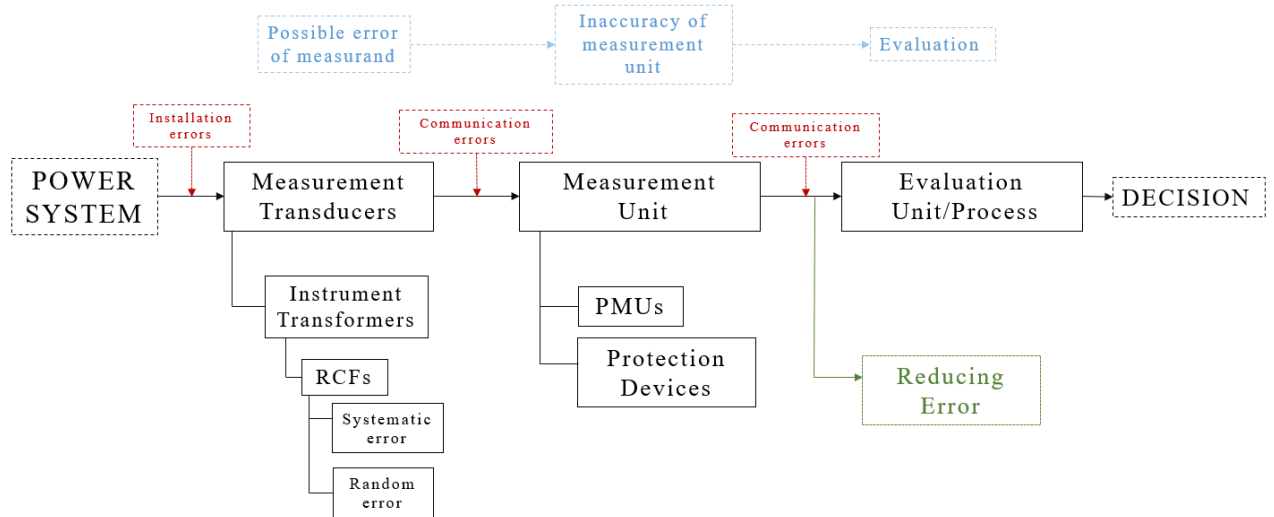


Figure 1-1: Power system measurement chain

How the different aspects of power system metrology are addressed by the theoretical aspects of each component contributing and how measurement standards attempt to set a harmonised approach to engineering applications, are addressed in detail within Chapter 2.

1.2 Why accurate instrument transformers are needed

Instrument transformers is an essential feature in obtaining power system measurements. Accuracy of an instrument transformer will change and deteriorate over time, due to temperature and environmental conditions. An instrument transformer requires periodic inspection and calibration if the accuracy of measurements obtained is important. For example, a phasor measurement unit (PMU) will produce synchrophasors to be used for small-signal stability analysis where the stability parameters must be extracted from data already constraint by noise. Measurement uncertainty of the synchrophasors must be as low as possible for those signal processing algorithms to perform well. Protection devices as another example, where it must discriminate carefully on what circuits to switch, isolating the faulted section but keeping as many as possible of users connected, an important strategy of smart grid operations.

State estimation is of specific interest in this research. Economic and reliable operation of the power system requires accurate knowledge of the state of the power system. This “state” refers to the values for voltage and current phasors (at least at 50 Hz) all over, as from this data, information on the extent of loading at critical assets (lines, transformers, generators) can be derived:

- voltage magnitude regulation and voltage stability,
- line losses, dynamic stability (small-signal oscillations),
- power factors reflecting the extent of useless (reactive) power,
- frequency and generation margin (difference between loading and generation),
- economic dispatch information.

This state of the power system is mostly estimated as not all of the points of interest to reveal the state, can be measured directly. Some points of interest are not equipped with instrumentation and points of interest are determined by the control room, for example a point where possible congestion in terms of power flow can develop if the controls available is not used (tap changers, additional transformers, lines, standby generation).

State estimation relies on a selected number of measurements and then derive (estimate) “measured” values at those other points of interest based on a mathematical modelling of the electrical network (power system). Outputs of the state estimator, being a mathematical tool, are under the direct influence of the field data accuracy. It is evident that accuracy of the data in use, is a strategical consideration/requirement of a state estimator.

Instrument transformers reduce high voltage and current values into a standardized value that is more convenient (i.e. 110 V and 5 A) for measurement purposes. Instrument transformers’ robust construction assures high reliability over time and adverse (short-circuits, extreme temperatures, humidity, dust etc.) operating conditions. This concept of accuracy for instrument transformers is internationally described by an IEEE standards document setting the accuracy requirements of instrument transformers, C57.13-2008 [1] .

1.2.1 Considerations on instrument transformer accuracy

Nominal conversion ratios specified on the instrument transformer’s nameplates differs from the actual conversion ratios due to loading, construction detail, temperature, humidity and age. This deviation from the nominal values is defined as a Ratio Correction Factor (**RCF**¹), a complex number, expressed by a magnitude correction factor (MCF) and phase angle correction factor (PACF). Using the nominal **RCF** as $1e^{j0}$, then:

$$\mathbf{RCF} = (1 \pm \mathbf{MCF})e^{j(0 \pm \mathbf{PACF})} \quad (1-1)$$

Comparing the relative contribution of error in measurements by the components of the measurement chain in Figure 1-1 when applied to a PMU, then errors in PMU measurements can be due to the RCFs of instrument transformers, A/D conversion and GPS synchronization uncertainties. Ratio errors of instrument transformers can range between $\pm 3\%$ - 10% in magnitude and $\pm 2^\circ$ - 6.7° in phase angle as stated in IEEE C57.13 [1], whereas PMU errors related to GPS synchronization uncertainties is in the range of 0.825×10^{-5} in magnitude and $\pm 0.021^\circ$ in phase angle. When using 16-bit A/D converters synchrophasor estimation error is considered negligible [2]. Therefore, the ratio errors of instrument transformers are the greatest source of measurement error when recording synchrophasors.

¹ Complex numbers are indicated by bold font type, variables by italic font type.

In order to eliminate the errors introduced by the deviation of nominal values at instrument transformers, calibration of the CTs and VTs can be done; also periodically if the changes over time are taken into account. Field calibration is a well-known concept. It requires expensive specialist equipment and operators, being done off-line. Such invasive procedure is disruptive and why only a selected view of the installed instrument transformers will be validated for accuracy performance.

1.3 Remote Calibration of instrument transformers: An opportunity brought about by synchrophasors

Synchrophasors are discussed in detail in Chapter 2. For the purpose of motivating why synchrophasors are an opportunity for an innovative approach to a better understanding of accuracy performance of instrument transformers, the application of synchrophasors in power systems are briefly discussed.

It was realised a few decades ago that power system dynamic phenomena resulting from the exchange of energy between different mechanical systems (using high inertia rotating generating equipment) interconnected by distributed loads in an electrical power system, can be studied if highly accurate measurements of synchronised voltage and current phasors at the system fundamental frequency is available. The concept of “synchrophasors” was soon adapted.

During the early 1990's the first PMU instrument was made available to power system operators and the application knowledge grew fast in the USA and Europe. Voltage stability could now be managed by knowing voltage, phase angle and frequency at the points of interest. Today, by means of enough voltage and current synchrophasor measurements, black-out conditions such as the 2003 incident in the USA where 50 million people were affected in the North Eastern parts and the Canadian province of Ontario. It resulted in a total power outage of 61.8 MW and power was not restored for 4 days [3].

Not every electrical utility track small-signal stability. Although it has gained significant application in the rest of the world, in Africa, not one electrical utility is doing it. Eskom, regarded as the leader in power system operations best practises in Africa, has a small investigation project going but no operational application of substance could be found.

Most electrical utilities have some type of power system state estimator in matching loading and demand, needed for stable network operations. It does not avoid the risk brought about by small-signal stability, but operations can be sustained to some extent if the state estimator produce useful results.

Recent advances in power system instrumentation and accurate time sources (such as GPS) being readily available, resulted in a widespread availability of synchrophasors and why an application opportunity for synchrophasors in addition to small-signal stability analysis, is addressed in this dissertation. The performance of state estimators can be improved by improving the accuracy of the field data. This accuracy relies, as discussed earlier, on the availability of validated RCF information. It is impractical and expensive to obtain it at every point where measurements are obtained for the power system state estimator.

An innovative additional application of synchrophasors is postulated as addressing the user requirement of the state estimator:

- Using validated RCF information at one location in the power system, then additional validation of RCF information is possible at any other remote location in the power system, by using voltage and current synchrophasor measurements at the local and the remote location and understanding the impedance in-between those 2 points.

Remote calibration of instrument transformers is a non-invasive and cost-effective approach to instrument transformer calibration if voltage and current synchrophasors are available across a known impedance.

This is an important opportunity for initiatives towards the future smart transmission and distribution grid and why this research aims at validation of concepts, until now only developed by theoretical models and tested by simulation where the outcomes could have been affected made by simplifications during either (or both) the theoretical modelling and the computer simulation studies.

1.4 Is the term “calibration” acceptable for remote calibration?

In the world of metrology, “calibration” can be considered as a holy grail to be upheld by very specific concepts and requirements. Traceability of every single component in use to declare that some measurand is the result of a “calibrated” measurement process, is needed for one. Different approaches exist to establish traceability, in the case of power system measurements and declaring an instrument transformer to be calibrated, it requires an unbroken chain of comparison to relating an instrument measurement to a known standard. This is needed to conclude on instrument bias, precision and accuracy. In metrological terms traceability is defined by the Joint Committee for Guides in Metrology (JCGM) in the International Vocabulary of Basic and General Terms in Metrology (VIM) [4] as:

“The property of a measurement result whereby the result can be related to a stated reference through a documented unbroken chain of calibrations, each contributing to the measurement uncertainty”

Calibration is defined by the JCGM in the VIM [4] as:

“Operation that, under specified conditions, in a first step establishes a relation between the quantity values with measurement uncertainties provide by measurement standards and corresponding indications with associated measurement uncertainties and, in a second step, uses this information to establish a relation for obtaining a measurement result from an indication.”

In [4] it is noted that calibration may be expressed by:

1. a statement;
2. calibration function;
3. calibration diagram;
4. calibration curve;

5. calibration table;
6. or an additive or multiplicative correction applies to the associated uncertainty.

Calibration should not be confused by the adjustment of a measuring system or the verification of calibration [4] and both steps of calibration should be used. It is common for only step one of calibration to be used, where an indication is given of what calibration should be, and step two is omitted for establishing the relation between the measured values and calibration data such as applying a correction factor to the measured data [5].

It is stated in note 6 of the definition of *metrological traceability* in [4] that the “*comparison between two measurement standards may be viewed as **calibration** if the comparison is used to **check** and, if necessary, **correct** the quantity value and measurement uncertainty attributed to one of the measurement standards.*” Where a *measurement standard* is defined as:

“realization of the definition of a given quantity, with stated quantity value and measurement uncertainty, used as a reference.”

From the above view to the field of metrology, it is concluded that the research reported in this dissertation can only be considered as calibration, if the calibration parameters derived (RCFs) by this methodology can be substantiated by traceability. *Traceability*, having an unbroken chain of calibration, is fundamentally constrained in power systems due to the aging of equipment and calibration data not properly documented.

Selected scientific papers constitute the core of the theoretical basis for the research reported in this dissertation, including those academic papers using the word “**calibration**”:

1. “Remote Measurement **Calibration**” - [6]
2. “Online **Calibration** of Voltage Transformers using Synchrophasor Measurements” - [7]
3. “Simultaneous Transmission Line Parameter and PMU Measurement **Calibration**” - [8]
4. “Three-phase Instrument Transformers **Calibration** with Synchrophasors” - [9]
5. Two P.h.D. thesis’s [10], [2] from reputable institutions contain specific chapters reporting the “**calibration**” of instrument transformers using synchrophasor measurements.

Reflecting the above references in the research on the underlying fundamental theoretical principles, it is evident that “calibration” is mostly used when referring to “remote calibration” in the context of instrument transformers that are literally located remotely.

Resulting from the research reported in this dissertation, a paper was presented at IEEE AMPS 2018² [11]. Experts in power system metrology participated in the discussion following the presentation. It was concluded that “**characterisation**” of remote instrumentation transformers by application of synchrophasors is preferred to “**calibration**” if the governing principles of metrology pertaining to this opportunity, is to be respected. For this reason, following the literature analysis and deriving a methodology to validate the opportunity for field applications, the dissertation reverts in Chapter 5 to using “**characterisation**” as the preferred concept.

1.5 Contributions to measurement uncertainty

Measurement uncertainty, when attempting a remote calibration of instrument transformers by the application of synchrophasors, has to collectively reflect the different sources such as measurement device accuracy, GPS time-stamping uncertainty, quantization noise and uncertainty of transmission line parameters.

Field application of a remote “calibration” methodology will require qualification and quantification of measurement uncertainty in order to validate the usefulness of the calibration data. What measurement uncertainty constitutes “an acceptable measurement uncertainty” and how each source contribute to the overall measurement uncertainty, is discussed and analysed in Chapter 2.

1.6 Benefits of remote calibration in power systems

Assuming highly accurate synchrophasors exist, calibration information of a local instrument transformer is available and that the methodology to derive the calibration data for instrument transformers located remotely was validated, then significant benefits for power system operation is evident.

Being a cost-effective and time-saving non-invasive solution, it allows for tracking system impedances, voltages and currents continuously and then continuously optimising power system operations as the state estimator will rely less on “estimate” performance and rather produce a “measured” power system state.

1.7 Research goal

By means of the research results reported in this dissertation, a better understanding of remote calibration (characterisation) of instrument transformers using synchrophasor measurements is used to validate the opportunity for field applications.

A thorough and critical literature overview of the concepts that forms the basis of remote calibration of instrument transformers is first presented in Chapter 2. Then, in Chapter 3, a critical analysis is done of existing remote calibration methods and how the contributions to uncertainty affect the assumptions needed to apply the remote calibration methodology.

² <http://amps2018.ieee-ims.org/>, Electronic ISBN: 978-1-5386-5375-3

In Chapter 4, the latter knowledge is used to derive a remote characterisation method in context of a field application where the ideal conditions used in the literature sources, no longer exist. This method is verified by computer simulation to confirm that the opportunity for remote calibration of instrument transformers, should exist.

Being a research-only M-Eng dissertation, validation of the Chapter 4 concepts is needed. A structured approach towards the acquisition of field data is adapted in Chapter 5. By means of controlled experimental conditions within an emulation setup, real-life synchrophasor measurements across a known transmission line are used to validate if this opportunity has sufficient substance for field application.

Measurement uncertainty is the main concern when the metrology of real-life systems is considered, and Chapter 6 is used to interpret the results of the research and how it was used to submit and present a paper at IEEE AMPS 2018 [11].

Chapter 7 recommend further work and discuss guidelines useful for extending this opportunity for remote characterisation of instrument transformers in support of power system state estimation and future smart grid operations.

1.8 Conclusion

Chapter 1 has introduced an innovative application of synchrophasors in addition to small-signal stability analysis. By means of knowing the calibration information of a local instrument transformer with sufficient certainty, also with voltage and current synchrophasors available locally and at a remote location across an impedance such as transmission line, it was motivated why the research postulation of “Remote characterisation of instruments transformers by means of synchrophasors”, has sufficient substance to be investigated as an opportunity to improve the performance of a power system state estimator.

CHAPTER 2: THEORETICAL PRINCIPLES OF REMOTE CALIBRATION

2.1 Introduction

The methodologies applied in remote characterisation of instrument transformers requires not only fundamental, but also specialist knowledge on a number of areas within power systems theory, power systems metrology, mathematical solutions in solving network equations and advances in power system instrumentation i.e. synchrophasors and state estimation. A review and evaluation of these aspects that are relevant and within context of the research reported in this dissertation, is presented next.

2.2 The evolution in power system measurements

Operational requirements of large power systems normally rely on a state estimator, of which the performance of the state estimator relies on the accuracy of measurements used as input to the state estimation process. From the outputs of the state estimator, decisions must be made and why it is of high importance that these measurements are accurate enough to allow a useful representation of the power system state.

Measurement in a power system necessitates the use of instrument transformers to reduce high voltages and currents to a usable and safe level. Instrument transformers are discussed in more detail in section 2.5 as they are an important contributor to uncertainty of power system measurements.

By means of mathematical modelling of a power system, additional system performance information can be derived than what is possible by direct measurements. This field of specialisation is known as state estimation and discussed in section 2.2.1.

Availability of high-precision time-stamping and a growing number of instruments that employ this technology, has resulted in synchrophasor measurements no longer being the domain of only PMU's - other power system instrumentation can produce synchrophasors in addition to the primary application (i.e. being a protection relay). Improving the performance of the state estimator by the innovative application of remote characterisation of instrument transformers is an important aspect of the research reported in this dissertation and why the measurement of synchrophasors is analysed in section 2.2.2.

2.2.1 State estimation

State estimation was first introduced by Fred Schweppe in the 1960s [12], and today state estimation plays an important role in the security, reliability and economy of power system operation. In de-regulated electricity markets, power system state estimators have an important impact on key economic and financial decisions [13] during energy arbitrage.

State estimation is the method of producing the best possible estimate of the true state of a system using the available imperfect measurement information achieved from the system and the mathematical relations between system state variables [10], [14]. Instrument transformers produce current and voltage measurement which can be processed by a SCADA system to provide real- and reactive power flow within the power system, regarded as information about the state of the electrical network.

A power system state estimator uses as input to the network mathematical model, a set of field measurements to derive voltages and currents (as output) at electrical nodes where direct measurements are not available. Traditionally, the field measurements were not synchronised resulting in a time-stamping uncertainty that will affect the certainty by which the state estimator can estimate (derive) additional data. If the resolution of the data set was not required to be high (a few minutes apart) then time-stamping uncertainty has a lesser impact on the performance of the state estimator. A higher resolution of the power system state has become more important due to the variability of grid-integrated renewable energy sources, the dynamic nature of loads and smart grid initiatives that stimulate advanced behaviour of users and suppliers of electricity.

This resolution in power system state observability has benefit by the increasing access to synchronized measurements made available by for example PMUs [10], [13], that specifically records voltage and current synchrophasors at a rate as high as the power system fundamental frequency if needed. Fundamental network theoretical principles are in use by the state estimator when processing voltage and current measurements as the network model are built on the assumed or monitored network operating conditions and consider all relevant network parameters, such as transmission line parameters [13].

Figure 2-1 show how a state estimator relies on different sets of input data to produce results that can be used in different areas of power system operation. It is a well-advanced and sophisticated application to the extent that state estimators should detect erroneous measurements and still provide an unbiased estimate of the state of the network [13].

A state estimator normally constitutes a set of non-linear equations and due to the continuous inflow of power system measurements, an over-determined set of equations must be solved. A system solution must be obtained by an approach such as a weighted least squares (WLS) approximation.

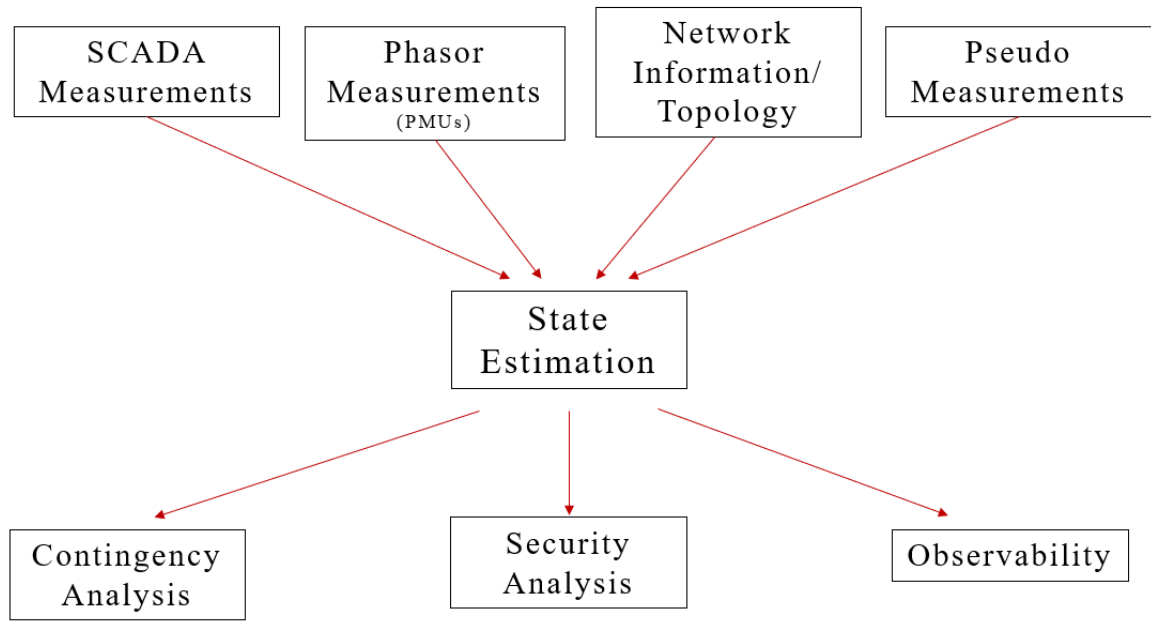


Figure 2-1: State estimation architecture

Outputs of the state estimator aims to be near the true value of the system state but is affected by noise, intermittent communication errors and inaccurate grid parameters [10]. Performance can be further affected by the hardware and software in use, location and quality of the field measurement units [13].

Placement of measurement devices impacts the measured and derived observability of the network; optimal placement of PMU and other measurement devices should be considered as a measurement device at each node is not economically viable [14].

A power system will contain observable and unobservable nodes. By careful placement of PMUs synchrophasor measurements at key locations can provide islands of observable networks [15]. Optimal meter placement techniques have been researched and specifications developed to realise an observable network by taking into account measurement design and measurement quality.

Remaining unobservable nodes can be estimated from the measurements at the observed nodes and the use of pseudo-measurements, where measurement information is obtained from historical and forecast data at unobservable nodes as illustrated in Figure 2-2.

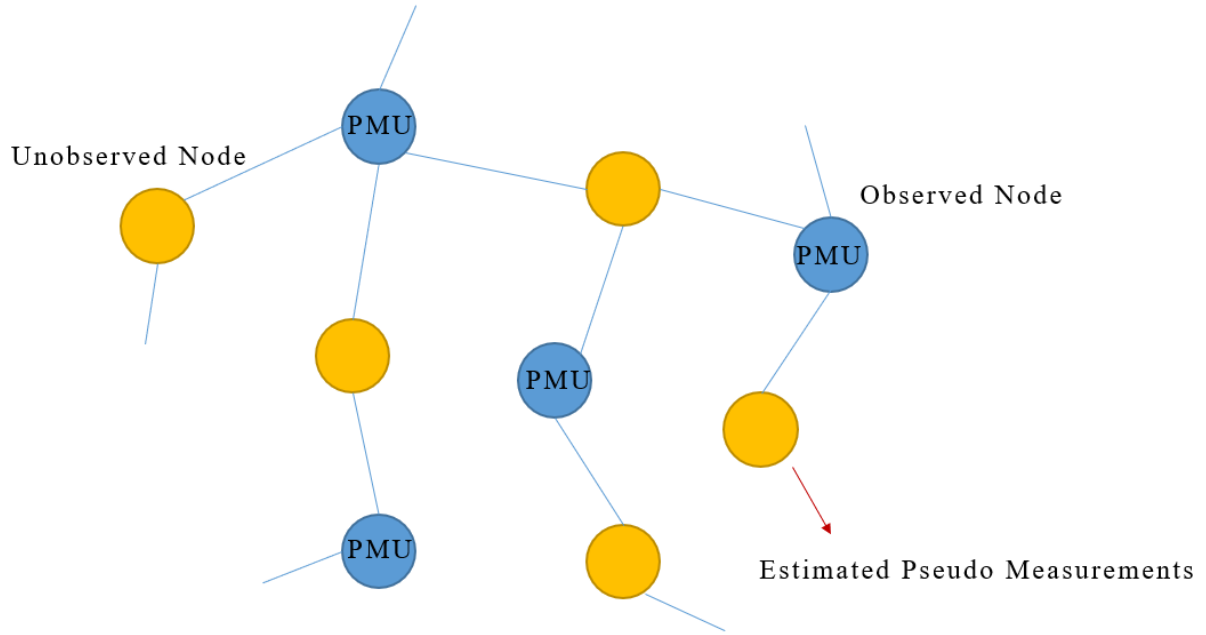


Figure 2-2: Estimation of system state at unobservable nodes for an observable network

An approach such as shown in Figure 2-2 allows PMUs to significantly improve the accuracy of state estimation and system observability. The principle of operation used in PMUs is analysed next.

2.2.2 Phasor Measurement Units

PMUs provides synchronized measurements of 50 Hz (system fundamental frequency) voltage and current phasors [16]. Synchronisation of the voltage and current measurements can be achieved by a GPS signal traceable to the Coordinated Universal Time standard. By this, synchrophasors are the important products of measurement.

PMUs, depending on their application, can also measure other quantities of concern such as individual phase voltages and currents, harmonics, local frequency and the rate of change of frequency (ROCOF) [15]. Synchrophasors obtained from different instruments supplied by different manufacturers, need to be comparable and why an international measuring standard specify how a synchrophasor must be obtained.

IEEE C37.118.1 (2011) define a synchrophasor as a representation of an analog time-dependent function by writing it in phasor notation as defined in equation (2-1) [17]:

$$x(t) = X_m \cos (2\pi f_0 t + \delta) \quad (2-1)$$

X_m : Magnitude of phasor measured at instance m

f_0 : Nominal System Frequency (50 Hz or 60 Hz)

δ : Instantaneous phase angle relative to a cosine function at f_0 that is synchronized to UTC

Nominal system frequencies are not necessarily fixed, it can deviate due to disturbances within the network such as localised reactive power changes causing a jump in zero crossings of the voltage signal under investigation.

This non-stationary 50 Hz (fundamental frequency in use in this dissertation) can be represented by a function $g(t) = f(t) - f_0$ where $g(t)$ represents the frequency difference from the nominal frequency. Equation (2-1) is rewritten in equation (2-2) below:

$$x(t) = X_m \cos (2\pi \int (g + f_0) dt + \delta) \quad (2-2)$$

$$x(t) = X_m \cos (2\pi f_0 t + \left(2\pi \int g dt + \delta\right))$$

The synchrophasor notation of equation (2-2) is shown in equation (2-3) below:

$$X = \frac{X_m(t)}{\sqrt{2}} e^{j(2\pi \int g dt + \delta)} \quad (2-3)$$

Analog-digital conversion of the substation signals is needed to apply the signal processing requirements of the IEEE C37.118.1 (2011) synchrophasor measurement standard as shown in Figure 2-3. It describes basic computational methods in calculating the synchrophasor from the sampled sinusoidal signal. The 50 Hz synchrophasors must be extracted from a mostly distorted waveform. How to contain spectral leakage, phase-angle jumps, GPS locking jitter and other real-life phenomena, is described [18].

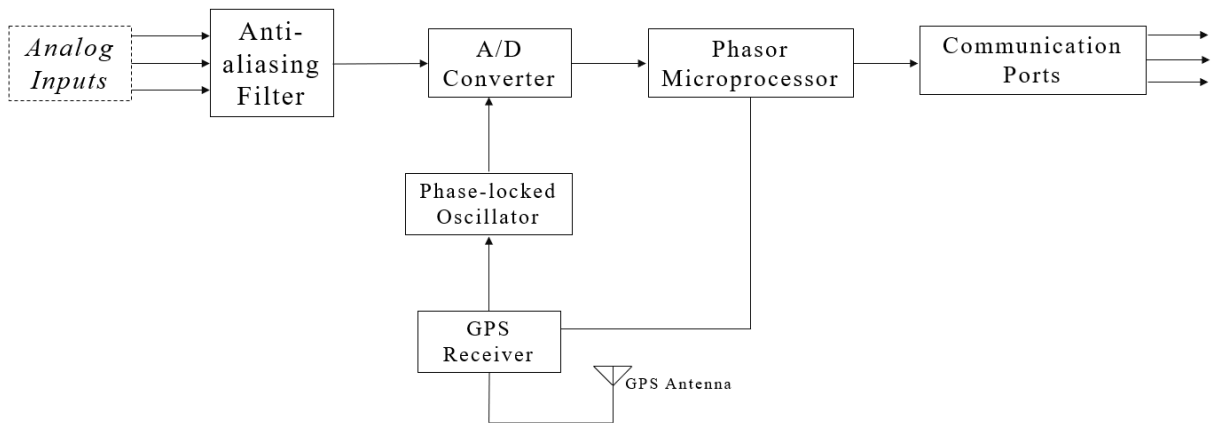


Figure 2-3: Schematic of the basic PMU architecture [19]

PMUs applications includes state estimation, small-signal stability analysis, adaptive protection and other innovations in power system operations [19]. State estimation based on low resolution SCADA data is improved to a resolution that can even include some dynamic phenomena.

It results in potentially huge volumes of data to be transferred from remote locations. Special consideration is given to address this constraint between the improved system observability and control that can only be realised if the data can be transferred at a rate that allows these improvements. It is generally referred to as a Wide Area Measurement System (WAMS) and the different aspects of it is presented in Figure 2-4.

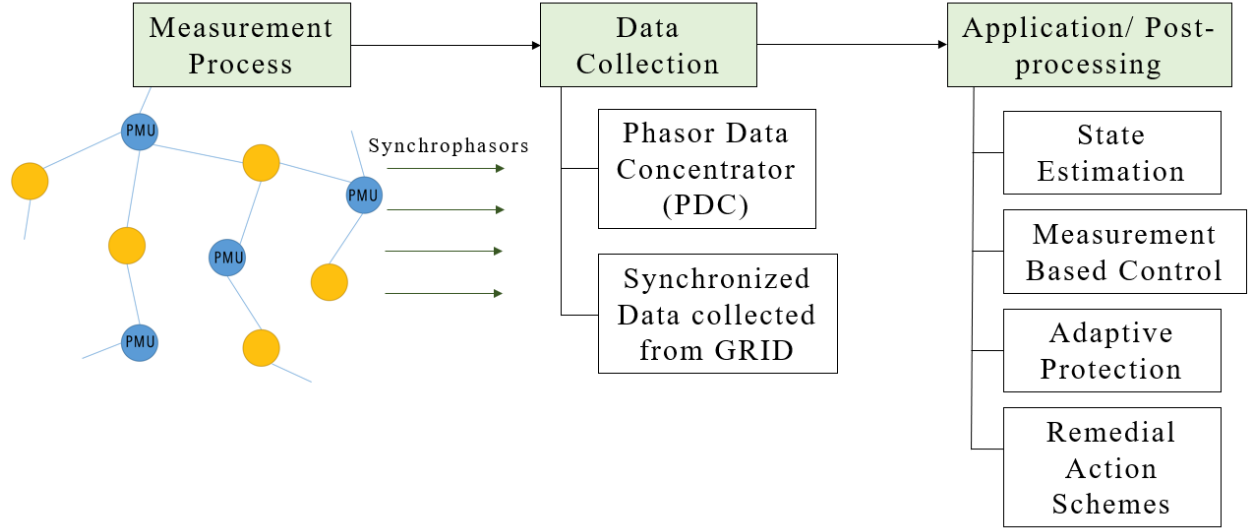


Figure 2-4: WAMS architecture

A WAMS is needed when utilities want to monitor larger areas of a power system to include dynamic phenomena that allow tracking and detecting grid instabilities to improve reliability and security.

Performance requirements of PMUs are set by the IEEE standard C37.118.1 [17]. An important assessment of the usefulness of a synchrophasor is the total vector error (TVE). Frequency error (FE) is another that requires specification as the rate of change of frequency (ROCOF) is an important consideration for power system operations. Synchronisation to UTC time with sufficient certainty is needed to meet the requirements of IEEE standard C37.118.1 [17].

Measured values of a sinusoid can include uncertainty in amplitude and phase [17]. The difference in the phase and magnitude from the theoretical value is defined by the TVE. It is evaluated by the square root difference between the real and imaginary parts of the theoretical actual phasor to the ratio of magnitude of the theoretical phasor as shown in equation (2-4). $\bar{X}_r(n)$ and $\bar{X}_i(n)$ are the sequences of estimates measured by the PMU under test, $X_r(n)$ and $X_i(n)$ are the sequences of theoretical values of the input signal at that moment in time n .

