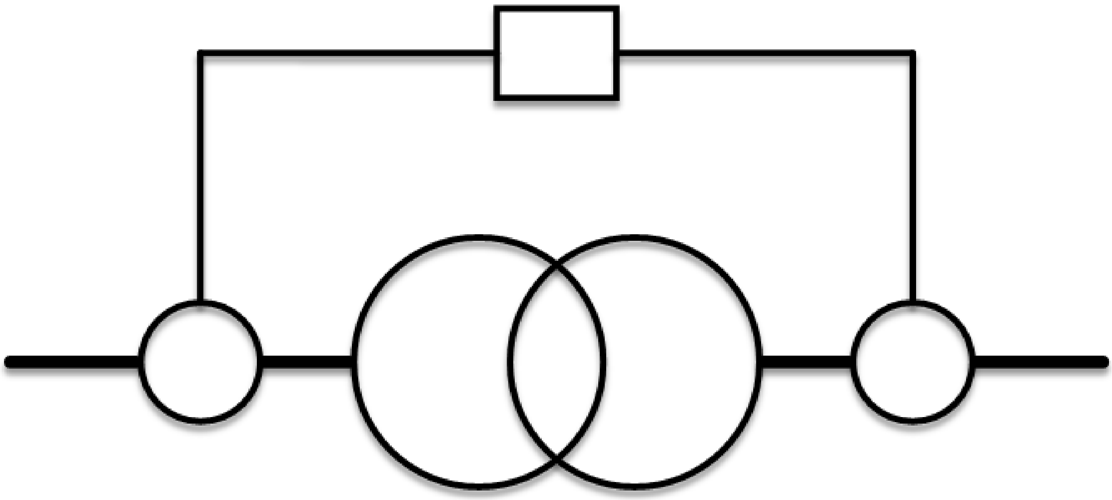
Differential Protection of Transformers



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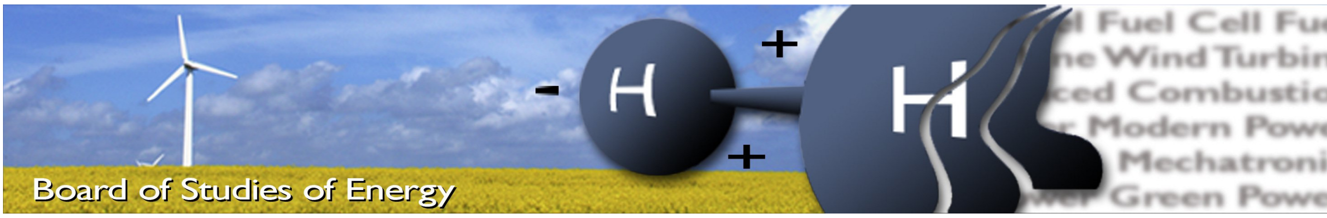

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SYNOPSIS:

This report was formed as a follow up project to the authors internship report, which dealt with wiring and designing a 60/20 kV substation. The project involves the technical aspect of configuring differential protection for a transformer. In order to successfully create a working differential protection, various transformer specific events are investigated. A practical example of parametrizing a transformer, simulating the inrushes in the transformer and then setting up differential relays to cope with the inrush is carried out. The project was semi successful, as working settings for the inrush were achieved, however due to technical constraints, a full differential protection for the transformer was not achieved.

Pages, total: 51
Appendix: 5
Supplements: 3

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Summary (Danish)

Dette projekt tager udgangspunkt i forfatterens praktikprojekt. Her arbejdede forfatteren med elektrisk design og konstruktion af højspændings understationer. Ud fra dette blev det besluttet at arbejde videre med et stykke arbejde udført på et transformer felt. Snitfladen for det tidligere projekt sluttede ved klemmerne på relæerne og de enkelte beskyttelseskomponenter.

For at fortsætte dette arbejde blev de tekniske aspekter af differentiale beskyttelse undersøgt. Det blev fundet at moderne differentiale beskyttelse er udført ved hjælp af digitale relæer. Der blev fundet forskellige styrker og svagheder ved transformer differentiel beskyttelse. En af styrkerne er at det er ekstremt hurtigt. En fejlramt transformer kan tages ud af drift på under en halv cyklus (10 ms). Udover dette er det en meget selektiv form for beskyttelse, da beskyttelsesområdet er fysisk afgrænset af strømtransformere.

Dog er systemet ikke perfekt, da det også har nogle ret markante svagheder. Ideelt burde strømmene kunne sammenlignes 1:1, og enhver afvigelse burde resultere i en udkobling. I virkeligheden er der dog adskillelige fejlkilder. Disse kommer fra transformerens egetforbrug, fejlmålinger i strømtransformerne grundet deres unøjagtighed, og fejlmålinger fra når strømtransformerne går i mætning. Udover disse, vil det også være nødvendigt at skalere strømmene på grund af det beskyttede objekt. Dettes gøres fra sag til sag, da det skifter med objektet. For en transformer betyder det at strømmene der bliver målt på hver side skal skaleres. Dette skal de da strømmene på sekundærsiden er invers proportionale med viklingsforholdet. Derudover skal der tages højde for vektor grupperingen af transformeren, da denne vil resultere i at sekundærsiden enten har positiv eller negativ faseforskydning. Bruges transformeren også til at skabe galvanisk isolation er det derudover vigtigt at man eliminerer den nul sekvens strøm der kan løbe i jordlederen i et jordet stjernepunkt, da denne ikke transformeres over til trekants viklingen.

Når en effekt transformer skal kobles ind på nettet sker dette ved først at koble primærsiden ind. Derefter kobler man sekundær siden med belastningen ind. Når primærsiden kobles ind opstår der en magnetisk transient, som gør at der løber en meget stor magnetiseringsstrøm. Denne startstrøm kan være så stor at den kan skade udstyr og være årsag til at spændingen falder lokalt, grundet spændingsfaldet igennem nettets modstand. Størrelsen af denne strøm bestemmes primært af kortslutningseffekten af det net som transformeren tilsluttes, samt størrelsen af transformeren. I rapporten evalueres flere metoder, som kan bruges til at reducere størrelsen af strømmen. Eftersom at startstrømmen opstår selvom sekundærsiden ikke er tilkoblet, ses den som en fejlstrøm af relæerne. Det fastslås dog at startstrømmen kan blive identificeret af relæerne ved at udføre FFT analyse på den. Dette er muligt da startstrømmen har et meget stort harmonisk indhold, da den store størrelse på den skyldes at transformeren går i mætning og derfor ikke opfører sig lineært. Særligt er den andenharmoniske strøm stor, og denne bruges derfor til at blokere for relæets udkoblingssystem.

For at verificere det arbejde der er udført i teoriafsnittet, er der udført laboratorie arbejde. I laboratoriet blev en transformer parametriseret, hvilket dannede grundlaget for en række simuleringer. Igennem simuleringerne blev det påvist at der opstod startstrømme der var cirka 20 gange så store som normalstrømmen i transformeren. Dette påviste at strømmene selv ved mindre transformere kan skabe problemer. For at teste de indstillinger der blev diskuteret i teoridelen blev to Siemens 7sd610 relæer programmeret. Herefter blev startstrøms simuleringerne testet på relæerne ved hjælp af en OMICRON CMC 256-6. Ud fra dette kunne det ses at startstrømmene blev detekteret og at udkoblingsmekanismerne blokeret i relæet.

Preface

This project is made as a follow up project to the internship report compiled by the author. The topic of the internship report was the physical aspects of differential protection of a distribution transformer. It involved designing and drawing schematics for the differential relay and auxiliary systems of the transformer bay. This project involves the theoretical aspects and programming of the relay.

Reading Guide

The report is written with the presumption that the reader has a general knowledge of electrical theory and basic electrical components. Therefore, some components and terms will be mentioned without further explanation.

The literature and sources are cited using the Harvard method, and appear in brackets, containing: the authors last name, firm or website, and the year of publication. If the source is used as a knowledge base, it will be referred to in the introduction to the chapter or section. If anything is taken directly from the source, it will be cited right after the use. All the sources are gathered in the bibliography where the URL for web pages is given along with the date of use.

Tables, figures and equations are numbered in the order of appearance, where the first numbers are the chapter and subsection numbers, and the last number is the object number. An example of this could be Figure 2.3 meaning the third Figure in Chapter 2. Equations are given in parentheses but are numbered the same way as Figures. Abbreviations used in the report are presented in a bracket after the full word or sentence for which they abbreviate.

The reports layout is designed for two-sided color print, and is meant to be setup as a book either by stitching or glued book binding.

Contents

1 Introduction

Transmission and distribution networks have moved from being a local entity to becoming a continent spanning machine, which consist of power plants, wind turbine farms, country-spanning transmission lines, etc. The joints connecting all these elements are the transformers. The transformers scale the voltages to connect the lower level distribution networks to the highway of electricity: the transmission network.

Typically, transformers are the piece of equipment in the chain that malfunctions first, if subjected to maloperation. At a household level, this is not an issue as the transformers used are cheap and replacements are stocked. In the distribution and transmission network however, transformers are expensive pieces of equipment with long delivery times. This necessitates protection systems for the transformers. In the transmission network three groups of electrical protection systems are typically used. The first is overcurrent protection. This is a simple form of protection, which is rather slow and does not provide much selectivity. It simply protects against large currents. It is typically added as a secondary form of protection, to provide backup protection if the main protection fails. The next type is distance protection. Distance protection works by measuring the voltage and currents, and using these to calculate the impedance of the surrounding network. By measuring the impedance on a line for example, the distance to a fault can be estimated. Furthermore, by dividing the surrounding network into zones, it provides selectivity and relatively fast protection. In the first zone as fast as 20-40 ms, and 300-400 ms in the second zone. Furthermore it can act as backup protection by reaching into the busbars and transformers the lines are connected to. [Ziegler, 2011] However, as the transformer is quickly damaged during a fault, faster and more selective protection is required. For this purpose, differential protection is utilized. By defining its zones with current transformers, it provides 100% selectivity, and tripping times can be under one cycle (20 ms at 50 Hz). [Ziegler, 2012] This is done by comparing the currents flowing into the transformer. Any internal error will show up as a differential current, and cause a trip. In the ideal system, this is very simple to do. In practice however, several sources can contribute to erroneous operation, which will require compensation. This is the subject of this report, in which the phenomena surrounding the differential protection will be investigated.

2 Problem Definition

In order to narrow the scope of this report, the problems to be researched must be defined. The objectives and limitations of the scope are defined. Differential protection can be applied to a great number of systems. As the title of the report implies, this report deals with only the protection of transformers. Additionally, differential protection can be applied to transformers with more than two windings, so in order to narrow the scope, only two winding transformers are evaluated. The scope of the report does not include in-depth work with tap changer transformers. As a note to these transformer limitations, some theory used is generalizable and could be applied to systems including these topologies, but this will not be elaborated on further.

The objectives and research questions of this project are presented in bullet form below.

- How does differential protection work?
- How does the differential protection deal with vector grouping, winding ratios and other transformer related scaling?
- How does the differential protection distinguish between fault and inrush currents?
- What is the cause of the inrush current, and how can it be mitigated?
- How are differential protection systems built in real life using numerical relays, and how are they programmed?
- How is the differential protection system tested?

Theory 3

In this chapter the necessary theory will be investigated. This is done in order to create a knowledge base to refer to when evaluating models and simulations. The objective is to cover all relevant fields, in order to centralize the knowledge required to carry out the differential protection of a transformer.

The knowledge in section 3.2 is, unless explicitly stated, compiled from Gerhard Ziegler's Numerical Differential Protection [Ziegler, 2012]

3.1 Configuration of a High Voltage Station

In order to provide some context to the project, the locations of various objects related to the subject are specified in this review of a typical substation. Everything in a high voltage station is constructed in a manner that ensures the maximum level of redundancy. In a typical substation such as a 150/60 kV station, there are typically two or more incoming 150 kV lines. The lines connect the substation with the neighbouring substations, and are part of the transmission network. The incoming lines are connected to a busbar, which can be designed in different manners to ensure redundancy.

The substation can be equipped with one or more 150/60 kV transformers. If the substation only has one 150/60 kV transformer, the need for redundancy in the connections is limited, as the substation will not be operational if the transformer malfunctions. However, if there are two or more transformers, the substation can remain at least partially operational if a proper busbar design is utilized. One method is to have twin busbars, and then install switchgear to enable switching between one or the other. This is a very flexible, albeit costly solution. Another method is to design the busbar in an H configuration. An example of an H configuration is shown in Figure 3.1. If a line is taken out of operation, the two transformers can be powered by the single line remaining. If part of the busbar is faulty, that part can be switched off at the connection in the middle of the H. By doing this, one 150/60 kV transformer remains operational, without the need to duplicate the entire busbar.

On the low voltage side of the transformers are another set of busbars, onto which the 60 kV distribution grid is connected. Some substations also have lower voltage levels, which means that there is another transformer connected to the 60 kV busbar, transforming the voltage down to the lower distribution level of 10 kV. This introduces yet another busbar, onto which several incoming and outgoing connections can be made. The same principle applies as from the higher voltage levels, as the busbars can be connected and disconnected to bypass a faulty transformer or similar. This is also shown in Figure 3.1, as any given

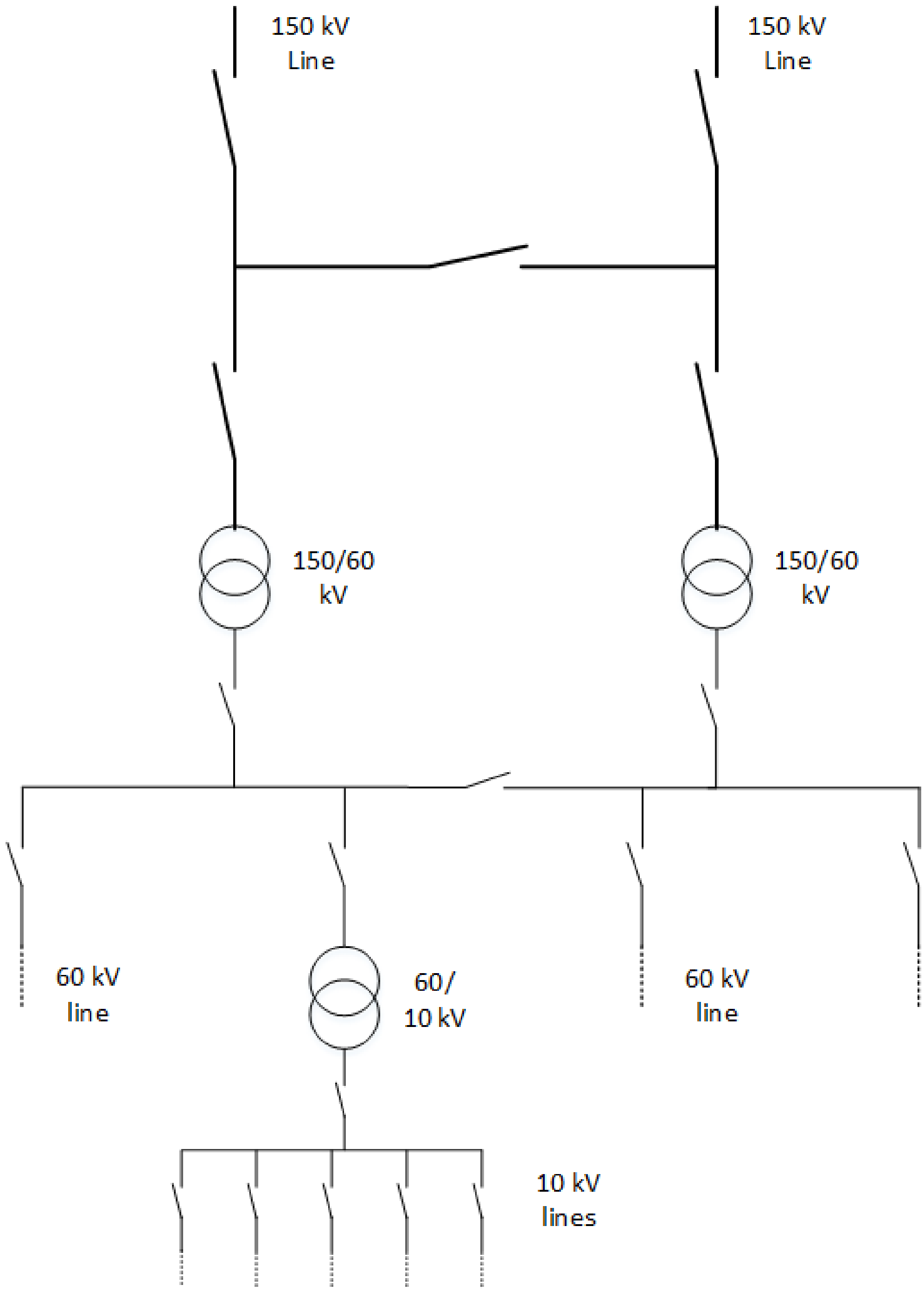

Figure 3.1. H configuration of 150/60 kV substation

component can fail, and the remaining system can still be powered, albeit not with the full power available. The switches shown are for illustration purposes only, as in reality each switching area can contain circuit breaker, disconnector and an earth switch. The circuit breaker is the load switching component, which can break the high currents during events such as short circuits. Besides the circuit breaker, each connection is also equipped with a disconnector, which is not designed for de-energizing the system but is there for the safety of personnel servicing the disconnected part. Each piece of cable and line is also equipped with an earthswitch, which can ground the system as another safety precaution.

3.2 Differential Protection

Differential protection is, as the name implies, a form of protection that utilizes measurements to detect differences. This is done by bounding an area by two measurements and evaluating the difference between the measurements.

3.2.1 Basic Principles of Differential Protection

The basic principle can be seen in Figure 3.2. The idea is that any fault occurring outside the bounded area is ignored, as this will not result in a difference in the current comparison between A1 and A2. A fault occurring within the bounded area will cause an inequality, which is detected by the differential protection. Differential protection provides fast and selective protection, which can send a trip signal in the time frame of one cycle, or 20 ms. This is opposed to protection measures such as distance protection, where some delay is required in order to ensure selectivity.

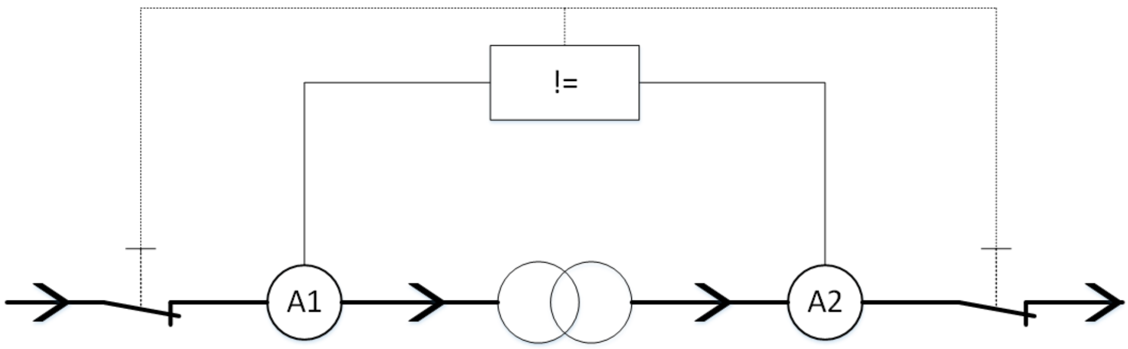

Figure 3.2. Simplified differential protection

3.2.2 Measurement Errors

In high power applications such as protection for a distribution transformer, the system becomes more complex. The basic principle applies as the sum of all currents flowing into the system must equal zero according to Kirchoff's current law. The difference is that in high voltage power transformer applications, the magnetizing current becomes too large to be neglected. [Ziegler, 2012]

Besides the magnetizing current, several sources of bias exist. One such source is the CTs used for measuring the currents. These are utilized due to the practicalities of measuring currents in a high power system. The bias from the CTs is proportional to the through current while the CTs are operating in the linear range. How large the error is depends on the type of CT. The typical classification of a CT follows IEC norm 60044-1.