Frequency and ROCOF are evaluated by the absolute value of the difference between the theoretical and estimated values in Hz and Hz/s [8]. Mathematical formulation of TVE, frequency error (FE) and ROCOF are set by the IEEE C37.118.1 [17] as shown in (2-5).

$$\text{TVE}(n) = \sqrt{\frac{(\bar{X}_r(n) - X_r)^2 + (\bar{X}_i(n) - X_i)^2}{(X_i(n) - X_r(n))^2}} \quad (2-4)$$

$$\text{FE} = |f_{\text{true}} - f_{\text{measured}}| = |\Delta f_{\text{true}} - \Delta f_{\text{measured}}| \quad (2-5)$$

$$\text{RFE} = |(df/dt)_{\text{true}} - (df/dt)_{\text{measured}}| \quad (2-6)$$

TVE, FE, and RFE performance requirements under various measuring scenarios are also set by IEEE C37.118.1 [17] in recognition of real-life field conditions. Different measurement classes are defined:

- P class PMU performance is intended for protection purposes as it is reliant on faster response and does not require explicit filtering for best accuracy.
- M class PMU performance is intended for highly accurate measurements at a slower speed.

With synchrophasors data, an important contributor to the field application of remote characterisation of instrument transformers, it is necessary for a broader understanding of how power system metrology can affect this opportunity. Theoretical considerations of metrology are addressed next.

2.3 Considerations on metrology

Metrology is known as the scientific study of a measurement with uncertainty and error in measurements - an important concept to be understood as pertaining to the research reported in this dissertation.

Decision making in power systems require measurements. Measurement instruments all contain a level of uncertainty and cannot provide the true value of the measurand. Thus, implicating that decision making based on these measurement results, is not based on the true value.

A measurand is defined as a particular quantity subject to assessment; the measurand is not defined by a specific value but by specifications of a quantity [20]. The specification of a measurand can include statements about quantities such as time, temperature and pressure to which the measurand is subjected to.

An investigation of the pillars of metrology is done in [5] to better process the incomplete knowledge received from instruments to useful knowledge. The most important pillars of metrology are identified as: uncertainty and calibration on traceability.

Uncertainty is defined in the GUM [20] that when all the known contributions to error have been evaluated and corrected, there remains a certain level of uncertainty about the correctness of the result. This implies random occurrence having an influence and the measurand as all known systematic errors has been compensated for [5].

Whilst the random error can be described by an associated probability density function, represented by its mean and standard deviation.

Standard deviation in metrology is defined as the standard uncertainty (u), usually with a pre-defined confidence interval from prior knowledge. This can be either calibration or other sources of information provided with the measurement instrument. The coverage factor, K , which is multiplied with the standard uncertainty ($U=Ku$), provides the expanded uncertainty over a larger/smaller confidence interval.

Standard uncertainty is the pillar that enables the ability of quantifying the doubt related to the measurand, by defining a certain quantifiable level of confidence to the lack of complete knowledge. But this is only applicable if all known levels of uncertainty have been evaluated and compensated for, implicating the need for calibration.

Calibration defined in the *International Vocabulary of Metrology* [4] as an “operation that, under specified conditions, in a first step, establishes a relation between the quantity values with measurement uncertainties provided by measurements standards and corresponding indications with associated measurement uncertainties and, in a second step uses this information to establish a relation for obtaining a measurement result from an indication.”

Methods of calibration can be by a statement, function, diagram, curve, table and so forth. This information can either be defined, or mathematically expressed by a function depending on the requirements of the use of the measurand. Information provided by the calibration certificate of the measurement instruments is of importance and should be used in processing the measurement result obtained.

Third pillar of metrology is the traceability [5]. Traceability is defined in *International Vocabulary of Metrology* [4] as a “property of a measurement result whereby the result can be related to a reference through a documented unbroken chain of calibration, each contributing to the measurement uncertainty.”

Noted on this definition is that it is required to establish a calibration hierarchy, where the sequence of calibration instances to from the final measurement is accurately documented and accredited by governing bodies concerning the specific measurement instrument.

Using these three pillars of metrology, the lack of knowledge of a measurand can be evaluated and expressed, thereby converting otherwise useless measurement results to useful data [5].

2.4 Selected topics from the theory of metrology

An overview of how the theory of metrology finds application in the research reported in this dissertation is briefly reviewed in this section.

Uncertainty of a measurand is defined by the “*Guide to the expression of Uncertainty in Measurement*”, as a parameter, associated with the result of a measurement, that characterizes the dispersion of the values that could reasonably be attributed to the measurand [20]. The measurand is a quantity that is the result of the measurement process. Theory of metrology applies to any process of measuring a quantity, at large.

Power system measurements is a subset of this broad field, especially required for the purpose of remote characterisation of instrument transformers where measuring uncertainty can negate the usefulness of the application.

Contributing factors to the uncertainty of a measurement process, identified in [20], are the following:

- Incomplete definition of the measured quantity;
- Imperfect comprehension of the definition of the measured quantity;
- Unrepresentative sampling of the measured quantity;
- Inadequate knowledge of the effect of the environmental effects;
- Personal bias in interpreting instruments;
- Finite instrument resolution or discrimination threshold;
- Incorrect reference material and incorrect use of parameters;
- Approximation and assumptions incorporated in the measurement method and procedure;
- Variations in repeated observation of the measurand under apparently identical conditions.

True value, X_T , of a quantity is defined as a value that is perfectly consistent to the theoretical definition of that quantity [20], [21]. The true value of a quantity can never be exactly known through a measurement process as it always will contain some error, contributing to the uncertainty on knowledge of the “true” value of a quantity.

Information from this measurement is based on a deviated value from the true value, known as the measured quantity, X_M [21]. This relative measurement error is normally defined by equation (2-7) below.

$$error = \frac{X_M - X_T}{X_T} \quad (2-7)$$

Measurement error can be divided into the contribution by random variations of the measurand and by systematic errors, meaning that only an estimate of the measurand and its associated error can be known. Uncertainties associated with the random and systematic errors can be evaluated.

Standard uncertainty is the result of a measurement expressed as a standard deviation and can be assessed by statistical methods used in the theory of metrology, Type A evaluation, or a Type B evaluation [20].

In Type B evaluation the estimated variance is evaluated from existing knowledge such as [20]:

- Previous measurement data;
- Experience of knowledge of the behaviour and properties of the relevant measuring equipment;
- Manufacturer’s specifications;

- Calibration data;
- Uncertainties assigned to reference data taken from handbooks.

For Type A evaluation the standard error/deviation, σ , is defined in equation (2-8) as:

$$\sigma^2 = \frac{1}{N-1} \sum_{n=1}^N (X_n - \bar{X})^2 \quad (2-8)$$

Errors are defined as either random or systematic. Random errors are uncontrollable and have different magnitudes and signs during each measurement. These errors arise from unpredictable or stochastic temporal and spatial variations of influence quantities [20].

Compensation by means of a correction factor is not possible for random errors, but the overall measurement error can be efficiently reduced by increasing the number of observations, N , if done in the same controlled conditions [21]. If the measurement of the same quantity is repeated a sufficient number of times, the mean of the random error tends to zero and the mean of the measured quantity tends to be the true value, that is if only a random error is present – this is known as the central limit theorem [21].

Statistically, the mean ($\bar{X}$) can be expressed for N different observations $X_1, X_2, \dots, X_N$ of the same quantity X , by equation (2-9) below [22]. Where if $N \rightarrow \infty$, the mean value would tend to become X_t , the true value:

$$\bar{X} = \frac{1}{N} \sum_{n=1}^N X_n \quad (2-9)$$

Systematic errors should have the same value and sign when a repetitive measurement of a quantity is obtained using the same measurement process, instruments and reference conditions [21]. Systematic errors cannot be eliminated but can be reduced using a compensation factor.

Combined standard uncertainty is the standard uncertainty of a measurement result obtained from the measured values of other quantities. It can either be determined by uncorrelated input quantities, shown in equation (2-10), or correlated input quantities, shown in equation (2-11). Where $u(x_i)$ is a standard uncertainty evaluated by a Type A evaluation:

$$u_c^2(y) = \sum_{i=1}^N \left(\frac{\partial f}{\partial x_i} \right)^2 u^2(x_i) \quad (2-10)$$

$$u_c^2(y) = \sum_{i=1}^N \sum_{j=1}^N \left(\frac{\partial f}{\partial x_i} \right) \left(\frac{\partial f}{\partial x_j} \right) u(x_i, x_j) \quad (2-11)$$

In the case of correlated input quantities, a degree of correlation is defined by a correlation coefficient between x_i and x_j , this is shown in equation (2-12). If the estimates are independent $r(x_i, x_j)$ will be zero.

$$r(x_i, x_j) = \frac{u(x_i, x_j)}{u(x_i)u(x_j)} \quad (2-12)$$

Uncertainty in measurements is an attempt to quantify the incompleteness of the knowledge about the true value of a measurand. Uncertainty is a field of specialisation and detailed analyses of theory and mathematical principles are presented in [20] and [21].

2.5 Instrument transformers

Instrument transformers are needed for galvanic insulation between the power system and instrumentation circuits, scaling the primary side quantities to standardised values such as 110 V and 5 A nominal values.

Voltage transformers (VTs) operated in power systems up to 132 kV will mostly be a magnetic transformer where two separate windings share a common magnetic steel core. Due to insulation requirements, power systems with voltages above 132 kV are normally equipped with capacitive voltage transducers (transformer is a term commonly in use although strictly a capacitive voltage divider).

Current transformers (CTs) are mostly magnetic and normally monitor the line currents [23] regardless of the transformer winding configuration (i.e. not the delta currents within the delta windings). Advances in current measurements include Rogowski coils and recently, optical current sensors.

Probably in the near future, both voltage and current transformers will no longer produce a secondary voltage and current to be measured, but rather convey a message based on the IEC 6182 substation automation protocol (i.e. goose message) from an optical port located on the VT or CT to an instrument that is fully digital.

Such development does not remove the interface converting the primary measured quantity, being an analog waveform, to a digital format. Performance considerations with respect to accuracy remain, however.

Different requirements relating to accuracy exist when considering an instrument transformer. For example, protection applications do not require highly accurate measurements as the difference between a “system normal” and a “system faulted” condition is significant. These aspects have been standardised and are discussed next.

2.5.1 Measurement accuracy

The IEEE standard C57.13.6-2008, “*Requirements of Instrument Transformers*”, is used for the selecting and designing VTs and CTs [24] appropriate for the application in mind. It can be understood that during the design of a magnetic interface between the power system voltage and current to the instrumentation circuit, that it is not possible to have an exact turns ratio for one. Due to the mechanical construction, the number of windings on the primary side that must perfectly couple by magnetic flux to the windings on the secondary side, cannot be set to result in for example a perfect 100:1 ratio. Also, the phase relation between the primary and secondary quantities can be skewed as a result of the magnetic characteristic of VT or CT.

In ideal instrument transformers the deviations from nominal ratios are 1 for the magnitude ratio correction factor (MCF) and 0 degrees for the phase angle correction factor (PACF), resulting in a complex ratio correction factor (RCF) [1]. In standards document, this complex RCF is also referred to as a vector because it consists of magnitude and phase angle.

In real-world applications, VTs and CTs are a source of biased measurements if not properly calibrated. Ratio correction factors are affected by temperature, loading, humidity, atmospheric pressure and ageing during the expected life-cycle.

The IEEE has established standardized methods for classifying instrument transformers as to their accuracy and connected burden. Burden refers to the amount of resistance and inductance connected to the instrument transformer’s secondary side.

Metering accuracy classes are defined by IEEE C57.13-2008 “*Standard Requirements for Instrument Transformers*” [1]. A transformer correction factor is defined as the factor by which the Watt-meter reading must be multiplied to correct the combined effect of the instrument transformer ratio correction factor and phase angle when deriving power from the secondary voltage and current quantities.

Accuracy classes for metering are based on requirements for the TCF for the VT and CT to be within certain specified limits when the power factor of the metered load is between 0.6 to 1.0, under the following specified conditions [1]:

Current Transformers: at the specified standard burden at 10 % and at 100% of the rated primary current.

Voltage Transformers:

- at any burden in VA (voltamperes) from zero to the specified standard burden;
- at the specified standard burden power factor;
- at any voltage from 90% to 110% of the rated voltage.

It should be noted that the accuracy class at a lower standard burden is not necessarily the same at the specified standard burden. Transformer correction factors for standard accuracy classes as defined in IEEE C57.13 (between 0.6 to 1.0 lagging power factor) are listed in Table 2-1.

Table 2-1: Standard accuracy class limits of TCF [1]

Metering accuracy class	Voltage transformers (at 90% to 110% rated voltage)		Current Transformers			
	Minimum	Maximum	At 100% rated current		At 10% rated current	
			Minimum	Maximum	Minimum	Maximum
0.3	0.997	1.003	0.997	1.003	0.994	1.006
0.6	0.994	1.006	0.994	1.006	0.988	1.012
1.2	0.988	1.012	0.988	1.012	0.976	1.024

For the different metering accuracy classes, parallelograms are used such as in Figure 2-5 to determine if the correction vector RCF is within the requirements of IEEE C57.13-2008. When the RCF dwells inside the border of the parallelogram, the standard is satisfied for a certain accuracy class. These parallelograms, for voltage and current transformers respectively, are shown in Figure 2-5 and Figure 2-6.

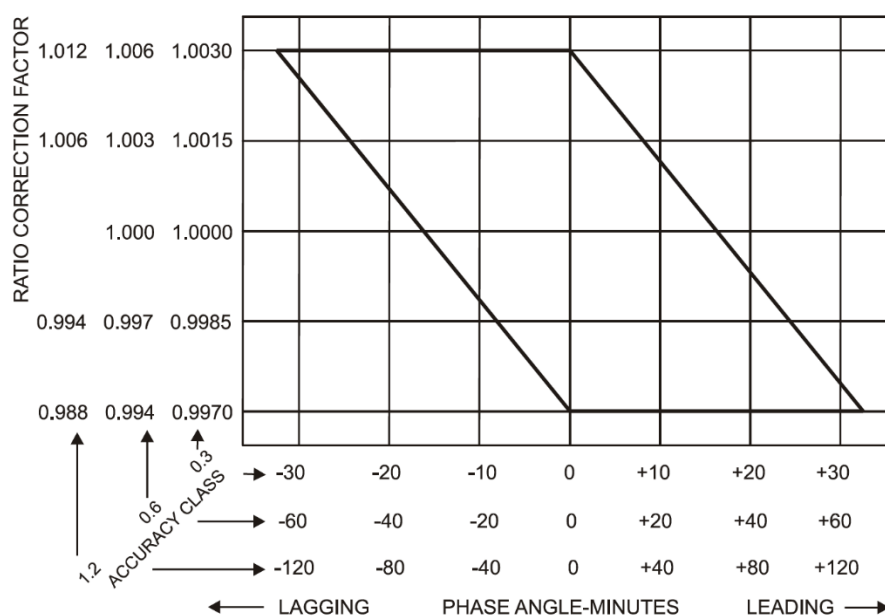


Figure 2-5: Limits for accuracy classes for voltage transformers for metering [1]

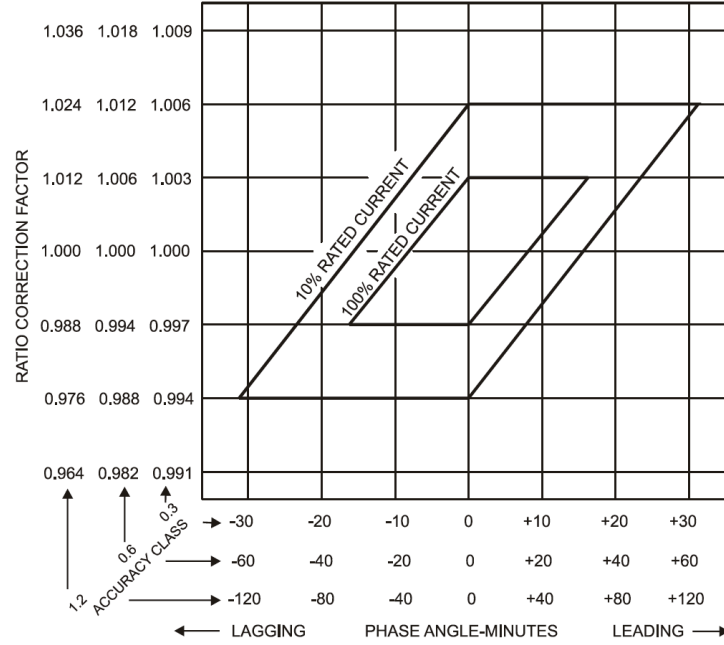


Figure 2-6: Limits for accuracy classes for current transformers for metering [1]

Calibration of an instrument transformer is a well-developed science and engineering practice widely applied. Some of the relevant principles are discussed next.

2.5.2 Standard methods for calibration of instrument transformers

Instrument transformer calibration can be done by standard methods [1] developed to this purpose. In general, the ratio between the primary and secondary quantities of an instrument transformer (voltage and current) is described by equation (2-13):

$$\frac{Q_1}{Q_2} = N_o(1 + a)e^{-jb} \quad (2-13)$$

In the equation above, Q_1 is the primary phasor at the fundamental frequency, Q_2 the secondary phasor at the fundamental frequency, N_o the nominal ratio, a is the ratio correction factor, and b is the phase angle correction factor. Calibration aims to determine a and b for the instrument transformer under test.

This standard method of calibration [1] was developed for a fundamental frequency component only. Distorted waveforms can impact the calibration performance of an instrument transformer. The RCF pertaining to higher frequency components (harmonics) do not perfectly relate to the RCF pertaining to the fundamental frequency. Phase angle, when using the 50 Hz calibration and RCF information, could lead to significantly incorrect results as frequency increase [1].

Limits for measurement uncertainty limits are defined [1] for revenue metering and other applications such as relaying and load control, shown in Table 2-2.

Table 2-2: Maximum uncertainty for ratio and phase angle [1]

Instrument Transformer Application	Maximum Uncertainty	
	Ratio	Phase Angle
Revenue metering	$\pm 0.1 \%$	$\pm 0.9 \text{ mrad} / \pm 0.5157^\circ$
Relaying, load control, similar applications	$\pm 1.2 \%$	$\pm 17.5 \text{ mrad} / \pm 1.0027^\circ$

For metering purposes, the calibration method should determine both ratio and phase angle as discussed next. When required for relaying purposes, only ratio must be determined, either experimentally or by means of computation.

2.5.2.1 Classification of calibration methods

Instrument transformer calibration methods are divided into null and deflection methods. The null-method makes use of networks in which suitable phasor quantities are balanced against each other [1], or in which the small variances are cancelled by the injection of a suitable voltage or current.

Phasor quantities can either be voltage or current of the transformer under test or the parameters which are known functions of these. The condition of balance or compensation is indicated by a null-detector. Benefits of the null-method include high precision and low uncertainty [1].

Deflection methods make use of deflections of appropriate instruments to measure quantities associated to the phasors under consideration or to their variance. An advantage of the deflection method is that it can be simple, but a disadvantage is the high level of uncertainty [1]. Deflection methods are not recommended by IEEE C57.13-2008 [1].

Two different null-methods exist, namely the direct-null and the comparative-null method.

1. Direct-null method:

- a. The ratio and phase relation of the primary and secondary phasors (current or voltage) are determined from the impedances of the measuring network;
- b. Voltage and current values are specific to the primary and secondary quantities considered.

2. Comparative-null method:

- a. Transformer under test is compared to an instrument transformer of known ratio through an impedance network.

In both the direct-null and comparative-null method, the ratio and phase angle of the reference instrument transformer and the critical impedance parameters [1] should be known. Specific tests for a CT and VT are discussed next.

2.5.2.2 Calibration methods of current transformers

Comparative-null methods measure through using magnetic effects (directly/indirectly) and measure a small difference between the output of the ratio standard and test transformer. It offers minimum uncertainty in the ratio and phase angle with errors at a level of 1 ppm to 20 ppm (parts per million) [1]. Initial design of the current-comparator test will be done in a special laboratory, but current-comparator based tests with a higher uncertainty are commercially available and as ease of operation increases, the calibration uncertainty will normally also increase [1].

Errors when using direct-null methods, where ratio and phase angles are determined from impedances, are within 200 ppm. These methods are used when the higher level of uncertainty [1] obtained, is acceptable.

CT calibration methods are discussed below, arranged from the highest to the lower accuracy as specified in IEEE C57.13-2008) [1].

Current comparator method (using a difference network)

This method has minimum calibration uncertainty between 1 ppm and 20 ppm in both ratio and phase angle. The current comparator makes use of ampere-turn balance to obtain zero average flux in the core, eliminating the main source of measurement error.

A circuit diagram is shown in Figure 2-7 to illustrate this simplistic measuring principle. A toroidal core of high permeability, located at d, carries a uniformly distributed detection winding that adequately samples the flux in the core and indicates its zero state by means of a detector connected across the winding terminals.

At point c, following an electrostatic shield is a compensation winding that is uniformly distributed on the core with the composite array nested within a magnetic shield of appropriate dimensions. The secondary and primary windings are placed over the shield, enclosing both core and shield. The shield functions as a second magnetic core and forms a CT with primary and secondary windings and is the first stage of an electromagnetic network with power transfer capability.

The compensation winding within the shield has a number of turns equal to the secondary winding and is connected across a secondary branch to provide a path for the error current of the first stage. If the comparator is adequately designed, the summation of the ampere-turns applied to the core is zero and the detector will indicate null.

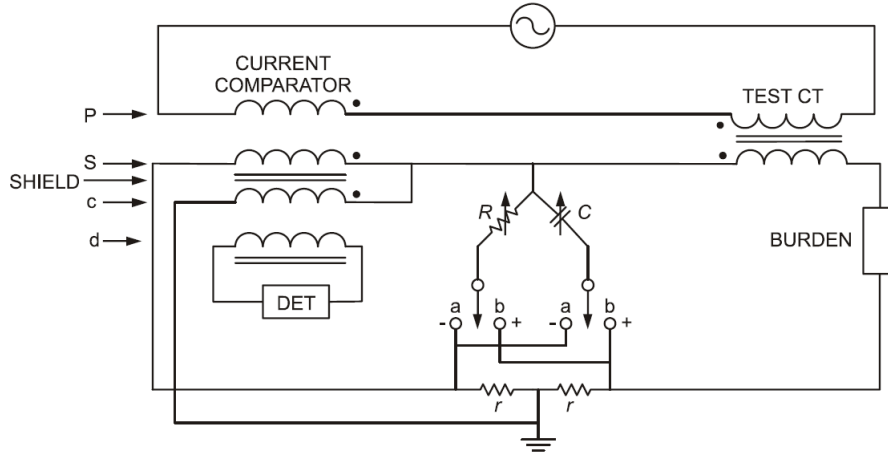


Figure 2-7: CT accuracy test for current comparator method [1]

The two-stage combination effectively appears as a short-circuit to the secondary winding of the CT under test and imposes no burden to the CT under test. With the secondary ending connected and the primary winding in series with the current comparator, the ampere-turn balance is maintained if the CT under test has zero error.

If an error exists, that current enters the comparator and upsets the balance. The resistor-capacitor network, as shown in Figure 2-7, is arranged to carry the difference in current and is adjusted to restore the balance. Error, ϵ , of the CT under test is then given by equation (2-14):

$$\epsilon = \pm \left(\frac{r}{R} + j\omega r C \right) \quad (2-14)$$

Above, $\frac{r}{R}$ is the ratio error and $\omega r C$ the phase angle error³.

This current comparator method using a difference network can be adjusted by adding an auxiliary transformer in the measuring circuit with the same nominal ratio that operates on the same balancing principle as the current comparator. Adding the auxiliary transformer increase the uncertainty in error calculation.

Standard current transformer (using a direct-null difference network)

The standard current transformer method requires a reference CT. Calibration uncertainty of this method is determined by the CT that serves as the ratio standard (being the reference) resulting from the accuracy and stability of its calibration data.

³ Phase angle error in the IEEE C5713-2008 methods are calculated in radians.

Figure 2-8 shows the circuit diagram of how the standard current transformer method is configured. It includes a current comparator that magnetically links the two secondary circuits and forms part of the measuring network. The primary windings of the CTs are in series with the secondary winding of the reference CT connected in series to the comparator winding having n_s number of turns and through a resistor, $2r$, tapped at its midpoint. Secondary winding of the test CT is connected to the second comparator winding with n_x number of turns.

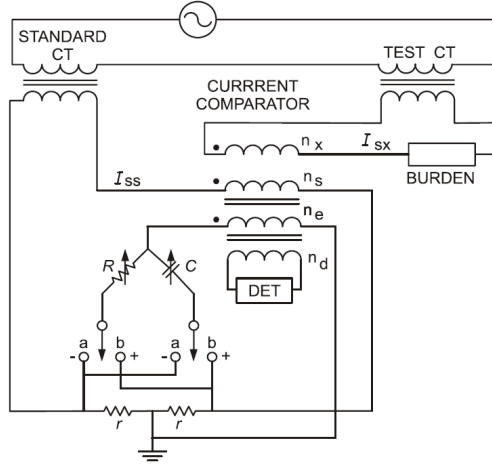


Figure 2-8: CT accuracy test for direct-null difference network [1]

To achieve a balanced magnetic condition, the comparator windings are orientated so that the ampere-turns act oppositely to the comparator core as required by balance equation (2-15):

$$I_{ss} \times n_s = I_{sx} \times n_x \quad (2-15)$$

I_{ss} is the nominal secondary current of the reference CT and I_{sx} the nominal secondary current of the CT under test.

In Figure 2-8, n_e indicates the number of turns on the error winding, distributed on the comparator core connected across the r segments through a RC network where the null balance has to be obtained. The error of the CT under test is given by equation (2-16) below, ϵ_s being the known error of the reference CT:

$$\epsilon = \epsilon_s \pm \left(\frac{n_e}{n_s}\right)\left(\frac{r}{R} + j\omega rC\right) \quad (2-16)$$

Two impedance method (direct-null network)

Various direct-null networks exist such as the example network shown in Figure 2-9. The minimum calibration uncertainty achievable with this method is 100 ppm, primarily set by the difficulty encountered during the design of the measurement circuit. During the design of the network, the stability of the impedance elements has to be determined.

The primary winding in Figure 2-9 is connected in series with the fixed four-terminal non-inductive resistor R_1 with the secondary winding in series with the adjustable four-terminal resistor R_2 and the primary winding of the variable mutually coupled inductor, M . Balance is achieved by adjusting R_2 and M to obtain a null condition at the detector.

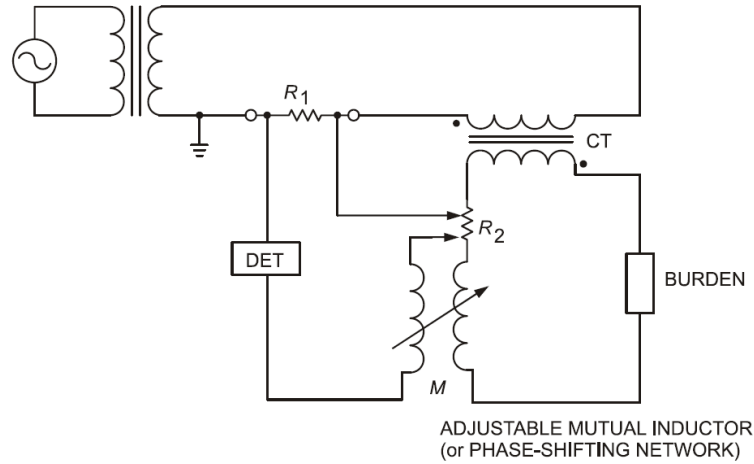


Figure 2-9: CT accuracy test with direct-null network [1]

Requirements for the balanced condition are set in equation (2-17) for ratio error and in equation (2-18) for phase angle.

$$N_x = \frac{R_2}{R_1} \quad (2-17)$$

$$\gamma_x = \frac{\omega M}{R_2} + (\theta_1 - \theta_2) \quad (2-18)$$

Where R_1 and R_2 are the ac resistance values, θ_1 and θ_2 phase angles in radians.

Standard current transformer method (using a comparative-null direct comparison network)

Figure 2-10 shows a typical circuit topology known as the comparative-null network similar to the topology of the direct-null network. Resistor R_1 is now replaced by a reference CT and a four-terminal resistor R_3 .

Balancing procedure of this method is identical to that of the direct-null method and similar minimum uncertainty (when using a direct-null network) can be achieved if the reference CT is well calibrated. Equation (2-19) determines the ratio and equation (2-20) phase angle.

$$N_x = N_s \frac{R_2}{R_3} \quad (2-19)$$

$$\beta_x = \beta_s + \frac{\omega M}{R_2} + (\theta_3 - \theta_2) \quad (2-20)$$

Where N_s and β_s are the ratio and phase angle of the reference CT, θ_3 and θ_2 the phase angles of the respective resistors.

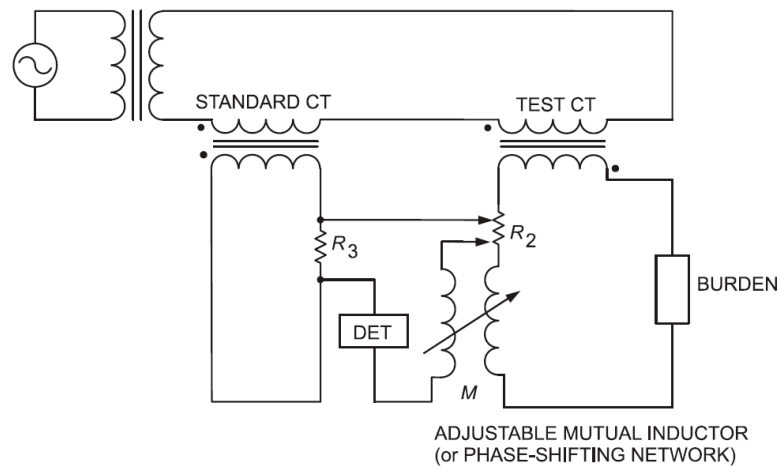


Figure 2-10: CT accuracy test with comparative-null network [1]

2.5.2.3 Calibration of voltage transformers

Both the direct-null and comparative-null methods can be used to determine the ratio and phase angle needed for voltage transformer calibration. For the comparative-null method the ratio and phase angle are determined using a reference transformer with known parameters.

Primaries of the VT under test and the reference VT are connected in parallel to a common source and measurements made at secondary level.

Two types of comparative-null methods exist, namely difference and direct comparison. Calibration uncertainty using a comparative-null method for calibrating a VT is less than 100 ppm [1].

In the direct-null method precision capacitors are used and divided into two main groups:

Group One – Voltage divider is created by connecting two capacitors in series to accommodate the voltage of the secondary and primary windings. It can be connected either in additive or subtractive mode. A null-detector is located between the two points of nearly equal voltage and is brought to null by injecting the adequate parameters.

Group Two – Each capacitor is connected in series to the winding of the current comparator and energized separately. Ratio balance is achieved by adjusting the number of turns on the comparator windings. Phase angle balance is achieved by the injection network operating in the third winding of the current comparator.

The direct-null method can also make use of resistive dividers, resulting in limited uncertainty and voltage range. Calibration uncertainty is in the range of 30 to 100 ppm depending on how careful measurements were done. The capacitive method is considered more accurate, being in the range of 2 ppm to 20 ppm.

Calibration methods for VTs are listed below, arranged from achieving the highest measurement accuracy (lowest uncertainty) to the lowest accuracy as describe in IEEE C57.13-2008 [1].

Current comparator capacitance ratio method (direct-null)

In Figure 2-11 the basic circuit configuration is shown. C_1 and C_2 are low-loss capacitors and accommodates the voltages of the primary and secondary windings in subtractive polarity. The current comparator is shown as a single magnetic core with three windings; n_1 , n_2 and n_d where n_2 is adjustable serving as a multiplier in larger steps, n_1 is also adjustable and provides a finer adjustment for the final ratio balance.

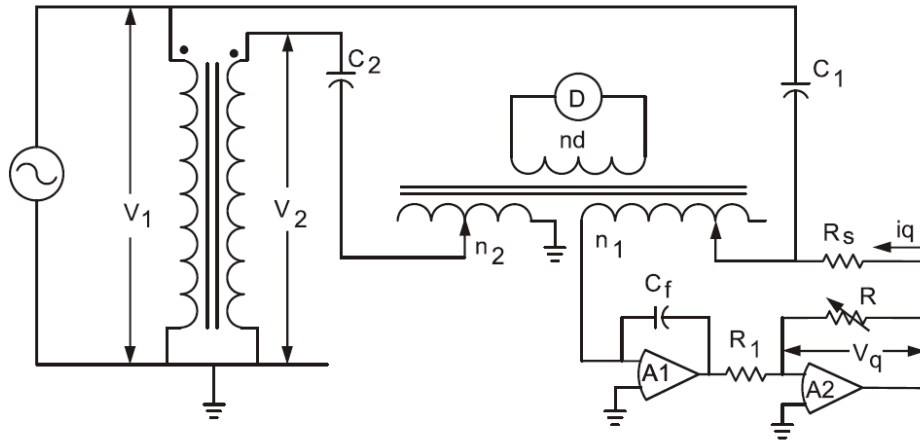


Figure 2-11: VT accuracy test with current comparator (direct-null) – Capacitance ratio method [1]

Operational amplifiers A_2 located across variable resistor R produce voltage V_q , proportional and in phase to V_1 . A_2 injects current I_q , proportional to R into n_1 providing quadrature balance. Ampere-turns balance is indicated by the null-detector at D . Balance equations are defined for ratio in equation (2-21) and for phase angle in equation (2-22) below:

$$N_x = \frac{V_1}{V_2} = \frac{C_2 \times n_2}{C_1 \times n_1} \quad (2-21)$$

$$\gamma_x = \frac{R_1}{R_2} (\omega \times R_s \times C_f) \quad (2-22)$$

This method is ideal for laboratory conditions to obtain a minimum calibration uncertainty of 20 ppm, the most accurate approach for VT calibration.

Capacitance divider method (direct-null network)

The capacitance divider method can have calibration uncertainty as low as 20 ppm for ratio and 20 μ rad for phase angle, shown in Figure 2-12. VT windings are connected in an additive mode to the capacitors C_1 and C_2 , accommodating the primary and secondary voltages. Inductive voltage dividers are used for adjustments in the ratio and phase angle. B is used for ratio balance.

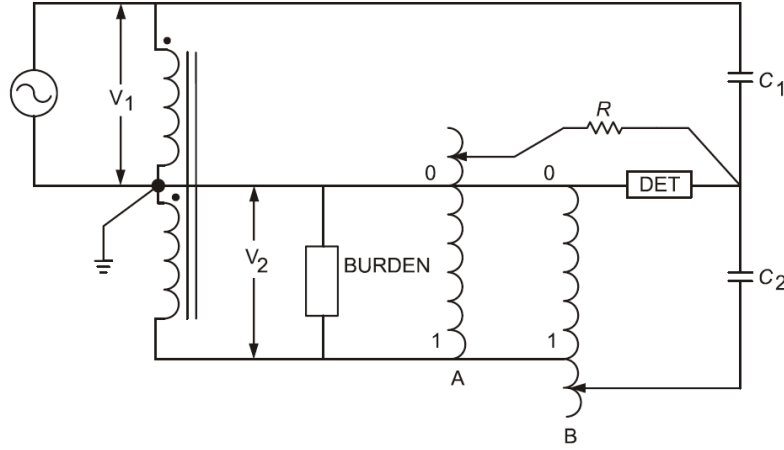


Figure 2-12: VT accuracy test (direct-null) – Capacitance divider method [1]

Quadrature balance is achieved by divider A by the injection of a small current through resistor R . In order to measure both the positive and negative errors adjustment above unity on B and below zero on A . Equation (2-23) is the ratio error and equation (2-24) the phase angle error, where N_a and N_b are the ratios of the dividers.

$$N_x = \frac{C_2}{C_1} N_b \quad (2-23)$$

$$\gamma_x = N_a \left(\frac{1}{j\omega C_2} \right) \quad (2-24)$$

Calibration uncertainty obtained by this method is dependent on knowledge of the capacitance ratio and can be best determined by using a transformer-ratio-arm bridge. The capacitance ratio should be determined at the time of calibration to ensure highest level of certainty.

Resistance divider method (direct-null network)

The resistance divider method has a minimum calibration uncertainty level of 100 ppm and is limited to tests done below 30 kV due to heating effects. Circuit topology of the method is shown in Figure 2-13. Resistance ratio is measured directly after measuring the variable transformer ratio. The resistance string is in series with the primary side of the mutually shared inductor M , connected to the high-voltage side of the VT under test.

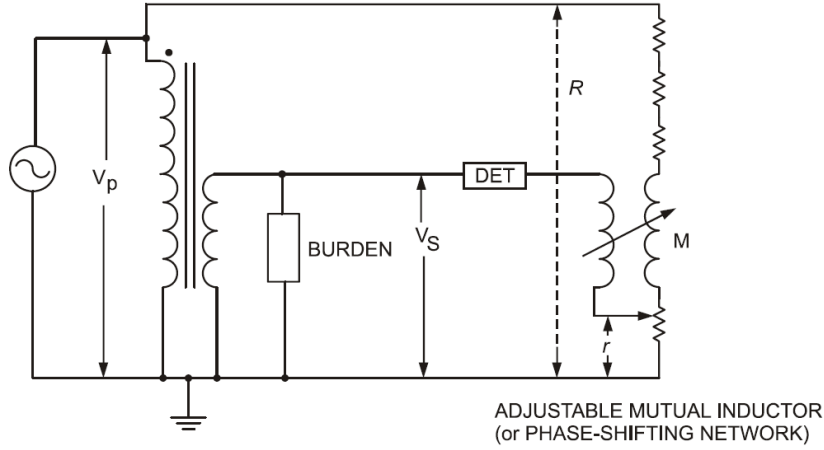


Figure 2-13: VT accuracy test (direct-null) – Resistance divider method [1]

Voltage equal and opposite to the secondary winding of the VT is provided by adjusting M and then R to achieve a null on the detector. Equation (2-25) describes the ratio equation for balance and the phase angle is described by equation (2-26):

$$N_x = \frac{V_p}{V_s} = \frac{R}{r} \quad (2-25)$$

$$\gamma_x = \omega \left(\frac{M}{r} - \frac{L'}{R} \right) \quad (2-26)$$

L' takes account of the phase angle resulting from the series combination of resistor R and the self-inductance in the primary winding of mutual inductor, M . V_p is the voltage on the primary side of the VT and V_s is the secondary side voltage.

Pseudo-bridge method (direct-null network)

The pseudo-bridge method has a minimum calibration uncertainty of 100 ppm, shown in Figure 2-14. Balance is obtained in the pseudo-bridge by adjustment of the capacitances C_2 and C_3 . Equations during balance for ratio and phase angle are shown in equation (2-27) and (2-28) respectively.

$$N_x = \frac{V_p}{V_s} = \frac{C_2}{C_1} \times \frac{R_4}{R_3} \quad (2-27)$$

$$\gamma_x = \omega [R_3 \times (C_1 + C_3) - R_4 \times (C_2 + C_4)] \quad (2-28)$$

Each parameter in equations (2-27) and (2-28) contribute to uncertainty, increasing the overall calibration uncertainty for ratio and phase angle. This method can be optimised by first determining capacitance by a Schering bridge and then to repeat the calibration measurements with the two RC networks interchanged.

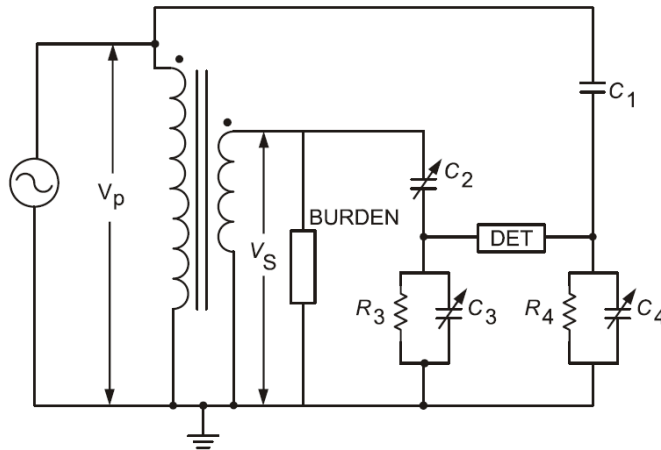


Figure 2-14: VT accuracy test (direct-null) – Pseudo bridge method [1]

Comparative-null methods

Comparative-null methods determine the balance for ratio and phase-angle by comparing the VT under test to that of a reference VT with parameters for ratio and phase angle known. Primary windings of the transformers are connected to a common source and measurements are made at secondary level.

A typical comparative-null method is shown in Figure 2-15. Calibration uncertainty obtained by this method depends on accurate knowledge of a pre-calibrated reference VT. Accuracy can be obtained up to a minimum calibration uncertainty of 2 ppm for ratio and 10 μ rad for the phase angle, depending on errors of the reference VT.

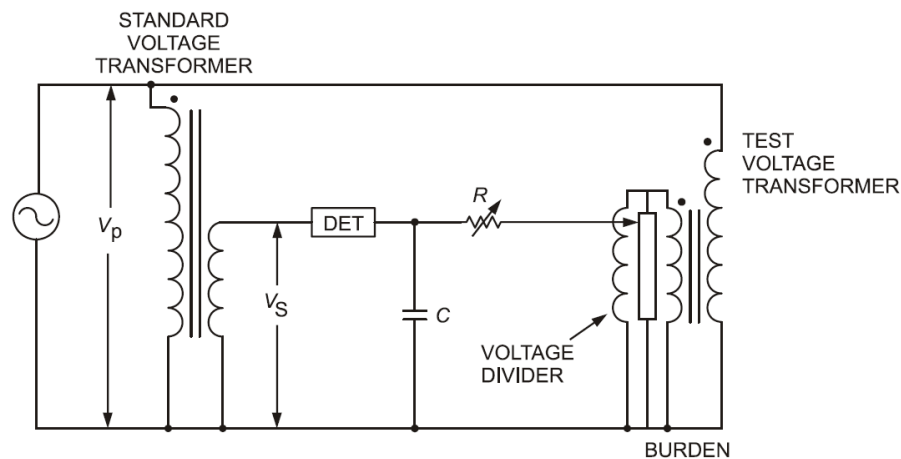


Figure 2-15: VT accuracy test – Comparative-null method [1]

A high-impedance inductive voltage divider is connected in Figure 2-15 to the secondary side of the VT under test. Balance is obtained for the in-phase voltage by fine-tuning the output of the voltage divider. Quadrature balance is achieved by adjusting either resistor R or capacitor C .

If voltage phase angle at the secondary side of test VT is leading the phase angle of the reference VT, resistor R will be located as shown in Figure 2-15. If voltage phase angle is lagging the phase angle of the reference VT, the locations of R and detector are interchanged.

Equations for balance in ratio and phase angle are shown below in equation (2-29) and (2-30) respectively.

$$N_x = \frac{N_s}{N_d} \quad (2-29)$$

$$\gamma_x = \theta_s + \omega CR \quad (2-30)$$

Where N_x is the ratio of the unknown VT, N_s the ratio of the reference VT and N_d the ratio of the inductive voltage divider.

2.5.2.4 Special considerations

Special considerations should be made when calibrating for metering purposes to avoid decreasing the accuracy of the calibration method [1]. These considerations include:

- Measuring network should avoid spurious magnetic coupling and generation of unknown electromagnetic forces. Consideration should be given to where the measuring network is placed as nearby electromagnetic fields can affect performance. Placement of CTs are the most important due to the increased magnetic fields resulting;
- Proper use of grounding, ground reference and electrostatic shielding;
- Minimum uncertainty in calibration data requires normal (nameplate) operating conditions of the transformer under test;
- Test equipment should have sufficient thermal capacity to accurately test CTs.

2.6 Transmission Line Parameters

An important requirement, for remote characterisation of an instrument transformer where an impedance is present between the two points where synchrophasors are recorded, is that line parameters are known with a high level of certainty. In a field application, the line parameters can be provided by the electrical utility who uses a computer simulation to obtain these parameters.

Simulations done in this research is based on modelling of the physical construction of a line to reflect tower geometry, conductor types and configuration. Transmission line parameters to be derived include resistance, conductance, capacitance and inductive reactance. These values depend on spiralling, temperature, frequency, magnetic and electrical factors, environmental and mechanical characteristics.

Transmission line parameters and modelling of a transmission line are briefly reviewed next.

2.6.1 Transmission line theory

Four basic impedance parameters are used to construct a circuit equivalent of a transmission line, series resistance R , series inductance L , shunt capacitance C and shunt conductance G . Generally referred to as “transmission line constants” as they should not change much over time as the physical construction of a transmission line should remain the same.

A 2-port network approach can be used to model the electrical relation between the input- and output parameters of a transmission line as shown in Figure 2-16. V_s and I_s are the sending end voltage and current fundamental frequency phasors, V_R and I_R are the receiving end voltage and current fundamental frequency phasors [15].

Modelling of a transmission line in this research, address fundamental frequency components only as the remote characterisation of the instruments transformers under investigation, make use of fundamental frequency synchronised voltage and current phasors (synchrophasors).

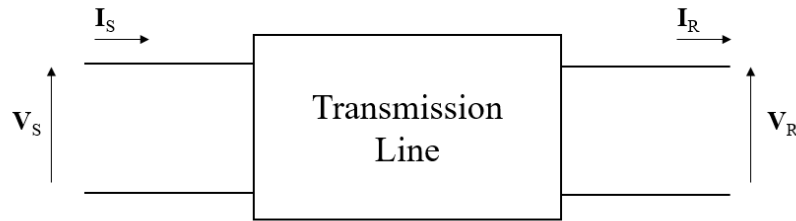


Figure 2-16: Two-port network for transmission line model

The relation between sending end and the receiving end voltage phasor can be described using a 2-port modelling approach in equation (2-31) below.

$$V_s = AV_R + BI_R \quad (2-31)$$

$$I_s = CV_R + DI_R$$

Where A , B , C , and D are complex parameters derived from transmission-line constants, R , L , C , and G .

$ABCD$ parameters are usually complex values. A and B are dimensionless, B is measured in ohms and C in Siemens. During modelling of a linear, passive, bilateral two-port networks by means of a 2-port $ABCD$ parameters approach, the relation in equation (2-32) applies [15]:

$$AD - BC = 1 \quad (2-32)$$

In 50 Hz networks, a short line is considered being less than 100 km, a medium line from 100 km to 300 km and long lines are more than 300 km long.

Shunt admittance and conductance can be neglected when modelling a short line as shown in Figure 2-17 for both single-phase or fully transposed three-phase lines operated under balanced loading conditions and symmetrical sinusoidal supply voltages.

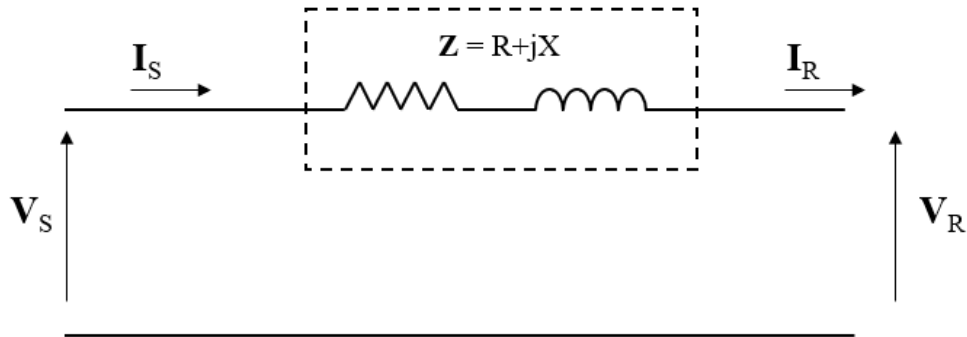


Figure 2-17: Short transmission line equivalent circuit model [15]

There are two different approximations for the medium length transmission line, depending on the nature of the network, known as a nominal π -circuit, shown in Figure 2-18, or the nominal T-circuit, shown in Figure 2-19. In the nominal π -circuit the lumped series impedance is placed in the middle, and the shunt admittance divided into two equal parts and placed at the ends of the line.

In the nominal T-circuit, the shunt admittance is placed in the middle and the series impedance divided into two equal parts placed at either side of the shunt admittance.

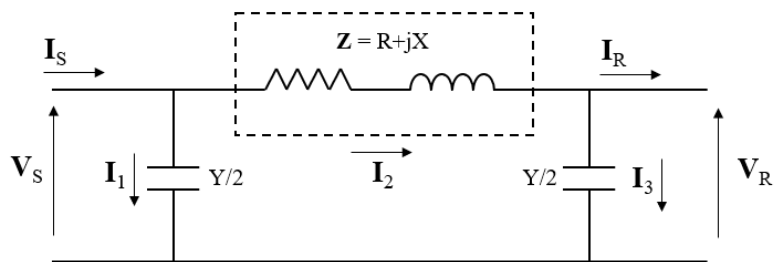


Figure 2-18: Medium length transmission line – nominal π -circuit

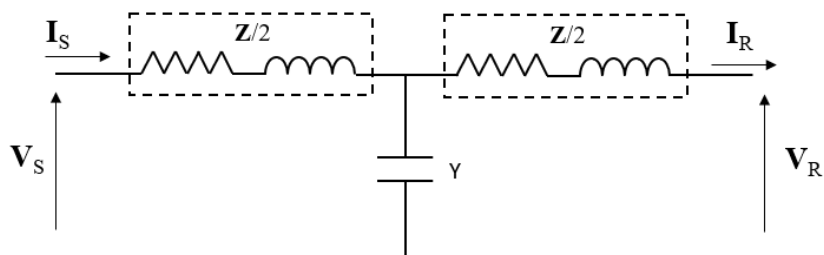


Figure 2-19: Medium length transmission line – nominal T-circuit

Considering the nominal π -circuit, Kirchoff's current and voltage laws are applied to derive the $ABCD$ parameters from transmission line parameters in equation (2-33) below.

$$\mathbf{A} = \mathbf{D} = 1 + \frac{\mathbf{YZ}}{2} \text{ (per unit)} \quad (2-33)$$

$$\mathbf{B} = \mathbf{Z} \Omega$$

$$\mathbf{C} = \mathbf{Y} \left(1 + \frac{\mathbf{YZ}}{4} \right) \text{ S}$$

The 2-port network equivalent is the same viewed from either end, $\mathbf{A} = \mathbf{D}$. $ABCD$ parameters in the nominal T-circuit are listed in equation (2-34) below.

$$\mathbf{A} = \mathbf{D} = 1 + \frac{\mathbf{YZ}}{2} \text{ (per unit)} \quad (2-34)$$

$$\mathbf{B} = \mathbf{Z} \left(1 + \frac{\mathbf{YZ}}{4} \right) \Omega$$

$$\mathbf{C} = \mathbf{Y} \text{ S}$$

In real life, transmission line parameters are distributed over the length of the line. If the line is less than 300 km, lumping those parameters as done above, is normally acceptable. An exact analysis of a transmission line requires consideration of the distributed nature.

Consider a length of line, Δx located at point x within the total distance l of a line as shown in Figure 2-20. $ABCD$ parameters per line-length Δx are referred to as distributed $ABCD$ parameters and become exact $ABCD$ parameters when accounting for the total length l as shown in equation (2-35) below.

$$\mathbf{A} = \mathbf{D} = \cosh(\gamma l) \quad (2-35)$$

$$\mathbf{B} = \sinh(\gamma l) \Omega$$

$$\mathbf{C} = \frac{\sinh(\gamma l)}{Z_c} \text{ (S)}$$

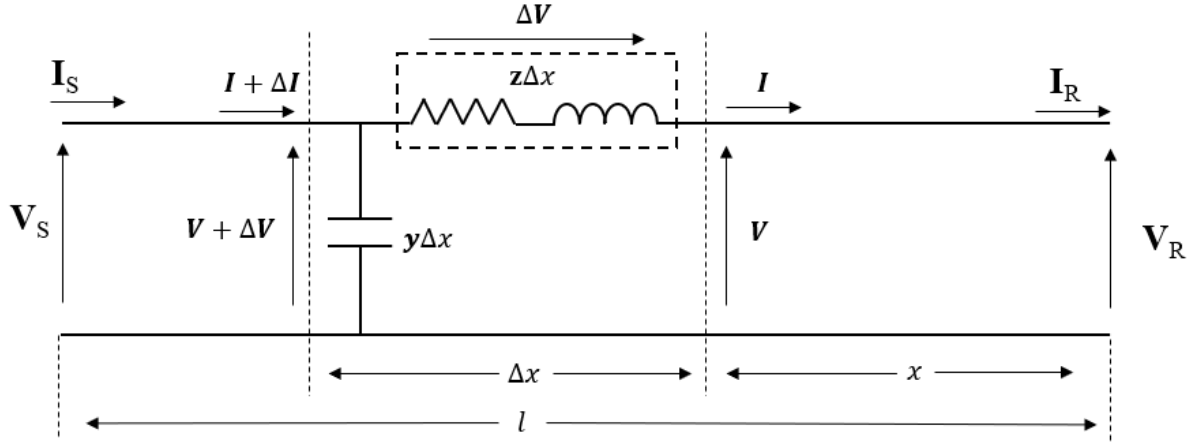


Figure 2-20: Distributed nature of transmission line parameters

An equivalent π -circuit identical in structure to that of the nominal π -circuit can be used to model the long line, shown in Figure 2-21 making use of equivalent impedance and admittance. It is convenient to represent the terminal characteristics of a transmission line by an equivalent circuit rather than $ABCD$ parameters when a power system simulator is to be used as solving current and voltages in an equivalent circuit is a well-used principle in computer modelling.

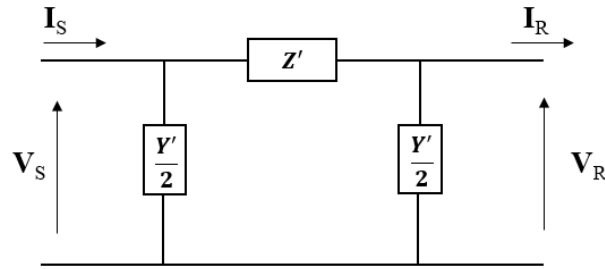


Figure 2-21: Equivalent π -circuit representation of long transmission line

Figure 2-21 is similar to the nominal π -circuit, except that Z' and Y' are now used instead of Z and Y , where Z' and Y are regarded as “equivalent” π -circuit impedance and admittance elements relating input- and output parameters of the long line in an “equivalent” way. Equivalent $ABCD$ parameters can be derived as shown in equation (2-36) below, taking into account the distributed nature of transmission line parameters.

$$A = D = 1 + \frac{Y'Z'}{2} \text{ (per unit)} \quad (2-36)$$

$$B = Z' \Omega$$

$$C = Y' \left(1 + \frac{Y'Z'}{4} \right) S$$

Where $\mathbf{Z}' = \mathbf{Z}_c \sinh(\gamma l)$ and $\frac{\mathbf{Y}'}{2} = \frac{\mathbf{Y}}{2} \left(\frac{\tanh(\frac{\gamma l}{2})}{\frac{\gamma l}{2}} \right)$

Transmission line parameters are useful to determine power transfer capabilities and constraints of a line resulting from the thermal-, voltage regulation and stability limitations.

2.6.2 Estimation of transmission line parameters

Transmission line parameters are used for a range of operational applications such as protection settings, locating faults, scheduling power flow and monitoring transmission losses. They cannot be measured directly as application of design values of voltage and current cannot be done by a simple instrument. They are mostly calculated using the construction data of the transmission line [25]. These calculations will include approximations of physical parameters i.e. the effect of sag (which is continuously changing), ambient conditions (temperature, wind) and loading conditions, but cannot be determined with high levels of certainty.

If synchronized measurements are available at both ends of the line, it is in principle possible to estimate the transmission line parameters [25], reflecting the real-life conditions. An innovative approach using synchrophasors is analysed in Chapter 3. It allows the parameters to be tracked over time as the values are not fixed. In [26] PMU measurements used to derive transmission line parameters recognising instrument transformers ratio errors. It has to be included as the PMU measurement that is used makes use of instrument transformers.

2.7 Conclusion

Fundamental aspects of power system principles and instrumentation needed to derive an improved understanding on the calibration of a remote instrument transformer, were studied. Collectively, it was realised that this opportunity will possibly be a “remote characterisation” rather than calibration as some aspects traditionally adhered to by “calibration” as understood by the metrology specialist, will possibly not be fully included.

It confirmed the dualism that is realised when remote characterisation of an instrument transformer has to be done: Transmission line parameters for the line of interest have to be first derived and are affected by a chain of events contributing to measurement uncertainty. From this, characterisation of the remote instrument transformer is done. Careful attention is needed in evaluation the opportunity to derive an improved understanding of the RCF at a remote instrument transformer such that the results can be useful for improving power system state estimation.

CHAPTER 3: REMOTE INSTRUMENT TRANSFORMER CALIBRATION

Calibrating an instrument transformer by means of a remote method whilst in operation has so much potential in saving cost, time and improving the understanding of system technical performance that the fundamental aspects have to be analysed in detail. This is done in Chapter 3, serving as the input to derive a methodology to test this innovative idea.

3.1 Introduction: Where the initial idea originated

Remotely calibrating measurements has the advantage of being non-intrusive as it can be done without taking the system off-line as normally needed. In-situ calibration is labour intensive and requires specialist technicians.

Literature being analysed in this chapter use the concept of “calibration” and not “characterisation”, motivated earlier in this document, as the preferred concept. The reason for using “calibration” in the heading of this Chapter 3 literally reflects the literature studied - this literature was obtained from peer-reviewed publications.

This dissertation respects and recognises the founding principles from the science of metrology and later on in this dissertation the concept of “characterisation” is preferred for reasons motivated earlier.

The idea of remotely calibrating instrument transformers was first introduced in 1986 by M.M. Adibi [6]. It is based on an offline error analysis of repetitive unsynchronised measurements at only one substation. Adibi’s initial research determined [6] the errors using repetitive measurements obtained from instrument transformers. Measurement uncertainty in this measurement chain is contributed by conversion ratios, transducers needed to convert a current signal to a voltage signal, A/D converters and also the wiring between these devices.

RMC (remote measurement calibration) proposed in [6] calibrated one substation at a time using measurement data collected that was routinely collected at the same measurements point as shown in Figure 3-1. This avoided time-skewing of data, errors in networks connection and network impedances.

Measurements required for this approach for calibration are current (I_m), voltage (V_m), active (P_m) and reactive power (Q_m), based on three principles:

- **MVA equality:** which is the equality between volt-amperes derived from the real and reactive and power, and volt-amperes derived from the product between current and voltage;
- **kV equality:** which is the equality of all circuit voltages connected to the same bus;
- **Bus summing:** which is the summation of real and reactive power around the bus.

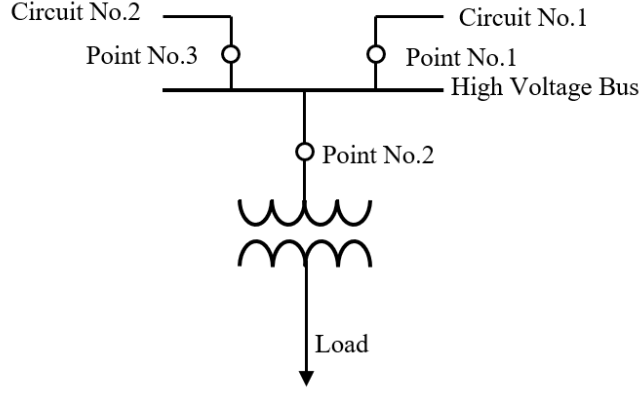


Figure 3-1: One-line diagram for RMC at one substation [6]

In equation (3-1) below, the relation at a certain time and location between measured and calibrated values is given. I_C , V_C , P_C , and Q_C are the respective calibrated values for current, voltage, active and reactive power. Coefficients A , B , and C are the zero off-set, the gain at origin and the quadratic coefficient respectively.

$$I_C = A + BI_m + CI_m^2 \quad (3-1)$$

$$V_C = A + BV_m + CV_m^2$$

$$P_C = A + BP_m + CP_m^2$$

$$Q_C = A + BQ_m + CQ_m^2$$

Calibration reference equations are used based on the three principles above, depending on the measurement data available from the substation.

- MVA equality calibration reference equation per point on the circuit:

$$MVA_1 = \sqrt{P_C^2 + Q_C^2} \quad (3-2)$$

$$MVA_2 = I_C \times V_C$$

$$\frac{MVA_1}{MVA_2} - 1 = 0$$

- kV equality if voltage data for more than one circuit or point per bus is available, where V_{C_1} and V_{C_2} are two different measured voltages at the same time at different locations:

$$V_{C_1} - V_{C_2} = 0 \quad (3-3)$$

- Bus summing if MW and MVAR data is available for all points per bus at a specific time and location:

$$\sum P_c = 0 \quad (3-4)$$

$$\sum Q_c = 0$$

Equations (3-1) to (3-4) are minimized over the entire set of measurements and for all the circuits to determine the quadratic coefficients in per unit using the Fletcher-Powell minimization method. The Fletcher-Powell method was developed in 1963 as an iterative gradient-descent method for finding a local minimum of a function with multiple variables. The method proved to quickly converge and to solve non-linear simultaneous equations [27].

Adibi's research initiated extensive research reported by various papers, using different approaches to the measurement problem and developing different algorithms for determining the ratio correction factor of instrument transformers

Improvement of this idea to do remote calibration of instrument transformers by estimating the RCF has later been researched using repetitive synchrophasor measurements. Two important PhD thesis publications represent the first significant contributions in this field. Both are analysed next with the goal to comprehensively evaluate opportunity for application under real-life conditions, being the focus of the research reported in this research dissertation

3.2 Remote calibration of instrument transformers by synchronised measurements

An important contribution analysed first, is the PhD thesis of M. Zhou, "*Advanced Systems Monitoring with Phasor Measurements*". M. Zhou worked under the guidance of Prof. Arun Phadke and Prof. James Thorp. Both professors are considered significant contributors to the Power Systems research industry and are associated with Virginia Tech in Blacksburg, Virginia, USA [28]

Together they received the Franklin Institute Benjamin Franklin Medal in Electrical Engineering in 2008 for their contributions in the power industry [29] and co-authored a publication titled "Synchronized Phasor Measurements and their Applications" [30] in 2008. Their research interests included power system engineering, power system protection and control, precise measurements, phasor measurement units and wide area measurements [28]. In 2016 Prof. Phadke also received the IEEE Medal in Power Engineering for his contributions to synchrophasor technology for monitoring, control and protection of electric power systems [31].

M. Zhou investigates different opportunities on the application of synchrophasor measurements to improve the performance of wide area monitoring (WAM) systems:

1. Optimal placement of PMUs by strategic installation of PMUs to progressively reach an optimised distribution of PMUs;
2. Synchrophasors being applied in state estimators to improve system state estimation;

3. Calibration on instrument transformers with synchrophasor to improve system monitoring accuracy [10].

In [32] various developments in state estimation are researched and analysed, as well as introducing a concept of using phasor measurements to estimate RCFs for instrument transformers that can improve the information on calibration. Using synchrophasors across a known impedance, a lightly loaded transmission line, VT correction factors are estimated. To estimate the CT correction factors, the VT correction factors are considered and synchrophasors across the line used during heavy loaded conditions.

Z. Wu [2] presented a three-phase instrument transformer calibration (“calibration” the concept in use by [2]) solution using synchrophasor measurements in addition to solutions for using PMUs to monitor small-signal stability, real-time topology tracking, real-time three-phase state estimation, islanding detection and system imbalances monitoring [2].

Analyses of the theoretical work done by Zhou [10] and Wu [2] are presented next.

3.2.1 “Advanced System Monitoring with Phasor Measurements” – M. Zhou

In Zhou’s method the combination of state estimation with instrument transformer calibration does not require the inclusion of accurate instrument transformer models, usually difficult to obtain [10]. The goal is to improve (calibrate) the RCF’s magnitude and angle by multiple synchrophasor measurements. Feasibility of this method has been investigated by means of computer simulation using the IEEE 14-bus systems [10].

Measurement contaminations is introduced to the synchrophasor measurements as shown by the voltage phasor measurement obtained, E in equation (3-5):

$$E = E_0 \times (a + jb) + \epsilon_E \quad (3-5)$$

E_0 represents the true voltage phasor, $(a + jb)$ the complex ratio correction factor and ϵ_E the Gaussian errors resulting from quantization errors in the PMU and GPS synchronization uncertainties.

Similarly, the current synchrophasor measurement I , is given by equation (3-6) below:

$$I = I_0 \times (c + jd) + \epsilon_I \quad (3-6)$$

Where I_0 represents the true current (synchrophasor) in the line from p to q with $(c + jd)$ the complex ratio correction factor (RCF) and ϵ_I the Gaussian errors resulting from quantization errors of the PMU and GPS synchronization uncertainties.