The norm dictates that the CTs are marked in a specific way. The marking is as follows: xPy z. The x is the accuracy limit factor (ALF), which indicates how accurate the CT is at the accuracy limit current (ALC). The ALF is given in percentage of deviation from the true current. The P simply indicates that this CT is for protection purposes. The y is the ALC, which is defined by multiples of the nominal current. Thus, if the transformer has a nominal current of 5 A in the secondary, the CT will have an accuracy equal to the ALF at a secondary current of $y \cdot 5$ A. The z indicates the maximum burden that can be connected to the secondary of the CT, and is usually given in VA. The burden comes from the resistance of the wires connecting the relay and the CT, and any resistance of the terminal, as a voltage will be induced in these by the current from the CT. If the specified burden is exceeded, the transformer will saturate prematurely, and the accuracy will decrease dramatically. All the variables are interconnected so the x value is only valid if the burden of the transformer does not exceed the z value while operating the CT at the y value. However, if the burden of the connected relay is lower than the z value while operating it at the y value, a new y' can be calculated, meaning that the CT can operate with a higher secondary current than indicated by y. Similarly, it can be calculated to be lower than the original value, if the burden is higher than specified.

If the fault occurs outside of the bounded area, it is not desirable to disconnect the transformer. If the fault current is large enough, it can send the CTs into saturation, which causes the false current to rise rapidly.

Another source of bias is the tap changer of the power transformer. As the current is measured on both sides, the ratio of the power transformer is utilized in this calculation. During operation of the tap changer, this ratio changes, which is a reason for the measurement errors.

These biases and the compensation for them is shown in Figure 3.3. The graph shows the differential current measured versus the through current, and the compensation required. The mismatch false current is due to the accuracy of the CTs and the tap changer. The CT false current is due to the effect of saturation in the CTs.

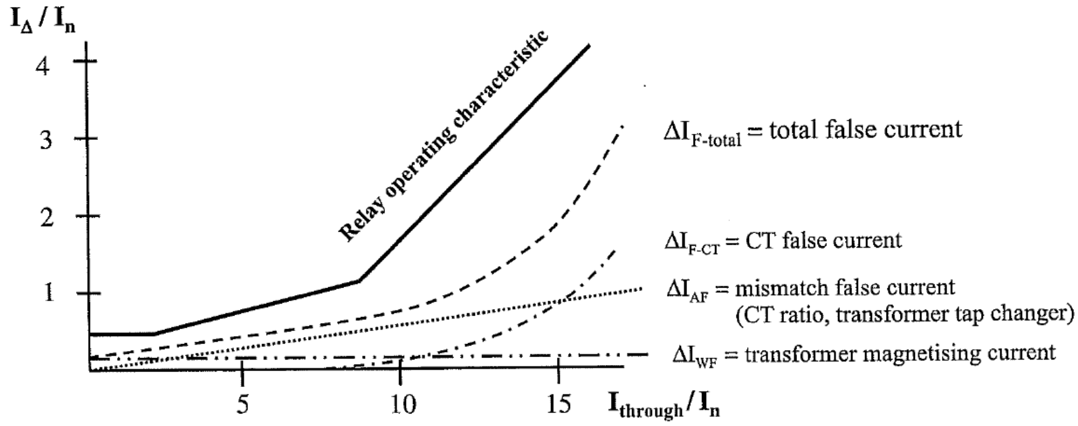

Figure 3.3. Compensation of operating characteristic for biases [Ziegler, 2012,Page 22]

Besides the previously mentioned phenomena, the localization of the differential protection also plays a role. The use of pilot wires can introduce measurement errors, but it is generally only a problem on distances greater than 25 km. Since this project is about protecting a transformer, both ends of the differential protection will always be relatively close compared to that, and thus not be a problem.

3.2.3 Compensation for Measurement Errors

As made clear from section 3.2.2, some criterion for when the differential protection should act is needed. This criterion is defined by the operating boundary. The operating boundary is the boundary between when something is considered an error in measurement or a fault. In other words, if the ratio between through current and differential current becomes too large, the differential protection needs to pick up on this and send a trip signal.

In order to define the operating boundary, two new currents, I_{Op} and I_{Res}, are introduced. The sign convention used is: currents entering the transformer are positive and currents exiting are negative.

The operating current I_{Op} is a current that triggers an operation such as tripping. The operating current is defined by equation (3.1), where the subscript of the measured currents denotes the associated CT.

The restraint current I_{Res}, acts as a stabilizer for the operation of the relay, preventing unwanted operations. The restraint current is defined in equation (3.2).

$$I_{Op} = |\underline{I}_1 + \underline{I}_2| \tag{3.1}$$

$$I_{Res} = |\underline{I}_1| + |\underline{I}_2| \tag{3.2}$$

Traditionally, the relay characteristic, which is the boundary between the operation and restraint areas, was defined by an offset linear function. Today, with the use of numerical relays, the operating current is defined by a piecewise linear function. This is done in order to fit the growth of the total false current as a function of through current, as shown in Figure 3.3.

By making the relay characteristic a piecewise linear function, the characteristic can be defined as three zones as shown in Figure 3.4.

Zone A is the first part of the characteristic, which accounts for the magnetizing current. The boundary is defined by equation (3.3). This setting is defined by the magnetizing current of the transformer.

Zone B accounts for the errors in measurements of the CTs, and is given by equation (3.4). From this it can be seen that the constant k_1, which is defined when selecting the CTs, determines how steep the slope of the function is.

Zone C covers the area where a large through current, such as in the event of an external fault, causes the CTs to enter saturation. It is defined by equation (3.5) and is dependant on k_2, which is a constant determined in the same manner as k_1, and I_{R0} which is the crossing with the x axis of this particular linear function.

$$\text{Zone A: } I_{Op} > I_B \tag{3.3}$$

$$\text{Zone B: } I_{Op} > k_1 \cdot I_{Res} \tag{3.4}$$

$$\text{Zone C: } I_{Op} > k_2 \cdot (I_{Res} - I_{R0}) \tag{3.5}$$

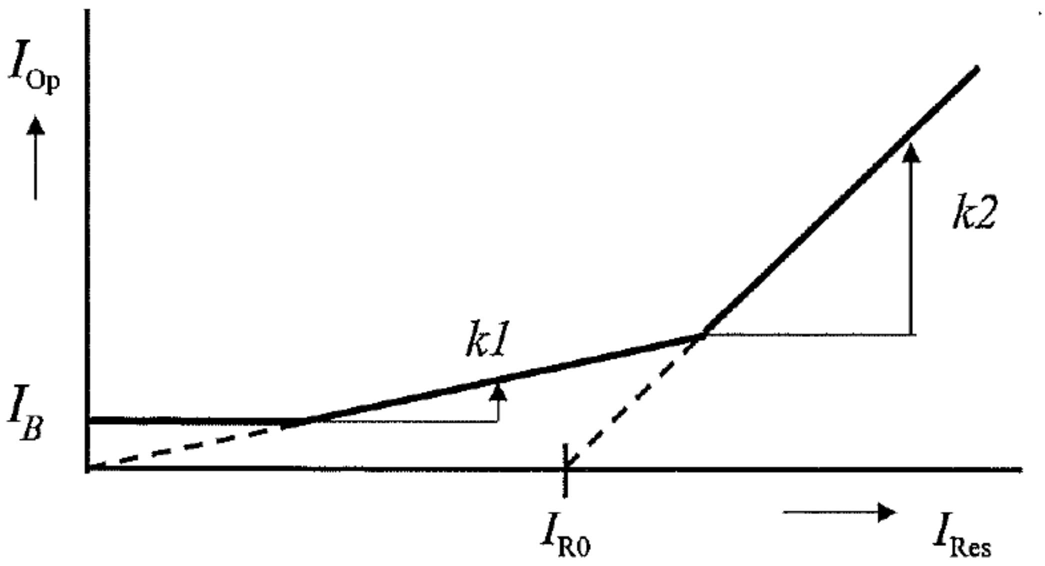

Figure 3.4. Zones for differential operation [Ziegler, 2012,Page 31]

The result of all this is, that the higher the through current (restraint current), the higher the differential current (operating current) must be in order to trigger an event (trip). The boundary is defined by the components used and is a piecewise linear function, whose slope increases depending on the through current (restraint current). As all the previously discussed theory is per phase, a translation to a three-phase system is required. As discussed, the distances for transformer differential protection are small, making communication trivial compared to a line differential protection. Due to this, a per phase comparison of the currents is appropriate.

3.2.4 Implementation of Differential Protection in Three Phase Transformers

The implementation of the differential protection is done on a case-by-case basis, as the implementation varies with type of transformer. This is due to the fact that transformers come in several different configurations. The vector group of the transformer matters, as the various configurations of star/star star/delta etc. introduce various degrees of lag and voltage differences with the same amount of windings, which must be compensated when comparing the currents. Furthermore, if the neutral of a star point is grounded on the primary, and ungrounded on the secondary, the zero sequence currents do not carry over. This must also be compensated for when comparing the currents. In order to review the compensations necessary, an example from [Ziegler, 2012] is reviewed. The transformer in the example is a Yd5 configured transformer, with a grounded neutral. In order to compare the currents on the primary and secondary side, several considerations must be made. The per phase comparison is carried out as according to Figure 3.5.

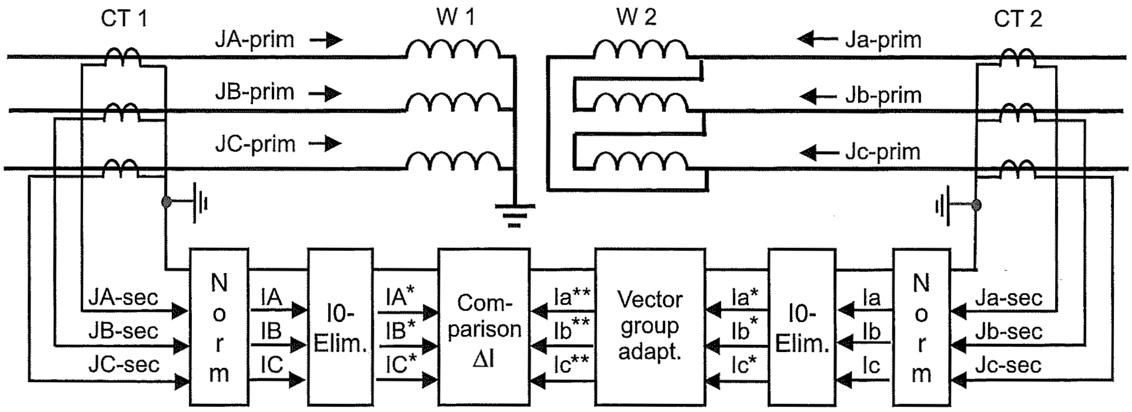

Figure 3.5. Comparison of currents [Ziegler, 2012,Page 174]

The first step in the process is to normalize the currents. This is done by bringing them to a common base, which relates to the rated power of the transformer, S, and the voltage of the accompanying winding, V_1 or V_2. The base is created per winding as shown in equation (3.6) and (3.7). The base is then used to create a per unit constant, which is multiplied onto each phase measurement from the CTs, as shown in equation (3.8) and (3.9), where J denotes the actual currents flowing in the system, and I, I^* and I^{**} denote the compensated currents. The subscripts follow the norm from the designation of the transformer, Yd5, where the capital is the primary side and the lowercase is the secondary side.

$$I_{n-Transf.-W1} = \frac{S}{\sqrt{3} \cdot V_1} \tag{3.6}$$

$$I_{n-Transf.-W2} = \frac{S}{\sqrt{3} \cdot V_2} \tag{3.7}$$

$$\begin{bmatrix} I_A \\ I_B \\ I_C \end{bmatrix} = \frac{I_{n-prim.-CT1}}{I_{n-Transf.-W1}} \cdot \begin{bmatrix} J_{A-sec.} \\ J_{B-sec.} \\ J_{C-sec.} \end{bmatrix} = k_{CT-1} \cdot \begin{bmatrix} J_{A-sec.} \\ J_{B-sec.} \\ J_{C-sec.} \end{bmatrix} \tag{3.8}$$

$$\begin{bmatrix} I_a \\ I_b \\ I_c \end{bmatrix} = \frac{I_{n-prim.-CT2}}{I_{n-Transf.-W2}} \cdot \begin{bmatrix} J_{a-sec.} \\ J_{b-sec.} \\ J_{c-sec.} \end{bmatrix} = k_{CT-2} \cdot \begin{bmatrix} J_{a-sec.} \\ J_{b-sec.} \\ J_{c-sec.} \end{bmatrix} \tag{3.9}$$

The next step is to decide if zero sequence elimination is necessary. As the primary side of the transformer is a grounded star configuration, and the secondary a delta configuration, it is indeed necessary, as the zero sequence current does not carry over. From the same reasoning, it is not necessary to carry out the operation on the secondary side. The zero sequence current is given by equation (3.10). The elimination is carried out by simply subtracting the zero sequence from the three currents on the primary (star) side of the transformer. This is done in matrix from in equation (3.11).

$$I_0 = \frac{1}{3} \cdot (I_A + I_B + I_C) \tag{3.10}$$

$$\begin{bmatrix} I_A^* \\ I_B^* \\ I_C^* \end{bmatrix} = \frac{1}{3} \cdot \begin{bmatrix} 2 & -1 & -1 \\ -1 & 2 & -1 \\ -1 & -1 & 2 \end{bmatrix} \cdot \begin{bmatrix} I_A \\ I_B \\ I_C \end{bmatrix} \tag{3.11}$$

Now that the currents are brought to a common base, and the zero sequence current is eliminated, the only thing remaining is to compensate for the vector group of the transformer. The transformer used in the example has the vector group Yd5, where the capital Y indicates that this is the primary winding. The number indicates how much the secondary lags the primary. In this case it lags the primary by $5 \cdot 30° = 150°$. It is this lag, along with the transformation difference between star and delta, that the vector group adaption accounts for. The general equation for this adaptation is given in equation (3.12), where k is the vector group number.

$$\begin{bmatrix} I_A^{**} \\ I_B^{**} \\ I_C^{**} \end{bmatrix} = \frac{2}{3} \cdot \begin{bmatrix} cos[k \cdot 30°] & cos[(k+4) \cdot 30°] & cos[(k-4) \cdot 30°] \\ cos[(k-4) \cdot 30°] & cos[k \cdot 30°] & cos[(k+4) \cdot 30°] \\ cos[(k+4) \cdot 30°] & cos[(k-4) \cdot 30°] & cos[k \cdot 30°] \end{bmatrix} \cdot \begin{bmatrix} I_A^* \\ I_B^* \\ I_C^* \end{bmatrix} \tag{3.12}$$

Now, the currents can be compared in order to determine if there are any differential currents. This is done by equation (3.13), where currents flowing into the protected object are considered positive.

$$\begin{bmatrix} I_{\Delta A} \\ I_{\Delta B} \\ I_{\Delta B} \end{bmatrix} = \begin{bmatrix} I_A^* \\ I_B^* \\ I_C^* \end{bmatrix} + \begin{bmatrix} I_A^{**} \\ I_B^{**} \\ I_C^{**} \end{bmatrix} \tag{3.13}$$

3.3 Transformer Specific Difficulties

In section 3.2 some general considerations for differential protection are reviewed. In order to specify this to transformer protection, further review is required. This is done in order to identify and compensate for transformer specific problems.

In section 3.3.1 an analysis of the single phase transformer is performed, in order to formulate a model using electrical equivalents to the magnetic properties of the transformer.

This is done to gain a better understanding of the transformer. The method used to derive the equivalent circuit and all formulas are sourced from [Umans, 2014].

In section 3.3.2 an analysis of the inrush phenomena is performed. This is done in order to evaluate the scale of the problem, mitigation methods, and how the relay knows it is inrush happening and not an internal fault. The knowledge in this section is compiled from [C4.307, 2013] and [Ziegler, 2012]

3.3.1 Transformer Equivalent Circuit

The transformer is a necessity in any power grid, as it scales the voltage up and down for transmission and distribution. The transformer works by converting the electrical energy into magnetic energy and then back again as a ratio of the windings. Ideally, this is done without any losses, meaning that the wires have no resistance, there is no leakage flux, and exciting current required to drive the flux is zero. Such a transformer is shown in Figure 3.6. In order to develop an accurate model for a transformer, first the ideal case must be considered. The principles discussed are for a single phase transformer, but can be scaled up and applied to a three-phase transformer.

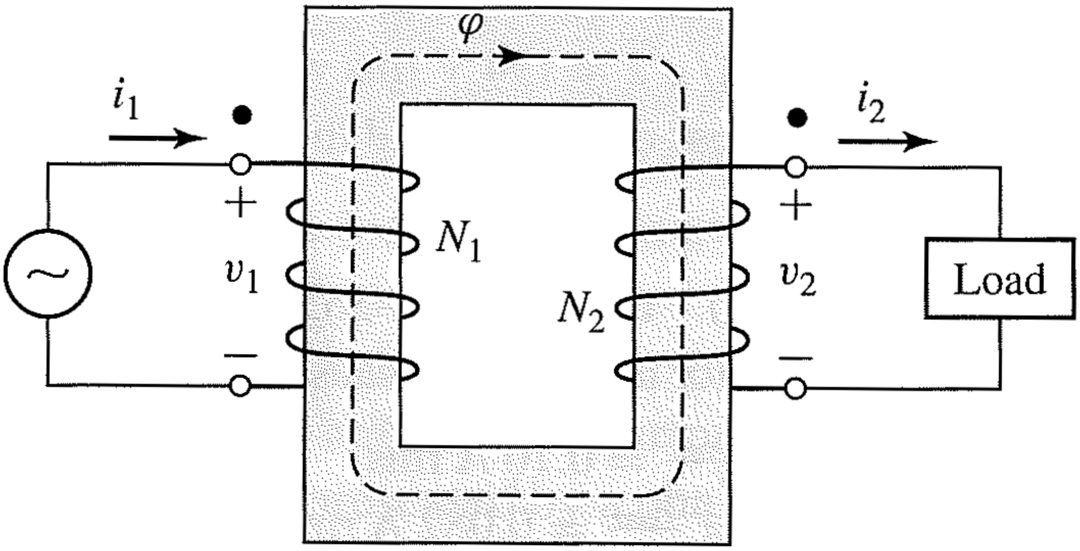

Figure 3.6. Ideal transformer [Umans, 2014,Page 70]

When an alternating voltage, v_1, is applied to the primary winding, an opposing emf, e_1, must be induced in the winding, which is driven by the changes in the flux, as shown in equation (3.14).

$$v_1 = e_1 = N_1 \cdot \frac{d\phi}{dt} \tag{3.14}$$

Since this flux is shared with the secondary windings, a voltage will be induced in these similarly to the primary as shown in equation (3.15).

$$v_2 = e_2 = N_2 \cdot \frac{d\phi}{dt} \tag{3.15}$$

From equations (3.14) and (3.15) it can be derived that the ratio between the voltages is the same as the ratio of the windings as shown in equation (3.16).

$$\frac{v_1}{v_2} = \frac{N_1}{N_2} \tag{3.16}$$

By connecting a load to the transformers secondary windings a load current, i_2, is drawn. This load current produces a magnetomotive force (mmf), $N_2 \cdot i_2$, in the secondary winding. The mmf is the driving force of the magnetic flux and is equivalent to the emf driving the electrical current. Since the ideal transformer's flux does not change due to the load, and the fact that it is lossless, the mmf must be balanced by a counteracting mmf in the primary winding as shown in equation (3.17).

$$N_1 \cdot i_1 = N_2 \cdot i_2 \tag{3.17}$$

From this it can be shown that the currents flowing in the primary and secondary are inversely proportional to the ratio of the windings as shown in equation (3.18).

$$\frac{i_1}{i_2} = \frac{N_2}{N_1} \tag{3.18}$$

Since the transformer is ideal, there are no losses. This means that the power going into the system must equal the power leaving the system as shown in equation (3.19).

$$v_1 \cdot i_1 = v_2 \cdot i_2 \tag{3.19}$$

Even though a real transformer approximates the theory discussed in this section, some losses and limitations apply. In order to approximate a real transformer, an electrical equivalent to the magnetic properties of the transformer is desired. In order to represent the complex numbers throughout this derivation, phasor representations of the voltages and currents will be used.