Equation (3-5) and (3-6) can be rewritten in rectangular coordinates, using a matrix format as shown in equation (3-7) and (3-8) below:

$$\bar{\mathbf{E}} = \begin{bmatrix} a & -b \\ b & a \end{bmatrix} \times \begin{bmatrix} E_{0r} \\ E_{0i} \end{bmatrix} + \begin{bmatrix} \varepsilon_{Er} \\ \varepsilon_{Ei} \end{bmatrix} \quad (3-7)$$

$$\bar{\mathbf{I}}_{pq} = \begin{bmatrix} c & -d \\ d & c \end{bmatrix} \times \begin{bmatrix} I_{0r} \\ I_{0i} \end{bmatrix} + \begin{bmatrix} \varepsilon_{Ir} \\ \varepsilon_{Ii} \end{bmatrix} \quad (3-8)$$

Where $\bar{\mathbf{E}}_0$ and $\bar{\mathbf{E}}_E$ each consist of real and imaginary components $E_{0r} + jE_{0i}$ and $\varepsilon_{Er} + j\varepsilon_{Ei}$ respectively.

If line parameters are known, the true current phasor measurement can be calculated as shown in equation (3-9) below,

$$\bar{\mathbf{I}}_{(pq)0} = \bar{\mathbf{Y}} \times \bar{\mathbf{E}}_0 \quad (3-9)$$

$$\begin{bmatrix} I_{(pq)r} \\ I_{(pq)i} \end{bmatrix} = \begin{bmatrix} Y_r & -Y_i \\ Y_i & Y_r \end{bmatrix} \times \begin{bmatrix} E_{0r} \\ E_{0i} \end{bmatrix}$$

$\bar{\mathbf{Y}}$ represents the conductance matrix of a line pq.

The relation between the measured current and voltage synchrophasor can now be written as shown in equation (3-10) below:

$$\begin{bmatrix} I_{(pq)r} \\ I_{(pq)i} \end{bmatrix} = \begin{bmatrix} c & -d \\ d & c \end{bmatrix} \times \begin{bmatrix} I_{0r} \\ I_{0i} \end{bmatrix} + \begin{bmatrix} \varepsilon_{Ir} \\ \varepsilon_{Ii} \end{bmatrix} = \begin{bmatrix} c & -d \\ d & c \end{bmatrix} \times \begin{bmatrix} Y_r & -Y_i \\ Y_i & Y_r \end{bmatrix} \times \begin{bmatrix} E_{0r} \\ E_{0i} \end{bmatrix} + \begin{bmatrix} \varepsilon_{Ir} \\ \varepsilon_{Ii} \end{bmatrix} \quad (3-10)$$

Using a simple two bus system shown in Figure 3-2, measurements from PMUs at bus p and bus q, result in four measurements: $\mathbf{V}_p$, $\mathbf{V}_q$, $\mathbf{I}_{pq}$, and $\mathbf{I}_{qp}$. Each of these measurements have their own calibration coefficients $\mathbf{CFV}_p$, $\mathbf{CV}_q$, $\mathbf{CI}_{pq}$, and $\mathbf{CI}_{qp}$, and are the true system state measurements of $\mathbf{V}_p$ and $\mathbf{V}_q$.

The above results in an underdetermined set of equations. There are more unknowns than the number of equations, with the possibility of an infinite number of solutions.

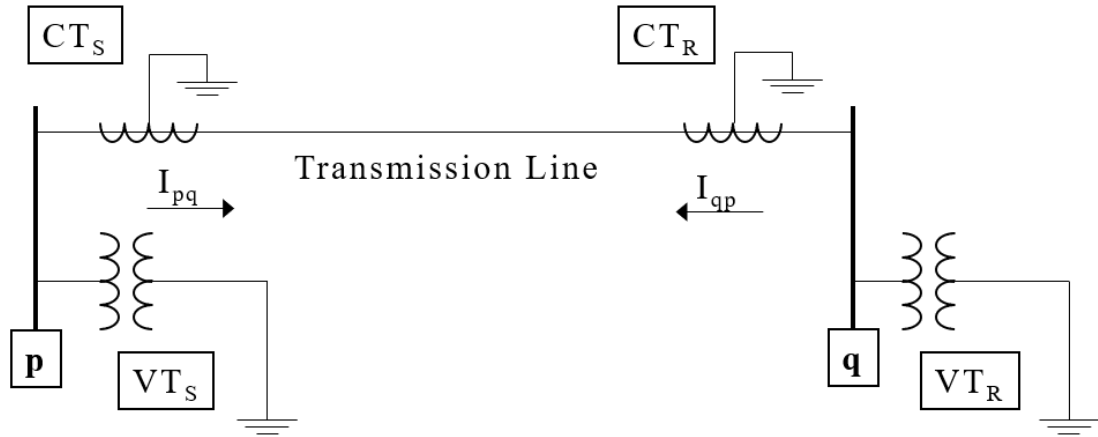


Figure 3-2: Two-bus system [10]

To find a solution that converges to a unique solution, the number of measurements must be increased by measuring over a longer period. It is generally assumed that the RCF will remain constant during such a period of investigation as instrument transformers operate linearly within their characteristic curve [10]. Therefore, the RCFs will remain fixed whilst the system operating conditions and system state may change.

The conventional system then reformulates the state estimation problem to incorporate the RCF and PACF as independent state variables. This is done in equation (3-11), represented by matrix $\bar{H}$ that combines the VT and CT ratio correction factor. $\bar{H}$ is composed by the derivatives of voltage and current phasor measurements to the system state and the complex VT and CT correction factors.

$$\bar{H} = \begin{bmatrix} \frac{\partial E_r}{\partial E_{0r}} & \frac{\partial E_r}{\partial E_{0i}} & \frac{\partial E_r}{\partial a} & \frac{\partial E_r}{\partial b} & \frac{\partial E_r}{\partial c} & \frac{\partial E_r}{\partial d} \\ \frac{\partial I_{(pq)r}}{\partial E_{0r}} & \frac{\partial I_{(pq)r}}{\partial E_{0i}} & \frac{\partial I_{(pq)r}}{\partial a} & \frac{\partial I_{(pq)r}}{\partial b} & \frac{\partial I_{(pq)r}}{\partial c} & \frac{\partial I_{(pq)r}}{\partial d} \\ \frac{\partial E_i}{\partial E_{0r}} & \frac{\partial E_i}{\partial E_{0i}} & \frac{\partial E_i}{\partial a} & \frac{\partial E_i}{\partial b} & \frac{\partial E_i}{\partial c} & \frac{\partial E_i}{\partial d} \\ \frac{\partial I_{(pq)i}}{\partial E_{0r}} & \frac{\partial I_{(pq)i}}{\partial E_{0i}} & \frac{\partial I_{(pq)i}}{\partial a} & \frac{\partial I_{(pq)i}}{\partial b} & \frac{\partial I_{(pq)i}}{\partial c} & \frac{\partial I_{(pq)i}}{\partial d} \end{bmatrix} \quad (3-11)$$

$$= \begin{bmatrix} a & -b & E_{0r} & E_{0i} & 0 & 0 \\ cY_r - dY_i & -(cY_i + dY_r) & 0 & 0 & Y_r E_{0r} - Y_i E_{0i} & -(Y_i E_{0r} + Y_r E_{0i}) \\ b & a & E_{0i} & E_{0r} & 0 & 0 \\ cY_i + dY_r & cY_r - dY_i & 0 & 0 & Y_i E_{0r} - Y_r E_{0i} & Y_r E_{0r} - Y_i E_{0i} \end{bmatrix}$$

Assume that:

$$\bar{T}_1 = \begin{bmatrix} \frac{\partial E_r}{\partial E_{r0}}(E_1) & \frac{\partial E_r}{\partial E_{i0}}(E_1) \\ \frac{\partial I_r}{\partial E_{r0}}(E_1) & \frac{\partial I_r}{\partial E_{i0}}(E_1) \\ \frac{\partial E_i}{\partial E_{r0}}(E_1) & \frac{\partial E_i}{\partial E_{i0}}(E_1) \\ \frac{\partial I_i}{\partial E_{r0}}(E_1) & \frac{\partial I_i}{\partial E_{i0}}(E_1) \end{bmatrix}, \dots, \bar{T}_n = \begin{bmatrix} \frac{\partial E_r}{\partial E_{r0}}(E_n) & \frac{\partial E_r}{\partial E_{i0}}(E_n) \\ \frac{\partial I_r}{\partial E_{r0}}(E_n) & \frac{\partial I_r}{\partial E_{i0}}(E_n) \\ \frac{\partial E_i}{\partial E_{r0}}(E_n) & \frac{\partial E_i}{\partial E_{i0}}(E_n) \\ \frac{\partial I_i}{\partial E_{r0}}(E_n) & \frac{\partial I_i}{\partial E_{i0}}(E_n) \end{bmatrix} \quad (3-12)$$

And that:

$$\bar{F}_1 = \begin{bmatrix} \frac{\partial E_r}{\partial a}(E_1) & \frac{\partial E_r}{\partial b}(E_1) & \frac{\partial E_r}{\partial c}(E_1) & \frac{\partial E_r}{\partial d}(E_1) \\ \frac{\partial I_r}{\partial a}(E_1) & \frac{\partial I_r}{\partial b}(E_1) & \frac{\partial I_r}{\partial c}(E_1) & \frac{\partial I_r}{\partial d}(E_1) \\ \frac{\partial E_i}{\partial a}(E_1) & \frac{\partial E_i}{\partial b}(E_1) & \frac{\partial E_i}{\partial c}(E_1) & \frac{\partial E_i}{\partial d}(E_1) \\ \frac{\partial I_i}{\partial a}(E_1) & \frac{\partial I_i}{\partial b}(E_1) & \frac{\partial I_i}{\partial c}(E_1) & \frac{\partial I_i}{\partial d}(E_1) \end{bmatrix}, \dots, \bar{F}_n = \begin{bmatrix} \frac{\partial E_r}{\partial a}(E_n) & \frac{\partial E_r}{\partial b}(E_n) & \frac{\partial E_r}{\partial c}(E_n) & \frac{\partial E_r}{\partial d}(E_n) \\ \frac{\partial I_r}{\partial a}(E_n) & \frac{\partial I_r}{\partial b}(E_n) & \frac{\partial I_r}{\partial c}(E_n) & \frac{\partial I_r}{\partial d}(E_n) \\ \frac{\partial E_i}{\partial a}(E_n) & \frac{\partial E_i}{\partial b}(E_n) & \frac{\partial E_i}{\partial c}(E_n) & \frac{\partial E_i}{\partial d}(E_n) \\ \frac{\partial I_i}{\partial a}(E_n) & \frac{\partial I_i}{\partial b}(E_n) & \frac{\partial I_i}{\partial c}(E_n) & \frac{\partial I_i}{\partial d}(E_n) \end{bmatrix} \quad (3-13)$$

The augmented Jacobian matrix, $\bar{H}_2$, for n number of measurements is shown in equation (3-12), also $\bar{W}$ the noise covariance matrix and $\bar{\Delta z}$, the appended measurement vector. The VT and CT correction factors remain fixed at different loading conditions and the number of unknown RCFs the same under n number of measurements (simulation of system state).

$$\bar{H}_2 = \begin{bmatrix} T_1 & 0 & 0 & F_1 \\ 0 & \ddots & 0 & \vdots \\ 0 & 0 & T_n & F_n \end{bmatrix}, \bar{W} = \begin{bmatrix} W_1 & 0 & 0 \\ 0 & \ddots & 0 \\ 0 & 0 & W_n \end{bmatrix}, \bar{\Delta z} = \begin{bmatrix} \Delta z_1 \\ \vdots \\ \Delta z_n \end{bmatrix} \quad (3-14)$$

Using the weighted least squares (WLE) method shown in equation (3-14), a starting value for $[E_{r1} \ E_{i1} \ \dots \ E_{rn} \ E_{in} \ a \ b \ c \ d]^T$ is assumed and a solution then pursued for the state vectors and RCFs. Iteration continues until the optimization method converges to a solution.

$$\begin{bmatrix} \Delta E_{r1} \\ \Delta E_{i1} \\ \vdots \\ \Delta E_m \\ \Delta E_{in} \\ \Delta a \\ \Delta b \\ \Delta c \\ \Delta d \end{bmatrix} = [\bar{H}_2 \bar{W}^{-1} \bar{H}_2]^{-1} \bar{H}_2 \bar{W}^{-1} \bar{\Delta z} \quad (3-15)$$

Zhou's simulations [10] were done on IEEE 14-bus system where different load conditions were created by multiplying both the generation values and the load values as set in base case, with a factor. It was assumed [7] that the complex correction factors were within the different IEEE C57.13 accuracy classes and that the VTs and CTs adopt accuracy classes 1.2 and 2.4. The Gaussian error of the PMUs due to the analog to digital conversion was considered negligible.

Simulation results were analysed according to the calibration performance during different numbers of simulations and to the relation of calibration performance during different loading conditions. Considering the calibration performance under different loading conditions, it was assumed that a PMU is installed at every bus on the IEEE 14-bus system and that each PMU measures both voltage and current synchrophasors. The number of simulations were 3, 5 and then 7. Each measurement scenario reflected three different system states: a heavy-load, a base-load and a light load state.

Standard deviations of the errors in the VT and CT RCFs were calculated using the Monte Carlo method with 100 trials. The number of simulations at different loading conditions determine the accuracy of the estimated RCFs as the standard deviation decrease when more simulations at different loading conditions are used.

In addition to the number of simulations used in the calibration process, the loading range included by the simulation affect calibration results. A light load was considered as 0.1 times the base load and a heavy load was 1.5 times the base load. Three different cases were analysed as shown in Table 3-1 for each loading case.

Table 3-1: System load conditions for each simulation for three different cases

CASE	Load Condition (of the base)		
	Simulation 1 (Light load)	Simulation 2 (Base load)	Simulation 3 (Heavy load)
A	0.1	1	1.5
B	0.25	1	1.25
C	0.5	1	1.05

In conclusion, Zhou developed and verified a method by means of simulations that seems to effectively improve the accuracy by which synchrophasor measurements can be obtained from instrument transformers. It is a “soft” calibration method as no precise models of the instrument transformers are required, and it can be implemented on-line to continuously adjust the RCFs for optimal accuracy under all operating conditions of the power system under interest.

The calibration principle in [32] makes use of the same line model shown Figure 3-2 and presents progress on the work done by Zhou in her thesis [10]. In the case of [32], improvement of the estimation of RCFs is achieved by estimating the RCF during two different phases:

- *Phase 1:* Light loading of the transmission line, with known and precise calibration information about the sending-end VT and then estimates the receiving-end VT’s RCF, if a light loading condition and the accuracy of the CTs are not critical to the estimation of the VTs;
- *Phase 2:* Using the estimated RCF of phase 1 to estimate the RCF of the CT’s at both ends under heavy loading conditions.

This method is computationally more efficient than the method used in the PhD thesis [10] but relies on the assumption that the measurements from CTs received under light loading conditions do not contain any errors.

3.2.2 “Synchronised Phasor Measurements Applications in Three-phase Power Systems” – Z. Wu

In Wu’s PhD thesis a method is developed for three-phase VT and CT calibration with synchrophasors that requires one pre-calibrated voltage transformer. This approach is also non-intrusive and seems to be a significant improvement in better understanding of the calibration status of VTs and CTs. It was only verified under simulated conditions requiring some assumptions that possibly not fully reflect operational conditions [2].

Two key assumptions are required:

1. The RCF of the CTs and VTs are fixed during a short period of time;
2. Line parameters provided by the electrical utility are an accurate reflection of field conditions.

Differentiating this method from [10] and [32] is the fact that it aims at to calibrate instrument transformer using three-phase measurements rather than single-phase measurements and that it distinguishes between sources of measurement uncertainty:

- Firstly, estimating the instrument transformer ratio error as the overall measurement error,
- Secondly, considering PMU measurement uncertainty separately from that of the instrument transformer.

A two-bus system is considered, shown in Figure 3-3re, presented by the general equivalent π -circuit for a transmission lines from point **p** to point **q**. The three-phase inductance between **p** and **y** is $\bar{Z}_{pq}^{abc}$ as defined by equation (3-16) and the three-phase admittance between **p** and **q** by $\bar{Y}_{pq}^{abc}$ in equation (3-17). Susceptance located at the sending end **p** is $\bar{B}_{p0}^{abc}$, and at receiving end **q** is $\bar{B}_{q0}^{abc}$ as defined by equation (3-18) and (3-19) respectively.

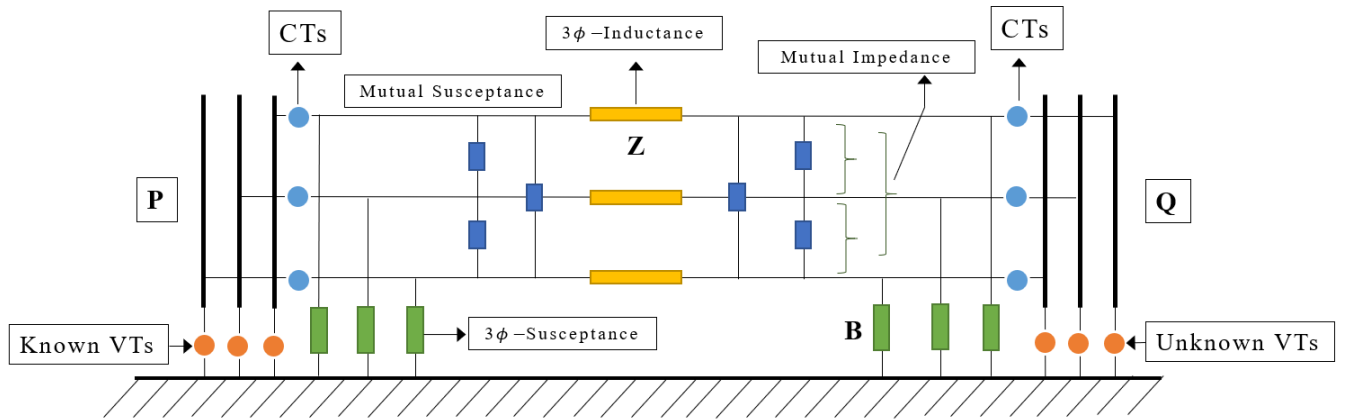


Figure 3-3: Two-bus system for three-phase transducer calibration

$$\bar{Z}_{pq}^{abc} = \begin{bmatrix} Z_{pq}^a & Z_{pq}^{ab} & Z_{pq}^{ac} \\ Z_{pq}^{ab} & Z_{pq}^b & Z_{pq}^{bc} \\ Z_{pq}^{ac} & Z_{pq}^{bc} & Z_{pq}^c \end{bmatrix} \quad (3-16)$$

$$\bar{Y}_{pq}^{abc} = (\bar{Z}^{abc})^{-1} = \begin{bmatrix} Y_{pq}^a & Y_{pq}^{ab} & Y_{pq}^{ac} \\ Y_{pq}^{ab} & Y_{pq}^b & Y_{pq}^{bc} \\ Y_{pq}^{ac} & Y_{pq}^{bc} & Y_{pq}^c \end{bmatrix} \quad (3-17)$$

$$\bar{B}_{p0}^{abc} = j \begin{bmatrix} B_{p0}^a + B_{p0}^{ab} + B_{p0}^{ac} & -B_{p0}^{ab} & -B_{p0}^{ac} \\ -B_{p0}^{ab} & B_{p0}^b + B_{p0}^{ab} + B_{p0}^{bc} & -B_{p0}^{bc} \\ -B_{p0}^{ac} & -B_{p0}^{bc} & B_{p0}^c + B_{p0}^{ac} + B_{p0}^{bc} \end{bmatrix} \quad (3-18)$$

$$\bar{B}_{q0}^{abc} = j \begin{bmatrix} B_{q0}^a + B_{q0}^{ab} + B_{q0}^{ac} & -B_{q0}^{ab} & -B_{q0}^{ac} \\ -B_{q0}^{ab} & B_{q0}^b + B_{q0}^{ab} + B_{q0}^{bc} & -B_{q0}^{bc} \\ -B_{q0}^{ac} & -B_{q0}^{bc} & B_{q0}^c + B_{q0}^{ac} + B_{q0}^{bc} \end{bmatrix} \quad (3-19)$$

Instrument transformers for each phase are installed at both sides. A VT in one of the phases at **p** is highly accurate and inductive with the correction factors of the remaining three instrument transformers for that phase (1 x VT and 2 x CT) instrument transformers unknown.

In order to satisfy Ohm's law, the voltage difference between two busses is equal to the voltage drop caused by the current flowing through the line resistance as stated by equation (3-20). This is valid when all measurements are accurate and not affected by correction factors.

$$\begin{bmatrix} E_{p0}^a \\ E_{p0}^b \\ E_{p0}^c \end{bmatrix} = \begin{bmatrix} E_{q0}^a \\ E_{q0}^b \\ E_{q0}^c \end{bmatrix} - \begin{bmatrix} Z_{pq}^a & Z_{pq}^{ab} & Z_{pq}^{ac} \\ Z_{pq}^{ab} & Z_{pq}^b & Z_{pq}^{bc} \\ Z_{pq}^{ac} & Z_{pq}^{bc} & Z_{pq}^c \end{bmatrix} \left(\begin{bmatrix} I_{qp0}^a \\ I_{qp0}^b \\ I_{qp0}^c \end{bmatrix} - \begin{bmatrix} B_{q0}^a & B_{q0}^{ab} & B_{q0}^{ac} \\ B_{q0}^{ab} & B_{q0}^b & B_{q0}^{bc} \\ B_{q0}^{ac} & B_{q0}^{bc} & B_{q0}^c \end{bmatrix} \begin{bmatrix} E_{q0}^a \\ E_{q0}^b \\ E_{q0}^c \end{bmatrix} \right) \quad (3-20)$$

$$\begin{bmatrix} E_{q0}^a \\ E_{q0}^b \\ E_{q0}^c \end{bmatrix} = \begin{bmatrix} E_{p0}^a \\ E_{p0}^b \\ E_{p0}^c \end{bmatrix} - \begin{bmatrix} Z_{pq}^a & Z_{pq}^{ab} & Z_{pq}^{ac} \\ Z_{pq}^{ab} & Z_{pq}^b & Z_{pq}^{bc} \\ Z_{pq}^{ac} & Z_{pq}^{bc} & Z_{pq}^c \end{bmatrix} \left(\begin{bmatrix} I_{pq0}^a \\ I_{pq0}^b \\ I_{pq0}^c \end{bmatrix} - \begin{bmatrix} B_{p0}^a & B_{p0}^{ab} & B_{p0}^{ac} \\ B_{p0}^{ab} & B_{p0}^b & B_{p0}^{bc} \\ B_{p0}^{ac} & B_{p0}^{bc} & B_{p0}^c \end{bmatrix} \begin{bmatrix} E_{p0}^a \\ E_{p0}^b \\ E_{p0}^c \end{bmatrix} \right) \quad (3-21)$$

Correction factors are included in equation (3-22) and (3-23) written in compact notation.

$$\bar{V}_p^{abc} = \bar{V}_q^{abc} - \bar{Z}_{pq}^{abc} (\bar{I}_{qp}^{abc} - \bar{B}_q^{abc} \cdot \bar{V}_q^{abc}) \quad (3-22)$$

$$\bar{V}_q^{abc} = \bar{V}_p^{abc} - \bar{Z}_{pq}^{abc} (\bar{I}_{pq}^{abc} - \bar{B}_p^{abc} \cdot \bar{V}_p^{abc}) \quad (3-23)$$

Where:

$\bar{V}_p^{abc}$ - Three-phase vector of voltage synchrophasors at bus **p**

$\bar{V}_q^{abc}$ - Three-phase vector of voltage synchrophasors at bus **q**

$\bar{I}_{qp}^{abc}$ - Three-phase vector current synchrophasors from bus **q** to **p**

$\bar{I}_{pq}^{abc}$ - Three-phase vector of current synchrophasors from bus **p** to **q**

Errors introduced into the synchrophasor measurements are due to instrument transformers and random measurement errors. This is combined into a single error ratio, since the dominant error is contributed by the instrument transformers. Random errors would tend to zero when the number of measurements is increased.

Measurement error is represented by a complex unknown, $diag(\bar{X}_x^{abc})$ in equation (3-24) below.

$$\bar{D} = diag(\bar{X}_x^{abc}) = \begin{bmatrix} \mathbf{X}^a & 0 & 0 \\ 0 & \mathbf{X}^b & 0 \\ 0 & 0 & \mathbf{X}^c \end{bmatrix} \quad (3-24)$$

The true values of $\bar{V}_p^{abc}$ and $\bar{V}_q^{abc}$ can be rewritten to include the measurement error of equation (3-24), shown in equation (3-25) and (3-26).

$$\bar{V}_{p_m}^{abc}(\bar{D}(\bar{K}_{v_p}^{abc})) = \bar{V}_{q_m}^{abc}(\bar{D}(\bar{K}_{v_p}^{abc})) - \bar{Z}_{pq}^{abc}(\bar{I}_{qp_m}^{abc} \bar{D}(\bar{K}_{i_{qp}}^{abc}) - \bar{B}_q^{abc} \cdot \bar{V}_{q_m}^{abc} \bar{D}(\bar{K}_{v_p}^{abc}))) \quad (3-25)$$

$$\bar{V}_{q_m}^{abc}(\bar{D}(\bar{K}_{v_p}^{abc})) = \bar{V}_{p_m}^{abc}(\bar{D}(\bar{K}_{v_q}^{abc})) - \bar{Z}_{pq}^{abc}(\bar{I}_{pq_m}^{abc} \bar{D}(\bar{K}_{i_{pq}}^{abc}) - \bar{B}_q^{abc} \cdot \bar{V}_{p_m}^{abc} \bar{D}(\bar{K}_{v_q}^{abc}))) \quad (3-26)$$

Where $\bar{K}_{v_p}^{abc}$ is the correction factor for the voltage synchrophasor measurements at **p**, $\bar{K}_{v_q}^{abc}$ the correction factor for the voltage synchrophasor measurements at **q**, $\bar{K}_{i_{qp}}^{abc}$ the correction factor for the current synchrophasor measurements from **q** to **p** and $\bar{K}_{i_{pq}}^{abc}$ the correction factor for the current synchrophasor measurement from **p** to **q**.

Instrument transformer calibration in this research requires that RCFs for both current and voltage must be calculated. Although the transmission line parameters in real world applications may introduce additional errors to the method, in this method line parameters had to be assumed as correct and accurate.

The voltage transformer at bus **p** is assumed to be accurate and calibrated and useful as reference transformer, meaning that $\bar{D}(\bar{K}_{v_p}^{abc})$ is not needed. Equation (3-25) and (3-26) contains 9 unknown RCFs and 6 equations, resulting in an underdetermined set of equations. When using several measurements from a range of loading conditions, an over-determined set of equations are obtained and increasing this number of measurements, improve the accuracy of the results [2].

Both the Newton-Raphson iteration and least squares estimation methods are used in [2] to calculate the RCFs. Least squares estimation is easier and converges faster than the Newton-Raphson iteration solution. In principle, both methods should obtain the same results.

Using the least squares estimation principle of $\bar{B} = \bar{A}\bar{X}$, the system equations for n number of measurements (representing the n number of loading conditions) can be rewritten as shown in equation (3-27) below.

$$\bar{\mathbf{B}} = \bar{\mathbf{A}}\bar{\mathbf{X}} \quad (3-27)$$

$$\begin{bmatrix} \mathbf{Y}_{pq}^{abc} \mathbf{V}_{p_1}^{abc} \\ (\mathbf{Y}_{pq}^{abc} + \mathbf{B}_q^{abc}) \mathbf{V}_{p_1}^{abc} \\ \vdots \\ \mathbf{Y}_{pq}^{abc} \mathbf{V}_{p_n}^{abc} \\ (\mathbf{Y}_{pq}^{abc} + \mathbf{B}_q^{abc}) \mathbf{V}_{p_n}^{abc} \end{bmatrix} = \begin{bmatrix} (\mathbf{Y}_{pq}^{abc} + \mathbf{B}_q^{abc}) \mathbf{D} \mathbf{V}_{q_1}^{abc} & 0 & -\mathbf{D}(\mathbf{I}_{qp_1}^{abc}) \\ \mathbf{Y}_{pq}^{abc} \mathbf{D} \mathbf{V}_{q_1}^{abc} & \mathbf{D}(\mathbf{I}_{qp_1}^{abc}) & 0 \\ \vdots & \vdots & \vdots \\ (\mathbf{Y}_{pq}^{abc} + \mathbf{B}_q^{abc}) \mathbf{D} \mathbf{V}_{q_n}^{abc} & 0 & -\mathbf{D}(\mathbf{I}_{qp_n}^{abc}) \\ \mathbf{Y}_{pq}^{abc} \mathbf{D} \mathbf{V}_{q_n}^{abc} & \mathbf{D}(\mathbf{I}_{qp_n}^{abc}) & 0 \end{bmatrix} \begin{bmatrix} \mathbf{K}_{vq}^{abc} \\ \mathbf{K}_{ipq}^{abc} \\ \mathbf{K}_{iqp}^{abc} \end{bmatrix}$$

Matrix $\bar{\mathbf{A}}$ and $\bar{\mathbf{B}}$ can be directly obtained from the line parameters and PMU measurements (voltage and current synchrophasors) with $\bar{\mathbf{X}}$ the vector of unknown RCFs. Application of least squares estimation and assuming the estimated value is $\hat{\mathbf{X}}$ and $\hat{\mathbf{B}}$ the corresponding result, the difference (error) between $\mathbf{B}$ and $\hat{\mathbf{B}}$ is then defined in equation (3-28).

$$\boldsymbol{\varepsilon} = \mathbf{B} - \hat{\mathbf{B}} = \mathbf{A}\mathbf{X} - \mathbf{A}\hat{\mathbf{X}} = \mathbf{B} - \mathbf{A}\hat{\mathbf{X}} \quad (3-28)$$

Least square estimation aims to find the solution to Equation (3-27) that minimises the error in Equation (3-28). The optimal solution is defined as:

$$\hat{\mathbf{X}} = (\mathbf{A}^T \mathbf{A})^{-1} \mathbf{A}^T \mathbf{B} \quad (3-29)$$

Current and voltage synchrophasors measured under different load scenarios are required to achieve measurement redundancy and to improve estimation accuracy. The period over which measurements are obtained is kept short to contain possible changes (temperature for example) that can affect the RCFs.

Testing of this approach to the remote calibration of instrument transformers [2] was done by simulation on a 500-kV transmission network using a light and heavy load scenario during a 24-hour period. Initially the A/D converter and the GPS synchronization uncertainties were considered negligible, but during a second simulation the error from PMU measurements were included.

- When the PMU measurement error are not included, the measurement errors of the VTs (synchrophasors at fundamental frequency) are in the order of 10^{-12} per unit for magnitude, and 10^{-11} degrees for phase angle.
- When the PMU measurement error is included, then the correction factors are in the order of 10^{-6} for magnitude and 10^{-5} for phase angle.

An overview of additional peer-reviewed literature on the remote calibration of instrument transformers using synchronized measurements is presented next.

3.3 Literature review on remote calibration of instrument transformers

In “*Online Calibration of Voltage Transformers using Synchrophasor Measurements*” [7], the multiplicative error of the ratio correction factors was investigated using the method developed in [2]. A solution was proposed that finds optimal locations for good quality measurements within the system to control the growth of error in the ratio correction factors, aiming to keep it below a predefined threshold.

In another study, “*A Novel Approach for Calibration of Instrument Transformers using Synchrophasors*”, [33], the estimation of the calibration factors is investigated by using a non-iterative approach. Sending end instrument transformers measurement were assumed to be exact.

Similar to [33], another study, “*Simultaneous transmission line parameter and PMU measurement calibration*” [8] also assumes that the sending-end current and voltage measurement are exact and estimates both the transmission line parameters and calibration factors for the receiving-end.

3.3.1 Comparative analysis of different remote calibration approaches

Remote calibration of instrument transformers has been widely investigated as seen in the previous section, whereas in this section a comparison is done between the methods. It is done based on the assumptions made regarding the system equations, solver method to determine the ratio correction factors and the validation methods used to test the methodology.

For simplification purposes the methods have been numbered as follows:

Method 1: “*Advanced Systems Monitoring with Phasor Measurements*” – [10]

Method 2: “*Three-phase Instrument Transformer Calibration with Synchronized Phasor Measurements*” – [2]

Method 3: “*Online Calibration of Voltage Transformers using Synchrophasor Measurements*” – [7]

Method 4: “*A Novel Approach for Calibration of Instrument Transformers using Synchrophasors*” – [33]

Method 5: “*Simultaneous transmission line parameter and PMU measurement calibration*” – [8]

3.3.1.1 Comparison of assumptions needed

Remote instrument transformer calibration methods assume that the correction factors remain constant during the investigation period and over different load conditions. Different assumptions are used on the availability of information in each method. A summary of the assumptions made are given in Table 3-2.