The first step is to recognize that the windings have resistance, which can be modelled as a resistor in series. This changes the voltage balance as described in equation (3.14), as the induced emf is now lower than the input voltage, due to the voltage drop in the resistor. This is shown in equation (3.20).

$$\underline{V}_1 = R_1 \cdot \underline{I}_1 + \underline{E}_1 \tag{3.20}$$

In the ideal transformer, all flux is contained within the core. This is not the case with a real transformer. There will always be some leakage to the air, which can be modelled by a leakage inductance, L_{l1}. This leakage induces a voltage in the primary winding, which varies linearly with the primary current. For ease of calculation, the leakage inductance is converted to a reactance as shown in equation (3.21).

$$X_{l1} = 2 \cdot \pi \cdot f \cdot L_{l1} \tag{3.21}$$

This adds a contribution to the voltage balance, which now changes to equation (3.22).

$$\underline{V}_1 = R_1 \cdot \underline{I}_1 + j \cdot X_{l1} \cdot \underline{I}_1 + \underline{E}_1 \tag{3.22}$$

In the ideal transformer, besides containing all the flux in the core, it required no energy to drive this flux. In a real transformer, this is not the case. The primary and the secondary windings are linked by their mutual flux, which requires a certain mmf. This mmf must be supplied by the primary current, and is called the exciting current, $\underline{I}_\varphi$. Furthermore, the secondary current will counteract the primary, as it will try to demagnetize the iron core. This mmf must also be supplied by the primary current.

This changes the mmf balance from equation (3.17), as the resultant mmf from the input and output is no longer equal to zero, but results in the mutual mmf as shown in equation (3.23).

$$N_1 \cdot \underline{I}_\varphi = N_1 \cdot \underline{I}_1 - N_2 \cdot \underline{I}_2 \tag{3.23}$$

Since the primary current $\underline{I}_1$ is composed of the exciting current $\underline{I}_\varphi$ and the load current, which is the load on the secondary transformed to the primary as per equation (3.18), it can be written as the sum of these, which changes equation (3.23) to equation (3.24)

$$N_1 \cdot \underline{I}_\varphi = N_1 \cdot (\underline{I}_\varphi + \underline{I}'_2) - N_2 \cdot \underline{I}_2 \tag{3.24}$$

The exciting current can be considered as a sinusoidal current consisting of two currents. One current $\underline{I}_c$ is there to account for the core losses, and is in phase with $\underline{E}_1$. The other lags it by 90° and is the magnetizing component I_m. These currents can be introduced to the equivalent circuit by adding a shunt branch, which consists of a resistor in parallel with an inductor. The inductor is represented by the reactance X_m in equation (3.25) where L_m is the mutual inductance and f is the frequency of the system.

$$X_m = 2 \cdot \pi \cdot f \cdot L_m \tag{3.25}$$

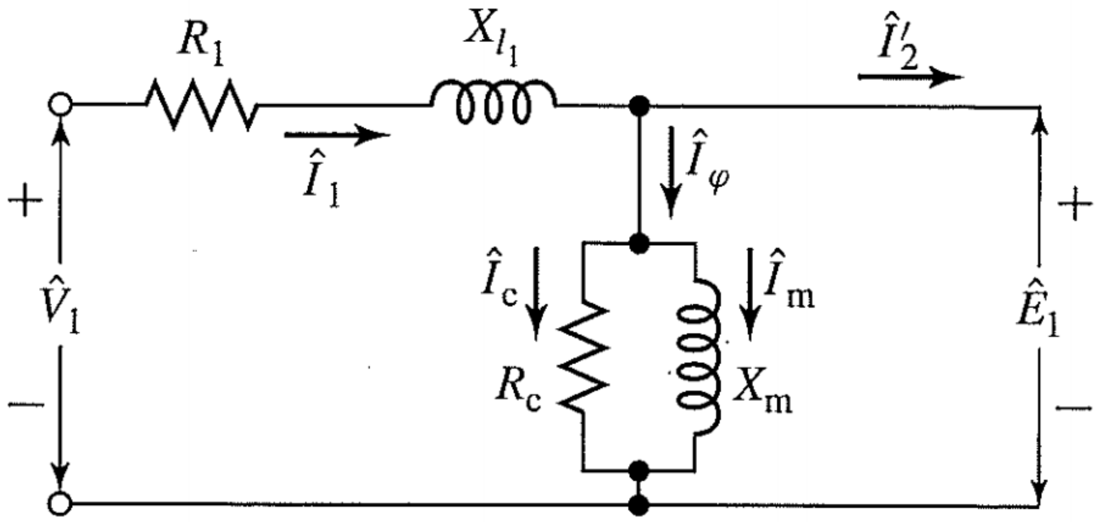

Figure 3.7. Primary side of non ideal transformer model [Umans, 2014,Page 75]

The equivalent as it is right now can be seen in Figure 3.7, where the current $\underline{I}'_2$ is the current entering the primary winding, and $\underline{E}_1$ is the induced emf in the primary winding.

Now, the secondary side can be considered. As both the core losses and the excitation of the core has been taken care of on the primary, all that remains is to consider the secondary leakage flux and winding resistance. These are introduced in Figure 3.8.

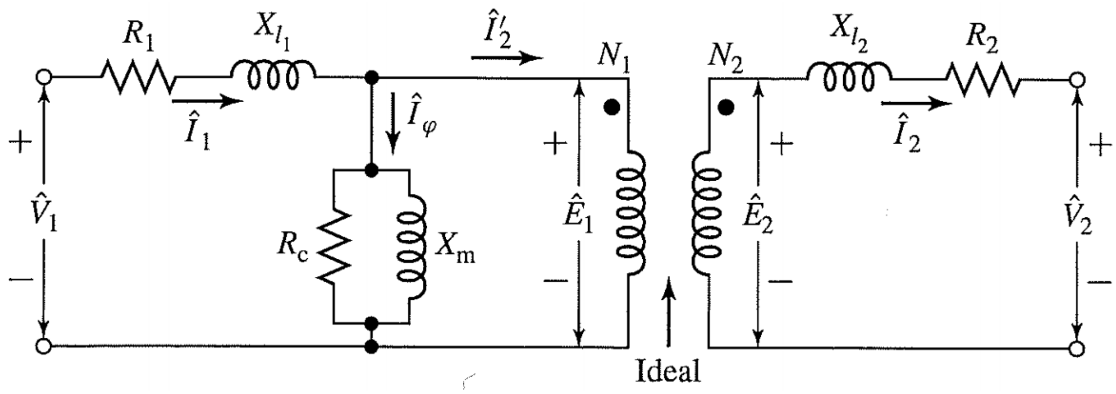

Figure 3.8. Non ideal transformer model [Umans, 2014,Page 75]

As all the non ideal aspects of the transformer have been extracted in the electrical equivalent, the ratio of the primary emf and the secondary emf equals that of the primary winding and secondary winding as shown in equation (3.26). This is equivalent to the previously discussed voltage ratio when considering the ideal transformer in (3.16). As such, any voltage, current and load can be transformed, so it becomes the equivalent of looking at it from either side. By using this property, the secondary leakage reactance X_{l2} and the winding resistance R_2 can be represented on the primary side of the ideal transformer element by X'_{l2} and R'_2, which is calculated as shown in equation (3.27) and (3.28).

$$\frac{\underline{E}_1}{\underline{E}_2} = \frac{N_1}{N_2} \tag{3.26}$$

$$X'_{l2} = \left(\frac{N_1}{N_2}\right)^2 \cdot X_{l2} \tag{3.27}$$

$$R'_2 = \left(\frac{N_1}{N_2}\right)^2 \cdot R_2 \tag{3.28}$$

All that remains within the transformer is to transform the secondary voltage to the primary voltage base. This is done as shown in equation (3.29)

$$V'_2 = \frac{N_1}{N_2} \cdot V_2 \tag{3.29}$$

At this point, the electrical equivalent of the transformer is complete. It is what is known as the T equivalent of a transformer. The T equivalent is a single phase equivalent. If a burden is connected to the transformer, they can be converted similarly to the secondary impedances in equations (3.27) through (3.29). The equivalent circuit to the transformer is shown in Figure 3.9. The transformer is considered an ideal transformer with the external impedances added, and in Figure 3.9 it is simply moved to the right and excluded after transforming the impedances to the primary side, as opposed to Figure 3.8, where the ideal transformer is still visible.

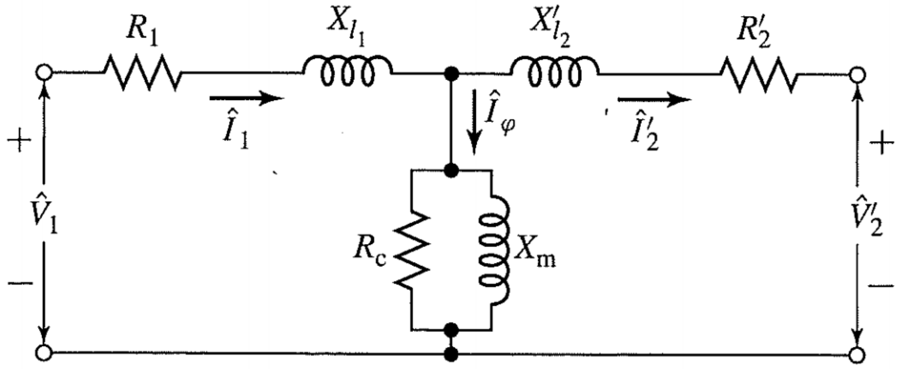

Figure 3.9. T equivalent to the transformer [Umans, 2014,Page 75]

3.3.2 Inrush Current

Inrush current is a phenomena that takes place in a transformer when the magnetic field in to the transformer is subjected to abrupt change. As the inrush current is a transient event caused by the magnetization of the transformer, it only flows into the transformer and not out the other side. Due to this, it causes a differential current, which is capable of tripping the differential protection. In order to narrow the scope of this report, only inrush of a single transformer due to initial energization will be investigated. This excludes series and parallel sympathetic inrush, where the inrush current is partially drawn through and from other transformers. It also excludes pseudo inrush, where the inrush is caused due to a fault being cleared, where the voltage returns to normal. The reason for this specification is due to the inrush being detected in the same manner, and acted upon in the same manner.

The theory derived in section 3.3.1 is all based on the linear relation between the current and flux. In a real transformer, the magnetic properties follow a hysteresis curve as shown in Figure 3.10. During steady state operation, the hysteresis curve is smaller and operates close to the linear approximation drawn in the figure. In steady state, the magnetizing current is typically 1-2% of the nominal current. However, during the the energization of the transformer, it can enter the saturation region due to the sudden change in voltage from naught to the point on wave (POW) voltage. In this scenario, the magnetizing current can be several times larger than the nominal current. Due to the generally inductive nature of the magnetizing current, which is in phase with the flux linkage, it lags the voltage by 90 degrees. Therefore, one of the worst cases of inrush current occurs when the transformer is energized at the zero crossing of the voltage. This causes a DC offset of the initial flux, which could have been avoided by energizing it at peak voltage. Such inrush current and corresponding flux linkage is illustrated in Figure 3.11. Besides the POW of the voltage during energizing, the residual flux of the transformer has an impact on the inrush. This can add to the effect from the POW voltage, causing a flux linkage which is up to 3 times larger than nominal. This is considered the absolute worst case of inrush current. As demonstrated in Figure 3.11, it will cause a DC offset of the flux linkage, which causes the inrush current to become several times larger. Due to the non-linearity of the transformer core, this DC offset in the flux linkage dues not equal a linear change in the current. Instead, it is capable of driving the transformer deep into saturation, where the current grows exponentially. This is shown in the bottom right pane of Figure 3.11. The inrush current is asymmetrical and decays rather slowly. The time it takes for the inrush current to decay is dependant on the inrush currents initial size and the series resistance of the system. The reason the series resistance of the system works as a dampener is due to the high current during the inrush. This high current will cause a voltage drop relative to the resistance size, which lowers the voltage on the transformer terminals, which lowers the flux linkage and in turn the rush current.

Due to the extreme non-linearity of the inrush current, its content is harmonic in nature. The harmonic content of the inrush current is shown in Figure 3.12. The largest of these beside the fundamental frequency is the second harmonic. This fact is exploited in the protection, as this is how the relays determine if the arising current differential is due to inrush or a fault. If a large second harmonic current is detected, the relay will block the

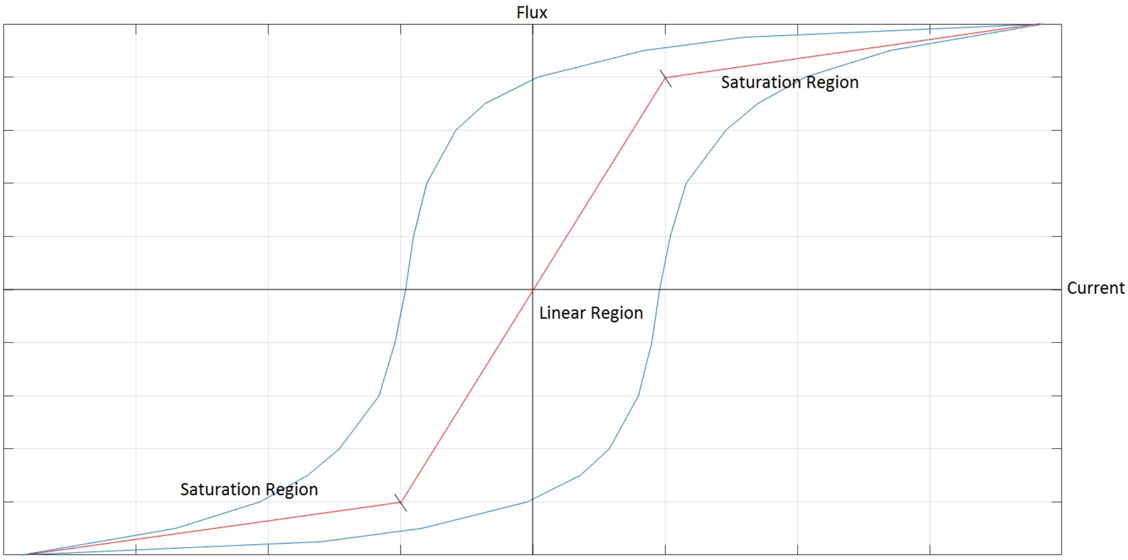

Figure 3.10. Typical hysteresis loop, with linear approximation

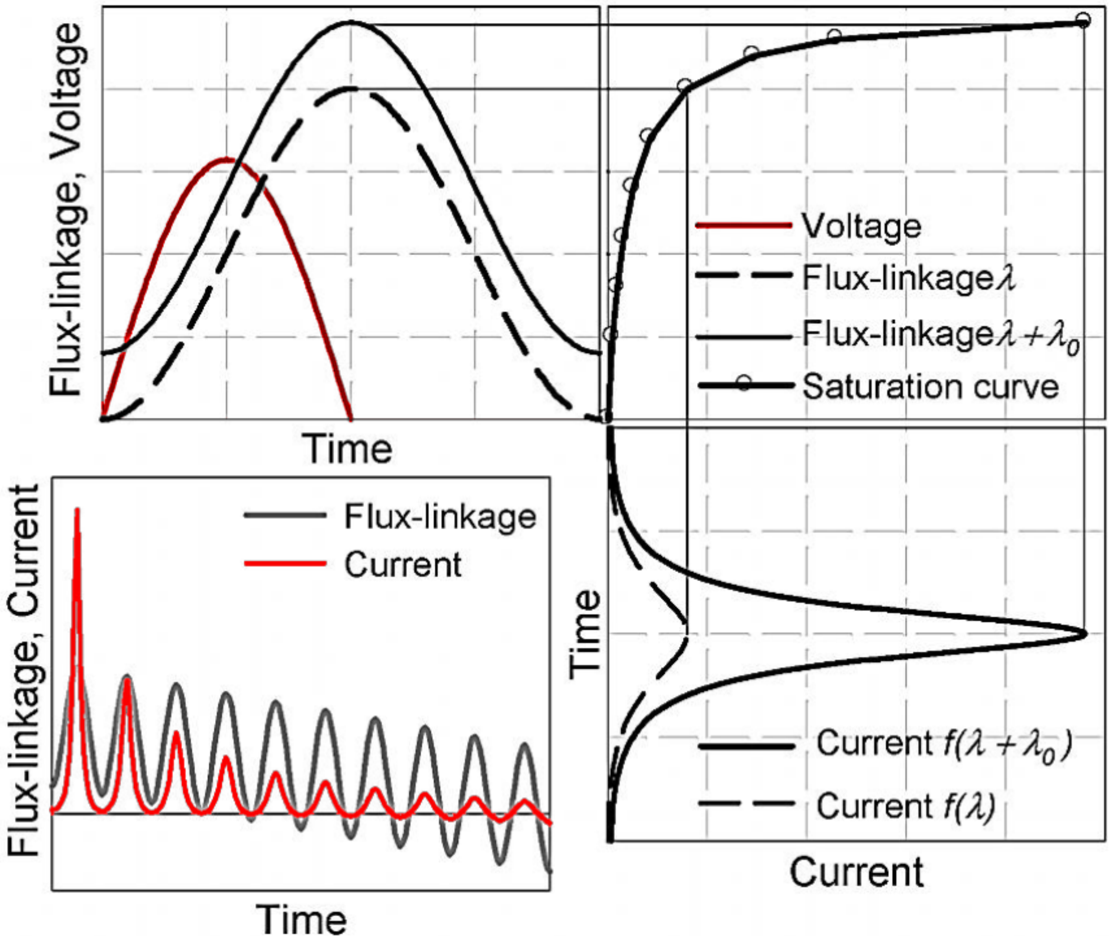

Figure 3.11. Waveforms of flux linkage and current during inrush with zero crossing voltage applied [C4.307, 2013] (Colorized by author)

protection features, and thus be unable to trip. Under normal circumstances, the setting is typically 15% of the fundamental frequency, as it has been experimentally determined that inrush currents rarely are below 17% second harmonic. A setting lower than 15% is not recommended as second harmonics can arise due to CT saturation, which can mistakenly trigger the inrush blocking during faults. One might want to use the third harmonic as an additional restraint as it is a large component in the inrush, but this would lead to false inrush blocking during short circuits, as this harmonic is very prevalent during short circuits due to CT saturation. [Ziegler, 2012]

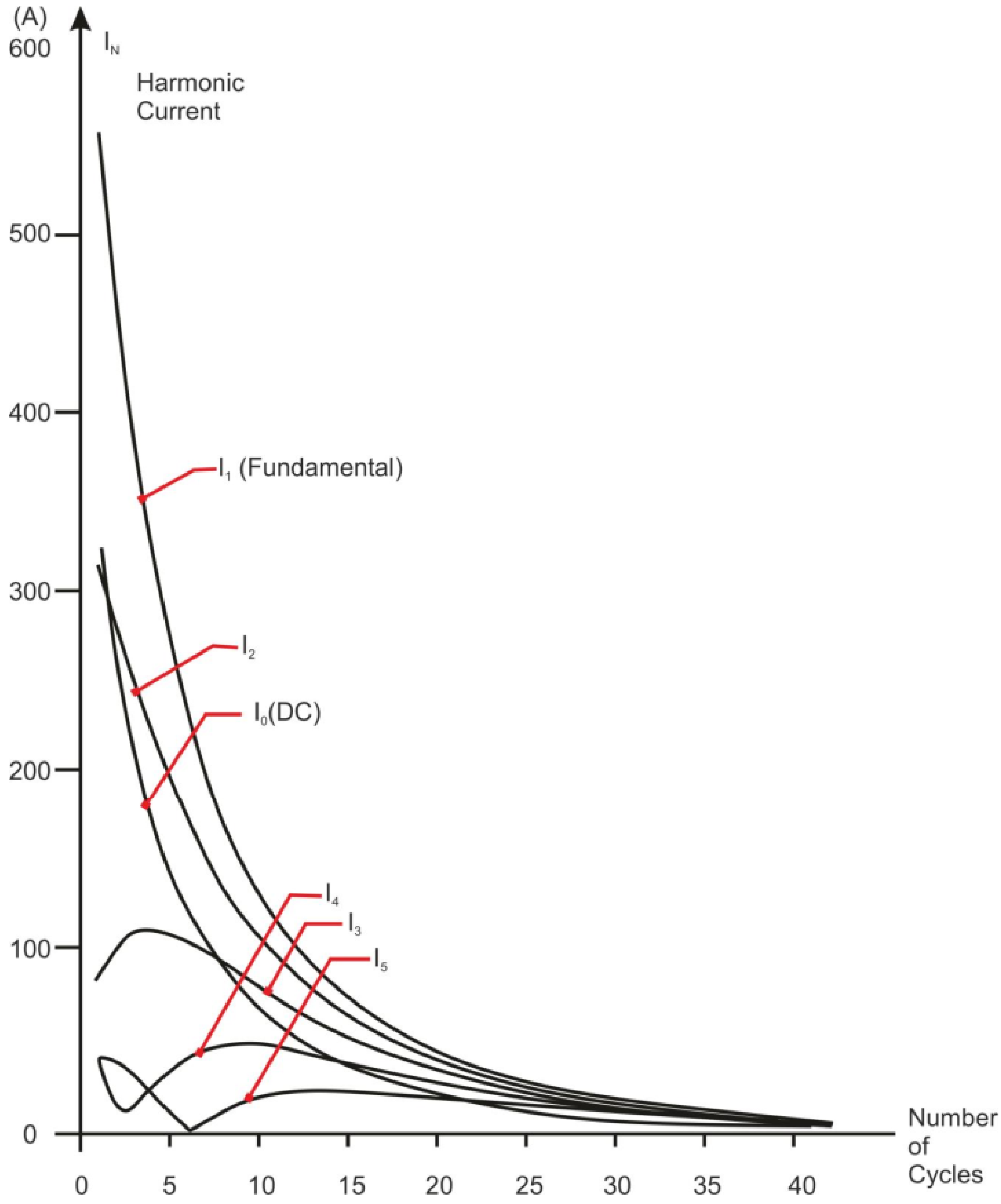

Figure 3.12. Harmonic content of inrush current [Bronzeado et al., 1996]

As previously discussed, the inrush current is capable of tripping the protection system.

This is mitigated by blocking the protection systems during the inrush by comparing the fundamental frequency with the second harmonic. However, the tripping of the protection systems is not the only effect of the inrush current, as the rush currents can be so large that they can damage the insulation of the windings. Therefore, it can be desireable to not just mitigate the false tripping of the protection, but also reduce the magnitude of the rush currents. The magnitude of the inrush current is primarily dependant on the following parameters.

- Design of the transformer, such as the type of magnetic steel used for the core, and the dimensions of it and operation point.
- Initial conditions, such as POW voltage and remanence flux.
- Dampening effects from the connected network, such as series resistance.

As for mitigation on an existing transformer, one option is to deflux the transformer before energizing it. This is however impractical, and not an option being used typically. Defluxing the transformer is connected to the initial conditions, as it means bringing down the remanence flux.

Another initial condition that can be manipulated is the POW voltage applied to the transformer. This is done by controlling the switching times of the circuit breaker, in order to ensure that the POW voltage is at its peak, and therefore the magnetizing current drawn being at its lowest. This relation between peak voltage and the smallest inrush current is only valid if there is no remanence in the core. Furthermore, energizing at the peak of the voltage curve can introduce overvoltage problems, which must be considered when designing such a mitigation method. It is very dependant on having repeatable closing times, as the delay in closing must be accounted for, in order to ensure connection at the desired POW. Furthermore, they must be able to close the different phases at different times as they are lagging each other by 120 degrees, and thus if all three were closed at the same time, even though phase one might be at the correct POW, phase two and three will be 120 and 240 degrees offset. Another improvement on this is to know the remanence flux of the transformer by controlling the de-energization as well. By doing this, the exact POW current can be matched, ensuring the lowest inrush possible. This is however not valid during a fault, as the breaker will disconnect all three phases at the same time. However, since this method is generally only applied on very high voltage systems (400kV and above), and as such systems rarely experience faults, this is not an issue.

As mentioned, the dampening of the inrush is controlled by the series resistance of the system. Therefore, it makes sense to simply connect a higher resistance during the energization of the transformer. In practice however, it is very involved and requires more circuit breakers or other expensive equipment.

Similar for all the mitigation techniques is that they add cost to the system. The more features the circuit breaker has, the costly it generally is. Due to this, an investigation of the inrush currents might be a better and more cost effective option, as they do not necessarily damage the transformer. Naturally, this depends on the transformer in question. The inrush current can be estimated by analytic calculations, but in practice it is better to simulate it with numerical software, as solutions for this are abundant. However, in order to explain the transient events, a simple method for modelling the inrush is reviewed

As previously mentioned, the phenomena of inrush current is a highly non-linear event. Therefore, the model derived in section 3.3.1 is not going to work without modification. The model is derived based on an assumption of steady state, which means that the transformer is operating in the linear part of the hysteresis loop shown in Figure 3.10. The slope of this linear region is defined by the inductance of the magnetizing branch in Figure 3.9. In order to model the transient events during inrush, this part of the hysteresis loop is not sufficient, as the transformer saturates and operates outside of the linear region.

In order to model this non-linear region, the hysteresis is divided into a piecewise linear shape, where the slope of the saturation area is defined by the air flux. The air flux arises as a consequence of the transformer reaching saturation, thus not being able to contain more flux. This will cause the flux to be driven in the coil itself, which requires more current than driving the flux in a steel core. The result of this is that the transformer's magnetizing branch has a certain inductance during normal operation and far lower inductance during saturation. This variability of the magnetizing inductance is shown as a reactor with a low/high symbol through it in Figure 3.13. This type of model is named Saturable Transformer Component (STC). In this model, the hysteresis and frequency dependant losses are considered linear, and it cannot model residual flux in the core. It also ignores capacitance between the windings, which is deemed acceptable due to the relatively low system frequency.

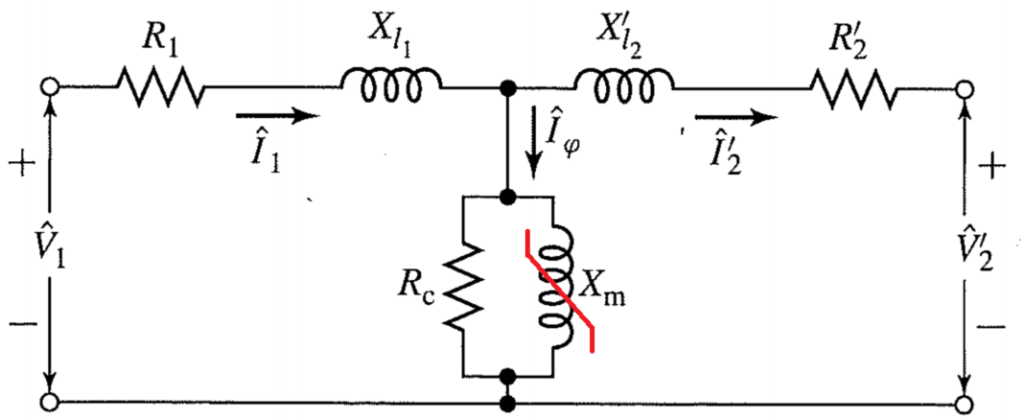

Figure 3.13. STC model of transformer [Umans, 2014] (Modified by author)

Its limitations are that it is a single phase model, which means that if it is extended to three phase it does not model the inter-phase coupling. Furthermore, it is limited to a maximum of three windings. When using the STC model in a three phase system, beside excluding the inter-phase coupling, it is only accurate in balanced operation.

Now the source of the inrush current and the main factors contributing to it has been determined. Some of the possible methods to mitigate the inrush and how to model it in order to determine the scale of the problem have been proposed. In order to review the events further, models of the system will be reviewed. Since simulation software is readily available, which have more advanced models of transformers, which account for all the events discussed and feature unbalanced operation, the models will be investigated using such a tool, namely PSCAD.

Modelling and Simulation 4

In this chapter, the theory compiled in chapter 3 will be utilized in order to make predictions of the problem in order to make a strategy for mitigating the problem. The model is reviewed in the simulation software PSCAD, which is described in section 4.1. In order to evaluate the transformer in question, the parameters for the PSCAD model are investigated in section 4.2.

In section 4.3 various scenarios are simulated, in order to determine how various systems affect the magnitude and decay of the inrush current, along with a fault scenario in section 4.4. This data is then to be used when setting up the differential relays.

4.1 PSCAD

PSCAD is the simulation software of choice in this report. One of the main advantages for this software is the interconnectivity with OMICRON, which allows for exports of scenarios directly from PSCAD to OMICRON. The OMICRON can then simulate the scenario to the relay, in order to check if the parameters of the relays are correctly set. PSCAD can model transformers using two different methods. One is the classic transformer equivalent, which is similar to the STC previously discussed. The other is the Unified Magnetic Equivalent Circuit (UMEC). By using the UMEC model, linkage between phases are accounted for, and it is capable of accurately modelling three phase transformers. However, due to its simpler methodology, the classic model is used in this project.

4.2 Parametrization of the Transformer

Similar for both the simplified STC model evaluated in section 3.3.2 and for models in PSCAD is that they require parameters which directly relate to the transformer in question. The parameters are determined by the impedance of the windings and the core of the transformer. These parameters must be determined in order to simulate the transient events in the transformer. The parameters are determined either by the data sheet of the transformer, or by carrying out short circuit and open circuit tests of the transformer. The parameters to be determined are the ones shown in Figure 3.13. Typically, all parameters are calculated in per unit (P.U.). Per unit is a unit system which works by referring all variables such as impedances, voltages and currents to a common base, in order to avoid confusion when working with transformers.

In the short circuit test the information is typically the voltage in percentage of the rated voltage, $V_{sc}\%$, and the active power P_{sc} per winding pair. From this data, the winding impedance is calculated by using equation (4.2) and from the copper losses in PSCAD.

This works due to the fact that the magnetizing impedance is magnitudes larger than the leakage impedance when not in saturation, enabling us to neglect it by moving it to the secondary terminals as shown in Figure 4.1. The effect of this is that the magnetizing branch is shorted out by the secondary. The short circuit test is carried out by applying a low voltage and then increasing it until the rated current flows in the circuit. The voltage applied is much lower than the rated voltage, thus ensuring that the transformer does not enter saturation. The error introduced by making this simplification is less than one percent. [Umans, 2014]

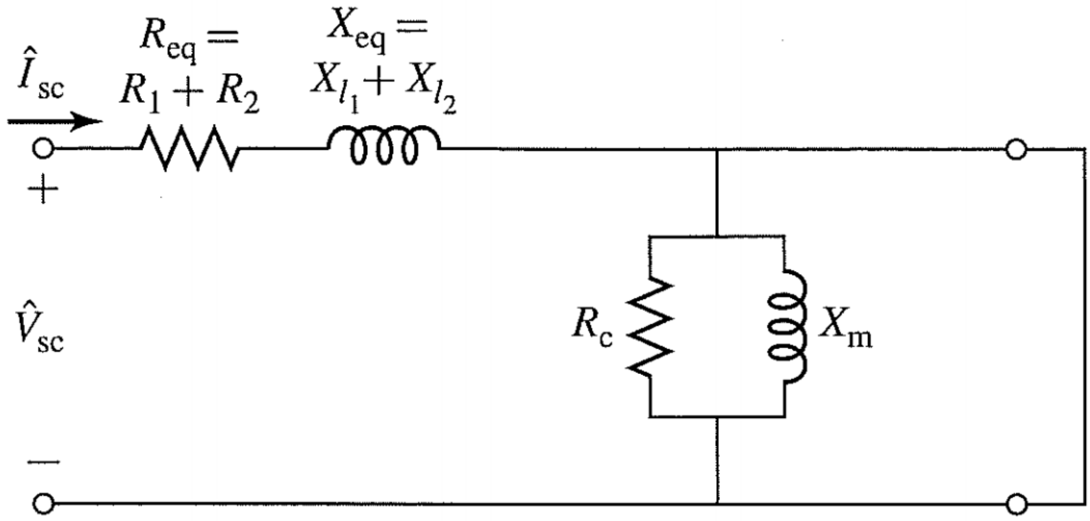

Figure 4.1. Cantilever simplification of the T equivalent [Umans, 2014]

PSCAD automatically calculates the winding resistance by using the copper losses in p.u. These losses are obtained using the open circuit test at the rated excitation voltage. By doing this, PSCAD will approximate the losses linearly, as is done in the STC model. The copper losses are found using (4.1), where S_3 is the rated three-phase power of the transformer and P_{sc} is the losses for all three phases measured during the open circuit test.

$$P_{sc-p.u} = \frac{P_{sc}}{S_3} \tag{4.1}$$

The leakage reactance is found using equation (4.2). The first part under the square root is the total short circuit impedance and the second part is the real part of the impedance.

$$X_{sc} = k \cdot \sqrt{(\frac{V_{sc}}{I_{sc}})^2 - (\frac{P_{sc}}{I_{sc}^2})^2} \tag{4.2}$$

As all the values calculated are per winding pair, a distribution between the primary and secondary is needed. For many applications distributing 50% on both sides in per unit is sufficiently accurate. However, as the transient inrush event is very dependant on the primary resistance, and as the secondary is not in play as there is open circuit, a more accurate distribution is wanted. One way to distribute it with higher accuracy is to measure the DC resistance on both sides of the transformer and then distributing the resistance as a ratio of these. This is done in equations (4.3) and (4.4). The distribution of X_{sc} is however not as easily done. In PSCAD the distribution is handled automatically. The only input needed is the total leakage reactance in p.u. and the copper losses in p.u.

$$R_{ACHV} = R_{sc} \cdot \frac{R_{DCHV}}{R_{DCHV} + R_{DCLV}} \tag{4.3}$$

$$R_{ACLV} = R_{sc} \cdot \frac{R_{DCLV}}{R_{DCHV} + R_{DCLV}} \tag{4.4}$$

Now that the parameters for the windings are taken care of, it is time to consider the core of the transformer, or in the electrical equivalent, the magnetizing branch. The values are obtained from the no load test as, theoretically, the only current that should be flowing in this test is the magnetizing current. When one side is open, the impedance at the terminals include the leakage impedance, but as this is so small compared to the magnetizing branch, it can be neglected. The test is conducted from the secondary, as this is more practical and safe due to the lower voltage required. The parameters to be determined for the model in PSCAD are the air core reactance in p.u., the magnetizing current in p.u. and the knee voltage in p.u.

The air core reactance is the reactance of a winding when the steel core of the transformer is fully saturated. When this happens, the only available reactance is that of the coil itself, with a core of air. It determines the flux to current ratio during the saturation. This reactance is based on the number of turns and the dimensions of the winding. It is typically printed on the nameplate of the transformer, as it requires knowledge that at best can only be estimated without dismantling the transformer. If the air core reactance is not known, it can be estimated to be approximately twice the leakage reactance. [HVDC.ca]

The magnetizing current is the current flowing in the magnetizing branch of the equivalent circuit. It is calculated by first calculating the iron losses by using equation (4.5), where P_{oc} is the resistive losses in watts, k is either 1 or 3 depending on Wye or Delta configuration and $V_{p.u.}$ is the excitation voltage. Then the no load current is calculated by equation (4.6), which is the total current entering the transformer. Here I_{oc} is the total current measured during the open circuit test, k is either 1 or 3 depending on Wye or Delta configuration. The magnetizing current can now be calculated, due to the fact that it lags the resistive current by 90 degrees. This is done in equation (4.7).

$$I_{loss} = \frac{P_{oc}}{k \cdot V_{oc}} \tag{4.5}$$

$$I_{no-load} = \frac{I_{oc}}{k} \tag{4.6}$$

$$I_m = \sqrt{I_{no-load}^2 - I_{loss}^2} \tag{4.7}$$

The knee voltage is either found in the data sheet or by experiment. Experimentally, it is found by sweeping the voltage supplied to the transformer. Usually this is done on the low voltage side, leaving the high voltage side open. The knee point is the point where the transformer enters saturation, and thus the linear relation between flux and current breaks down and becomes non linear. As the flux is proportional to the voltage, this breakdown can be found by comparing the voltage and current, and then finding the point where they are no longer linear. The knee voltage is defined by when an increase in the voltage applied to a transformers secondary by 10% corresponds in a current increase of 50%.

The data for the parametrization can be found in section 5.1, where the tests described in this section are carried out. This data is the data used for the simulation carried out in section 4.3.

4.3 Simulation of the Inrush Current

Now that the software for the simulation has been reviewed, and the parameters for the model have been acquired, the system can be simulated. This is done in order to estimate the magnitude of the inrush current and to review its harmonic content. The second harmonic content of the inrush current should be very large and can therefore be used as a constraint against tripping. The simulation can then be exported and used in the OMICRON, in order to simulate the inrush scenario for the relay. This is done in chapter 6. The setup used in the simulation is shown in Figure 4.2. The values of the inductor and resistor change depending on whether it is the weak or strong system.