Table 3-2: Summary of assumptions

Method	Assumptions		
	Transmission Line Parameters	Sending-end VT	Sending-end CT
1	Known	Unknown	Unknown
2	Known	Known	Unknown
3	Known	Known	Unknown
4	Known	Known	Known
5	Unknown	Known	Known

3.3.1.2 Comparison of solver method of methodology

Constructing the equations over a transmission line and considering all the unknown parameters and measurements, all approaches result in an under-determined system with more unknowns than knowns. Performing measurements under different load conditions increases the number of knowns, whilst the number of unknown correction factors remain the same.

The system of equations is now an over-determined system and different mathematical methods exists to estimate the unknown correction factors. Least-squares estimation and Newton-Raphson are commonly used throughout. A summary of the solver methods is listed in Table 3-3.

Table 3-3: Summary of solver methods used

Method	Solver Method	
	Least-squares Estimation	Newton-Raphson
1	x	x
2	x	x
3	x	
4	x	
5	x	

3.3.2 Comparison on how the methodology was verified/validated

To test the methods developed in the literature, different methods are used to verify the methodologies using simulations based on real network situations.

Table 3-4: Validation Methods

Method	Validation Methods
1	Simulation-base validation on an IEEE 14-bus system over three different load conditions depending on the base load, a light-, medium-, and heavy-load condition. It was found that the estimation of CT correction factors was dependent on the load topology and is more accurate under heavier load conditions.
2	Simulation-based validation on the Dominion Virginia Power 500kV transmission network where the load change was based on an average 24-hour load, dynamic load change from 32% to 98%.
3	Simulation based studies on three different topologies: IEEE 18-bus system, IEEE 300-bus system and 2383-bus Polish system. Simulations done on 12 different operating conditions.
4	Simulation-based studies on IEEE 14-bus 220kV system.
5	Simulation-based studies on 500 kV transmission network based on an average 24-hour load, dynamic load change from 32% to 98%.

3.3.2.1 PMU measurement error contribution

In the Method 1, [10], the synchrophasor measurement uncertainty was only due to the uncalibrated instrument transformers. Gaussian errors and errors due to the quantization of analog to digital conversion, were considered negligible. Method d [2] also considered the biggest contribution to measurement uncertainty that of the uncalibrated instrument transformers.

Method 3 is based on method 2, using the errors from PMU measurements and errors contributed by the ratio correction factors [7]. Method 4 detected and discarded bad data but did not consider the contribution of PMU errors in isolation [33]. The last method, [8], relied on a pre-calibrated PMU and did not consider synchrophasor recording uncertainty in isolation.

3.4 Conclusion

Five known approaches to the remote calibration of instrument transformers were investigated. Although fundamentally similar, each method is unique in the assumptions made and how the method was verified. They were only tested by computer simulations, lacking the validation by field data.

Different sources to measurement uncertainty (i.e. synchrophasor recording, line parameters changes) may impact the usefulness of any of these methods and requires careful analysis.

CHAPTER 4: THE OPPORTUNITY FOR REMOTE CALIBRATION

From the theory reported in Chapter 2 and the analysis of known methods developed for remote calibration of instrument transformers in Chapter 3, a method is now derived from the understanding gained. The goal is to formulate a method where assumptions that possibly can invalidate the method, can be included progressively whilst still allowing for a controlled experimental environment that will allow scientific sound results.

4.1 Introduction

A single-phase methodology is used to test the opportunity for remote calibration of instrument transformers. System equations are derived to include the measurement uncertainty contributed by real-life synchrophasors because in Chapter 6, validation will be done using real-life synchrophasors.

Chapter 5 verifies the usefulness of this methodology by computer simulation. Chapter 6 validates results obtained in Chapter 5.

Chapter 7 concludes on the field application possibility of remotely characterising calibration performance of instrument transformers.

4.2 How to derive the RCF for a remote instrument transformer

Observe the well-known single-phase pi-equivalent of a transmission line shown in Figure 4-1. It is assumed that V_S , I_S and V_R , I_R are measured synchronously (synchrophasors). The **RCF** of the local VT (VT_S) is known, that is both the MCF and the PACF.

The goal is to derive the **RCF** for the remote VT (VT_R), remote CT (CT_R) and the local CT (CT_S). Being synchrophasors at the system fundamental frequency, all phasors used in the modelling in this paper only address the fundamental frequency.

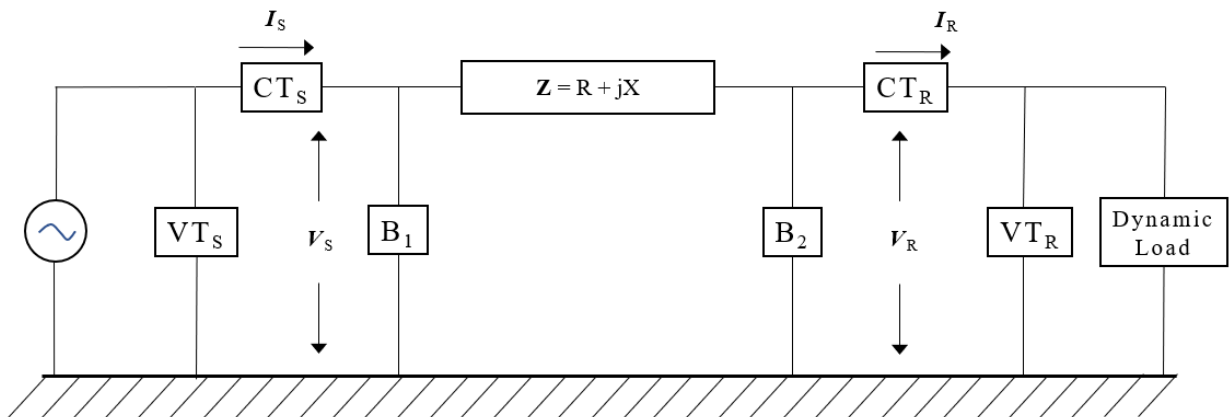


Figure 4-1: Transmission line pi-network

In Figure 4-1 the notation used represents the following:

- V_S, V_R : Sending-end and receiving-end voltage synchrophasor
- I_S, I_R : Sending-end and receiving-end current synchrophasor
- B_1, B_2 : Shunt susceptance at fundamental frequency (and fixed during the measurements)
- Z : Line impedance consisting of $R+jX$ (resistance and inductive impedance respectively and fixed during the measurements).

It is clear that knowledge of transmission line parameters is needed. Line parameters can be derived from construction data and are estimations at best.

Direct measurements at transmission level is not straightforward. This research is largely founded in the opportunities arising from power system performance improvement by innovative applications of synchrophasors. For this reason, the calculation of line parameters from voltage and synchrophasors across a transmission line, is considered next. If it is possible to do this with sufficient measurement certainty, then a significant obstacle to the remote characterisation of instrument transformers is addressed.

4.3 Accurate measurement of transmission line parameters

Availability of network coherent data, such as synchrophasors across the transmission line of interest should in principle allow the calculation of line parameters. Included in the measured values for voltage and current synchrophasors to do this, is uncertainty ascribed to measurement.

This difference between the true and measured synchrophasor values directly impact the certainty by which the line parameter can be estimated, which directly affects the computed RCF value of a remote instrument transformer.

An improved approach to derive line parameters from synchrophasors is reported in [26]. This includes the estimation of the correction factors (RCF) to correct for systematic errors as introduced by the instrumentation channel (instrument transformer, cabling, burden and measuring instrument).

Application of this method [26] presents a mathematical challenge as both the impedance parameters of the line and the calibration factors for the instrumentation channel must be estimated simultaneously. The number of equations now has a high number of unknowns, meaning that the problem can become ill-conditioned even if it is overdetermined by continuously updating the set of synchrophasors measured across the line.

A novel solution to address the above constraint is reported in [26] by first estimating correction factors for systematic measurement errors at both ends of the line and then by using measurements of average line temperature to identify corrections factors that optimize line impedance parameter estimation.

Validating the opportunity for remote calibration of instrument transformers using synchrophasors requires the assumption that the line parameters are known in the research reported in this dissertation. In real field application it will be required that line parameters are estimated before correction factors of the instrument transformers are derived.

4.4 System equations

By using basic principles of network theory, sending- and receiving-end fundamental frequency voltage and current phasors can be formulated in equations (4-1) and (4-2).

$$\mathbf{I}_R = (\mathbf{V}_S - \mathbf{V}_R) / \mathbf{Z} - \mathbf{I}_2 \quad (4-1)$$

$$\mathbf{I}_S = \mathbf{I}_1 + (\mathbf{V}_S - \mathbf{V}_R) / \mathbf{Z} \quad (4-2)$$

Where:

$$\mathbf{I}_1 = jB_1 \mathbf{V}_S \quad (4-3)$$

$$\mathbf{I}_2 = jB_2 \mathbf{V}_R \quad (4-4)$$

Equation (4-1) and (4-2) can be multiplied by the line impedance $\mathbf{Z}$ and then using $\mathbf{I}_1$ and $\mathbf{I}_2$ in equation (4-3) and (4-4), the sending-end voltage synchrophasor $\mathbf{V}_S$ is derived in equation (4-5) below.

$$\mathbf{I}_R \mathbf{Z} = (\mathbf{V}_S - \mathbf{V}_R) - jB_2 \mathbf{Z} \mathbf{V}_R \quad (4-5)$$

$$\therefore \mathbf{V}_S = \mathbf{V}_R (1 + jB_2 \mathbf{Z}) + \mathbf{Z} \mathbf{I}_R$$

Receiving end voltage synchrophasor $\mathbf{V}_R$ is derived in equation (4-6) below.

$$\mathbf{I}_S \mathbf{Z} = jB_1 \mathbf{V}_S \mathbf{Z} + (\mathbf{V}_S - \mathbf{V}_R) \quad (4-6)$$

$$\therefore \mathbf{V}_R = \mathbf{V}_S (1 + jB_1 \mathbf{Z}) - \mathbf{Z} \mathbf{I}_S$$

In a field application, the measured value is assumed to not be correct and the difference between the measured current ($\mathbf{I}_{meas}$) and the true value ($\mathbf{I}_{true}$) related by the true RCF for the instrument transformer is accordingly only an estimate. Starting with the sending- and receiving-end CT, the RCF is defined as $\mathbf{RCF}_{IS}$ at the sending end and as $\mathbf{RCF}_{IR}$ at the receiving end in equations (4-7) and (4-8):

$$\mathbf{I}_{Smeas} = \mathbf{RCF}_{IS} \mathbf{I}_{Strue} \quad (4-7)$$

(4-8)

$$I_{R_{meas}} = \mathbf{RCF}_{IR} I_{S_{true}}$$

At the receiving end, the difference between the measured voltage (V_{meas}) and the true voltage (V_{true}) is related by a RCF for the VT ($\mathbf{RCF}_{VR}$) in equations (4-9) and (4-10).

$$V_{S_{meas}} = \mathbf{RCF}_{VS} V_{S_{true}} \quad (4-9)$$

$$V_{R_{meas}} = \mathbf{RCF}_{VR} V_{R_{true}} \quad (4-10)$$

Where:

RCF_{VS}: Ratio Correction Factor for VT at sending end.

RCF_{VR}: Ratio Correction Factor for VT at receiving end.

RCF_{IR}: Ratio Correction Factor for CT at receiving end.

RCF_{IS}: Ratio Correction Factor for CT at sending end.

Remote calibration methods are based on four important assumptions:

- Instrument transformers are operated within the linear area of operation and the **RCF** of both VTs and CTs remain constant during the period of investigation;
- A two-bus equivalent pi-model of a transmission line is a sufficient representation of the operational status of the power system pertaining [9], [33], [34];
- **RCF_{VS}** of the VT at the sending end is known (obtained by field calibration). This allows for changing equation (4-9) to:

$$V_{S_{meas}} = V_{S_{true}} \quad (4-11)$$

- Estimation of transmission line parameters is accurate as obtained from construction data or derived from synchrophasor measurements across the line [26].

Equations (4-5) and (4-6) can be rewritten taking into account the RCF pertaining and resulting in equations (4-12) and (4-13):

$$V_S = \mathbf{RCF}_{VR} V_R (1 + jB_2 Z) + Z \mathbf{RCF}_{IR} I_R \quad (4-12)$$

$$\mathbf{RCF}_{VR} V_R = V_S (1 + jB_1 Z) - Z \mathbf{RCF}_{IS} I_S \quad (4-13)$$

Three unknown correction factors exist in equations (4-12) and (4-13) resulting in an under-determined system of equations when only one set of synchrophasor measurements is available. Continuously using new sets of synchrophasor measurements change this under-determined scenario to an over-determined set of equations, analysed in section 4.5.

4.5 Estimation of RCFs

It is necessary to assume that the RCF of instrument transformers remain constant during the assessment period and that the system is operating under different loading conditions. To estimate a solution for the RCF, several measurements now must be collected during this period.

For any loading condition N from the total number of conditions observed, the number of system equations is $2N$ containing three unknown $RCFs$ (ratio correction factors). Consequently, the number of equations increases, and the estimation problem now makes use of an over-determined set of equations shown in equations (4-14) and (4-15).

$$\mathbf{V}_{S_1} = \mathbf{RCF}_{VR} \mathbf{V}_{R_1} (1 + jB_2 \mathbf{Z}) + \mathbf{Z} \mathbf{RCF}_{IR} \mathbf{I}_{R_1} \quad (4-14)$$

↓

$$\mathbf{V}_{S_N} = \mathbf{RCF}_{VR} \mathbf{V}_{R_N} (1 + jB_2 \mathbf{Z}) + \mathbf{Z} \mathbf{RCF}_{IR} \mathbf{I}_{R_N}$$

$$\mathbf{RCF}_{VR} \mathbf{V}_{R_1} = \mathbf{V}_{S_1} (1 + jB_1 \mathbf{Z}) - \mathbf{Z} \mathbf{RCF}_{IS} \mathbf{I}_{S_1} \quad (4-15)$$

↓

$$\mathbf{RCF}_{VR} \mathbf{V}_{R_N} = \mathbf{V}_{S_N} (1 + jB_1 \mathbf{Z}) - \mathbf{Z} \mathbf{RCF}_{IS} \mathbf{I}_{S_N}$$

4.5.1 Least-squares estimation

An over-determined set of equations can be solved by using a least-squares estimation approach. To do this, equations (4-14) and (4-15) have to be re-arranged and simplified to the form:

$$\mathbf{Ax} = \mathbf{b} + \boldsymbol{\varepsilon} \quad (4-16)$$

The goal of least squares estimation is to estimate the unknown quantities in $\mathbf{x}$, meaning that equations (4-14) and (4-15) should be rearranged so that $\mathbf{x}$ is a matrix of unknowns, being $\mathbf{RCF}_{VR}$, $\mathbf{RCF}_{IR}$, and $\mathbf{RCF}_{IS}$.

Using a similar simplification method as used in [2] and [7], simplification of equations (4-14) and (4-15) results in equation (4-17). Vector $\bar{\mathbf{x}}$ is a $[2N \times 1]$ vector containing the unknown ratio correction factors, $\bar{\mathbf{A}}$ is a $[2N \times 4]$ matrix and $\bar{\mathbf{b}}$ is a $[2N \times 1]$ vector containing voltage synchrophasor measurements.

$$\begin{bmatrix} \mathbf{V}_{S_1} & -\mathbf{V}_{R_1} & -\mathbf{I}_{S_1} & 0 \\ 0 & \mathbf{V}_{R_1} & 0 & -\mathbf{I}_{R_1} \\ \downarrow & \downarrow & \downarrow & \downarrow \\ \mathbf{V}_{S_N} & -\mathbf{V}_{R_N} & -\mathbf{I}_{S_N} & 0 \\ 0 & \mathbf{V}_{R_N} & 0 & \mathbf{I}_{R_N} \end{bmatrix} \begin{bmatrix} (1+jB_1\mathbf{Z})^2 \\ (1+jB_1\mathbf{Z})(\mathbf{RCF}_{VR}) \\ (\mathbf{Z})(1+jB_1\mathbf{Z})(\mathbf{RCF}_{IS}) \\ (\mathbf{Z})(\mathbf{RCF}_{IR}) \end{bmatrix} = \begin{bmatrix} 0 \\ \mathbf{V}_{S_1} \\ 0 \\ \mathbf{V}_{S_N} \end{bmatrix} \quad (4-17)$$

$$\bar{\mathbf{A}} = \begin{bmatrix} \mathbf{V}_{S_1} & -\mathbf{V}_{R_1} & -\mathbf{I}_{S_1} & 0 \\ 0 & \mathbf{V}_{R_1} & 0 & -\mathbf{I}_{R_1} \\ \downarrow & \downarrow & \downarrow & \downarrow \\ \mathbf{V}_{S_N} & -\mathbf{V}_{R_N} & -\mathbf{I}_{S_N} & 0 \\ 0 & \mathbf{V}_{R_N} & 0 & \mathbf{I}_{R_N} \end{bmatrix} \quad (4-18)$$

$$\bar{\mathbf{x}} = \begin{bmatrix} (1+jB_1\mathbf{Z})^2 \\ (1+jB_1\mathbf{Z})(\mathbf{RCF}_{VR}) \\ (\mathbf{Z})(1+jB_1\mathbf{Z})(\mathbf{RCF}_{IS}) \\ (\mathbf{Z})(\mathbf{RCF}_{IR}) \end{bmatrix} \quad (4-19)$$

$$\bar{\mathbf{b}} = \begin{bmatrix} 0 \\ \mathbf{V}_{S_1} \\ \downarrow \\ 0 \\ \mathbf{V}_{S_N} \end{bmatrix} \quad (4-20)$$

Residual values are contained in vector $\bar{\mathbf{e}}$ representing the deviation from the true value $\bar{\mathbf{A}}\bar{\mathbf{x}} = \bar{\mathbf{b}}$ and can be written as $\bar{\mathbf{e}} = \bar{\mathbf{b}} - \bar{\mathbf{A}}\bar{\mathbf{x}}$ (needed to improve the RCF).

An ideal least square estimator will find a solution for $\bar{\mathbf{x}}$ to have the sum of the squared residuals as zero. In real-life applications $\bar{\mathbf{x}}$ can be regarded as an assessment of the quality of the estimation and $\bar{\mathbf{e}}$ will never be exactly zero due to measurement uncertainty.

A least square estimator is defined in (4-21) if the pseudo-matrix, $(\bar{\mathbf{A}}^T\bar{\mathbf{A}})^{-1}$, exists. Consequently, it requires that $2N > 4$ and that $\bar{\mathbf{A}}$ is linearly independent.

$$\bar{\mathbf{x}} = (\bar{\mathbf{A}}^T\bar{\mathbf{A}})^{-1}\bar{\mathbf{A}}^T\bar{\mathbf{b}} \quad (4-21)$$

By increasing the number of measurements, the accuracy by which the **RCFs** is derived will be improved when the standard deviation from the absolute (precise) value [9] is decreased.

4.6 Conclusion

A mathematical method was derived based on a critical and comparative study of peer-reviewed literature sources on how to use voltage and current synchrophasor data to improve the measurement uncertainty of a remote voltage and current instrument transformer, including a local current instrument transformer. This method derives a ratio correction factor and requires the calibration information of the local voltage transformer to be known with sufficient certainty by means of available calibration data. Also, the line parameters of the transmission line in-between the two sets of instrument transformers must be known. If not, innovative approaches to derive this information making use of synchrophasors have been published.

The method derived in Chapter 4 is verified in Chapter 5 by implementing it in Matlab® and using test data from a controlled simulation implemented in Matlab® Simulink. Measurement uncertainty resulting from real-life time-stamping of synchrophasors and other sources of measurement uncertainty resulting from the signal analysis and processing when recorded by the IEEE C37.118.1 measurement standard, is included in Chapter 6 to validate if the opportunity has field application potential.

CHAPTER 5: VERIFICATION OF METHODOLOGY

Computer simulation of a power system allows for perfectly synchronised measurements at any network points, removing all measurement uncertainty resulting from quantization noise, GPS time-stamping and other contributing factors such as temperature of an instrument transformer. Verification of the methodology derived in Chapter 4 is done in Chapter 5 to confirm that the optimization method converges under different conditions, and where the effects of those conditions are fully controllable.

From this understanding of the performance of this methodology gained in Chapter 5, field data is used in Chapter 6 to further test the principle as final validation and to conclude if, and why, this innovative approach should be further researched.

5.1 Introduction

Transmission line model data is first calculated by using construction data of a real-life transmission line. This line was chosen as it was studied by a number of other researchers, i.e. parameters for this line were derived in [26] by field measurements. It was concluded that the line parameters for this specific line are known as well as possible making use of the best approaches currently known.

A Matlab® Simulink model was constructed to represent this transmission line including the instrument transformers at the sending- and receiving-ends. Synchrophasors at different loading conditions were produced by the simulation and used to test the mathematical model developed in Chapter 4. Verification was now possible as deriving the “unknown” RCFs could be compared to “known” RCFs, being specified in the Matlab® Simulink model. The measurement process reflecting the field application could be simulated as if characteristics of RCFs were not available.

During the simulation, the assumptions identified in Chapter 3 when implementing this method in an operational condition were used, repeated below:

- Instrument transformers are operated within the linear area of operation and that the **RCF** of both VTs and CTs remain constant during the period of investigation;
- A two-bus equivalent pi-model of a transmission line is a sufficient representation of the operational status of the power system pertaining [33], [9], [34];
- **RCF_{VS}** of the VT at the sending end is known (as obtained by field calibration). This allows for changing equation (4-9) to:

$$V_{S_{meas}} = V_{S_{true}} \quad (5-1)$$

- Estimation of transmission line parameters are accurate, as obtained from construction data or derived by application of synchrophasor measurements [26] .

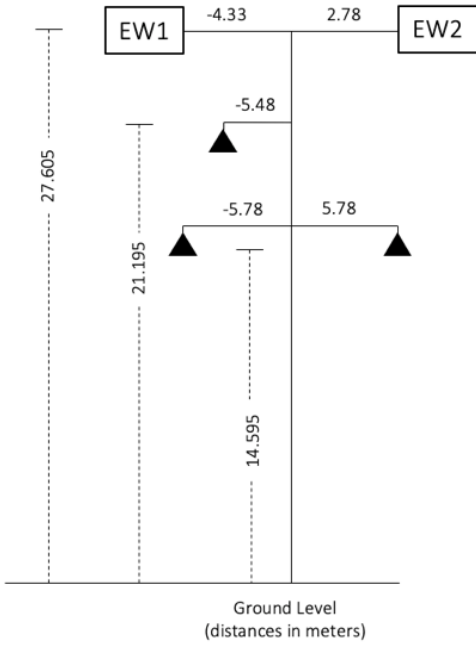
This simulation-based verification is considered as control experiment with which the emulation data obtained in Chapter 6 can be compared. For the purpose of the Matlab® Simulink model, the sending-end voltage source was assumed to be a 330 kV 50 Hz ideal voltage source as in the real life, it is a generating (hydro) station with no other local loads and feeding energy into a transmission system via this 521 km 330 kV line with no loading or generation between sending- and receiving end.

5.2 Transmission line data

Transmission line data used to construct the Matlab® Simulink model is shown in Table 5-1. From this, transmission line parameters were calculated.

Aluminium conductor steel reinforced (ACSR) conductors were used to construct the overhead transmission line specified in Table 5-1.

Table 5-1: Transmission line data

Conductor		Zebra ACSR 400 mm ²			
Level span length		S = 260 m			
Reference line sag		D _{ref} = 6.85 m			
Line weight		W = 1.63 kg/m			
Breaking load		H _{max} = 133 000 N			
Horizontal tension component		H = 19 950 N			
Thermo-elongation coefficient		α _{AS} = 19.91 /°C			
Thermo-resistivity coefficient		α = 0.0038			
Number of conductors per phase		2			
Aluminium stranding		54 (3.18 mm)			
Steel stranding		7 (3.18 mm)			
Bundle spacing		380 mm			
Rating		860 A/ph			
Earth wire		2			
Earth wire 1 & 2		Galvanized steel, Strand = 19, Diameter = 2.64 mm, Resistivity = 1.85 Ω/km			
Environment Data		Earth-resistivity = 700 Ω/km, Max ambient temp = 80°C			
					
				Inter-conductor spacing	
				A – B	6.6 m
				B – C	11.6 m
				C – A	13.1 m
				A – E/W1	6.5 m
				B – E/W1	13.1 m
				C – E/W1	16.5 m
				A – E/W2	10.5 m
				B – E/W2	15.6 m
				C – E/W2	13.4 m
				Geometric Mean Diameter (ph-ph)	
Geometric Mean Diameter (ph-e/w1)		11.19647 mm			
Geometric Mean Diameter (ph-e/w2)		12.95111 mm			
Resistance (pos seq)		0.0674 Ω/km			
Reactance (pos seq)		0.3273 Ω/km			
Susceptance (pos seq)		3.4452 Ω/km			

5.2.1 Resistance of the transmission line

Conductor Ohmic resistance is the result of spiralling, temperature, frequency and current magnitude of the conductors [15] were used to construct a transmission line at 330 kV over a 521 km distance. Spiralling describes the result of using alternate layers of strands causing the actual strand length to be 1 – 2 % longer than the specified conductor length [15].

Temperature is assumed fixed at 20°C in this research. An increase in temperature will result in an increase of the conductor resistance resulting from the thermos-resistivity coefficient. Practically, it was not possible to get a useful idea of the real temperatures of this line as no climatic data exist and many different climatic conditions are encountered over the 521 km of this line.

If the operating temperature is kept at 20°C over the 521 km line, then by using two conductors (Table 5-1), the effective line resistance is shown in Table 5-2.

Table 5-2: Resistance over transmission line

Resistance per km	0.0337 Ω
Total resistance (521 km)	17.5577 Ω

5.2.2 Capacitance

Capacitance (F/m) of a single-phase transmission line to the grounded neutral based on the line geometry, is defined as in equation (5-2) .:

$$C = \frac{2\pi\epsilon}{\ln\left(\frac{D}{r}\right)} \quad (5-2)$$

Where D is distance (m) between conductors, r is the radius (m) of the conductor and ϵ is the dielectric constant of air, $\epsilon = 1.00059$ for dry-air at 20°C.

Equation (5-2) assumes uniform charge distribution but in the presence of other conductors such as resulting from the construction of a transmission line, charge distribution is non-uniform [15]. Transposition of a transmission line aims at restoring the charge distribution so that each phase occupies a specific position for one-third of the total line length [15]. This is known as transposition of a transmission line and needed to distribute the capacitance and inductance of the 521 km line evenly.

The equivalent distance (in m) between the conductors is defined by D_{eq} in equation (5-3) below.

$$D_{eq} = \sqrt[3]{D_{ab}D_{bc}D_{ac}} \quad (5-3)$$

Where D_{ab} (in m) is the distance between phase a and b, D_{bc} between b and c, and D_{ac} between a and c.

The equivalent radius (m) of the conductors, D_{SC} , is derived from the number of conductors used, 2 in this case and defined in equation (5-4) below.

$$D_{SC} = \sqrt{rd^2} \quad (5-4)$$

With d the distance (m) between the conductors and r the radius (m) of the conductor.

Capacitance (F/m) for a transposed transmission line is defined in equation (5-5) using the line geometric data.

$$C = \frac{2\pi\epsilon}{\ln\left(\frac{D_{eq}}{D_{SC}}\right)} \quad (5-5)$$

The capacitance calculations are listed in Table 5-3.

Table 5-3: Capacitance calculations

D_{eq}	$D_{eq} = \sqrt[3]{D_{ab}D_{bc}D_{ac}}$ $D_{eq} = \sqrt[3]{(6.6)(11.6)(13.1)}$ $D_{eq} = 10.0098 \text{ m}^4$
D_{SC}	$D_{SC} = \sqrt{rd^2}$ Radius calculated from the cross-sectional area of 400 mm². $r = \sqrt{\frac{400}{\pi}} = 11.2837 \text{ mm} = 0.01128 \text{ m}$ $D_{SC} = \sqrt{(0.01128)(0.38)^2}$ $D_{SC} = 0.0403 \text{ m}$
C	$C = \frac{2\pi\epsilon}{\ln\left(\frac{D_{eq}}{D_{SC}}\right)}$ $C = \frac{2\pi\epsilon}{\ln\left(\frac{10.0098}{0.0403}\right)}$ $C = 1.0093 \times 10^{-11} \text{ F/m}$ $= 0.1009 \text{ nF/km}$
Total capacitance (521 km)	5.2587 μF

⁴ Note that the calculated GMD between the phases is different from the specified GMD of 9.98709 m. The calculated GMD is used to determine the inductance and capacitance values.

5.2.3 Inductance

Inductance of an overhead transmission line is the result of the internal and external inductances due to magnetic flux inside and outside the conductor [15]. Inductance, L , is defined as number of flux linkages produced per ampere of current flowing through a conductor as shown in equation (5-6) below.

$$L = \frac{\lambda}{I} \quad (5-6)$$

Where λ is the flux linkages (Wb-t/m) and I the rms current (A).

Inductance per meter of a two-wire line (therefore single-phase) is defined in equation (5-7) [15] below.

$$L = (4 \times 10^{-7}) \ln \frac{D}{r'} \text{ H/m} \quad (5-7)$$

Where D is the distance between conductors in meter, r' the geometric mean radius (GMR) of the stranded conductor defined by $r' = e^{-\frac{1}{4}}(r)$ and r the radius calculated from the cross-sectional area in meters.

To determine the inductance for the entire distance of the three-phase transmission line and to take in account unbalance flux-linkages, the transposed equation is defined in equation (5-8) below.

$$L = (2 \times 10^{-7}) \ln \frac{D_{xy_eq}}{D_{yy_eq}} \text{ H/m} \quad (5-8)$$

Where D_{xy_eq} is the equivalent geometric mean distance (GMD) in meters between the conductors and D_{yy_eq} the equivalent geometric mean radius of the conductor in meters.

D_{xy_eq} is defined by equation (5-9) below.

$$D_{xy_eq} = \sqrt[3]{D_{ab}D_{bc}D_{ac}} \quad (5-9)$$

If more than one conductor per phase is used, which is common in high-voltages to reduce the electric field strength, the GMR must be adjusted accordingly [15]. This concept is known as “bundling” and used to reduce corona as corona cause power loss, communication interference and audible noise [15]. Series reactance of the line is reduced (an advantage) by increasing the GMR of the bundle [15].

In the case of a two-conductor bundle, with d the bundle spacing (m), the equivalent GMR (m) is defined by equation (5-10) below.

$$D_{yy_eq} = \sqrt{r'd} \quad (5-10)$$

Three and four conductor bundle configurations will change equation (5-10) due to its configuration, but it is not applicable in this case [15]. The inductance calculations are listed in Table 5-4.

Table 5-4: Inductance calculations

D_{xy_eq}	$D_{xy_eq} = \sqrt[3]{D_{ab}D_{bc}D_{ac}}$ $D_{xy_eq} = D_{eq}$ $D_{eq} = 10.0098 \text{ m}$
D_{yy_eq}	$D_{yy_eq} = \sqrt{r'd}$ $D_{yy_eq} = \sqrt{(e^{-\frac{1}{4}})(0.01128)(0.38)}$ $D_{yy_eq} = 0.0578 \text{ m}$
L	$L = (2 \times 10^{-7}) \ln \frac{D_{xy_eq}}{D_{yy_eq}} \text{ H/m}$ $L = (2 \times 10^{-7}) \ln \frac{10.0098}{0.0578} \text{ H/m}$ $L = 1.0308 \times 10^{-6} \text{ H/m}$ $= 1.0308 \text{ mH/km}$
Total inductance (521 km)	0.5371 H

5.3 Simulation model

Transmission line parameters as derived in section 5.2 from the transmission line geometry and construction data were used to construct a simulation model for verification of the mathematical principles in use. A simplified block-diagram of the model is given in Figure 5-1. An ideal voltage source injects energy at the sending-end and instrument transformers at both ends feeds current and voltage to two different PMUs that records the synchrophasors at sending- and receiving end.

A dynamic load is connected to the receiving-end to model changing loading conditions. Instrument transformers were modelled as ideal linear transformers that converts the primary voltages and currents to the standardised instrumentation requirement of 110 V and 1 A.

A pi-equivalent circuit was used to model the transmission line as used when deriving the system equations. A discrete Fourier transform calculated the fundamental frequency voltage and current synchrophasors at both the primary and secondary side of the instrument transformers exported to the Matlab® implementation of the mathematical model deriving the RCFs.