The parameters for the transformer are as described in table 5.1.4. The transformer is setup to be a delta/wye transformer with a line-to-line voltage ratio of 400/230 V. The simulations are run with a step time of 25 microseconds. The voltage source is an ideal source set to 400 V line-to-line, and a frequency of 50 hz. As the inrush current will vary depending on the connected system, three cases are investigated. A very weak system, an intermediate system based on the lab, and a very strong system. The very weak system has a short circuit power of 0.1 kVA. The intermediate system is based on knowledge about the isolating transformer used in the lab, which is 30 kVA. The very strong system has a short circuit power of 200 MVA. The short circuit power can be represented by a short circuit impedance in series with the source. The stronger the system is, the smaller the impedance and vise versa. The impedance is given by equation (4.8), where S_{sc} is the short circuit power in VA, V is the line-to-line voltage.

$$Z_{sc} = \frac{V^2}{S_{sc}} \tag{4.8}$$

Recalling that the impedance can be defined by the dc resistance and the reactance, it can be found using equation (4.9), where R is the DC resistance of the connected system, and X is the reactance of the system.

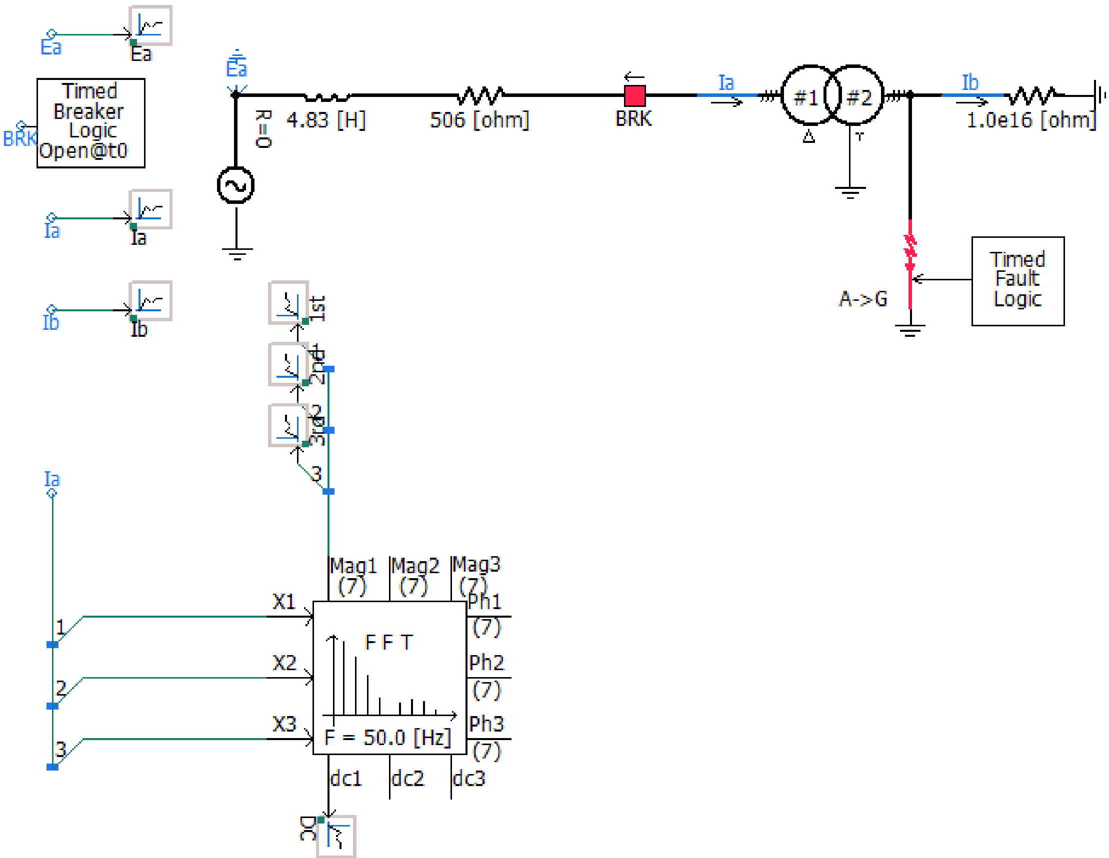

Figure 4.2. PSCAD simulation setup with parameters for the weak system

$$|Z_{sc}| = \sqrt{R^2 + X^2} \tag{4.9}$$

From this it is obvious that the impedance can be represented by a resistor and inductor in series. As the total impedance can be calculated from the short circuit power, and knowing that it consists of the DC resistance and reactance, all that remains is the ratio between reactance and resistance. In transmission networks this ratio, $\frac{X}{R}$, is above 10. The lower the voltage level is, the lower this ratio is and thus, the more dominant the resistance is. An estimate for this ratio is given in equation (4.10). This ratio was determined by discussion with the student counsellor.

$$\frac{X}{R} = 3 \tag{4.10}$$

By solving for X and R, with the short circuit power varying we get the data presented in table 4.3. As the simulation needs the input in inductance and not reactance, it is transformed by dividing the reactance by $2 \cdot \pi \cdot 50$ resulting in the L column.

The secondary side is shown connected to the ground through a resistance. This is done in order to overcome errors in the simulation, as it will not run with a floating secondary.

S_{sc} [VA]	X [Ω]	L [H]	R [Ω]
1.00e2	1.52e3	4.83e0	5.06e2
3.00e4	5.06e0	1.61e-2	1.69e0
2.00e8	7.59e-4	2.42e-6	2.53e-4

Table 4.1. X, L, and R values for varying short circuit power

The resistance is set to 1e16. It limits the current flowing in the secondary to under 1e-12 ampere in the simulation, which can therefore be neglected. In order to control the POW voltage, a breaker is introduced. The fault component is disabled for the inrush tests.

4.3.1 Inrush with Weak System

The first scenario tested is that of the weak system. The breaker is set to close 0.06 seconds into the simulation, which coincides with a rising zero crossing for phase one. It closes all three phases simultaneously. The POW voltages can be seen in Figure 4.3. This should result in the largest positive inrush current possible without remanence. As the other phases are lagging by 120 and 240 degrees, they will not be near the zero crossing, and it is expected that the inrush in these phases will have a smaller magnitude than in phase one. Furthermore, as the voltage in these phases is decreasing, it is expected that the inrush currents associated with these be negative.

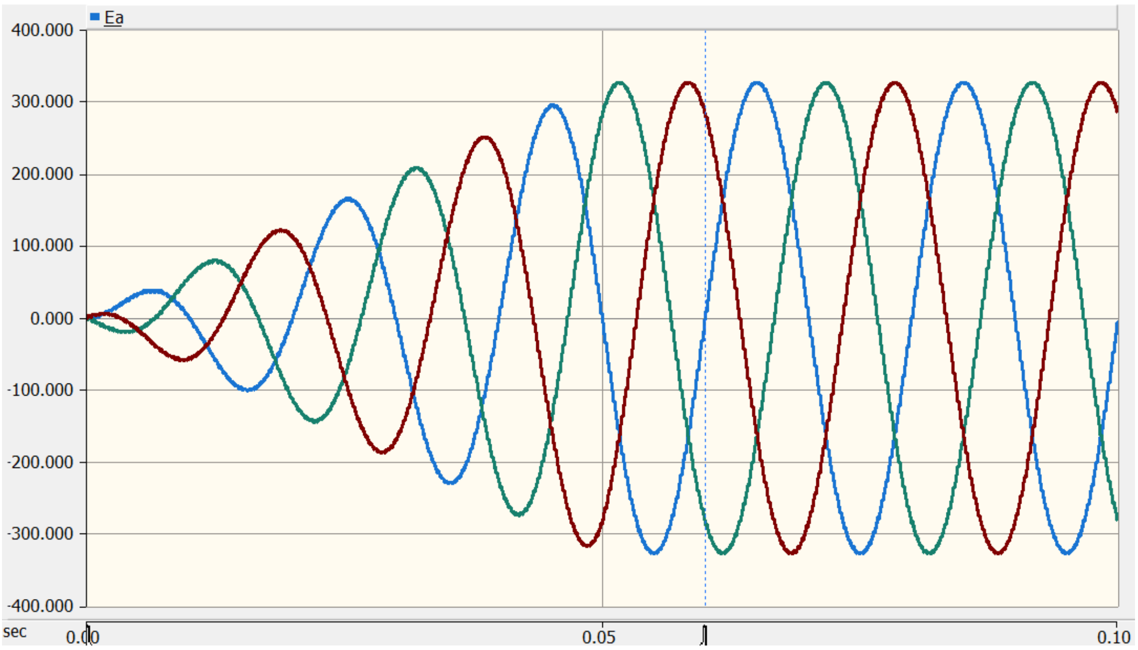

Figure 4.3. Point on wave voltages for all 3 phases. Dotted line indicates the switching instant at 0.06 seconds. Phase 1, 2, and 3 in order are: blue, green, and red.

As can be seen in Figure 4.4 inrush is occurring. It is however tiny in magnitude and hard to discern from the magnetizing current. Due to this, it would not cause a trip as it is less that the DC bias discussed in section 3.2. As this is the worst case for the transformer during a zero remanence start, it is obvious that a weak system will not provide any meaningful test data.

The next objective is to analyze the harmonic content for blocking of the trip signal in the

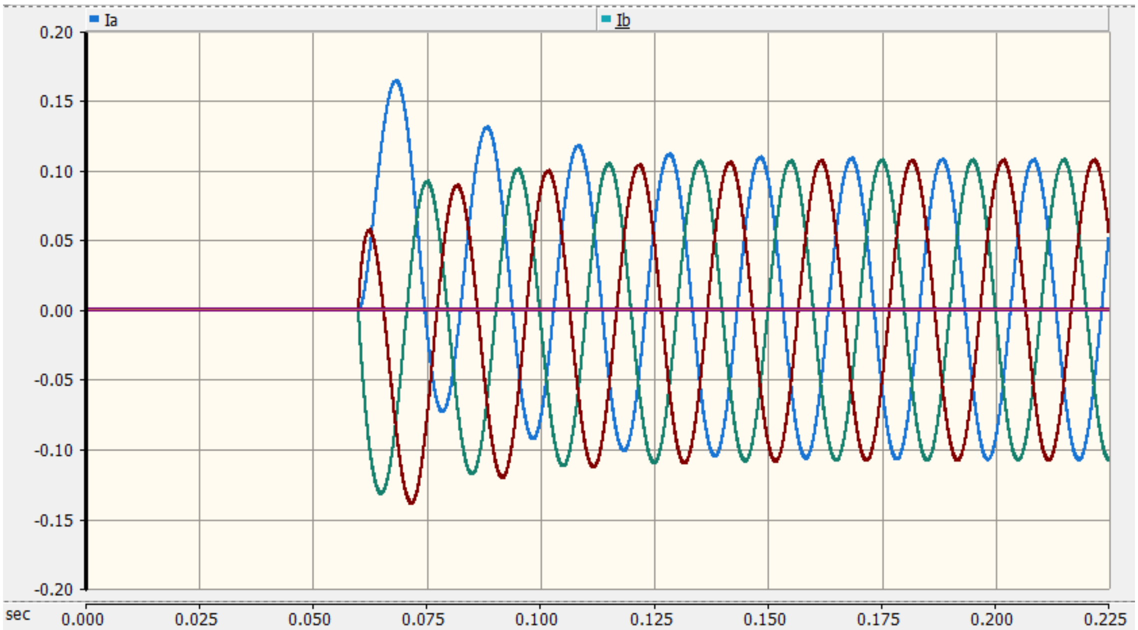

Figure 4.4. Inrush current simulation for all three phases with weak system. Phase 1, 2, and 3 in order are: blue, green, and red.

relay. This is done using the Fast Fourier Transform (FFT) block in PSCAD, which will extract the desired harmonics magnitudes and angles. Only the magnitudes are desired, as the numerical relay blocks inrush tripping by looking at the ratio between the fundamental and the second harmonics magnitude, as mentioned in chapter 3. As mentioned, the third harmonic cannot be used for blocking, but for completeness this is also included in the simulation. In order to be able to compare more directly to Figure 3.12 used in section 3.3.2, the DC component is also extracted. The harmonics of the inrush current in phase one can be seen in Figure 4.5.

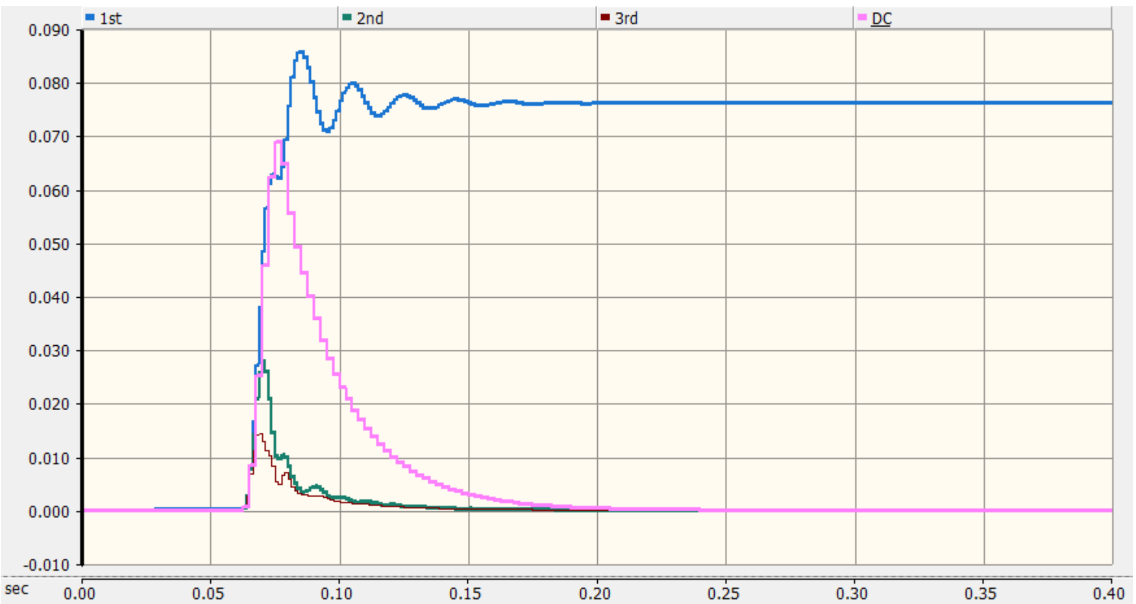

Figure 4.5. Harmonics of inrush current in phase one

From the figure it can be seen that the DC component is almost as large as the fundamental frequency during the inrush. Furthermore, the second harmonic is clearly very large in presence, with values of over 33% of the first harmonic. This means that the default relation used in Siemens numerical relays shown in equation (4.11), where I_1 is the fundamental frequency component and I_2 is the second harmonic component, will accurately detect the inrush, and has potential to be tuned higher. By studying the harmonics, it can be seen more clearly just how fast the inrush decays with the weak network. This is most likely due to the very high resistance of 500 Ω, as this dampens the inrush as discussed in section 3.3.2.

$$\frac{I_2}{I_1} > 0.15 \tag{4.11}$$

4.3.2 Inrush with Intermediate System

The second scenario is that of the intermediate system. The closing conditions for the breaker are the same as in the previous scenario, and the reasoning for the expectations remain the same.

In Figure 4.6 the inrush currents can be seen. The 80 A peak current is surprising as the rated current of the transformer is 3.6 A. This means that the inrush peak is approximately 20 times larger than the nominal current. However, as the dampening of the inrush is very heavy, as shown by the short time constant, the energy dissipated should not be damaging.

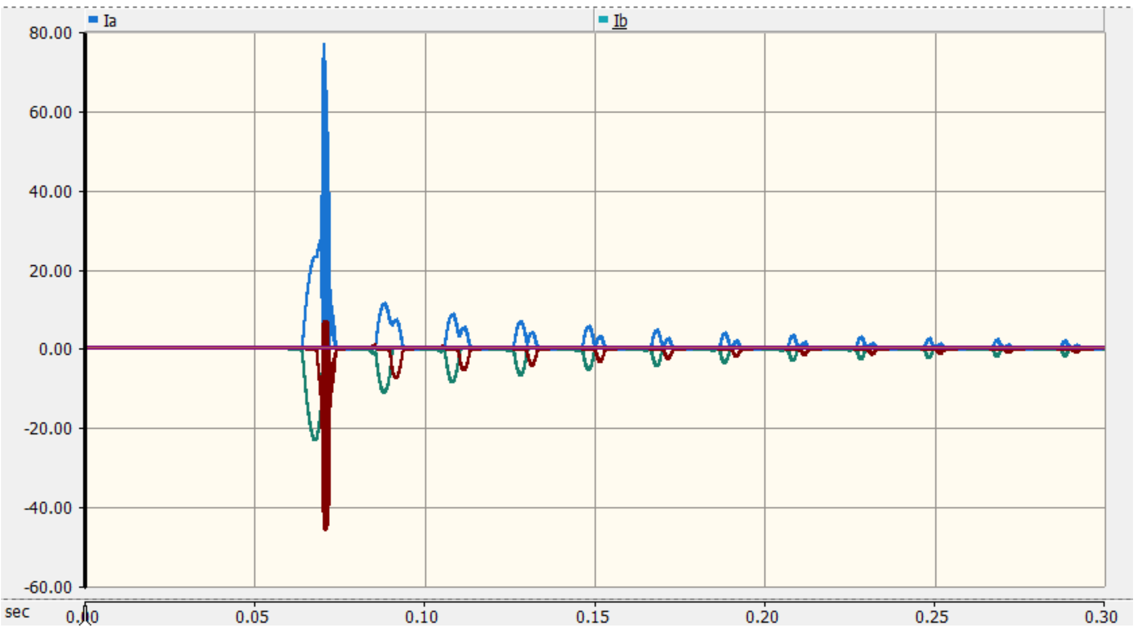

Figure 4.6. Inrush current simulation for all three phases with intermediate system. Phase 1, 2, and 3 in order are: blue, green, and red.

In Figure 4.7, the inrush content of phase one is displayed. As with the previous case, it can be seen that the DC component is very large. This coincides well with the non linear nature and large offset of the inrush current. Furthermore, the second harmonic is very large in presence, with values of almost 50% of the first harmonic. This means that the relation described in equation (4.11) should accurately detect the inrush and block the tripping action. As the second harmonic is so large, the blocking criterion could be tuned to be higher than the default 15%.

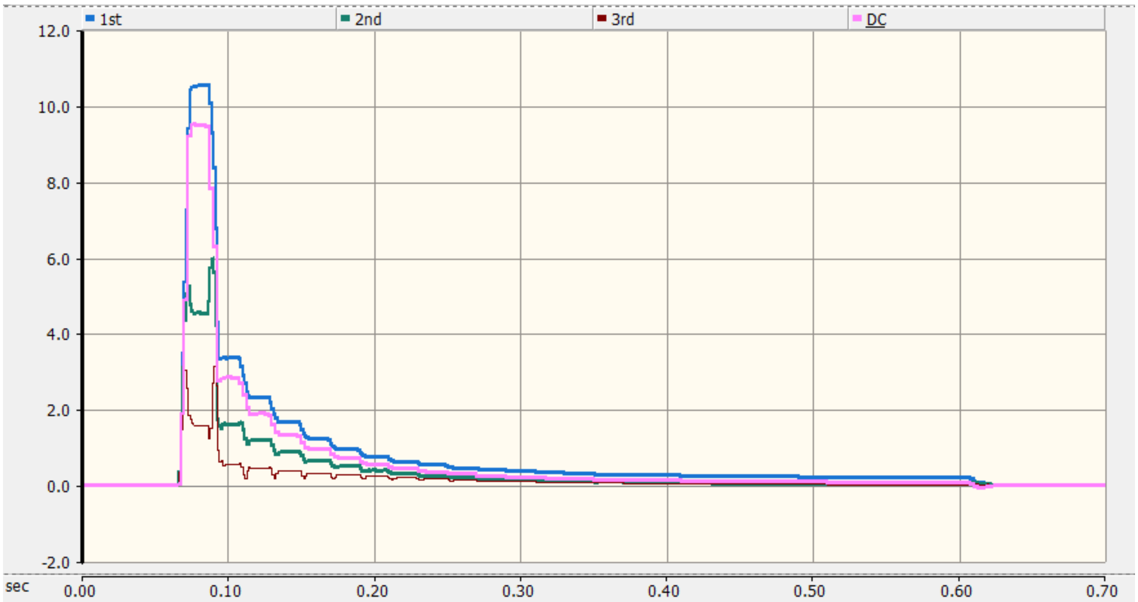

Figure 4.7. Harmonics of inrush current in phase one

4.3.3 Inrush with Strong System

The last case in this report is the case of inrush currents in a very strong system. The system is unrealistically strong for this voltage level, but it should demonstrate the absolute maximum amount of inrush that could occur using this transformer. In Figure 4.8 the inrush current of the transformer can be seen. As expected, it is larger in magnitude and the dampening is minuscule when comparing with the previous cases. It is important to note the difference in timescale. This inrush current is not even down to 80 A after 1.2 seconds, whereas with the intermediate system, it was almost completely gone after 0.3 seconds.

In Figure 4.9 the harmonics of the inrush current can be seen. What is interesting when looking at this at a long timescale like this, is that it enters a quasi-steadystate. The third harmonic is almost instantly gone after the switching occurs, but the ratio between the second and first harmonic remain what appears to be constant. This ratio could potentially be used to set the inrush blocking ratio.

4.3.4 Results

From this section, it is clear that the system the transformer is connected to is just as important as the transformer itself, as it can make the inrush vary by several orders of magnitude. As the intermediate system is the one which emulates the lab conditions the closest, this is the scenario which will be used for further analysis. The data acquired in this section can now be used in setting the parameters of the relay. More specifically, it can be used to adjust the inrush blocking, and adjust the expectations of peak currents. Furthermore, the scenario simulated can be exported using the analog data export block

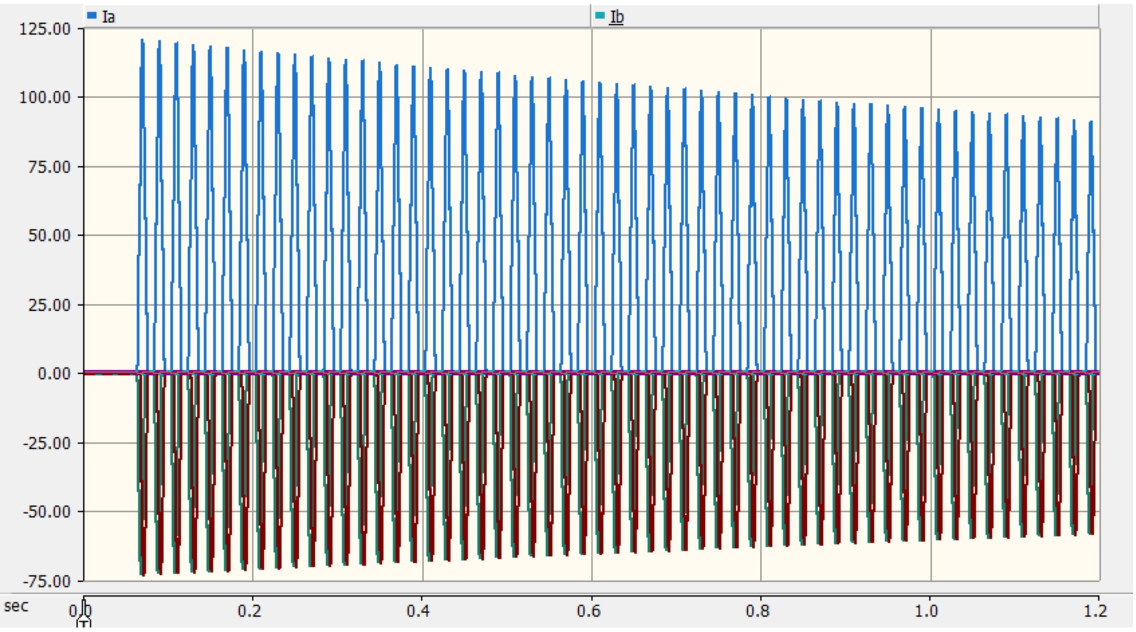

Figure 4.8. Inrush current simulation for all three phases with strong system. Phase 1, 2, and 3 in order are: blue, green, and red.

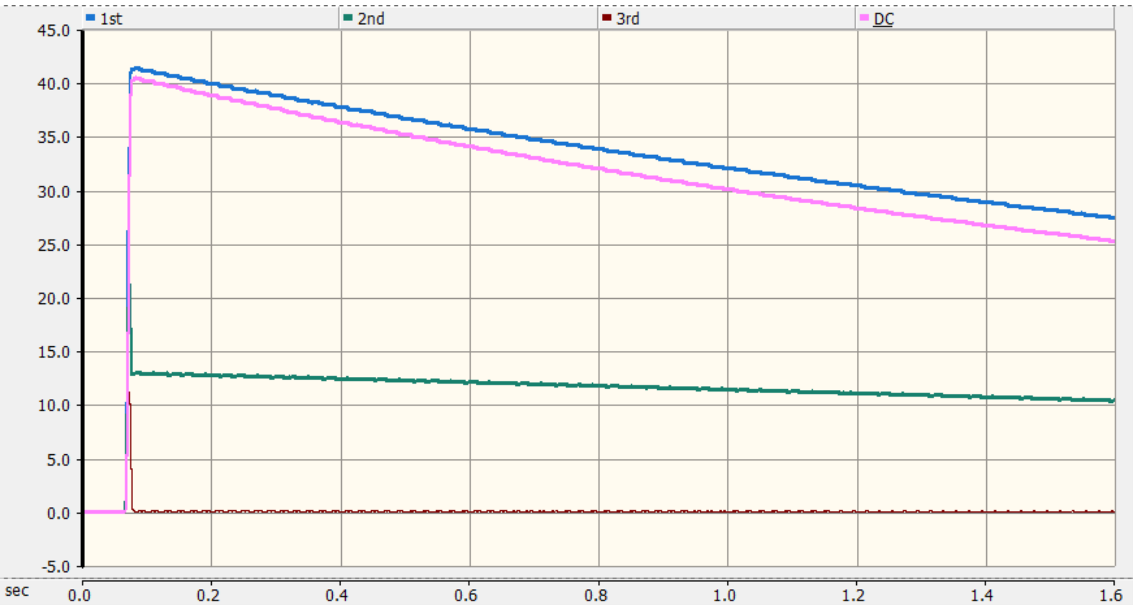

Figure 4.9. Harmonics of inrush current in phase one

shown in Figure 4.10. In this simulation, the data to be exported are the current measurements from the primary and secondary side of the transformer. This data can then be imported to the OMICRON. This is done in chapter 6.

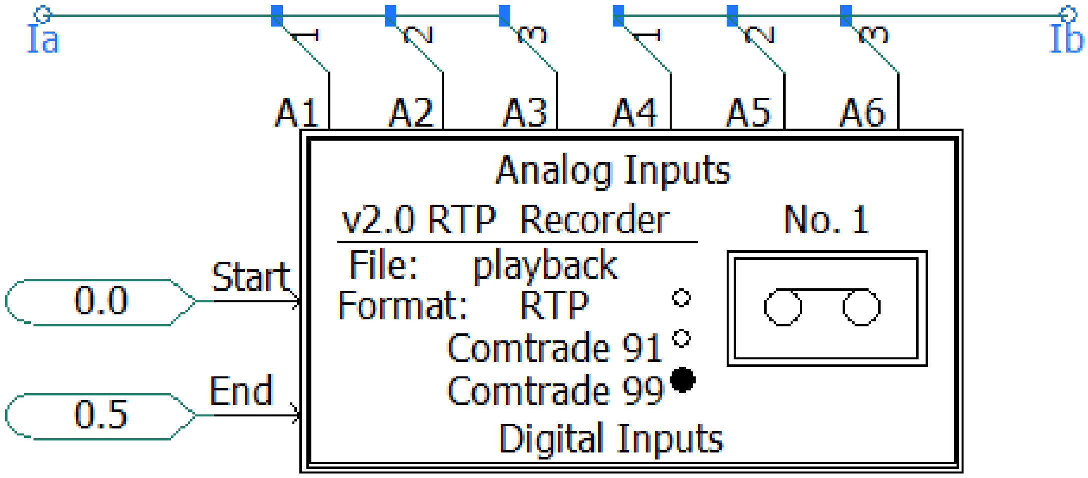

Figure 4.10. Data export block in three phase simulation

4.4 Simulation of an Internal Fault

In order to test the settings of the relay, a fault scenario is used. This is done in order to purposefully make the relay trip. The parameters for the fault scenario are from the intermediate system discussed in section 4.3.2. The fault is injected on the secondary side of the transformer, as shown in Figure 4.2. The fault is from phase one to neutral. The fault is injected at 0.6 seconds into the simulation and lasts for the remainder of it. The result of the fault can be seen in Figure 4.11. The inrush is still visible in the figure, as this is used later in section 6.2. It is clear that large currents are occuring during the fault, but in order to visualise what is happening more clearly, a zoomed in view is presented in Figure 4.12. From this, it can be seen that the fault in phase one on the secondary results in large currents in phase two and three on the primary side of the transformer. This is not surprising considering the delta connection in the primary. As with all the other cases, the current passing through the secondary current reading is not visible as it is very small compared to the primary. Therefore, this scenario should definitely cause a trip.

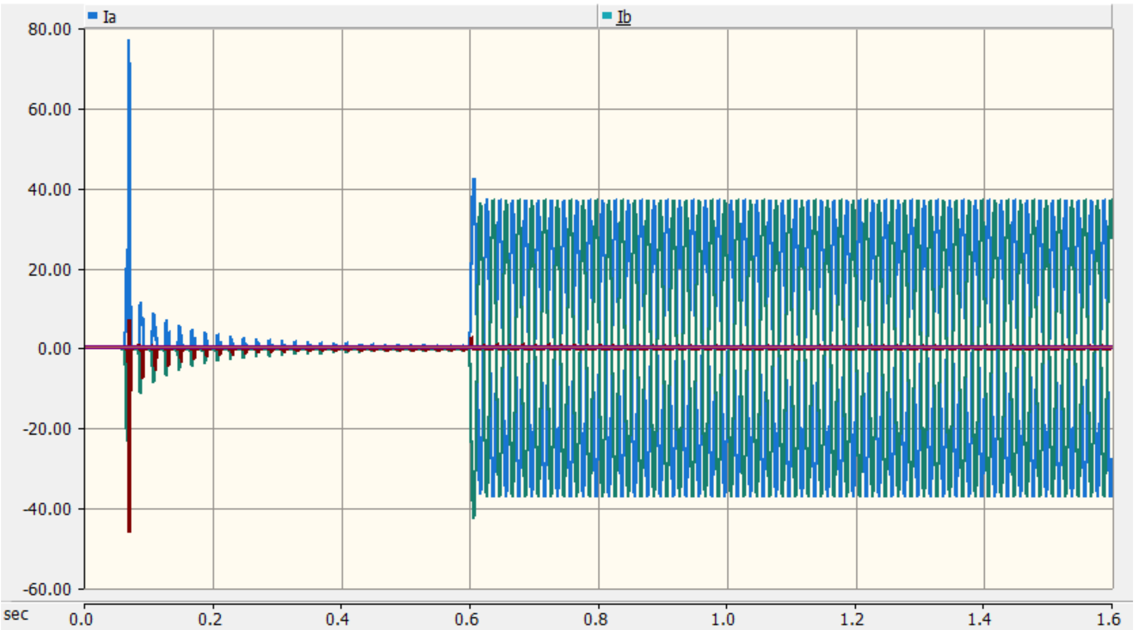

Figure 4.11. Fault in secondary phase one to neutral

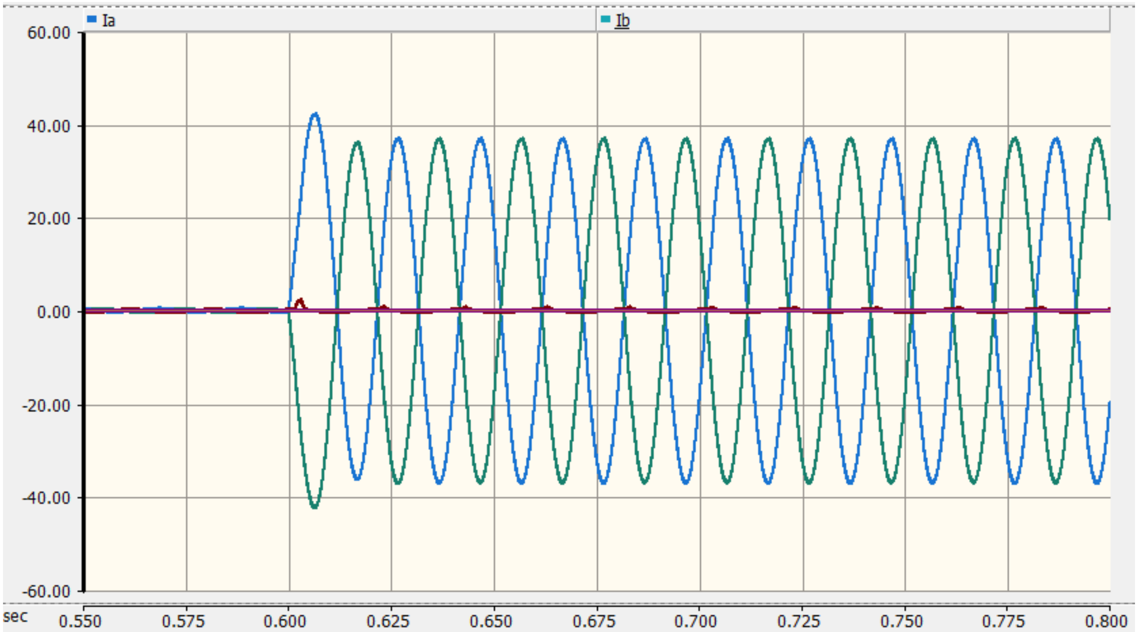

Figure 4.12. Fault in secondary phase one to neutral (zoomed)

Laboratory 5

In order to continue with the modelling of the transformer, some lab work is required. The lab work is done in order to create simulations, which are as close to reality as possible. This is done by taking a real transformer and then using the theory previously discussed in order to parametrize it. These parameters are then used in the simulations.

5.1 Parametrization of Transformer

In order to continue working with simulations, the parameters of the transformer must be determined. These parameters are discussed in detail in section 4.2. In order to determine the parameters three tests types are conducted. The transformer in question is a 400/230 DYn11 with a rated power of $S_n = 2.5$ KVa and a rated frequency of $f_s = 50$ Hz. The transformer is rated for a line current of 3.6 A. The DYn11 designation means that it is a Delta/Wye transformer with vector group 11. The vector group indicates the lag of the low voltage (LV) in respect to the high voltage (HV). Vector group 11 equals a lag of 330 degrees, or vice versa that the LV leads the HV by 30 degrees. The equipment used in sections 5.1.1, 5.1.2 and 5.1.3 is listed in table 5.1.

Equipment Name	Model	AAU Number
Three phase power analyzer	Voltech PM300	93642
Autotransformer 400/400 V 10 A	Lübcke RV31002-20	89119
DYn11 400/230 2.5 kVA transformer	Dantrafo DT 18784-1	N/A

Table 5.1. Equipment used in parametrization of the transformer

5.1.1 Short Circuit Test

The short circuit test is performed in order to determine the conductor losses, leakage reactance, and air core reactance. It is done by shorting out the Wye winding, connecting the power analyzer and then connecting the delta winding to an auto transformer. The auto transformer is connected to the laboratory mains. A schematic for the short circuit test can be seen in Figure 5.1. The reason for the delta winding being used for the short circuit test is to keep the currents as low as possible. The power analyzer measures the voltage, current and power for all three phases. The following bullet points are then carried out and repeated three times in order to form an average.

- Raise voltage till the rated current of 3.6 A flows into the transformer per phase.
- Note the short circuit voltage, current, and power for all three phases.
- Decrease the voltage to zero.

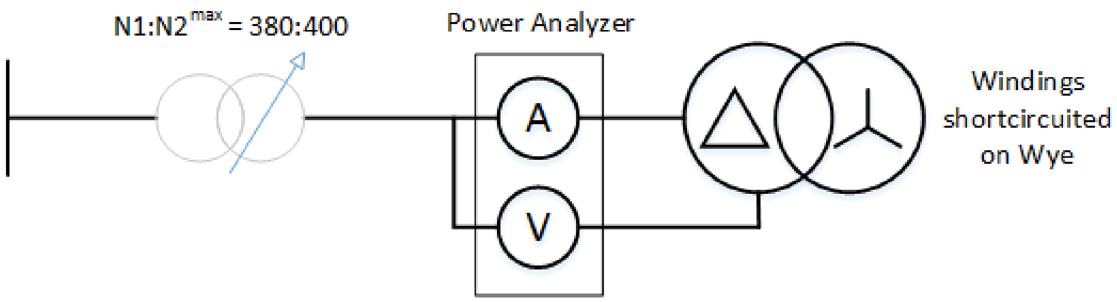

Figure 5.1. Setup for short circuit test

The leakage reactance and copper losses can now be calculated by using the equations in section 4.2. The calculations are done in section 5.1.4.

5.1.2 Open Circuit Test

The open circuit test is performed in order to determine the parameters of the magnetizing branch. It is done by connecting an auto transformer to the transformers Wye winding, and leaving the delta winding open. A power analyzer is connected in order to measure the open circuit voltages, currents and powers for all three phases. A schematic for the open circuit test can be seen in 5.2. The following bullet points are then carried out and repeated three times in order to form an average.

- Raise voltage to the rated phase to phase voltage of 230 V on the Wye winding.
- Note the open circuit voltage, current, and power for all three phases.
- Decrease the voltage to zero.