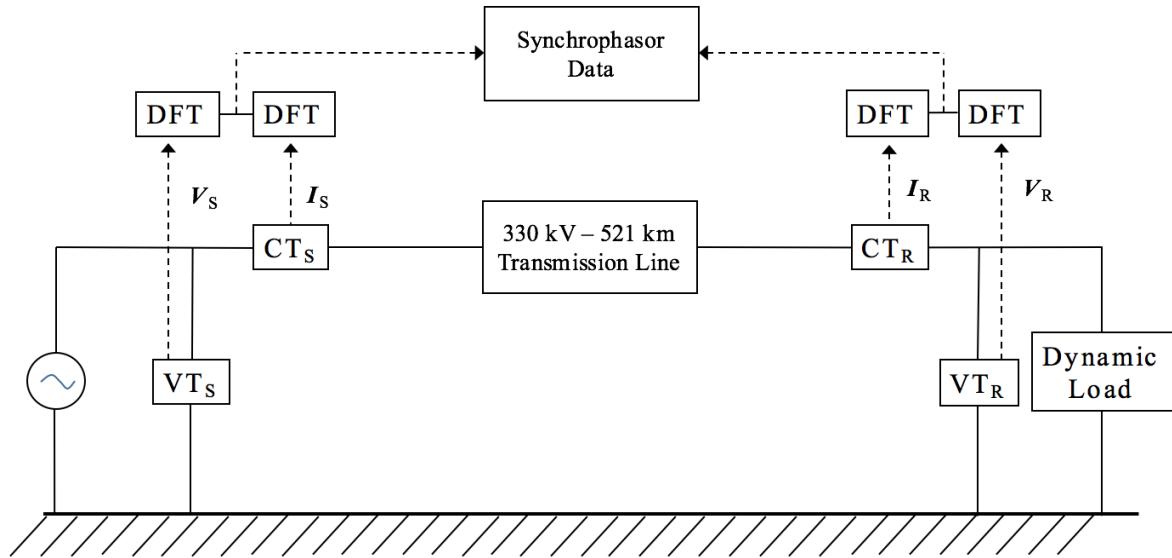


Figure 5-1: Matlab® Simulink model

5.3.1 Dynamic load change

The transmission line delivered energy to a load changing from 5 – 80 MW at a constant power factor reflecting the real-life loading of the specific line. Figure 5-2 depicts how the active and reactive power at a constant power factor of 0.97 was changed over a period of 60 sec (the real-life loading changed over a period of 24 hours) in time-increments of 0.002 seconds.

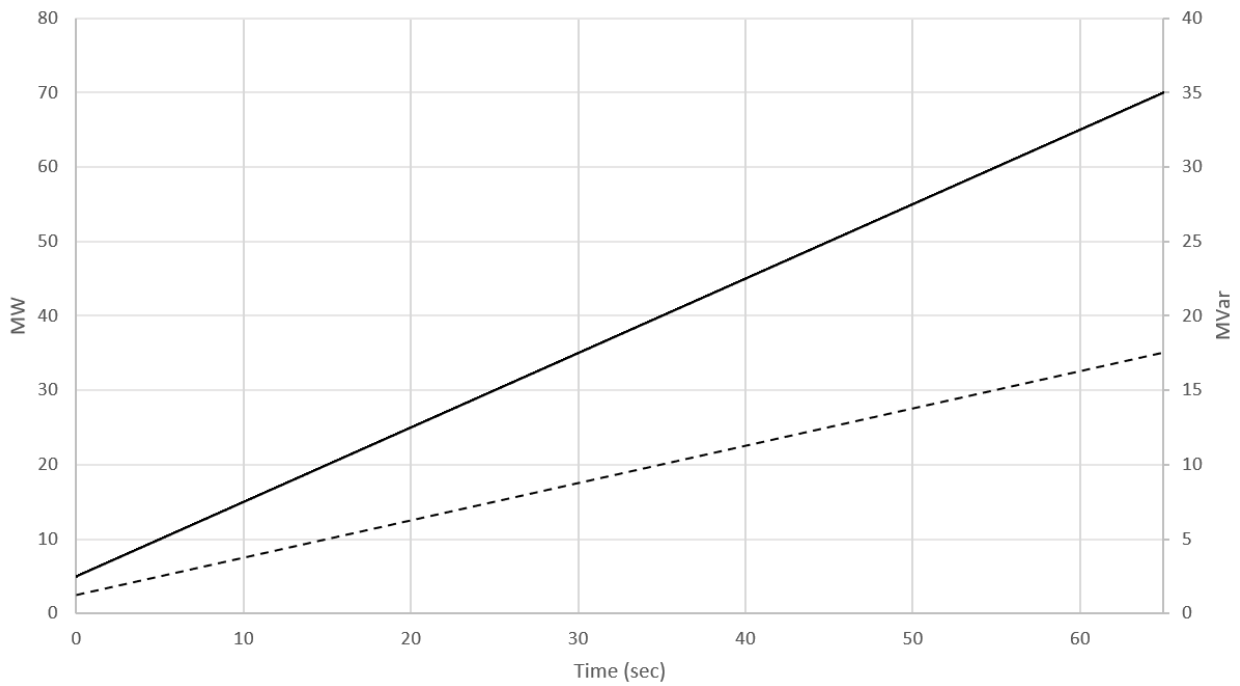


Figure 5-2: Active power and reactive power of dynamic load

5.4 Collection of synchrophasor data

The Matlab® Simulink model was implemented as a dynamic simulation whilst adjusting the load. Using the DFT function block at each instrument transformer, synchrophasor data at both ends of the line at the instrument transformers were recorded whilst the load was gradually increased at a constant power factor.

For control purposes, synchrophasor data was recorded at both the primary and the secondary side of each instrument transformer resulting in 8 sets of synchrophasors for each set-point of loading over the time of the simulation.

5.5 Estimation of RCFs

The mathematical methodology developed in the previous section was implemented within a Matlab® script using the simulation recorded data required to solve the over-determined set of equations using the least-square estimator.

The actual RCF of the CTs and VTs was then compared to the calculated RCF using the methodology derived in Chapter 4. These results are shown in Table 5-5 for the difference between ideal and calculated values, and in Table 5-6 the percentage deviation between calculated and nominal values.

Table 5-5: Simulation results – Deviation in size from nominal

	CT @ Sending-end	CT @ Receiving-end	VT @ Receiving-end
Size (ratio)	2.2406×10^{-4}	-6.4029×10^{-5}	-5.0266×10^{-5}
Angle (degrees)	1.3186×10^{-5}	1.0413×10^{-4}	3.5045×10^{-2}

Table 5-6: Simulation results – TVE

	CT @ Sending-end	CT @ Receiving-end	VT @ Receiving-end
TVE _{RCF} (%)	2.2406×10^{-2}	6.41×10^{-3}	6.14×10^{-2}

5.6 Analysis of estimation results

Estimations of the RCFs for all three unknown instrument transformers in the simulation are shown in the previous section. The average deviation for the ratio is 0.0036 % and 0.0065 % for the phase angle from the nominal RCFs.

5.7 Conclusion

Verification of the methodology was done in this chapter by means of computer simulation. First the transmission line parameters of a real-life line were calculated using the geometric parameters and conductor data. A Matlab® Simulink model was developed to represent the transmission line, the instrument transformers on both sides and the measurement process for synchrophasors. The calculated transmission line parameters were used in the Matlab® Simulink model⁵.

Simulation studies were performed increasing the load at a constant power factor at the receiving-end. Synchrophasor data was recorded during the simulation using the DFT Matlab® function block. The methodology presented in Chapter 4 was formulated into a Matlab® script, where the synchrophasor data was then extracted from the simulation to estimate the RCF.

The estimated RCF was compared to the nominal RCF of the unknown instrument transformers. It was verified that proposed methodology can estimate the RCF with an average deviation in magnitude of 0.0036 % and 0.0033 % in phase angle. These results confirmed why a number of publications reported the possibility of using synchrophasors to improve the measurements at instrument transformers, as a novel approach that need further development and why the proposed methodology is evaluated next in Chapter 6 by introducing real-life measurement conditions.

⁵ The Matlab® Simulink model can be found at <https://drive.google.com/open?id=1ggPc2Na96Pw9ObTI76PcHhDUfteJixt2>

CHAPTER 6: VALIDATION OF OPPORTUNITY TO USE SYNCHROPHASORS TO IMPROVE CALIBRATION DATA OF INSTRUMENT TRANSFORMERS

A high level of certainty in the RCF is required as derived from the field data. Validation of the results obtained in Chapter 5 is required, as the use of field data introduces measurement uncertainty that may prevent this opportunity as a practical way of improving the conversion ratio data of an instrument transformer.

6.1 Introduction

Results obtained by verification as reported in Chapter 5 make use of ideal conditions in a computer simulation and can lead to results being overly optimistic. By using real-life synchrophasors, the results of Chapter 5 are now validated.

It is not a full field study as the influence of temperature and other climatic factors on VT and CT performance are not included. By only introducing real-life synchrophasors, the contribution to measurement uncertainty by a typical synchrophasor recorder is included. How well the mathematical model can derive the RCFs adding a single source of measurement uncertainty, is isolated by this approach.

In the literature review reported in Chapter 2, it was found that within all the different sources of measurement uncertainty, the synchrophasor recorder could be the dominant contributor and why using it as a first means to validate if the methodology to derive RCFs from field data, makes sense.

Chapter 6 aims to validate what this research is fundamentally about: *Is the opportunity of using voltage and current synchrophasors to remotely derive an assessment of the possible deviation of a RCF to improve the performance of a system state estimator realistic?*

How the real-life synchrophasors were introduced into this study, whilst controlling the other parameters that can influence the outcome, is addressed in the next section.

6.2 Validation of the results obtained by simulation

A type of “hardware-in-the-loop” simulation was used as it combines results obtained from computer simulation (where control variables could be perfectly controlled) with measuring real-life IEEE C37.118.1 [17] compliant synchrophasors. This process is referred to as emulation as high-precision hardware was used to emulate the voltage and current waveforms across a transmission line, similar to measure at instrument transformers in a real substation at both ends of the line.

A block diagram of the emulation setup is shown in Figure 6-2. From an equivalent circuit point of view, the required test setup required is simplistic, but underlying fundamental measurement constraints can compromise the usefulness of the results. This equivalent circuit model aims to represent energy transfer over a 521 km 300 kV overhead transmission line, being injected by large rotating hydro-generators and then delivered to a variable load on the receiving end.

Computer simulations as used in Chapter 5 addressed the transmission line of the test. Waveforms, as expected from the instrumentation circuits at both ends, were reproduced by an Omicron™ CMC256plus™ waveform generator at 110 V_{rms} and 1 A_{rms}. This is a precision instrument with negligible contribution to overall measurement uncertainties. A technical specification is attached in Appendix C.

Phase and amplitude differences across the line could be precisely reproduced from computer simulations. Only one Omicron waveform generator was required as the test setup is based on a single-phase equivalent model of the transmission line. This allowed for the phase difference between the sending and receiving ends to be emulated with the best certainty possible because two different channels of the same Omicron waveform generator were produced by the same signal processing units within the same instrument.

Two different synchrophasor recorders (from the same manufacturer) were time-stamped by two different GPS receivers, shown in Figure 6-1. Measurement uncertainty of real-life synchrophasors as contributed by PMUs itself due to possible quantization and time-stamping errors are therefore included in this experimental model.

When using two different GPS receivers geographically far from each other to time-stamp synchrophasors, it is possible that two different sets of satellites are used as time reference. To what extent this introduced an additional uncertainty in synchrophasor recordings, could not be established during the literature study.

It could be that during the test setup, that time-stamping certainty is better in a laboratory than for a distributed GPS measurement scenario. Nonetheless, the GPS time stamp effect due to remotely located GPS receivers was not considered in the emulations done in this research due to practical limitations.

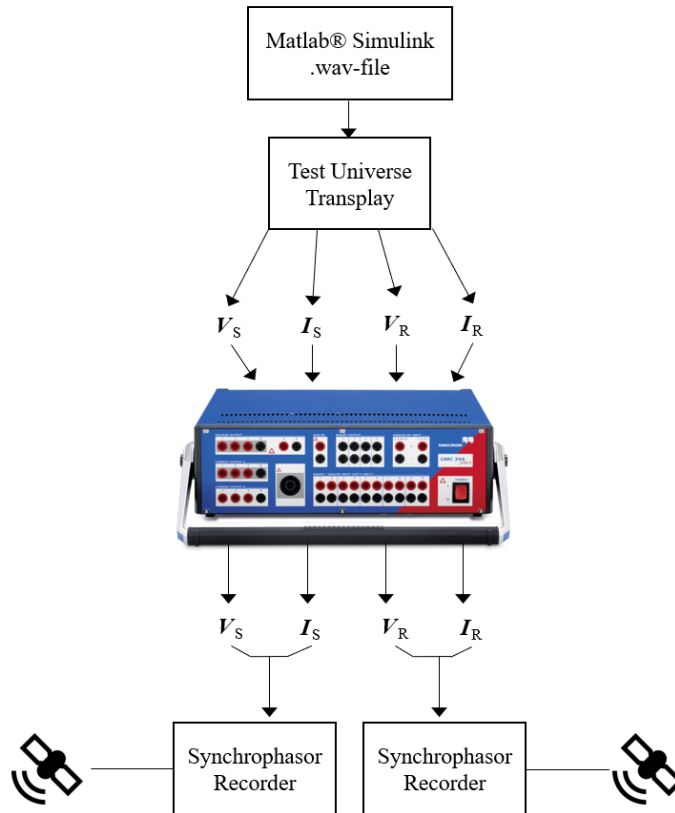


Figure 6-1: Experimental setup using a CMC256plus to generate both the sending- and receiving end waveforms, measured by two different synchrophasor recorders

In the overall uncertainty in measurement, the contributions by the VTs and CTs are excluded as the direct reproduction of the simulated voltage waveforms was 110 V_{rms} and the current waveforms was at a nominal value of 1 A_{rms}. For the purpose of this research, the contribution to uncertainty by the synchrophasor recorders at the end of the lines is therefore included whilst the contribution by the VT, CT and cabling are excluded. This allows a phased-in analysis of the different sources of measurement uncertainty in future work.

Production of the secondary signals, measured at the instrument transformers, is played out by a single CMC256plusTM device. A .wav file must be created using four channels, two for current and two for voltage to be used by the CMC256plusTM device for reproduction. In Figure 6-2 the .wav file creation is illustrated.

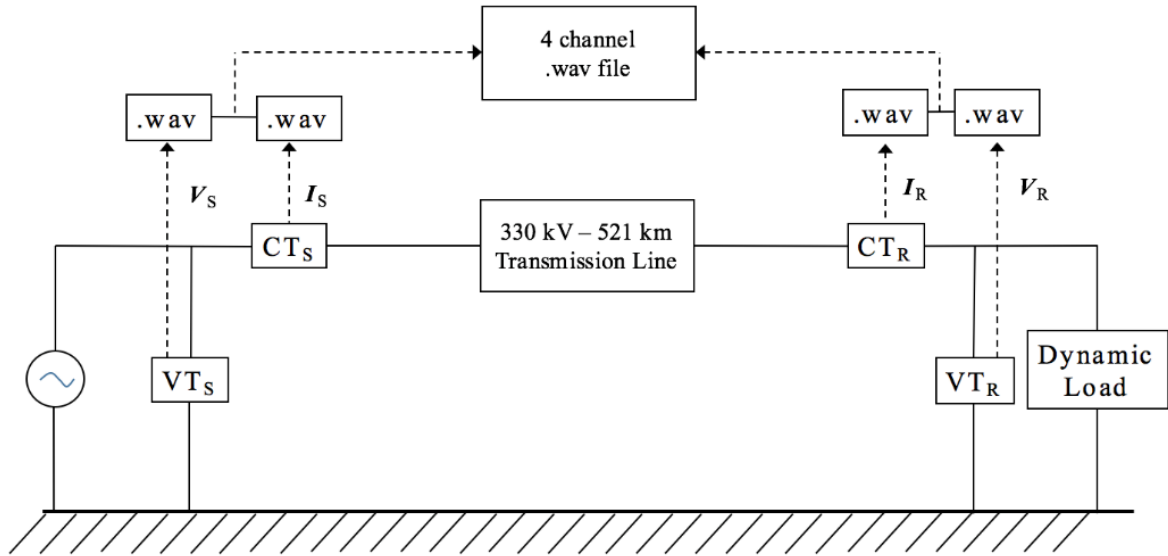


Figure 6-2: Matlab® .wav file creation

From the computer simulation, waveforms are stored in a .wav file, as shown in Figure 6-2 and assigned to four channels (2 x VT and 2 x CT) on the CMC256plus™ device. Analog voltage and current waveforms are then recorded by the two synchrophasor recorder devices illustrated in Figure 6-1.

Recorded synchrophasors measurements are then imported into Matlab® for analysis and application of the mathematical methodology developed in Chapter 4. Software from Omicron™, Test Universe Transplay™ [35] controlled the CMC256plus™ device (specifications in Appendix D).

6.3 Analysis of uncertainty contribution

An overview is given of the possible contributions to the chain of measurement uncertainty in the emulation setup as the aim of the emulation setup is to determine (isolate) the contribution of real-life measurement and data acquisition of synchrophasors. The emulation setup was shown in Figure 6-1 and in Figure 6-3, the locations for the possible contributions to uncertainty are shown.

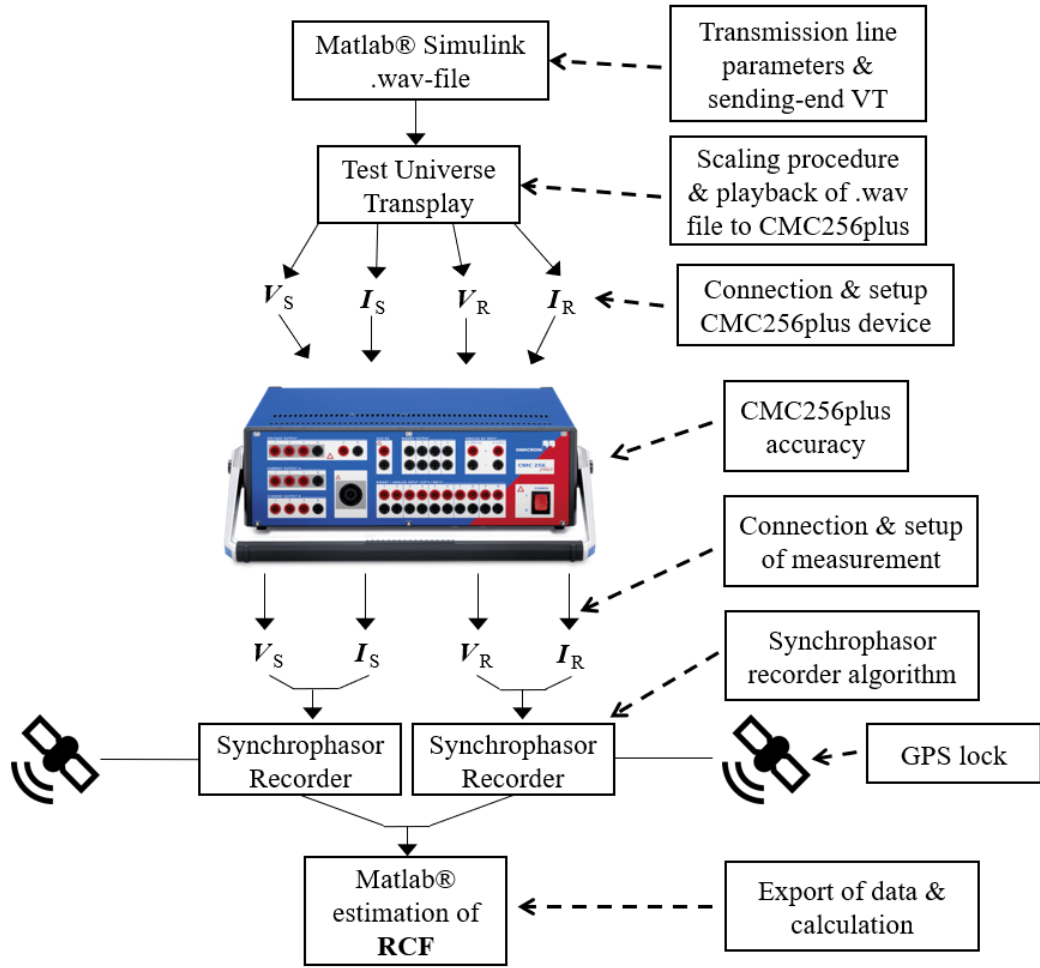


Figure 6-3: Contributions to uncertainty in the emulation setup

Transmission line parameters were estimated from line construction data and kept constant throughout the emulation tests. The generated .wav file contains the results of simulating the transmission line loading conditions, instrument transformers included. This .wav file is needed by Test Universe Transplay™ to control the CMC256plus™ device.

Amplitude of the waveform in .wav file is scaled for each channel to be within -1 and 1 and a scaling factor is used in Test Universe Transplay™ to obtain nominal values of 110 V_{rms} and 1 A_{rms} from the CMC256plus™ device.

Outputs of the CMC256plus™ device are measured directly by the synchrophasor recorder, commensurate with the IEEE C37.118.1 [17] requirements. GPS time-stamping is not perfectly reliable and those synchrophasors without GPS lock are discarded from the dataset used for the estimation of the RCF for each instrument transformer (GPS time-stamping cannot be assumed to be 100% reliable in terms of being permanently locked).

During each of the above phases of simulation, emulation and measurement, uncertainty is present. It can even include experimental error during the experiment or an unknown element within the software used.

Definition of limitation where measurement uncertainty arises, is needed to define the scope of research. In this research, only the contribution of real-life synchrophasors to the overall measurement uncertainty is considered and, as motivated, assumed to be successfully implemented. It is assumed that the software process within Test Universe Transplay™ and the signal processing within the CMC256plus™ device do not add significant uncertainty to how the RCF were estimated.

6.4 Equipment used for emulation

Waveform generation equipment and synchrophasor recorders used in the emulations are discussed below.

6.4.1 Omicron™ CMC256plus™

Computer simulated waveforms were reproduced by an Omicron™ CMC256plus™ waveform generator and recorded by two different PMUs time-stamped by two different GPS receivers. The CMC256plus™ is a high-precision calibration instrument [36].

Generation of the output analog waveform is done digitally [36] and the CMC256plus™ use error correction algorithms to produce highly accurate results. It has 10 output channels which can be independently adjusted for amplitude, phase and frequency. Six channels are designated for current and the remaining four for voltage. By controlling each output channel using the Test Universe Transplay™ software, the CMC256plus™ output channels are fully user configurable and were set up to reproduce the VT and CT signals needed for this research.

6.4.2 Synchrophasors recorders

The measurement platform used in this research digitises voltages and currents at a sample rate of 500 kHz and then digitally decimates it to always have 1000 cycles per fundamental frequency cycle available. No hardware zero-cross detection is required to remain synchronised to the fundamental frequency voltage waveform as the samples are digitally fitted into each fundamental frequency voltage signal. From these 1000 samples per fundamental frequency waveform time period, the requirements for frequency analysis are applied to prevent spectral leakage (such as having 2^n samples).

Measurement performance of this instrument is certified as compliant to Class A of the IEC 61000-4-30 power quality (PQ) measurement standard, the edition 3 version [37] that stipulates how voltage and current parameters have to be measured.

Additional functionality (recording synchrophasors simultaneously) was built into this instrument as time-stamping of the PQ parameters was already done by means of GPS. This allowed the IEEE C37.118.1 PMU measurement standard to be implemented in the same instrument initially designed to be a PQ instrument.

Recording of synchrophasors was confirmed to be well within the IEEE C37.118.1 measurement requirement. Total Vector Error (TVE) remains well below the minimum requirements of 1%. Detailed specifications of this instrument can be found in Appendix B.

6.5 RCF estimation with measured synchrophasors

Data was recorded at both ends of the simulated line using direct current and voltage measurements as inputs to the synchrophasor recorder. This excluded the contribution of error by an additional transducer between the simulated substation instrumentation circuits and the synchrophasor recorder.

Figure 6-4 and Figure 6-5 show how the measured voltage and current synchrophasor changed as function of loading.

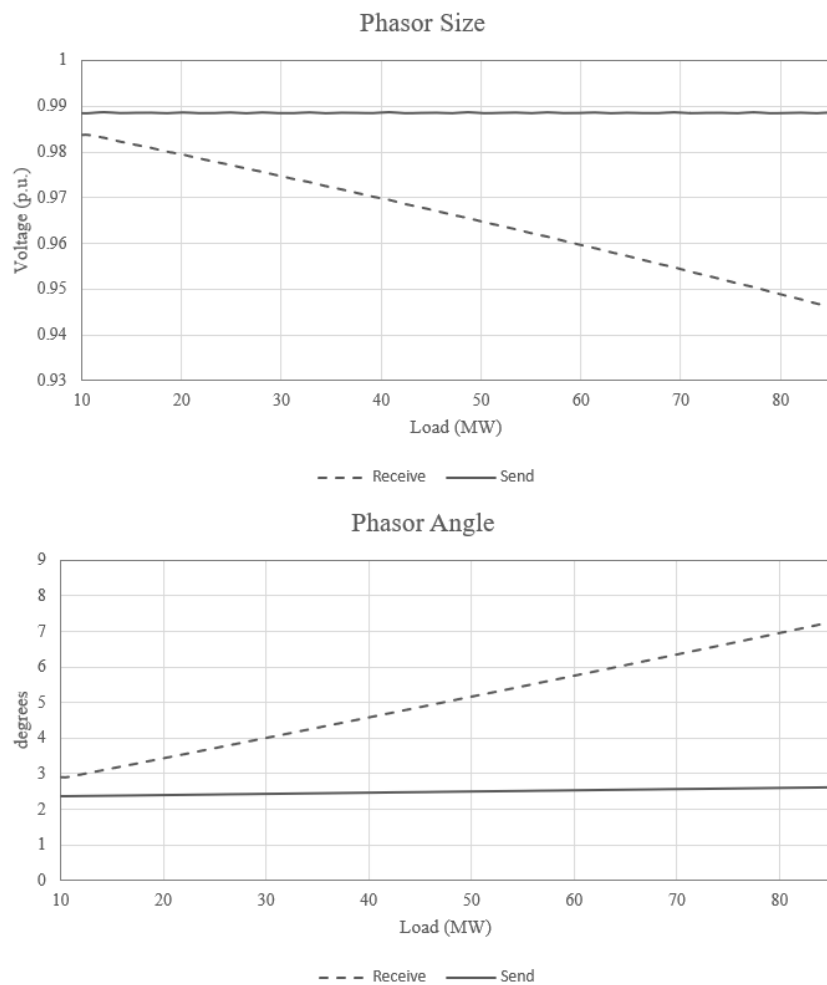


Figure 6-4: RMS voltage of synchrophasor (top) and angle (bottom) across transmission line

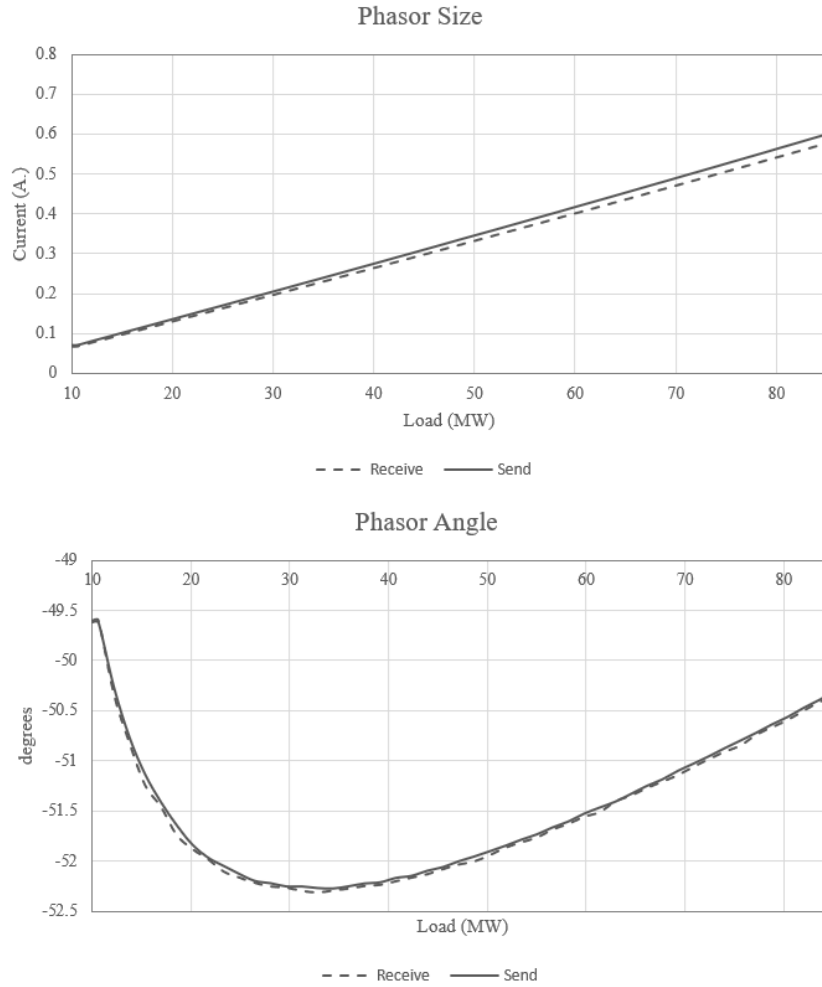


Figure 6-5: RMS current of synchrophasor (top) and angle (bottom) in transmission line

A first evaluation on the measurement uncertainty introduced by real-life synchrophasors, was by considering only one synchrophasor recorder to measure across the emulated line. Measurement uncertainty is only due to one instrument using only one GPS to timestamp synchrophasors. Two channels of the synchrophasor recorder were used to measure voltage synchrophasor and two channels to measure current.

Additional measurement uncertainty was then introduced by using two synchrophasor recorders timestamped by two different antenna's and two different GPS receivers, located at the sending- and receiving end of the emulated transmission line. This state in measurement uncertainty contribution reflects a similar condition as expected during field application.

The recorded data from the synchrophasor-recorders was validated for GPS locking conditions (valid time-stamping) and then imported into Matlab[®] where the RCFs of the unknown instrument transformers were calculated.

Scenarios emulated were:

- 1 Measure at both ends of transmission line with one synchrophasor recorder using only one GPS antenna;

Compare the RCFs calculated from the measurements to the RCFs found by computer simulation.

- 2 Measure at sending and receiving end of the transmission line with two different synchrophasor recorders using two separate GPS antennas;

Compare the RCFs calculated from the measurements to the RCFs found by the previous scenario using only one synchrophasor recorder.

- 3 Measure at sending and receiving end of the transmission line with two different synchrophasor devices, with two separate GPS antennas.

Compare the RCFs calculated from the measurements to the RCFs found by computer simulation.

Observe that the reference values for RCFs, considered as the “true” values are those obtained by computer simulation only. RCFs then derived from measured data, are compared against this set of RCFs.

Results are tabulated below.

Table 6-1: RCFs estimated from using one synchrophasor recorder

	CT @ Sending-end	CT @ Receiving-end	VT @ Receiving-end
Magnitude (ratio)	0.9923	0.9916	0.9991
Angle (degrees)	−0.0198	0.0475	−0.0120

Table 6-2: RCFs estimated from using two synchrophasor recorders

	CT @ Sending-end	CT @ Receiving-end	VT @ Receiving-end
Magnitude (ratio)	1.0299	0.9915.	0.9991
Angle (degrees)	−0.0265	0.0557	−0.0090

Table 6-3: Deriving the RCFs using one synchrophasor recorder compared to using simulation results (Scenario 1)

Deviation	CT @ Sending-end	CT @ Receiving-end	VT @ Receiving-end
Size (ratio)	-7.8427×10^{-3}	-8.2665×10^{-3}	-4.8896×10^{-4}
Angle (degrees)	-1.9792×10^{-2}	4.7433×10^{-2}	-2.9464×10^{-2}

Table 6-4: Deriving the RCFs using two synchrophasor recorders compared to using one synchrophasor recorder (Scenario 2)

Deviation	CT @ Sending-end	CT @ Receiving-end	VT @ Receiving-end
Size (ratio)	3.7601×10^{-2}	-1.8632×10^{-4}	3.7330×10^{-5}
Angle (degrees)	-6.6284×10^{-3}	8.1898×10^{-3}	3.0325×10^{-3}

Table 6-5: Deriving the RCFs using two synchrophasor recorders compared to the nominal values found by computer simulation (Scenario 3)

	CT @ Sending-end	CT @ Receiving-end	VT @ Receiving-end
Size (ratio)	2.9758×10^{-2}	-8.4528×10^{-3}	-4.5163×10^{-4}
Angle (degrees)	-2.6420×10^{-2}	5.5623×10^{-2}	-2.6431×10^{-2}

A view on how to compare the results listed in Table 6-1, Table 6-2 and Table 6-3 is needed and it was decided to use the similar TVE (total vector error) approach of the IEEE C37.118.1-2011 as reference.