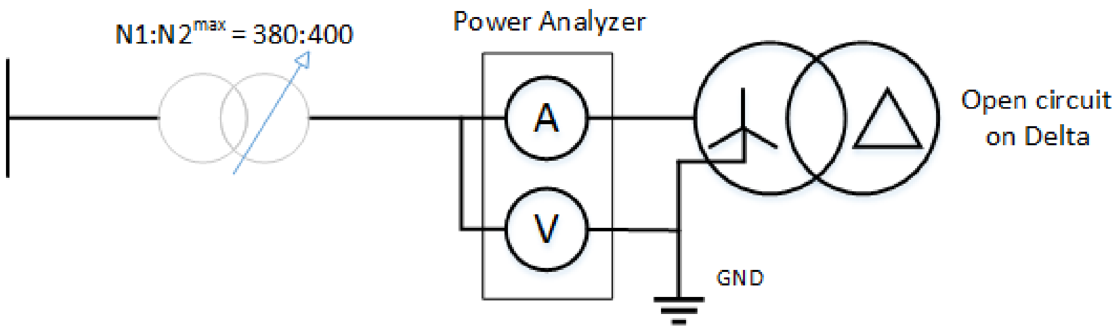

Figure 5.2. Setup for open circuit test

Using this data, the magnetizing current can be calculated by using the equations in section 4.2. This is done in section 5.1.4.

5.1.3 Determination of the Knee Voltage

In order to simulate the saturation of the transformer, the knee voltage must be determined. It is determined by leaving the high voltage side open, and slowly increasing the voltage on the low voltage side. This is done for safety reasons, as it keeps the operating voltage lower. The current is then logged for every increase in the voltage. As the test is conducted from the low voltage side, the rated voltage is 230 V line-to-line. Due to this, the voltage regulation can be done using an auto transformer. A schematic for the test is shown in Figure 5.3.

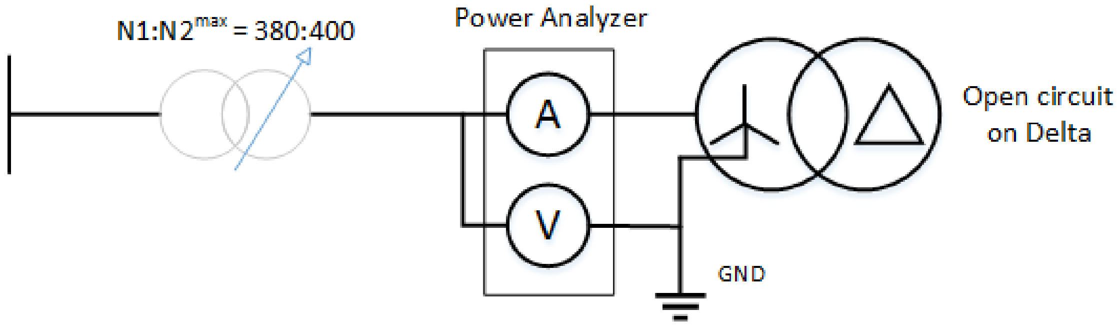

Figure 5.3. Setup for knee voltage test

The steps for the test are described below in bullet form.

- Apply voltage in 10 V increments line-to-line, by slowly increasing the voltage to avoid transients.
- Log the voltage and current from each phase.
- repeat until 230 volt line-to-line is applied.

After this, care must be taken in not overloading the transformer. Therefore, the voltage will be brought up from zero to the desired voltage in each step before every test. The final voltage is expected to be approximately 460 volts line-to-line, as this is 1.15 times the rated voltage, which is a typical design criteria.

- Slowly ramp up the voltage from 0 to the desired voltage, with the same 10 volt increments.
- Quickly log the currents and voltages for all phases in order to reduce the time under load.
- Decrease voltage to 0.

The data logged can then be plotted in order to determine the knee voltage point by looking at the voltage/current relation as described earlier. This is done in section 5.1.4

5.1.4 Calculations and Results

From the conducted tests, the parameters for the PSCAD model can be determined. When carrying out the tests described, some effects of imbalance are noted in that the resistive load and currents were different for each phase. This difference is suspected to be caused by the non linearity and non symmetrical construction of the transformer, as it is a three legged transformer with shell type windings. This can result in one leg carrying more flux than the others, as it is not necessarily evenly distributed. As the PSCAD model will model all phases identically with the classical approach, these imbalances are accounted for by taking an average of the three phases in the calculations. For the copper and eddy losses, the total power losses are wanted and are therefore summed.

When determining the knee point of the transformer, the relation of 10% increase in voltage resulting in a 50% increase in current is sought after. The voltages and currents measured can be seen in Figure 5.4. This expression is equal to finding the place where the ratio between the change in voltage and current in percent is equal to 1/5. From the data acquired, it could be determined that this point lies some place between 1.0653 and 1.0893 volt in p.u. In order to accurately estimate the knee point, spline interpolation was used to generate more data points. From this interpolation, it was found that the ratio was 1/5 at 1.0807 volt p.u.

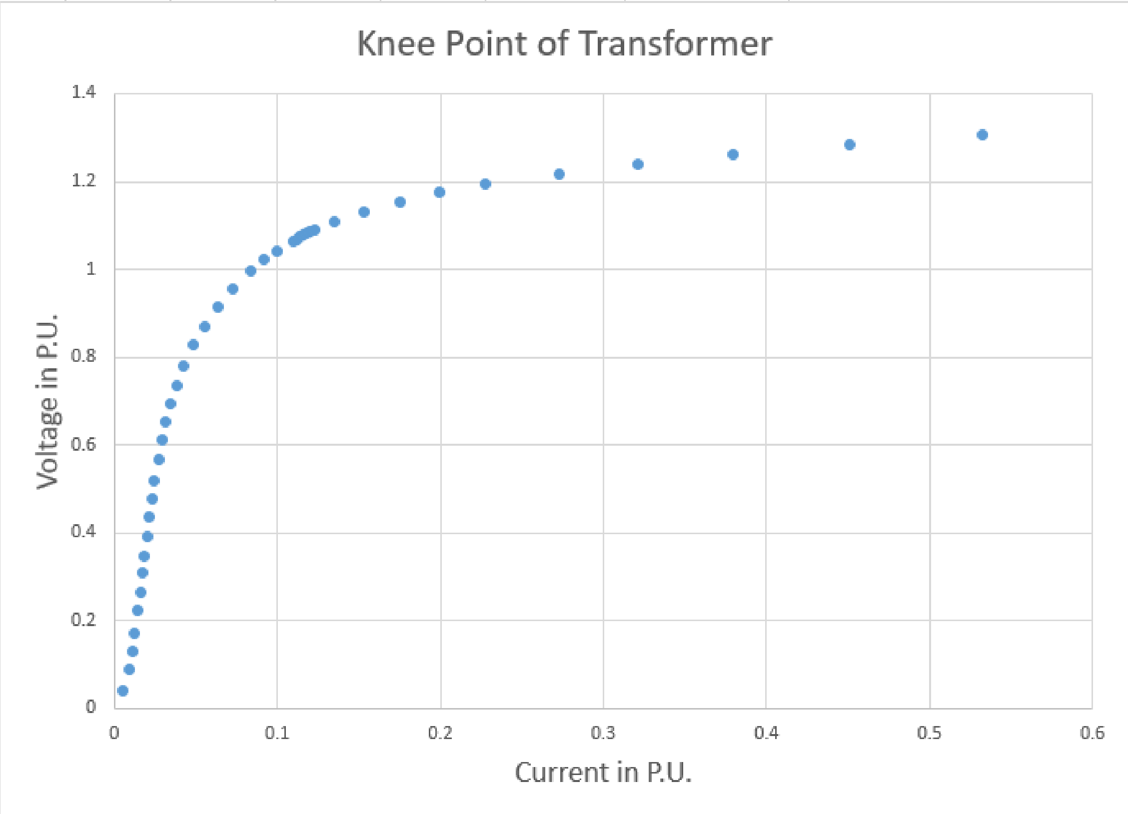

Figure 5.4. Plot of the measured voltages and currents in the knee point determination lab in p.u.

The parameters are presented in table 5.1.4. The calculations are done using MATLAB R2017b and Microsoft Excel 2016. The MATLAB file for calculating parameters based on the open circuit and shirt circuit tests can be found in Appendix C. The full data set recorded during the open circuit and short circuit labs can be found in Appendix A. The data and calculations for the determination of the knee point can be found in Appendix B.

Parameter	Value
Leakage Reactance	0.0159 P.U.
Eddy Current Losses	0.0294 P.U.
Copper Losses	0.0228 P.U.
Air Core Reactance	0.0318 P.U.
Magnetizing Current	2.7%
Knee Voltage	1.08 P.U.

Table 5.2. Results of parametrization of transformer

Relay Settings and Testing 6

In section 3.2, the fundamentals of differential protection are described. In the section, it is described that current measurements on both sides of a transformer are taken, which then undergo various operations in order to scale them based on the vector group of the transformer, the winding ratio, and varying CT ratios. In real life applications, the state of the art is to use numerical relays. This relay terminology is a remnant, as they are not just relays anymore. They are often mentioned as IED or Intelligent Electronic Device, as they essentially are computers with various binary and analogue inputs and outputs. The relays used in this project are Siemens Siprotec 7SD61, and are differential relays. They are capable of providing differential protection not only for transformers, but also transmission and distribution systems such as overhead lines and cables. As this project scope only includes transformers, some settings are omitted and disabled in the relays. Because the relays are multipurpose, not only in that they can be used for different systems, but also allow a great degree of customization in the usage of CTs etc. some programming is necessary. In section 6.1, the specifics about programming the relays will be elaborated. In section 6.2 the settings will be tested with simulated scenarios.

6.1 Programming the Relays

When programming relays, it is important to note that there are two relays to program. In this section, one is named Local or relay 1 interchangeably, and the other is named Remote or relay 2 interchangeably. In this section the various parameters for the relay will be investigated and set in correspondence to the information gathered in section 3.2. The primary source for programming the relays is the manual for the relay [Siemens, 2016].

The relay is programmed using Siemens DIGSI software. DIGSI is a graphical user interface software in which various parameters on the relays can be set. Furthermore, it can be used to create special functions, should the user need it. It is programmed by accessing "addresses" and toggling them or inputting a value.

The first settings to change are the device configuration settings. In this menu, settings relating to the function of the relay can be changed. For the scope of this report, only the differential protection is enabled at address 112. The 7SD61 can be ordered with an option to include a power transformer in its protection zone, but the particular relay used here is not built with that option. The address of this setting is 143. As this option is missing, it is impossible to test the transformer fault scenario, as it cannot account for the vector grouping or winding ratio of the transformer, and thus will see the phase shift and transformation ratio as errors. For the sake of completion, the missing settings will be evaluated and elaborated, but not actually programmed. Since the purpose of the inrush test is to test if the relay properly picks up the second harmonic content and blocks for tripping, it can still be tested, as any tripping due to vector grouping or winding ratio should be blocked. This means that when testing the inrush scenario, it should stay online. However, as soon as the second harmonic content drops to below the specified level, it should send a trip signal due to the previously mentioned reasons.

The next group of settings is labelled Power System Data 1. This group relates to the system the relays are used to protect. The first subgroup of settings is called "Transformers" and relates to the connection of the CTs. Here, the star point of the CTs can be defined as being towards the line or the busbar. This is done on address 201, and is left at the default towards line, as this does not really matter in this case as no CTs are used in the lab. The next two options on address 205 and 206 are the primary and secondary currents of the CT, which are set to 100 and 1, as this is the ratio used in the OMICRON when simulating the scenarios. This means that the currents measured by the relay are scaled up by a factor of 100 when displaying them on the LCD. As the transformer has an earthed star connection on the secondary side, it is necessary to have some earth fault protection. This can be done by a separate earth fault relay, or it can be handled by an optional purchase in the differential relay. The way it works is by having a separate CT measure the current flowing in the earth connection, which is then compared to the current flowing in the phases. By doing this selectivity is obtained as it only protects within the boundary created by the four CTs. If this is desired it is important to enable the I4 CT in address 220. Furthermore, the ratio of the earth CT and the phase CTs must be defined in 221. This is necessary as the earth fault transformer can be much smaller, as there normally should not be a current present in it, thus it does not need to be able to handle the full load of the transformer.

The next subgroup is labelled "Power System". Here, information regarding the system being protected are defined. First, the earthing of the system is defined. This is done in address 207 and options are: Solid Earthed, Peterson Coil, and Isolated. For the simulations, a solid earth is used and therefore this is the setting defined here. Furthermore, the frequency of the system is defined in address 230, which is set to 50 Hz. The next subgroup is "Breaker", which contains only one setting, namely dead time for CB test-auto re-closure. This is the time it takes for the breaker connected to this particular relay to re-close after breaking a fault. As no physical breakers are present in this report, it is left at the default 0.10 seconds. The last subgroup is labelled "CT Data" and relates to the specific CTs used in the system. Recall that there are three regions of operating the system as seen in Figure 3.4 defined by equations (3.3) to (3.5). First is at low currents where CT error does not matter and only the transformer magnetizing current is compensated for. The second region is where CT error starts to compound and requires a slope k based on the CTs in question. The last region is the saturation region, where the CTs start to saturate. The first setting in the relay, at address 251, is the ratio between the actual ALF (ALF') and the nominal ALF of the CTs. This is given by equation (6.1), where n' is the operational ALF, n is the rated ALF from the specs, P_N is the rated burden of the CT, P_i is the internal burden of the CT, and P' is the burden connected to the CT. P' is found by measuring the DC resistance of the connected wiring and then using the relation that $P' \approx R_{wire} \cdot I$, where I is the rated secondary current. P_i is typically available in the test report from the factory, but can be calculated similarly to P', by measuring the DC resistance of the CT. Siemens recommend that this ratio is kept below 1.5, and if this is not possible with the selected CTs, considerations should be made to select other CTs.

$$\frac{n'}{n} = \frac{P_N + P_i}{P' + P_i} \tag{6.1}$$

The next setting is called "CT error in % at ALF'/ALF" and is at address 253. This is the transformation error specified in the datasheet for the CT plus a safety margin. Siemens recommends for a 5P, where it could be 1% at rated current, to add a safety margin of 2% adding up to a total of 3% in this setting. The next setting is called "CT error in % at ALF and is at address 254. This is the number before the P plus a safety margin. For a 5P siemens recommends adding a safety margin of 5% adding up to 10%. These CT settings address the issue of transformation error and defines a slope similarly to equation (3.4). They do however not address the issue of CT saturation defined in the last region. This is instead done by "High-speed charge comparison", where the relay calculates the charge and compares it to the previous charge. The charge is calculated by equation (6.2), where the integration time is $\frac{1}{4}$ of a period, or 5ms at 50 Hz. The relays then compare the charge measured at both ends of the system and will provide high speed tripping if they are not equal. These settings for the CTs are all bounded by the fact that the CTs must be selected via three criteria. The first criterion is that the ratio between the maximum fault current and the nominal primary current must not be larger than the operational ALF. The second criterion is that the operational ALF must be at least 30 (Calculated by solving for n' in equation (6.1)), or the CTs must be guaranteed to not saturate in under $\frac{1}{4}$ of a period. The third criterion is that the ratio between the primary currents at both ends of the system must be below 8, thus a transformer must have a winding ratio of maximum 8.

$$Q = \int_{t1}^{t2} i(t)dt \tag{6.2}$$

For the testing of the inrush scenario, all of these values can be set very low, as there are in fact no CT's connected and thus no error imposed by them. Therefore, the settings are selected to follow those of a 5p CT. This means that address 251 = 1.00, 253 = 3.0% and 254 = 10%.

That concludes the power system data 1 settings. The next settings group is called power systems data 2, which contains information about the system. First, there is information about the current level of the system. This setting is located at address 1104, and is the basis for the systems calculations. Ideally this would be set to 3.6 A, as this is the current rating of the transformers primary side, but it does not go lower than 10, so it will be set to that. It is important to set the current levels corresponding to which winding the relay is connected to. When working with a transformer differential, different options are available. It can include settings such as full scale voltage, power, line angle, etc. In address 1103 the full scale voltage can be set. This is the rated voltage of the end of the system being observed. It is important that this is set correctly, with respect to what side of the transformer the relay is at, as it is used in the per unit calculations. It is furthermore all the relay needs to know about the winding ratio, as the vector group is dealt with elsewhere. In address 1106 the operation power can be set. It is the highest apparent power the transformer can transfer for any winding pair. Thus, in the case of this report, that value would be set to 2.5 kVA. Had the differential relay has the transformer options enabled, the vector group could be set. This is important as previously mentioned it will cause a phase shift. This is set in address 1161 and 1162. The methodology is that the vector group is set for each relay, such that the relay for a winding has the corresponding vector group. In the case of this report, the transformer has the vector group Dyn11, so for the local relay the vector group should be set to 0 as it is the reference. For the remote relay, the vector group should be set to 11. In address 1163 the zero sequence elimination mentioned in section 3.2 is enabled or disabled. As the transformer in question has a grounded star point on the secondary side, this should be enabled in the remote relay. The next subgroup is Line Status, which defines parameters for when it is allowed to reset the trip signal and other overheard line specifics. As automatic re-closure of a transformer is not permitted after a trip, these settings are left at default settings.

The next settings group is named Differential Protection. The first option is at address 1201, and enables or disables the differential protection. Naturally, this should be enabled in our case. The next option is at address 1210 and is the I-DIFF > Pickup value. This is the DC offset described in section 3.2, by equation (3.3). Siemens recommends taking the magnetizing current and then doubling the value for this bias. The magnetizing current of the transformer in question has been calculated to be 2.7% of the full load current in section 5.1.4, which is 2.7% of 3.6 A. The minimum allowed value in the relay is 10 A, which is the setting used. The next option is I-Diff during switch on. Recall that an inrush occurs when switching the transformer on. Siemens recommend a setting of 4 times the charging or magnetizing current, which equals to $4 \cdot 0.027 \cdot 3.6$ A, thus lower than the 10 A minimum setting. Please note that the inrush can be much larger than this. Therefore, it is mitigated by other means than a simple added restraint current. The next parameter is I-DIFF» at address 1233, which is the "Pickup value charge comparison stage". This is the stage that reacts to very large short circuit currents, and is therefore very fast. It must be set to exclude the inrush current, as it is not supposed to pick this up. From the simulations we know that the largest expectable rush current is approximately 80 A, which is coincidentally the smallest value allowable in the relay. The next parameter is I-DIFF» at address 1235, which is switch on of the charge comparison. Depending on the object protected, stray fluxes can cause the charges to differ on the secondary and primary side during switch on, which can cause a faulty trip. Siemens recommend setting this value to two to three times the I-DIFF» value if the protected object is a bushing transformer. As this is not the case, it is set to the same as I-DIFF.

The next settings group relates to inrush currents. For the scope of this project, it is one of the most important settings. It is enabled by toggling address 2301. At address 2302 the amount of second harmonic in percent of the fundamental which must be present for the inrush blocking to be enabled is defined. By default this is set to 15%. This value is a good starting point, as it is lower than what should be expected from a transformer, thus successfully blocking the relay from tripping during inrush. The next setting is called Cross Block and is located at address 2303. By enabling cross block, inrush in one phase will block tripping action for all phases. Please recall from section 3.3.2 that one phase can be without inrush if it is switched at the right time, while the others are experiencing heavy inrush. This means that a potential error on that phase can be observed and the relay will then trip, if cross blocking is not enabled. As this relay is not meant for transformers, if a phase was without blocking a trip would occur. Therefore, cross blocking is enabled, which allows for the inrush scenario to be tested without tripping. The next parameter is at address 2305, and is the maximum inrush peak value. As the name implies, this is to be set to the highest inrush expected. It supersedes the inrush blocking, and thus if this peak is exceeded then the relay will trip, even if the second harmonic content is greater than the previously defined value. The highest expected value is 80 A, as shown earlier in section 4.3. The minimum value the relay allows is however 110 A, which is the value set. The last parameter available to tune here is the time for cross block, at address 2310. By default it is set to zero, but for some tests in section 6.2 it will be changed to a higher value. This concludes the differential protection settings.