TVE is rewritten in equation (6-1) and considered as a measure of how the RCF when derived, differ from the value found by computer simulation and regarded as the nominal value.

$$\text{TVE (\%)} = 100\% \times \frac{|\text{RCF}_{meas} - \text{RCF}_{cont}|}{|\text{RCF}_{cont}|} \quad (6-1)$$

Where RCF_{meas} is the **RCF** estimated from the emulation measurements and RCF_{cont} is the controlled **RCF** to which the estimated **RCF** is compared.

Table 6-6: Emulation results – TVE

	CT @ Sending-end	CT @ Receiving-end	VT @ Receiving-end
Scenario 1 -TVE_{RCF} (%)	0.785	0.830	0.071
Scenario 2 -TVE_{RCF} (%)	3.789	0.023	0.007
Scenario 3 -TVE_{RCF} (%)	2.976	0.850	0.065

6.6 Results Analysis

In Scenario 1 the RCFs were determined by using measurements from only one synchrophasor recorder measuring both the sending- and receiving-end synchrophasors obtained from the playback of the waveforms from the Omicron™ CMC256plus™ waveform generator. In this case an average deviation from nominal of -5.5327×10^{-3} in magnitude and $5.8072 \times 10^{-3}^\circ$ in phase angle was obtained. Only one synchrophasor recorder contributed to measurement error and only one GPS receiver is used.

In Scenario 2, two different synchrophasor recorders and two different GPS antennas measures across the transmission line. RCFs were derived and compared to the RCFS obtained during Scenario 1. The average deviation in magnitude were 1.2484×10^{-2} and for phase angle $1.5313 \times 10^{-3}^\circ$.

The final scenario, Scenario 3 compares the RCFs of Scenario 2 to the RCFs obtained by computer simulation only. Average deviation in the magnitude for the RCFs of the instrument transformers were 6.9513×10^{-3} and $9.2383 \times 10^{-4}^\circ$ for the phase angle.

6.7 Conclusion

Validation of the estimation methodology derived in Chapter 4 was done by means of an emulation study. The computer simulation developed in Chapter 5 represents the transmission line that was consequently used to generate waveforms as expected from instrumentation circuits at both ends of a transmission line. Waveforms were reproduced using an Omicron™ CMC256plus™ waveform generator set at 110 V_{rms} and 1 A_{rms}.

Real-life synchrophasor recorders measured the waveform reproduction done by the Omicron™ CMC256plus™ instrument. Data was imported to Matlab® for initial analysis and final application of the mathematical methodology developed in Chapter 4.

Three different scenarios were investigated and, in each scenario, the estimated RCFs were compared to a reference RCF obtained from computer simulation only, considered to be the lowest measurement uncertainty scenario. It was found that the impact of measurement uncertainty due to the time-stamping and quantization noise of two different PMUs at both ends of the line, is on average less than 0.6851 % for magnitude and 0.00026 % for phase angle.

This result validated the opportunity of remotely calibrating instrument transformers using synchrophasor recorders. Measurement uncertainty contributed by using real-life synchrophasor recorders does not adversely affect the original concept of how synchrophasor data can be used to do much more than small-signal stability analysis such as remotely improve the calibration data of instrument transformers. Other contributions to measurement uncertainty should still be investigated in future research aiming at a pragmatic engineering solution to be used by operators of real power systems.

CHAPTER 7: CONCLUSION AND RECOMMENDATIONS

Accurate field data obtained from power systems is required to ensure system reliability, security, operation and control of the network. State estimators (as example) evaluate field data of current, voltage, real and reactive power for monitoring system performance.

Performance of this state estimator relates directly to the accuracy of field measurements. Each measurement is a result of a chain of instrumentation- and data processing and handling processes. During any one of these phases, measurement errors can result. Overall measurement certainty is a collective reflection of errors during each measurement phase.

Field data is primarily obtained from instrument transformers (VTs & CTs) where calibration ensures accurate measurements. Physical calibration methods are tedious, labour-intensive and costly. Using synchrophasor data across a transmission line was the basis of a novel idea to remotely calibrate instrument transformers [7], [8], [10] in an attempt to improve the measurement uncertainty of the field data used by system state estimators.

The increased availability of synchrophasor data in power systems is the reason for doing additional research to establish if this opportunity still applies when using in real-life conditions and not only the ideal assumptions of the literature analysed in Chapter 2 and 3.

7.1 Is the opportunity for remote calibration viable?

Remote calibration of instrument transformers is a novel idea. Presented in literature, it was only verified by computer simulations that possibly exclude important real-life conditions. Assumptions for the computer simulations include:

- Accurate knowledge of transmission line parameters exists;
- Transmission line parameters will remain fixed during the evaluation period;
- RCFs does not deviate during the evaluation period;
- Synchrophasor data is accurate;
- Knowledge of calibration data of at least one instrument transformer exist; and
- RCFs remain fixed over different loading conditions.

In real-life conditions, each of those assumptions could have an important, and different effect on the accuracy by which RCFs can be estimated. Field testing of this idea and assumptions is constrained by a number of practical factors.

Systematic investigation of each assumption and the impact on how accurately an RCF can be estimated, is required. Measurement uncertainty could constrain the field application and is the reason why the contribution of synchrophasor recorders across an emulated transmission line was studied in this research.

When calibration data is limited to only the sending-end VT, an over-determined linear system must be solved over different load conditions to estimate the RCF for the remaining instrument transformers using least squares estimation. Unknown RCFs to be derived were for the sending-end CT, remote CT and remote VT.

Line parameters were estimated from construction data of a real-life 330 kV 521 km transmission line and were kept constant during the evaluation period. A measurement system was implemented in a Matlab® Simulink model to collect synchrophasor data to verify remote calibration idea.

Impact of real-life synchrophasor recorders at both ends of the line adds measurement uncertainty due to time-stamping and quantization noise was assessed in this research by means of an emulation study. It is concluded that the uncertainty added by real-life measurements do not realistically limit, within the constraints of this study, the concept of remotely calibrating instrument transformers. Initial assumptions made about the field conditions justifies further research to evaluate the principle and are discussed in the next section.

7.2 Future Work

The following future work may be conducted to augment the results from this study:

- Comprehensive field testing of principle to include all sources of measurement uncertainty;
- How the traceability from a true metrological approach to calibration of the CTs & VTs can affect the calibration data;
- What the different requirements are when using different types of instrument transformers, for example a magnetic VT compared to a capacitive VT and optical CTs against magnetic CTs;
- Transmission line parameters: Is construction data good enough for sufficient certainty on the transmission line parameters or should it rather be estimated from synchrophasor measurements?
- How transmission line parameters and RCFs are affected by temperature and other climatic factors;
- How the growth of error affects the calibration principle starting at only one VT with known calibration data;
- Detailed analysis of the collective impact of all assumptions needed to derive a RCF under field conditions.

BIBLIOGRAPHY

- [1] IEEE, *Standard Requirements for Instrument Transformers IEEE Std. C57-13 (Revision of IEEE Std. C57.13-1993)*, 2008.
- [2] Z. Wu, *Synchronized Phasor Measurement Applications in Three-phase Power Systems*, Blacksburg, Virginia, 2013.
- [3] U.S. - Canada Power System Outage Task Force, "Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations", April 2004.
- [4] Joint Committee for Guides in Metrology 200:2012, "International Vocabulary of Metrology – Basic and General Concepts and Associated Terms (VIM 2008 with minor corrections)," 2012. [Online]. Available: <http://www.bipm.org/en/publications/guides/vim.html>. [Accessed March 2017].
- [5] A. Ferrero, "The Pillars of Metrology," *IEEE Instrumentation & Measurement Magazine*, vol. 18, no. 6, pp. 7-11, December 2015.
- [6] M. M. Adibi and D. K. Thorne, "Remote Measurement Calibration," *IEEE Transactions on Power Systems*, Vols. PWRS-1, no. 2, pp. 194-199, 1986.
- [7] A. Pal, R. Chatterjee, J. S. Thorp and V. A. Centeno, "Online Calibration of Voltage Transformers Using Synchrophasor Measurements," *IEEE Transaction on Power Delivery*, vol. 31, pp. 370-380, 2016.
- [8] Z. Wu, L. Zora and A. Phadke, "Simultaneous transmission line parameter and PMU measurement calibration," in *Power & Energy Society General Meeting*, Denver, CO, USA, 2015.
- [9] Z. Wu, K. Thomas, R. Sun, V. A. Centeno and A. G. Phadke, "Three-phase Instrument transformer calibration with synchronized phasor measurements," in *Innovative Smart Grid Technologies*, Washington, DC, 2012.
- [10] M. Zhou, *Advanced System Monitoring with Phasor Measurements*, Blacksburg, Virginia, 2008.

- [11] S. Rens, J. Rens, J. Holm, G. Botha and J. Desmet, "On the Remote Calibration of Instrument Transformers: Validation of Opportunity," in *9th International Workshop on Applied Measurements for Power Systems*, Bologna, Italy, 2018.
- [12] F. C. Schweppe and J. Wildes, "Power System Static-State Estimation, Part I: Exact Model," *IEEE Transactions on Power Apparatus and Systems*, Vols. PAS-89, no. 1, pp. 120-125, 1970.
- [13] M. Göl, A. Abur and F. Galvan, "Metrics for Success-Performance Metrics for Power System State Estimators and Measurement Designs," *IEEE Power & Energy Magazine*, vol. 10, no. 5, pp. 50-57, September/October 2012.
- [14] C. Muscas, F. Pilo, G. Pisano and S. Sulis, "Optimal Placement of Measurement Devices in Electric Distribution Systems," in *IEEE Instrumentation and Measurement Technology Conference Proceedings*, Sorrento, Italy, 2006.
- [15] J. D. Glover, M. S. Sarma and T. J. Overbye, *Power System Analysis and Design*, vol. 5, Stamford, CT: Cengage Learning, 2012.
- [16] R. Nuqui and A. Phadke, "Phasor measurement unit placement based on incomplete observability," in *Power Engineering Society Summer Meeting*, Chicago, 2002.
- [17] IEEE, *Standard for Synchrophasor Measurements for Power Systems IEEE Std C37.118*, 1-2011.
- [18] D. Dotta, J. H. Chow, L. Vanfretti, M. S. Almas and M. N. Agostini, "A MATLAB-based PMU simulator," in *IEEE Power & Energy Society General Meeting*, Vancouver, BC, Canada, 2013.
- [19] A. G. Phadke and J. S. Thorp, "History and Applications of Phasor Measurements," in *Power Systems Conference and Exposition*, Atlanta, USA, 2006.
- [20] Joint Committee for Guides in Metrology 100:2008, "Evaluation of measurement data — Guide to the expression of uncertainty in measurement," 2008. [Online]. Available: <https://www.bipm.org/en/publications/guides/gum.html>. [Accessed March 2017].
- [21] S. Salicone, "Measurement Uncertainty," in *An Approach via the Mathematical Theory of Evidence*, New York, Springer Science+Business Media, 2007, pp. 1-15.
- [22] C. Dubois, L. Leblond, J.-M. Pou and A. Ferrero, "Covariance Evaluation by Means of Uncertainty Assessment," *IEEE Instrumentation & Measurement Magazine*, pp. 12-18, December 2016.

- [23] ITITech, "Instrument Transformer Basic Technical Information and Applications," Dec 2009. [Online]. Available: www.gegridsolution.com. [Accessed 24 May 2016].
- [24] IEEE, "C57.13.6-2008 Standard Requirements for Instrument Transformers," IEEE, 2008.
- [25] D. Shi, D. Tylavsky, N. Logic and K. M. Koellner, "Identification of Short Transmission-Line Parameters from Synchrophasor Measurements," in *North American Power Symposium*, Calgary, Canada, 2008.
- [26] D. Ritzmann, J. Rens, P. S. Wright, W. Holderbaum and B. Potter, "A Novel Approach to Non-invasive Measurement of Overhead Line Impedance Parameters," *IEEE Transactions on Instrumentation and Measurement*, vol. 66, no. 6, pp. 1155-1163, June 2017.
- [27] R. Fletcher and M. Powell, "A Rapidly Convergent Descent Method for Minimization," *The Computer Journal*, vol. 6, no. 2, pp. 163-168, 1963.
- [28] Virginia Tech, "Virginia Tech - College of Engineering," [Online]. Available: <https://ece.vt.edu/people/profile/phadke>. [Accessed 12 October 2018].
- [29] Franklin Institute, "Franklin Institute," April 2008. [Online]. Available: <https://www.fi.edu/laureates/arun-phadke>. [Accessed 11 October 2018].
- [30] A. Phadke and J. Thorp, *Synchronized Phasor Measurements and their Applications*, Springer, 2008.
- [31] IEEE, "IEEE - Medal in Power Engineering Recipients," [Online]. Available: <https://www.ieee.org/about/awards/bios/power-engineering-recipients.html>. [Accessed 11 October 2018].
- [32] A. Phadke, J. Thorp, R. Nuqui and M. Zhou, "Recent Developments in State Estimation," in *Power Systems Conference and Exposition*, Seattle, WA, USA, 2009.
- [33] T. P. Hinge and S. S. Dambhare, "A novel approach for calibration of Instrument Transformers using synchrophasors," in *National Power Systems Conference*, Bhubaneswar, India, 2016.
- [34] K. V. Khandeparkar, S. A. Soman and G. Gajjar, "Detection and Correction of Systematic Errors in Instrument Transformers along with Line Parameter Estimation using PMU Data," *IEEE Transactions on Power Systems*, vol. PP, no. 99, 2016.

- [35] OMICRON, “OMICRON - Test Universe,” [Online]. Available: <https://www.omicronenergy.com/en/products/test-universe/>. [Accessed 30 October 2018].
- [36] OMICRON Electronics, “Omicron Energy,” [Online]. Available: <https://www.omicronenergy.com/en/products/cmc-256plus/>. [Accessed October 2016].
- [37] IEC, IEC 61000-4-30: Electromagnetic compatibility (EMC) – Part 4-30: Testing and measurement techniques – Power quality measurement methods, IEC, 2015.
- [38] CTLab, “CTLab,” [Online]. Available: http://www.ctlab.com/wp-content/uploads/2017/10/CTLAB_FactSheets_VectoII.pdf. [Accessed 1 November 2017].
- [39] OMICRON, “OMICRON CMC 256plus Documents,” [Online]. Available: <https://www.omicronenergy.com/en/products/cmc-256plus/documents/>. [Accessed 13 November 2018].
- [40] A. Ferrero, “Measurements on electric power systems: are we prisoners of tradition?,” in *Applied Measurements for Power Systems (AMPS), 2013 IEEE International Workshop on*, Aachen, Germany, 25-27 Sept. 2013.
- [41] M. M. Adibi, K. A. Clements, R. J. Kafka and J. P. Stovall, “Remote Measurement Calibration,” *IEEE Computer Applications in Power*, vol. 3, no. 4, pp. 37-42, 1990.

APPENDIX A – ON THE REMOTE CALOBRATION OF INSTRUMENT TRANSFORMERS: VALIDATION OF OPPPORTUNITY [11]

On the Remote Calibration of Voltage Transformers: Validation of Opportunity

Sané Rens, *Student Member, IEEE* Johan Rens¹, *Member, IEEE*, Johann Holm¹, Gerhard Botha¹,
Senior Member IEEE and Jan Desmet², *Senior Member IEEE*

¹North-West University Potchefstroom, South Africa

²Ghent University, Campus Kortrijk, Belgium

Abstract—Remote calibration of instrument transformers seems possible if sufficient certainty in field measurements can be achieved. This opportunity, until now, was only investigated from a theoretical point of view and in this paper, is now further investigated by using real-life synchrophasors. A transmission line is emulated, and voltage and current synchrophasors collected across the transmission line by two different synchrophasor recorders to derive a ratio correction factor for the remote instrument transformers.

Index Terms— Instrument Transformers, Ratio Correction Factor, Least Squares Estimate, Measurement Uncertainty, Phasor Measurement Units, Transmission Line Parameters, GPS Timestamping.

I. INTRODUCTION

State estimation of a power system supports the power system's security, efficiency, and economic operation. It requires voltage and current field data at nodes equipped with the instrumentation to measure voltage and current. Because not all nodes can be measured, the state of the power system must be estimated by deriving voltages and currents from a set of equations to be solved from a reduced number of known variables.

The accuracy of the state estimation process relies on the accuracy of measured field data. A chain of measurement events can affect the certainty of the measured data subjected to the state estimator. Instrument transformers, additional transducers used for input signal condition to the measuring instrument, analog-to-digital (A/D) converters, scaling and conversion procedures, and communication equipment all contribute to the uncertainty in measurement.

Errors in this measurement chain are the result of systematic, random or even installation errors. Instrument transformers reduce line voltages and currents into lower standardized values that are more convenient for measurement purposes. Nominal conversion ratios, specified on the nameplate, may differ from the actual conversion ratios due to manufacturing reasons, drift over time and environmental conditions (temperature, humidity).

Deviation from the nominal value is corrected by a ratio correction factor (**RCF**¹). It is a complex quantity, expressed as

a magnitude correction factor (MCF) and a phase angle correction factor (PACF). Ideally, the MCF must be 1, and the PACF 0°. If not, the measured voltage and current data can affect the ability of the state estimator in accurately estimating the state of the power system.

To eliminate biased measurements of instrument transformers, calibration of Voltage Transformers (VTs) and Current Transformers (CTs) should ideally be performed periodically as the **RCF** can change over time. Traditionally, calibration has been done by means of field work. It is an invasive approach performed during an out-of-service condition. It is time-consuming, expensive, labor intensive and impractical to do regularly [1].

The idea of remotely calibrating instrument transformers was first introduced in [1]. Remote calibration is a non-invasive approach and can be done online, this advantage compared to the traditional approach forms the basis of the research results reported in this paper. The approach in [1] is based on an off-line error analysis of repetitive measurements that are not synchronously measured across the transmission line.

Further development on the remote calibration of instrument transformers [2, 3] estimated the **RCF** by means of repetitive and synchronized measurements across the transmission line. The results reported in [2, 3] were obtained by a theoretical model tested under computer simulated conditions and support why this paper use two different synchrophasor recorders to record voltage and current synchrophasors across an emulated model of a real-life 330 kV transmission line. Such an approach introduces a realistic representation of the synchrophasor measurement uncertainty.

How the rest of the measurement chain (i.e. VT, CT, cabling) contributes to the uncertainty in **RCF**, is not included. It is assumed that the **RCF** for the local VT and the transmission line parameters are known. The goal is then to derive the **RCF** for the remote VT and CT.

Firstly, theoretical aspects of measurement uncertainty and remote calibration are considered. Emulation of the measurement system is introduced next. Lastly, the opportunity for field implementation of remote VT calibration is discussed.

¹ Symbols in bold signifies complex quantities and variables are italic.

II. UNCERTAINTY IN MEASUREMENT

To accurately model estimation of an RCF in a controlled environment, an absolute reference is required. For this reason, a computer simulation of a real-life transmission line was used as reference case and the measurement uncertainty contributed by only the synchrophasor recorders, systematically included. First, only one synchrophasor recorder was used and a second synchrophasor recorder used to emulate the field application. During this investigation, the contribution to measurement uncertainty by the VTs, CTs and cabling was excluded.

Theoretical aspects of metrology are briefly reviewed and the sources of error in the measurement chain considered with specific reference to synchrophasors.

A. Theory of Metrology

Modern power systems require several types of measured and derived data that require recognition of applicable metrology. The data obtained from any measurement instrument will contain a certain level of uncertainty. Consequently, it cannot provide the true (exact) value of measurement for the parameter of interest, implying that measurement results can affect a power system's operational decisions negatively.

An investigation of the pillars of metrology done in [4] analyzes the incomplete knowledge set produced by a measurement system resulting from measurement uncertainty, calibration of instruments and traceability of results.

This is only applicable if all known levels of uncertainty have been evaluated and compensated for, implying the need for calibration.

Traceability is a property of a measurement result whereby that result can be related to a reference value through a documented unbroken chain of calibration [4]. In real-life systems, traceability of instrument transformer calibration can be difficult to obtain, supporting the need for innovative solutions such as the remote calibration of instrument transformers.

B. Error Analysis

Random, systematic, installation and intermittent errors can all contribute to measurement errors in a power system [1]. IEEE Std. C57.13 [5] sets the accuracy requirements of instrument transformers and defines the allowable error in specified accuracy classes.

Random errors are caused by accuracy performance of an instrument. Systemic errors are caused by reduction of instrument accuracy over time. These errors occur with the same value and sign when the measurement of a quantity is repeated when following the same measurement process with the same measurement instruments under the same reference conditions [6]. Systemic errors cannot be fully eliminated but can be reduced by applying a correction factor, including compensating for temperature and other environmental factors [1].

Installation errors can be caused by incorrect use of ratio factors and accuracy of instrument documentation [1].

Intermittent errors are those being caused by communication interference of measurements and/or malfunction of telemetering equipment [1].

C. Synchrophasor Measurement Uncertainty

Phasor Measurement Units (PMUs) are the traditional solution to record synchronized voltage and current phasors at the fundamental frequency.

Synchrophasors require time-stamping (using for example GPS) of voltage and current phasors within an accepted level of measurement and time-stamping uncertainty. The synchrophasor measurement standard, IEEE Std. C37.118 [7] requires that the Total Vector Error (TVE) should be less than 1 %.

Synchrophasor measurement errors can be due to the RCF of the instrument transformers (not being $1\angle 0^\circ$), quantization noise (introduced by A/D conversion) and GPS time-stamping uncertainty [8].

The field data in this research flagged the discarded phasors that were recorded when time-synchronization was lost. A synchrophasor recorder, developed in South Africa, was used for all measurements.

Quantization errors are considered negligible [8] when recording IEEE Std. C37.118 compliant synchrophasors at a resolution higher than 16 bits.

D. Instrument transformer ratios

The remaining errors in the measurement chain are those introduced by the instrument transformers itself and the cabling equipment between the instrument transformer and the measuring instrument. An instrument transformer will be rated to convert the primary quantity by a ratio that allows a secondary value to be within a standardized range such as 110 V and 5/1 A. A nominal nameplate value will normally only state the amplitude conversion factor, for example if the line voltage is 11 kV and the instrumentation circuit require 110 V, then a ratio of 100:1 will be found on the nameplate of the VT.

It is then assumed that primary voltages will relate by a factor of 100 and be in phase (0° degree phase shift). It is impossible to manufacture the instrumentation transformer to have a perfect RCF of $1\angle 0^\circ$. Also, this RCF could change with time and environmental factors.

Application of the RCF is adjust the difference between the measured and true phasors:

$$I_{meas} = RCF_I I_{true} \quad (1)$$

$$V_{meas} = RCF_V V_{true} \quad (2)$$

III. PRINCIPLES OF REMOTE CALIBRATION

Estimation of transmission line parameters is needed in calculating the RCF from synchrophasors recorded across a line as shown in Fig. 1. Errors within the experimental model are identified as the RCF brought about by the instrument transformers.

Light and heavy load conditions are used in [9] to estimate the RCF and does not require accurate instrument transformer

models for calibration as it is usually difficult to obtain. This approach has been tested on a IEEE 14-bus system to evaluate feasibility. Kirchhoff's current and voltage laws are used to the system state based on a single-phase equivalent circuit [9] and is then solved iteratively. It is further developed in [8] for application in a three-phase power system. Both methods ([8], [9]) requires at least one pre-calibrated VT and known transmission line parameters.

A non-iterative method is used in [10] to derive the **RCF** for the remote instrument transformers. This method requires both the CT and VT at the sending end to be pre-calibrated and that transmission line parameters are known.

Another method in [11] estimates both the transmission line parameters but is dependent on the assumption that both the initial current and voltage measurements are calibrated.

In this paper, it is assumed that only the sending end VT has reliable calibration information. Also, transmission line parameters at the fundamental frequency are known by for example deriving it from synchrophasors recorded across the line as discussed in section IV.

A. Formulation of Method to derive the remote RCF

Observe the well-known pi-equivalent of a transmission line shown in Fig. 1. V_S , I_S and V_R , I_R are synchrophasors. The **RCF** of the sending end VT (VT_S) is known, that is both the MCF and the PACF. The primary goal is to derive the **RCF** for the remote VT (VT_R), but during this, the **RCF** for the sending- and receiving end CT is also derived. These synchronized phasors only address the fundamental frequency.

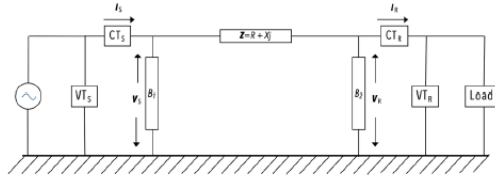


Fig. 1: Transmission line pi-network

The following notation is adopted for Fig. 1:

- V_S, V_R : Sending-end and receiving-end voltage synchrophasor.
- I_S, I_R : Sending-end and receiving-end current synchrophasor.
- B_1, B_2 : Shunt susceptance at fundamental frequency.
- Z : Line impedance consisting of $R + jX$ (resistance and inductive impedance respectively) at fundamental frequency.

Remote calibration methods are based on three important assumptions. Firstly, that instrument transformers are operated within the linear area of operation and that the **RCF** of both VTs and CTs remain constant during the period of investigation. It can change over time due to for example temperature, but the set of measurements excludes such change. Secondly, that a two-bus equivalent pi-model of a transmission line is a sufficient representation of the operational status of the power

system [8], [12], [10]. Thirdly, that the **RCF** of the VT at the sending end is known (obtained by field calibration for example).

A **RCF** of $1\angle 0^\circ$ (**RCF_{VS}**) was used for the sending end VT in [10], [8], also in the modelling below. Sending- and receiving end fundamental frequency voltage and current phasors can be related by network theory:

$$I_R = (V_S - V_R)/Z - I_2 \quad (1)$$

$$I_S = I_1 + (V_S - V_R)/Z \quad (2)$$

Where:

$$I_1 = jB_1 V_S$$

$$I_2 = jB_2 V_R$$

Multiply (1) and (2) by $Z = 1/Y$ and substitute for I_1 and I_2 allow for the sending end voltage synchrophasor V_S to be derived as:

$$I_R Z = (V_S - V_R) - jB_2 Z V_R \\ \therefore V_S = V_R(1 + jB_2 Z) + Z I_R \quad (3)$$

And the receiving end voltage synchrophasor V_R as:

$$I_S Z = jB_1 V_S Z + (V_S - V_R) \\ \therefore V_R = V_S(1 + jB_1 Z) - Z I_S \quad (4)$$

The difference between the measured current phasor (I_{meas}) and the true phasor value (I_{true}) at the receiving end can be related by **RCF_{IR}**:

$$I_{meas} = \text{RCF}_{IR} I_{true} \quad (5)$$

Similarly, the difference between the measured voltage phasor (V_{meas}) and the true voltage phasor (V_{true}) at the receiving end requires a ratio correction factor (**RCF_{VR}**):

$$V_{meas} = \text{RCF}_{VR} V_{true} \quad (6)$$

Introducing a **RCF** into (3) and (4) and assuming that **RCF_{VS}** is known, then (3) and (4) can be rewritten as:

$$V_S = (\text{RCF}_{VR} V_{Rtrue})(1 + jB_2 Z) + Z(\text{RCF}_{IR} I_{Rtrue}) \quad (7)$$

$$\text{RCF}_{VR} V_{Rtrue} = V_S(1 + jB_1 Z) - Z(\text{RCF}_{IS} I_{Strue}) \quad (8)$$

Where;

- RCF_{IR}**: Ratio Correction Factor for VT at receiving end,
- RCF_{VR}**: Ratio Correction Factor for CT at receiving end,
- RCF_{IS}**: Ratio Correction Factor for CT at sending end.

Estimation of transmission line parameters is needed in solving the above model. It can be estimated from construction data or can be derived from synchrophasors. Such field application is discussed in section IV.

Observe that in equations (7) and (8), three unknown correction factors exist. An under-determined set of equations has to be solved if only one set of synchrophasor measurements is available (by for example Newton-Raphson iteration). It has to be assumed that a **RCF** remains constant during the assessment period and that the instruments transformers remained within their characteristic curve [9, 11]. Temperature and other environmental factors will need consideration if the dataset reflects such a time period.

Synchrophasor recordings have to reflect different load conditions [3]. For N load conditions, the number of systems equations will be $2N$ and with 3 unknown ratio correction factors, an over-determined set of equations are obtained. This can be solved by least-squares estimation:

$$\mathbf{Ax} = \mathbf{b} + \boldsymbol{\varepsilon} \quad (9)$$

Where equations (7) and (8) is rewritten so that $\mathbf{x}$ is a $[2N \times 1]$ vector containing the unknown ratio correction factors, $\mathbf{A}$ a $[2N \times 4]$ matrix and $\mathbf{b}$ a $[2N \times 1]$ vector respectively containing the transmission line parameters (known) and synchrophasor measurements (known).

Residual values are contained in vector $\boldsymbol{\varepsilon}$:

$$\boldsymbol{\varepsilon} = \mathbf{b} - \mathbf{Ax} \quad (10)$$

The sum of the squared residuals in $\boldsymbol{\varepsilon}$ will be zero when a solution for $\mathbf{x}$ is obtained, that is the fundamental principle of least square estimation. This least square estimator is defined as:

$$\mathbf{x} = (\mathbf{A}^T \mathbf{A})^{-1} \mathbf{A}^T \mathbf{b} \quad (11)$$

The relation in (11) requires that $\mathbf{A}^T \mathbf{A}$ exists and why $2N > 4$. When $\mathbf{x}$ is determined from a set of field measurements, $\mathbf{RCF}_{VR}$, $\mathbf{RCF}_{IR}$ and $\mathbf{RCF}_{IS}$ is considered to be a solution when the sum of the squared residuals in (9) is zero. An increase in the number of measurements improve the accuracy by which the $\mathbf{RCFs}$ can be derived as it decreases the standard deviation from the absolute (precise) value [8].

IV. MEASUREMENT OF TRANSMISSION LINE PARAMETERS

The availability of network coherent data (synchrophasors) across a transmission line of interest, should in principle allow the calculation of line parameters. Included in the measured values for voltage and current synchrophasors, is uncertainty in measurement. Field application of remote VT calibration require that line parameters must be known and can be estimated by the methodology reported in [13].

This difference between the true and measured synchrophasor value directly impact the certainty by which the line parameter can be estimated and can defy the purpose of using a better estimation of line parameters to improve power system operational aspects.

Estimation of the $\mathbf{RCF}$ for the instrument transformers requires that transmission line parameters are known with sufficient certainty. An improved approach to derive line parameters from synchrophasors [13] included the estimation of the correction factors ($\mathbf{RCF}$) to correct for systematic errors introduced by the instrumentation channel (instrument transformer, cabling, burden and measuring instrument).

It presents a mathematical challenge as both the impedance parameters of the line and the calibration factors for the instrumentation channel must be estimated simultaneously. The number of equations now has a high number of unknowns, meaning that the problem can become ill-conditioned even if it is overdetermined.

A novel solution to the above constraint is reported in [13] that first estimates the correction factors for the systematic measurement errors at both ends of the line, and then by using measurements of average line temperature identifies the corrections factors that optimize the line impedance parameter estimation.

The goal in this paper is to derive the $\mathbf{RCF}$ for the instrument transformers assuming that transmission line parameters are known with sufficient certainty.

V. EMULATION MODEL

A computer simulation was used to emulate voltage and current waveforms at both ends of a transmission line. Transmission line parameters (derived from construction data) of a real-life 330 kV, 521 km line were used. Temperature was assumed to be constant during the loading conditions.

A Matlab® Simulink model simulated a single-phase pi-equivalent of this line. Voltage and current waveforms were recorded in the simulation model at both ends of the line whilst the loading of this line was changed from 10 – 80 MW (single phase) reflecting real-life loading of this line.

The simulated waveforms were reproduced by an Omicron™ CMC256plus™ waveform generator (110 V and 5 A) and recorded by two different synchrophasor recorders equipped with two different GPS receivers as shown in Fig. 2. Uncertainty in synchrophasor measurements is included whilst in the overall measurement uncertainty as expected during field application, the contribution by the VTs and CTs are excluded. Direct reproduction of the simulated voltage waveforms is done at 110 V_{rms} and current waveforms at a nominal value of 1 A_{rms} (by the CMC256plus™).

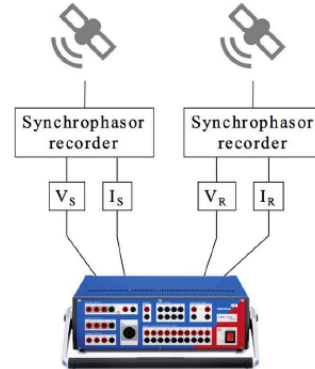


Fig. 2: Experimental setup using a CMC256plus to generate both the sending- and receiving end waveforms, measured by two different synchrophasor recorders

VI. ANALYSIS OF EMULATION MEASUREMENTS

Synchronized measurement of voltage synchrophasors, measured across the emulated transmission line and at the secondary terminals of the sending end VT and the receiving end VT, is shown in Fig.3 as the loading of the line changes.

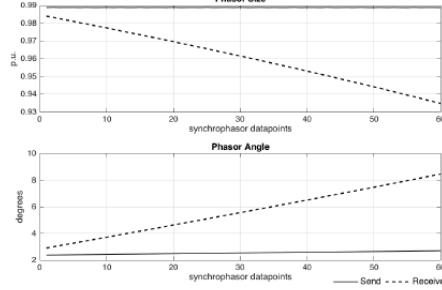


Fig. 3: RMS Voltage synchrophasor size and angle across the transmission line

Current synchrophasors at the sending and receiving end of the transmission line are shown in Fig. 4.

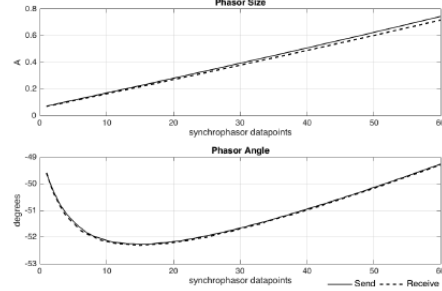


Fig. 4: RMS Current synchrophasors into and out of the transmission line

The contribution to measurement uncertainty in the synchrophasors across the line is assumed to be fully excluded when a computer simulation is done and considered the reference solution. A Matlab® Simulink model of the measurement setup was used.

As first evaluation of how measurement uncertainty is introduced by real-life synchrophasors, only one recorder was first used to measure across the emulated line. During this scenario, measurement uncertainty is contributed by one instrument only.

Secondly, two recorders with two different GPS antennas were used to independently record synchrophasors across the line. Measurement uncertainty now reflects a similar condition as expected during field application.

An error tolerance of 1×10^{-12} were used in the least square estimator and the **RCF** for each of the above scenarios calculated.

The total vector error, TVE is calculated, where **RCF_{cont}** is the controlled **RCF** (known) and **RCF_{meas}** the measured) ratio correction factor:

$$TVE = \frac{|\mathbf{RCF}_{cont} - \mathbf{RCF}_{meas}|}{|\mathbf{RCF}_{cont}|} \quad (12)$$

Table 1 compares how **RCF** is affected by measurement uncertainty introduced by an additional synchrophasor recorder.

Table 1: Difference in RCF estimation between one and two synchrophasor recorders

	$\Delta \mathbf{MCF}$ (p.u.)	$\Delta \mathbf{PACF}$ (deg)	TVE (%)
$\Delta \mathbf{RCF}_{VR}$	3.90×10^{-5}	-1.78×10^{-4}	3.91×10^{-3}
$\Delta \mathbf{RCF}_{IR}$	8.04×10^{-7}	1.07×10^{-3}	1.95×10^{-3}
$\Delta \mathbf{RCF}_{IS}$	5.08×10^{-3}	-1.12×10^{-3}	3.81×10^0

The difference in **RCF** between the reference case (computer simulation) and when two synchrophasor recorders (field application) are used is listed in Table 2.

Table 2: Difference in RCF estimation between the ideal (simulated) and two synchrophasor recorders

	$\Delta \mathbf{MCF}$ (p.u.)	$\Delta \mathbf{PACF}$ (deg)	TVE (%)
$\Delta \mathbf{RCF}_{VR}$	-4.47×10^{-4}	-2.94×10^{-2}	6.79×10^{-2}
$\Delta \mathbf{RCF}_{IR}$	-6.24×10^{-5}	4.57×10^{-2}	4.69×10^{-2}
$\Delta \mathbf{RCF}_{IS}$	5.07×10^{-3}	-1.67×10^{-3}	3.80×10^0

It can be concluded from Table 2 that the measurement uncertainty resulting from using two different synchrophasor recorders the **RCF** for a remote VT and CT is affected by less than 0.5% in magnitude and in phase angle, less than 0.03%.

VII. CONCLUSION ON THE OPPORTUNITY FOR INSTRUMENT TRANSFORMER REMOTE CALIBRATION

The principle of remotely calibrating a VT seems to be useful from the theoretical studies reported in literature [2], [3], [9]. As measurement uncertainty could constraint the field application of this novel idea, measurement uncertainty contributed by the synchrophasor recorders across a transmission line was systematically evaluated. VTs and CTs also contribute to measurement uncertainty, but for the purpose of this paper, only the PMU measurement uncertainty by two different synchrophasor recorders was considered.

If calibration data of only the sending end VT is available, an over-determined set of equations needed to be solved in deriving an **RCF** for the remaining instrument transformers (one local CT, a remote VT and CT). This was achieved by means of least squares estimation.

Line parameters for a real-life 330 kV 525 km transmission line were calculated from construction data and used to model a measurement system that collects synchrophasors across the line.

It is concluded that the impact of measurement uncertainty due to the time-stamping uncertainty and quantization noise of different PMUs at both ends of the line, is less than 0.05% in magnitude and less than 0.03% in phase angle. This validates that the opportunity for remote calibration of VTs and CTs by means of synchrophasors, justifies further research by evaluating if the principle is still useful when including the remaining measurement uncertainty in the measurement chain as contributed by CTs, VTs and cabling used in substations.

VIII. REFERENCES

- [1] M. M. Adibi and D. K. Thorne, "Remote Measurement Calibration," *IEEE Transactions on Power Systems*, Vols. PWR-1, no. 2, pp. 194-199, 1986.
- [2] A. Pal, "On-line Calibration of Voltage Transformers Using Synchrophasor Measurements," *IEEE Transactions on Power Delivery*, vol. 31, no. 1, pp. 370-380, 2016.
- [3] Z. Wu, Synchronized Phasor Measurement Applications in Three-phase Power Systems, Virginia, Blacksburg: Virginia Polytechnic Institute and State University, 2013.
- [4] A. Ferrero, "The Pillars of Metrology," *IEEE Instrumentation & Measurement Magazine*, vol. 18, no. 6, pp. 7-11, December 2015.
- [5] IEEE, "C57.23-2008 Standard Requirements for Instrument Transformers," IEEE, 2008.
- [6] S. Salicone, "Measurement Uncertainty," in *An Approach via the Mathematical Theory of Evidence*, New York, Springer Science+Business Media, 2007, pp. 1-15.
- [7] IEEE, *Standard for Synchrophasor Measurements for Power Systems IEEE Std C37.118*, 1-2011.
- [8] Z. Wu, K. Thomas, R. Sun, V. A. Centeno and A. G. Phadke, "Three-phase Instrument transformer calibration with synchronized phasor measurements," in *Innovative Smart Grid Technologies*, Washington, DC, 2012.
- [9] M. Zhou, Advanced Systems Monitoring with Phasor Measurements, Blacksburg, Virginia, 2008.
- [10] T. P. Hinge and S. S. Damhare, "A novel approach for calibration of Instrument Transformers using synchrophasors," in *National Power Systems Conference*, Bhubaneswar, India, 2016.
- [11] Z. Wu, L. T. Zora and A. G. Phadke, "Simultaneous transmission line parameter and PMU measurement calibration," in *Power & Energy Society General Meeting*, Denver, CO, USA, 2015.
- [12] K. V. Khandeparkar, S. A. Soman and G. Gajjar, "Detection and Correction of Systematic Errors in Instrument Transformers along with Line Parameter Estimation using PMU Data," *IEEE Transactions on Power Systems*, vol. PP, no. 99, 2016.
- [13] D. Ritzmann, J. Rens, P. S. Wright, W. Holderbaum and B. Potter, "A Novel Approach to Non-invasive Measurement of Overhead Line Impedance Parameters," *IEEE Transactions on Instrumentation and Measurement*, vol. 66, no. 6, pp. 1155-1163, June 2017.
- [14] A. G. Phadke, J. S. Thorp, R. F. Nuqui and M. Zhou, "Recent developments in state estimation with phasor measurements," in *IEEE/PES Power Systems Conference and Expo*, Seattle, WA, 2009.
- [15] D. Ritzmann, W. Holderbaum, B. Potter and P. Wright, "Improving the accuracy of synchrophasor-based overhead line impedance measurement," in *IEEE International Workshop on Applied Measurements for Power Systems*, Aachen, 2015.
- [16] D. Ritzmann, P. S. Wright, W. Holderbaum and B. Potter, "A Method for Accurate Transmission Line Parameter Estimation," *IEEE Transactions on Instrumentation and Measurement*, vol. 65, no. 10, pp. 2204-2213, 2016.
- [17] D. Shi, D. J. Tylavsky and N. Logic, "An Adaptive Method for Detection and Correction of Errors in PMU Measurements," *IEEE Transactions on Smart Grid*, vol. 3, no. 4, pp. 1575-1583, 2012.
- [18] M. M. Adibi, K. A. Clements, R. J. Kafka and J. P. Stovall, "Remote Measurement Calibration," *IEEE Computer Applications in Power*, vol. 3, no. 4, pp. 37-42, 1990.
- [19] S. Chakrabarti, G. Sivanagaraju and S. C. Srivastava, "Uncertainty in transmission line parameters: Estimation and impact on line," *IEEE Transactions on Instrumentation and Measurements*, vol. 63, no. 6, pp. 1496-1504, Jun 2014.

APPENDIX B - TECHNICAL SPECIFICATIONS OF MEASUREMENT DEVICE [38]

Voltage Inputs	
Number of channels	4 x differential (3/4 Wire + 4 th Diff)
Measurement input range	0-600 V _{AC} ± 850 V _{DC}
Input Impedance	> 1MΩ
Current Inputs	
Number of channels	4 x galvanically isolated
Measurement input range	0-6 A _{AC} ± 8 A _{DC}
Max continuous current	10 A _{RMS}
3 sec Overcurrent withstand	50 A _{RMS}
VA burden @ 5 A _{RMS}	< 1 VA
Galvanic isolation	1 kV
Current Transducer Inputs	
Number of channels	4 x differential
Measurement input range	0 -1 V _{AC} ± 1.5 V _{DC}
Input impedance	> 200 kΩ
Digital Inputs	
Number of channels	4 x galvanically isolated
Max voltage input	300 V _{DC}
Digital Outputs	
Number of channels	4 x galvanically isolated
Max voltage, current	300 V _{AC} , 100 mA _{AC}
Accuracy & Bandwidth	
Overall Accuracy	0.1 % on reading (10% - 100%)
Power frequency measurement range	DC, 40 – 60 Hz & 50 – 70 Hz
Harmonic & inter-harmonic bandwidth	1 – 64 th ; 2 – 9 kHz
Synchronised data sampling rate	500 kHz
Fast transient capturing	> 20 μs
ADC Resolution	16-bit
Communication	
Security	Permanent 128-bit encryption
Ethernet	2 x Gigabit ports
PTP support	IEEE1588
POE Plus Support	IEEE802.3at (30W)(48)
Clocks	
Built-in GPS	U-Blox LEA-6T
GPS clock sync accuracy	± 100 ns (from absolute time)
PTP clock sync accuracy	± 1 μs (from absolute time)
NTP clock accuracy	± 1 ms (from absolute time)
Built-in clock accuracy	± 1 ppm (32 sec per annum)

APPENDIX C – TECHNICAL SPECIFICATIONS OF OMICRON™ 256PLUS™ [39]

CMC 256plus



CMC 256plus – High precision relay test set and universal calibrator

The CMC 256plus is the first choice for all test applications where six current outputs and high voltage amplitudes combined with a particularly high accuracy are required. This unit is not only an excellent test set for protection devices of all kinds, but also a universal calibration tool. Its high precision allows the calibration of a wide range of measuring devices, including: electricity meters of class 0.2S, transducers, power quality measurement devices and phasor measurement units (PMU). Its unique accuracy and flexibility make the CMC 256plus ideal for protection and measurement equipment manufacturers for research and development, production and type testing.

Technical Data¹

Current generators		
Setting range	6-phase AC (L-N)	6 x 0 ... 12.5 A
	3-phase AC (L-N)	3 x 0 ... 25 A (Group A II B)
	1-phase AC (3L-N)	1 x 0 ... 75 A (Group A II B), 2 x 0 ... 37.5 A
	DC (3L-N)	1 x 0 ... ±35 A (Group A II B), 2 x 0 ... ±17.5 A
Power	6-phase AC (L-N)	6 x 80 VA typ. at 8.5 A, 6 x 70 VA guar. at 7.5 A
	3-phase AC (L-N)	3 x 160 VA typ. at 17 A (Group A II B), 3 x 140 VA guar. at 15 A (Group A II B)
	1-phase AC (3L-N)	1 x 480 VA typ. at 51 A (Group A II B), 2 x 240 VA at 25.5 A, 1 x 420 VA guar. at 45 A (Group A II B), 2 x 210 VA at 22.5 A
	1-phase AC (L-L)	1 x 320 VA typ. at 8.5 A (Group A II B), 2 x 160 VA at 8.5 A, 1 x 280 VA guar. at 15 A (Group A II B), 2 x 140 VA at 7.5 A
	1-phase AC (L-L-L)	1 x 320 VA typ. at 8.5 A (40 VRMS, Group A and B in series), 1 x 280 VA guar. at 7.5 A (40 VRMS, Group A and B in series)
	DC (3L-N)	1 x 480 W typ. at ±35 A (Group A II B), 2 x 240 W at ±17.5 A, 1 x 470 W guar. at ±35 A (Group A II B), 2 x 235 W at ±17.5 A
	Accuracy ²	error < 0.015 % rd. ³ + 0.005 % rg. ² typ. at 0 ... 12.5 A error < 0.04 % rd. + 0.01 % rg. guar. at 0 ... 12.5 A
	Distortion (THD+N) ⁴	< 0.025 % typ., < 0.07 % guar.
	Ranges	1.25 A / 12.5 A (Group A, B) or 2.5 A / 25 A (Group A II B)
	Resolution (for respective range)	50 µA / 100 µA / 500 µA / 1 mA
	Max. compliance voltage (L-N)/(L-L)	15 Vpk / 60 Vpk
	Connection	4 mm (0.16 in) banana sockets / combination socket (Group A only)

Voltage generators		
Setting range	4-phase AC (L-N)	4 x 0 ... 300 V (VL4(t) automatically calculated: VL4 = (VL1+VL2+VL3)*c or freely programmable)
	3-phase AC (L-N)	3 x 0 ... 300 V
	1-phase AC (L-L)	1 x 0 ... 600 V
	DC (L-N)	4 x 0 ... ±300 V
Power	3-phase AC (L-N)	3 x 100 VA typ. at 100 ... 300 V, 3 x 85 VA guar. at 85 ... 300 V
	4-phase AC (L-N)	4 x 75 VA typ. at 100 ... 300 V, 4 x 50 VA guar. at 85 ... 300 V
	1-phase AC (L-N)	1 x 200 VA typ. at 100 ... 300 V, 1 x 150 VA guar. at 75 ... 300 V
	1-phase AC (L-L)	1 x 275 VA typ. at 200 ... 600 V, 1 x 250 VA guar. at 200 ... 600 V
	DC (L-N)	1 x 420 W typ. at ±300 V, 1 x 360 W guar. at ±300 V
	Accuracy ⁵	Error < 0.015 % rd. ⁶ + 0.005 % rg. ² typ. at 0 ... 300 V Error < 0.04 % rd. + 0.01 % rg. guar. at 0 ... 300 V
	Distortion (THD+N) ⁴	0.015 % typ., < 0.05 % guar.
	Ranges	150 V / 300 V
	Resolution	5 mV / 10 mV in range 150 V / 300 V
	Connection	4 mm (0.16 in) banana sockets / combination socket (1,2,3,N)
Generators, general		
Frequency	Range sine signals	10 ... 1000 Hz
	Range harmonics / interharmonics ⁸	10 ... 3000 Hz
	Range transient signals ⁹	DC ... 3.1 kHz
	Accuracy / drift	±0.5 ppm / ±1 ppm
	Resolution	< 5 µHz
	Error at 50 / 60 Hz	< 0.005 % typ., < 0.02 % guar.
Phase	Angle range	-360° ... +360°
	Resolution	0.001°
Bandwidth (-3 dB)	Simulated power S, P (calibration of energy meters)	Error < 0.05 % rd. typ., < 0.1 % rd. guar.
	Temperature drift	< 0.001 % / °C typ., < 0.005 % / °C guar.

¹ All data specified are guaranteed, except where indicated otherwise. OMICRON guarantees the specified data for one year after factory calibration, within 23 °C ± 5 °C (73 °F ± 10 °F) in the frequency range from 10 to 100 Hz and after a warm-up phase > 25 minutes

² Rload: 0 ... 0.5 Ω

³ rd. = reading, rg. = range

⁴ THD+N: Values at 50/60 Hz, > 1 A / 20 V with 20 kHz bandwidth

⁵ Rload: > 250 Ω

⁶ Amplitude derating at > 1000 Hz

⁷ Data are valid from 0.1 to 12.5 A (current amplifier A or B) and 50 to 300 V (voltage amplifier) at 50/60 Hz

Permissible load for current outputs:

Range 1.25 A: 0 to 1 Ω and 1 VA max., cos φ = 0.5 to 1

Range 12.5 A: 0 to 0.5 Ω and 6 VA max., cos φ = 0.5 to 1

Permissible load for voltage outputs:

10 VA max. at 50 to 300 V, cos φ = 0.5 to 1

Technical Data CMC 256plus (continued)

Low level outputs¹

Number of outputs	6 (12 with Option LLO-2)
Setting range	0 ... ±10 Vpk
Max. output current	1 mA
Accuracy	Error < 0.025 % typ., < 0.07 % guar. at 1 ... 10 Vpk
Resolution	250 µV
Distortion (THD+N) ²	< 0.015 % typ., < 0.05 % guar.
Unconventional CT/VT simulation	linear, Rogowski (transient and sinewave)
Overload indication	Yes
Isolation	SELV
Usability	Completely independent from internal amplifier outputs
Connection	16 pin combination socket (rear side)

Auxiliary DC supply

Voltage ranges	0 ... 264 VDC, 0.2 A / 0 ... 132 VDC, 0.4 A / 0 ... 66 VDC, 0.8 A
Power	Max. 50 W
Accuracy	Error < 2 % typ., < 5 % guar.

Binary inputs

Number	10
Trigger criteria	Toggling of potential-free contacts or DC voltage compared to threshold voltage
Input characteristics	0 ... ±600 VDC threshold or potential-free
Ranges	100 mV / 1 V / 10 V / 100 V / 600 V
Resolution of threshold	±2 mV, ±20 mV, ±200 mV, ±2 V, ±20 V in ranges
Sample rate	10 kHz (resolution 100 µs)
Time stamping accuracy	±0.00015 % of rd. ³ ±70 µs
Max. measuring time	Infinite
Debounce / Deglitch time	0 ... 25 ms / 0 ... 25 ms
Counting function	< 3 kHz at pulse width > 150 µs
Galvanic isolation	5 galvanically isolated groups (2+2+2+2+2)
Max. input voltage	CAT IV / 150 V, CAT III / 300 V, CAT II / 600 V (850 Vpk)

Counter inputs 100 kHz

Number	2
Max. counting frequency	100 kHz
Pulse width	> 3 µs
Threshold voltage	6 V
Voltage hysteresis	2 V
Max. input voltage	±30 V
Isolation	SELV
Connection	16 pin combination socket (rear side)

Trigger on overload

Supported generators	Current generators
Timer accuracy	Error < 1 ms

Binary outputs, relays

Type	Potential-free relay contacts, software controlled
Number	4
Break capacity AC	Vmax: 300 VAC / Imax: 8 A / Pmax: 2000 VA
Break capacity DC	Vmax: 300 VDC / Imax: 8 A / Pmax: 50 W

Binary outputs, transistor

Type	Open collector transistor outputs
Number	4
Update rate	10 kHz
Imax	5 mA
Connection	16 pin combination socket (rear side)

DC voltage measuring input

Measuring range	0 ... ±10 V
Accuracy	Error < 0.003 % rg. ⁴ typ., < 0.02 % rg. guar.
Input impedance	1 MΩ

DC current measuring input

Measuring range	0 ... ±1 mA, 0 ... ±20 mA
Accuracy	Error < 0.003 % rg. ⁴ typ., < 0.02 % rg. guar.
Input impedance	15 Ω

Analog AC+DC measuring inputs⁴

Type	AC + DC analog voltage inputs (current measurement with external current clamps or shunt resistors)
Number	10
Nominal input ranges (RMS values)	100 mV, 1 V, 10 V, 100 V, 600 V
Amplitude accuracy	Error < 0.06 % typ., < 0.15 % guar.
Bandwidth	DC ... 10 kHz
Sampling frequency	28.44 kHz, 9.48 kHz, 3.16 kHz
Input impedance	500 kΩ // 50 pF
Transient input buffer at 28 kHz	3.5 s for 10 input channels / 35 s for 1 input channel
Transient input buffer at 3 kHz	31 s for 10 input channels / 5 min. for 1 input channel
Transient trigger	Threshold voltage, power quality trigger: sag, swell, harmonic, frequency, frequency change, notch
Measurement functions	I (AC + DC), V (AC + DC), phase, frequency, power, harmonics, transient recording, event recording, trend recording
Input overload indication	Yes
Input protection	Yes
Max. input voltage	CAT IV / 150 V, CAT III / 300 V, CAT II / 600 V (850 Vpk)
Galvanic isolation	5 groups (2+2+2+2+2)

Time synchronization

Timing accuracy	IRIG-B synchronization with CMIRIG-B GPS synchronization with CMGPS 588
To external voltage	Error < 1 µs typ., < 5 µs guar. Error < 1 µs typ., < 5 µs guar.
Precision Time Protocol (PTP)	Reference signal on binary input 10: 10 ... 300 V / 15 ... 70 Hz IEEE 1588-2008 IEEE C37.238-2011 (Power Profile) IEC/IEEE 61850-9-3 (Utility Profile)

With the unique PermaSync functionality, analog and Sampled Values outputs stay permanently in sync with the internal CMC time reference.

When a CMC is time-synchronized (IRIG-B, GPS, or PTP), the output quantities are continuously synchronized to the external time source.

With CMIRIG-B it is also possible to transmit the internal PPS signal of the CMC to the device under test (e.g. PMUs or IEDs stimulated with a synchronized Sampled Values data stream).

¹ For directly testing relays with low level inputs by simulating signals from non-conventional CTs and VTs with low level interfaces and for controlling external amplifier units

² THD+N: Values at 50/60 Hz, 20 kHz measurement bandwidth, nominal value, and nominal load

³ rd. – reading, rg. – range

⁴ Up to three inputs can be used for measuring RMS values, frequency, and phase angle without the EnerLyzer software license. Full functionality requires EnerLyzer software license

IEC 61850 GOOSE ¹	
Simulation	Mapping of binary outputs to data attributes in published GOOSE messages. Number of virtual binary outputs: 360 Number of GOOSEs to be published: 128
Subscription	Mapping of data attributes from subscribed GOOSE messages to binary inputs. Number of virtual binary inputs: 360 Number of GOOSEs to be subscribed: 128
Performance	Type 1A; Class P2/3 (IEC 61850-5). Processing time (application to network or vice versa): < 1 ms
VLAN support	Selectable priority and VLAN-ID
IEC 61850 Sampled Values (Publishing) ¹	
Specification	According to the "Implementation Guideline for Digital Interface to Instrument Transformers Using IEC 61850-9-2" of the IEC International Users Group ("9-2LE") and IEC 61869-9.
Sampling Rates	4000 Hz, 4800 Hz, 12800 Hz, 15360 Hz, 14400 Hz
Synchronization	Synchronization attribute (smpSynch) is set when the CMC is in synchronized operation mode. Sample count (smpCnt) zero is aligned with top of the second. Accuracy data see above
VLAN support	Selectable priority and VLAN-ID
Max. number of SV streams	4
Power supply	
Nominal input voltage ²	100 ... 240 VAC, 1-phase
Permissible input voltage	85 ... 264 VAC
Nominal frequency	50/60 Hz
Permissible frequency range	45 ... 65 Hz
Rated current	12 A at 115 V / 10 A at 230 V
Connection	Standard AC socket (IEC 60320)
Environmental conditions	
Operation temperature ³	0 ... +50 °C (+32 ... +122 °F)
Storage temperature	-25 ... +70 °C (-13 ... +158 °F)
Humidity range	Relative humidity 5 ... 95 %, non-condensing
Equipment reliability	
The product adheres to the electromagnetic compatibility (EMC) Directive (CE conform).	
EMC Emission	International/ Europe IEC/EN 61326-1, EN 55032/ CISPR 32 (Class A), IEC/EN 61000-3-2/3 North America 47 CFR 15 Subpart B (Class A) of FCC
EMC Immunity	International/ Europe IEC/EN 61326-1, IEC/EN 61000-6-5, IEC/EN 61000-6-4
The product adheres to the low voltage Directive (CE conform).	
Safety	International/ Europe IEC/EN 61010-1, IEC/EN 61010-2-030 North America UL 61010-1, UL 61010-2-030, CAN/CSA-C22.2 No. 61010-1, CAN/CSA-C22.2 No. 61010-2-030
Mechanical tests	International/ Europe IEC 60068-2-6 (20 m/s ² at 10 ... 150 Hz), IEC 60068-2-27 (15 g/11 ms half-sine)

Miscellaneous	
Weight	16.0 kg (35.3 lbs)
Dimensions (W x H x D, without handle)	450 x 145 x 390 mm (17.7 x 5.7 x 15.4 in)
PC connection	Two PoE ⁴ Ethernet ports: • 10/100/1000 Base-TX • IEEE 802.3af compliant • Port capability limited to one Class 1 (3.84 W) and one Class 2 (6.49 W) powered device USB ports: • USB Type-B port (PC) • USB Type-A port (Wi-Fi adapter for wireless control)
Signal indication (LED)	> 42 V for voltage outputs AUX DC
Connection to ground (earth)	4 mm (0.16 in) banana socket (rear side)
Hardware diagnostics	Self diagnostics upon each start-up
Galvanically separated groups	The following groups are galvanically separated from each other: mains, voltage amplifier output, current amplifier group A/B, auxiliary DC supply, binary/analog input
Protection	All current and voltage outputs are fully overload and short circuit proof and protected against external high-voltage transient signals and overtemperature
Certifications	
 	
Developed and manufactured under an ISO 9001 registered system	

Ordering information

CMC 256plus with Test Universe	
VE002724	CMC 256plus Essential
VE002725	CMC 256plus Standard
VE002726	CMC 256plus Enhanced
VE002727	CMC 256plus Complete

CMC 256plus with CMControl (without Test Universe)	
VE002721	CMC 256plus with CMControl P App activation key
VE002715	CMC 256plus with CMControl P

The CMControl can also be ordered as add-on together with a CMC 256plus with Test Universe software or as a later upgrade.

CMC 256plus hardware options	
VEH02703	Option LLO-2 if ordered with a new unit
VEH02704	Option LLO-2 if ordered as an upgrade

¹ Testing with GOOSE and Sampled Values functionality requires software licences for the corresponding configuration modules

² For line inputs below 115 VAC, it is not possible to drive all outputs (voltage output, current output, Aux DC) simultaneously at full load. All other technical specifications (e.g. the maximum output power of a single amplifier) are not affected

³ For an operational temperature above +30 °C (+86 °F) a duty cycle of down to 50 % may apply

⁴ PoE = Power over Ethernet

APPENDIX D – OVERVIEW OF SPECIFICATIONS FOR TEST UNIVERSE™ PACKAGE [39]

TU Package Overview



For the combination of CMC test sets¹ and Test Universe software, four different packages as well as optional add-ons are offered, which are tailored to diverse focal points of use. Each of these packages contains a selection of software modules that can be either used independently from each other for single tests or be embedded into test plans for automated testing:

- > **Essential:** offers a good introduction with basic functions and modules; can serve as a foundation for individually compiled packages
- > **Standard:** contains all modules that are typically used for settings-based testing of protection devices
- > **Enhanced:** like Standard, specifically extended by functions for system-based testing and transient simulation as well as for free programming
- > **Complete:** covers all functions and software modules that are offered for controlling CMC test sets

A package can be extended at any time by ordering additional single modules or optional add-ons.

		Packages				Add-ons		
		Essential	Standard	Enhanced	Complete	Measurement Equipment Testing	IEC 61850 Basic	IEC 61850 Advanced
OMICRON Control Center ²	Automation tool, document-oriented test plan, template and report form	■	■	■	■			
QuickCMC	Convenient manual testing in the Test Universe environment	■	■	■	■			
State Sequencer	Determining operating times and logical timing relations by state-based sequences	■	■	■	■			
TransPlay	Playback of COMTRADE files, recording of binary input status	■	■	■	■			
Harmonics	Generation of signals with superimposed harmonics	■	■	■	■			
CB Configuration	Module for setting the CB simulation	■	■	■	■			
Ramping	Determining magnitude, phase, and frequency thresholds by ramping definitions	■	■	■	■			
Pulse Ramping	Determining magnitude, phase, and frequency thresholds	□	■	■	■			
Overcurrent ³	Automatic testing of positive/negative/zero sequence overcurrent characteristics	□	■	■	■			
Distance	Impedance element evaluations using single-shot definitions in the Z-plane	□	■	■	■			
Advanced Distance	Impedance element evaluations using automatic testing modes	□	■	■	■			
VI Starting	Testing of the voltage dependent overcurrent starting function of distance relays	□	■	■	■			
Autoreclosure	Testing of the autoreclosure function with integral fault model	□	■	■	■			
Single-Phase Differential	Single-phase tests of the operating characteristic and the inrush blocking	□	■	■	■			
Advanced Differential	Comprehensive three-phase differential relay testing (four modules)	□	■	■	■			
Annunciation Checker	Verification of the correct marshalling and wiring of protection devices	□	■	■	■			
Power	Testing with visualization and assessment in the P-Q plane (basic)	□	■	■	■			
Advanced Power	Testing with visualization and assessment in the P-Q plane (enhanced)	□	■	■	■			
Advanced TransPlay	Playback and processing of COMTRADE, PL4, or CSV files	□	■	■	■			
Transient Ground Fault ⁴	Simulation of ground-faults in isolated or compensated networks	□	□	■	■			
Synchronizer	Automatic testing of synchronizing devices and synchro-check relays	□	□	■	■			
Meter	Testing of single and multifunction energy meters	□	□	□	■	■		
Transducer	Testing of measurement transducers	□	□	□	■	■		
PQ Signal Generator	Simulation of power quality phenomena according to IEC 61000-4-30 and IEC 62586	□	□	□	■	■		
IEC 61850 Client/Server	Automatic SCADA testing in accordance with IEC 61850	□	□	□	■		■	■
GOOSE Configuration	Testing with GOOSE according to IEC 61850	□	□	□	■		■	■
Sampled Values Configuration	Testing with Sampled Values according to IEC 61850-9-2 ("9-2 LE") and IEC 61869-9	□	□	□	■			■
CMControl P App	Quick and easy manual testing of protection and measurement devices	□	■	■	■			
RelaySimTest ⁴	System-based protection testing by simulating realistic power system events	□	□	■	■			
CM Engine	Programming interface for controlling CMC test sets with user specific software	□	□	■	■			
EnerLyzer / EnerLyzer Live	Analog measurements and transient recording with CMC test sets	□	□	□	■			
TransView	Transient signal analysis for COMTRADE files	□	□	□	■			
ADMO	Asset and maintenance management for protection systems	□ ⁵	□ ⁵	□ ⁵	□ ⁵			
	Test set management	■	■	■	■			
IEDScout	Universal software tool for working with IEC 61850 IEDs					■	■	

Contained in all packages: Binary I/O Monitor, AuxDC Configuration, ISIO Connect (for ISIO 200), Polarity Checker (for CPOL2).

¹ CMC 356, CMC 256plus, CMC 430 and CMC 353

² Includes licenses for Pause Module, ExeCute, TextView

³ Includes license for Overcurrent Characteristics Grabber

⁴ RelaySimTest license also includes the licenses for Transient Ground Fault and NetSim

⁵ Free trial version (time licensed) with full functionality included in all packages

■ Contained
□ Optionally available