Although the differential protection on both sides of the transformer should detect the same errors, extra trip commands should not be necessary. However, in address 1301 such a command can be enabled. The action for receiving the command from the opposing relay can be defined in address 1302, where it can be set to an alarm or a trip. In address 1303 a delay for the tripping command can be introduced and in 1304 the trip length can be defined. In order to communicate with the remote relay, different techniques can be used. It can communicate via a network, via copper wires or fibreoptics. In the lab the relays are connected by fibreoptics. This is defined in the settings, along with settings pertaining to the maximum delay in communication before an alarm is raised. In address 4701 and 4702 the relays are labelled with an identifying number. Default setting is naming them 1 and 2, and this is fine for the scope of this project. In a larger system a more complex naming scheme might be used. Furthermore, in address 4710 it is defined which relay is the local relay. In this case it is relay 1.

6.2 Testing the Relay Settings

In order to verify the settings made in section 6.1 tests must be carried out. The way this is done is by simulating the desired scenarios for the relays, and then monitoring the actions taken by the relay. By doing this, the relay settings can be tested without ever being connected to the transformer they are meant to protect. This makes testing easier, as it is all done via computer, instead of having to deal with the practicalities of testing in real life.

The desired scenarios are simulated in appropriate software, such as PSCAD, where the desired variables, such as the current measurements, are exported into an external file. This file is then imported into software which controls an OMICRON CMC 256 (referred to as OMICRON). The OMICRON is, as previously mentioned, a signal generator with built in amplifiers. It can generate the waveforms desired from the simulation scenario. Naturally, it is impractical to generate the real currents which the scenario calls for, in case of the inrush upwards of 80 A. Therefore, the signals are scaled down, as with a CT. This essentially means that the currents the OMICRON outputs can be seen as the secondary currents of the CTs, which allows it to be connected directly to the current measuring circuits of the relays. A schematic showing the connections and process is shown in Figure 6.1. The signals are scaled 100:1, meaning that the 80 A peak is scaled down to 800 mA, which is then output to the relays. The relays then read the values at 800 mA and scale them back up to the 80 A in the software.

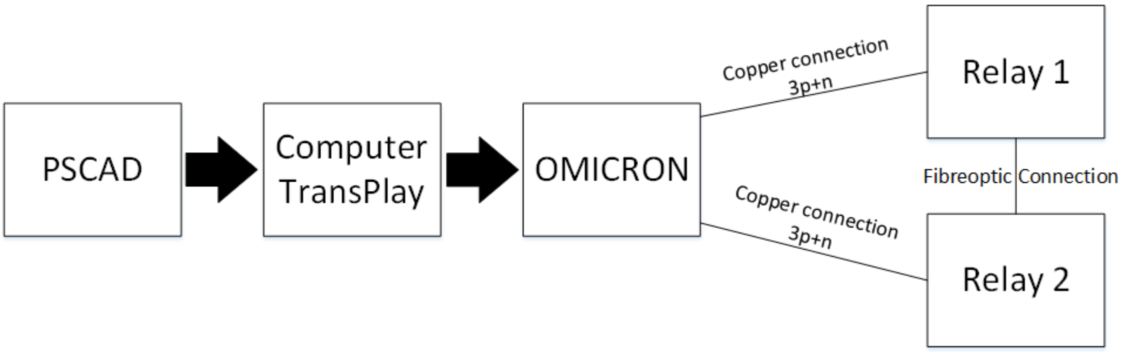

Figure 6.1. Schematic of the relay test setup

As previously mentioned the relays are not transformer differential relays, but rather line differential relays. Due to this it is not possible to accurately determine if a fault caused a trip rather than just the vector grouping, zero sequence currents or winding ratio when running the scenarios. Regardless, in order to verify that the relays are setup properly, and ensure that they will in fact issue a trip command, they are tested with a fault scenario. The scenario is the one shown in Figure 4.11.

When doing this, the relays did not react to the input. This is speculated to be because the relays are not designed to work with transformers at this voltage nor power level. Therefore, in order to make sure the relays are operational, the internal scaling is changed. By doing this, the relays are tricked into thinking that the 40A currents during the faults are much higher. This is done by changing the ratio of the CTs in the settings of the relay from 100:1 to 1000:1. The conversion scheme from computer through OMICRON to relay goes like this: 40 A -> 400 mA -> 400 A. By doing this, and using the fault scenario, the relays react and send a trip signal. This means that the relays are functional.

The next test is to determine whether or not the inrush blocking works. As there is no option to monitor whether or not the inrush block has been triggered this is done by using the fault scenario again. Please recall from Figure 4.11 that it contains the inrush currents in the start of the simulation. In the settings for the relay cross blocking is enabled and a time for cross blocking is defined in address 2310 of the relay. This time is set to three seconds, which is longer than the simulation. By doing this, the relay should detect the second harmonic content of the inrush and then block the tripping action of the relay for three seconds. As a result, the fault which starts and stops within the first two seconds should go unnoticed.

When running the scenario like this, the fault current can be read out on the LCD screen of the relay, but no tripping occurs. This means that the inrush detection was in fact successful, rendering this test successful.

7 Conclusion

The author began the work by identifying that there is a trend towards decentralization of the energy production taking place. One of the engineering challenges this will pose, is that it shifts the scope of fault on the distribution transformer from being an outage for consumers to also shutting down production from these decentralized units. During the internship the author acquired skills in designing the protection for the transformer, and learned a great deal about the safety equipment associated with transformer protection.

In this work a systematic study of differential protection of a small transformer was carried out. It was determined that the inrush currents associated with the magnetization transients not only were large enough to cause a false differential current, but could in fact be large enough to destroy the equipment. Simulations were conducted using parameters fitted from a real transformer. It was found that even if the current was not large enough to cause damage, it could still cause a false positive in the protection. The inrush current was found to be of considerable harmonic character, caused by the non-linear nature of the transformer during saturation. By performing FFT on the current waveform a ratio of the fundamental frequency and the second harmonic was computed as a possible blocking criterion for the protection system. In the lab two Siemens 7SD610's were programmed to pick up the inrush current. An inrush scenario corresponding to the simulation conditions was performed using an OMICRON CMC 256-6. The calculated blocking ratio successfully prevented tripping action, demonstrating quantitative agreement between simulation and experiment.

Even though the project has been concluded, and the most important aspects have been investigated and tested, it has potential for further work. As it has been determined that the ratio for blocking inrush tripping could be tuned, it would be of interest to see exactly how much. Additionally, by acquiring a larger transformer plus relays with more options, through-fault scenarios could be tested using the OMICRON CMC 256-6 and verified experimentally. With the current setup, the inrush current simulated in section 4.3.2 could be verified experimentally.

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Open and Short Circuit Data A

SC test performed from delta winding

V_sc is phase to ground voltage I_sc is line current

Attempt	V_sc V			I_sc A			P_sc A		
	R	S	T	R	S	T	R	S	T
1	5.352	5.289	5.726	3.249	3.398	3.616	17.017	17.405	20.29
2	5.734	5.365	5.811	3.484	3.441	3.667	19.546	17.88	20.89
3	5.734	5.364	5.821	3.48	3.436	3.668	19.524	17.85	20.94
Average	5.60667	5.33933	5.786	3.4043	3.425	3.6503	18.696	17.712	20.707

OC test perfomed from Wye winding

V_1 is phase to ground volta I_oc is line current

Attempt	V_1 V			I_oc A			P_oc W		
	R	S	T	R	S	T	R	S	T
1	132.58	132.1	132.74	0.4348	0.6014	0.5521	15.741	19.571	37.3
2	134.25	133.98	134.49	0.4564	0.6321	0.5802	15.965	19.811	38.84
3	132.86	132.63	133.12	0.4385	0.6089	0.5578	15.7	19.673	37.72
Average	133.23	132.903	133.45	0.4432	0.6141	0.5634	15.802	19.685	37.953

B Knee Voltage Data and Calculations

#	V_1 V				I_oc A				P_oc W			
	R	S	T	AVG	R	S	T	AVG	R	S	T	AVG
1	5.594	5.295	5.729	5.5393	0.0403	0.0245	0.0407	0.0351	0.1155	0.0391	0.0284	0.061
2	11.958	11.718	12.136	11.937	0.0639	0.0396	0.0639	0.0558	0.4739	0.2095	0.2028	0.2954
3	17.267	17.07	17.613	17.317	0.0781	0.0486	0.078	0.0682	0.9208	0.4408	0.4686	0.6101
4	22.6	22.71	22.91	22.74	0.0903	0.0572	0.0896	0.079	1.4801	0.7542	0.8037	1.0127
5	29.5	29.49	30.02	29.67	0.1039	0.0658	0.1034	0.091	2.338	1.2198	1.3991	1.6523
6	34.97	34.77	35.3	35.013	0.1143	0.0724	0.1135	0.1001	3.124	1.6635	1.9208	2.2361
7	40.8	40.53	41.12	40.817	0.1245	0.0793	0.1238	0.1092	4.046	2.145	2.571	2.9207
8	46.16	45.94	46.6	46.233	0.1336	0.0857	0.1333	0.1175	4.982	2.676	3.252	3.6367
9	51.78	51.66	52.24	51.893	0.1435	0.0929	0.1432	0.1265	6.046	3.296	4.007	4.4497
10	57.86	57.73	58.28	57.957	0.154	0.1004	0.1538	0.1361	7.298	4.013	4.903	5.4047
11	63.26	63.17	63.62	63.35	0.1641	0.1077	0.164	0.1453	8.516	4.718	5.757	6.3303
12	68.78	68.5	69.03	68.77	0.1751	0.1156	0.1752	0.1553	9.854	5.463	6.686	7.3343
13	75.44	75.29	75.76	75.497	0.1895	0.1267	0.1903	0.1688	11.604	6.492	7.907	8.6677
14	81.3	81.19	81.77	81.42	0.2044	0.1382	0.2062	0.1829	13.279	7.451	9.054	9.928
15	86.45	86.25	86.89	86.53	0.2192	0.1501	0.2222	0.1972	14.842	8.296	10.08	11.073
16	92.01	91.69	92.42	92.04	0.2384	0.1663	0.2431	0.2159	16.613	9.263	11.186	12.354
17	97.63	97.57	98.11	97.77	0.2614	0.187	0.2696	0.2393	18.54	10.309	12.379	13.743
18	103.55	103.31	103.86	103.57	0.2908	0.2126	0.3014	0.2683	20.72	11.412	13.557	15.23
19	109.66	109.51	110.17	109.78	0.3285	0.2457	0.3418	0.3053	23.18	12.726	14.813	16.906
20	115.41	115.3	115.89	115.53	0.3714	0.2826	0.3861	0.3467	25.74	14.074	15.87	18.561
21	121.18	121.13	121.62	121.31	0.4227	0.3259	0.4397	0.3961	28.68	15.413	16.926	20.34
22	126.67	126.58	127.35	126.87	0.4851	0.3757	0.5034	0.4547	31.97	16.811	17.746	22.176
23	132.16	132.26	132.76	132.39	0.5614	0.4373	0.5789	0.5259	35.65	18.455	18.228	24.111
24	135.45	135.38	136.1	135.64	0.6187	0.4795	0.6349	0.5777	38.36	19.404	18.271	25.345
25	138.1	138	138.73	138.28	0.671	0.5208	0.6892	0.627	40.81	20.16	18.304	26.425
26	141.33	141.26	141.78	141.46	0.7422	0.5749	0.7568	0.6913	43.82	21.37	18	27.73
27	144.53	144.44	144.99	144.65	0.8293	0.6409	0.8433	0.7712	47.42	22.45	17.458	29.109
28	146.89	147	147.6	147.16	0.9064	0.7026	0.9285	0.8458	50.85	22.85	17.326	30.342
29	150.09	150	150.8	150.3	1.0325	0.7974	1.0549	0.9616	55.73	23.95	16.068	31.916
30	153.1	153.01	153.82	153.31	1.1795	0.914	1.2111	1.1015	61.4	24.49	14.932	33.607
31	155.67	155.62	156.37	155.89	1.3361	1.0403	1.3706	1.249	66.42	25.54	13.478	35.146
32	158.11	158.21	158.94	158.42	1.5164	1.1928	1.5664	1.4252	72.58	25.58	12.231	36.797
33	161.35	161.45	162.23	161.68	1.8132	1.442	1.8891	1.7148	82.39	25.5	9.936	39.275
34	164.2	164.32	165.12	164.55	2.121	1.7064	2.227	2.0181	92.42	24.8	8.069	41.763
35	167.12	167.07	167.92	167.37	2.502	2.02	2.618	2.38	103.58	25.89	4.211	44.56
36	169.99	170.15	170.95	170.36	2.957	2.422	3.114	2.831	117.14	25.13	2.077	48.116
37	172.99	173.17	174.02	173.39	3.477	2.87	3.667	3.338	132.95	25.15	-1.742	52.119

First thing is to put everything in P.U. Then the rate of change between each point is determined. Then the ratio of the rate of change is taken. The desired point is where the ratio is 1/5 or 0.2.

V_base=132.79
S_base=833.33
I_base=6.27554

I	V	I% diff	V% diff	V%/I%
0.0056	0.0417			
0.0089	0.0899	58.787	115.5	1.9647
0.0109	0.1304	22.327	45.063	2.0183
0.0126	0.1712	15.829	31.319	1.9786
0.0145	0.2234	15.197	30.475	2.0054
0.0159	0.2637	9.9004	18.009	1.819
0.0174	0.3074	9.1318	16.575	1.815
0.0187	0.3482	7.6381	13.271	1.7374
0.0202	0.3908	7.6576	12.242	1.5987
0.0217	0.4365	7.5318	11.684	1.5513
0.0231	0.4771	6.7617	9.3058	1.3762
0.0247	0.5179	6.9003	8.5556	1.2399
0.0269	0.5685	8.7281	9.7814	1.1207
0.0292	0.6131	8.3532	7.8458	0.9393
0.0314	0.6516	7.7749	6.2761	0.8072
0.0344	0.6931	9.515	6.3677	0.6692
0.0381	0.7363	10.842	6.2256	0.5742
0.0427	0.78	12.089	5.9357	0.491
0.0487	0.8267	13.817	5.9925	0.4337
0.0552	0.87	13.548	5.2408	0.3868
0.0631	0.9135	14.249	5	0.3509
0.0725	0.9554	14.803	4.5806	0.3094
0.0838	0.997	15.643	4.3563	0.2785
0.0921	1.0215	9.8567	2.4548	0.249
0.0999	1.0413	8.5338	1.9414	0.2275
0.1102	1.0653	10.255	2.2997	0.2243
0.1229	1.0893	11.553	2.2598	0.1956
0.1348	1.1082	9.6823	1.7352	0.1792
0.1532	1.1318	13.687	2.1292	0.1556
0.1755	1.1545	14.552	2.0049	0.1378
0.199	1.1739	13.387	1.6807	0.1255
0.2271	1.193	14.107	1.6251	0.1152
0.2732	1.2175	20.318	2.0557	0.1012
0.3216	1.2391	17.691	1.7751	0.1003
0.3793	1.2604	17.931	1.7158	0.0957
0.4511	1.283	18.95	1.7885	0.0944
0.5319	1.3058	17.909	1.7786	0.0993

After spline interpolation, more points are acquired, and the knee point can be acurately determined. It is found in the table below to be 1.0807 V p.u.

I	V	I% diff	V% diff	V%/I%
0.0056	0.0417			
0.0089	0.0899	58.787	115.5	1.9647
0.0109	0.1304	22.327	45.063	2.0183
0.0126	0.1712	15.829	31.319	1.9786
0.0145	0.2234	15.197	30.475	2.0054
0.0159	0.2637	9.9004	18.009	1.819
0.0174	0.3074	9.1318	16.575	1.815
0.0187	0.3482	7.6381	13.271	1.7374
0.0202	0.3908	7.6576	12.242	1.5987
0.0217	0.4365	7.5318	11.684	1.5513
0.0231	0.4771	6.7617	9.3058	1.3762
0.0247	0.5179	6.9003	8.5556	1.2399
0.0269	0.5685	8.7281	9.7814	1.1207
0.0292	0.6131	8.3532	7.8458	0.9393
0.0314	0.6516	7.7749	6.2761	0.8072
0.0344	0.6931	9.515	6.3677	0.6692
0.0381	0.7363	10.842	6.2256	0.5742
0.0427	0.78	12.089	5.9357	0.491
0.0487	0.8267	13.817	5.9925	0.4337
0.0552	0.87	13.548	5.2408	0.3868
0.0631	0.9135	14.249	5	0.3509
0.0725	0.9554	14.803	4.5806	0.3094
0.0838	0.997	15.643	4.3563	0.2785
0.0921	1.0215	9.8567	2.4548	0.249
0.0999	1.0413	8.5338	1.9414	0.2275
0.1102	1.0653	10.255	2.2997	0.2243
0.112	1.0691	1.6723	0.3641	0.2177
0.114	1.0732	1.7857	0.3768	0.211
0.116	1.077	1.7544	0.3597	0.205
0.118	1.0807	1.7241	0.3448	0.2
0.12	1.0843	1.6949	0.3321	0.196
0.1229	1.0893	2.4038	0.4614	0.1919
0.1348	1.1082	9.6823	1.7352	0.1792
0.1532	1.1318	13.687	2.1292	0.1556
0.1755	1.1545	14.552	2.0049	0.1378
0.199	1.1739	13.387	1.6807	0.1255
0.2271	1.193	14.107	1.6251	0.1152
0.2732	1.2175	20.318	2.0557	0.1012
0.3216	1.2391	17.691	1.7751	0.1003
0.3793	1.2604	17.931	1.7158	0.0957
0.4511	1.283	18.95	1.7885	0.0944
0.5319	1.3058	17.909	1.7786	0.0993

Open and Short Circuit Calculations

C

14-01-18 19:27 C:\Users\Slumme\Dropbox\...\Transformer.m 1 of 1

```
clc;clear all;
%Transformer Lab test
%% Open circuit test results - Average of all measurements
V_oc=[133.23;132.903;133.45];
I_oc=[0.4432;0.6141;00.5634];
P_oc=[15.802;19.685;37.953];

%% Short circuit test results - Average of all measurements
V_sc=[5.60667;5.33933;5.786];
I_sc=[3.4043;3.425;3.6503];
P_sc=[18.696;17.712;20.707];

%% Calculations
%per unit base
S_base=2500;
%Per unit base for primary
V_base1=400;
I_base1=S_base/(V_base1*sqrt(3));
Z_base1=V_base1^2/S_base;
%per unit base for secondary
V_base2=230;
I_base2=S_base/(V_base2*sqrt(3));
Z_base2=V_base2^2/S_base;

P_sc_total=P_sc(1)+P_sc(2)+P_sc(3);
P_sc_avg=P_sc_total/3;
P_sc_totalpu=P_sc_total/S_base %copper losses in per unit

V_sc_avg=mean(V_sc); %average of all phases to correct for imbalance
I_sc_avg=mean(I_sc);

V_oc_avg=mean(V_oc); %average of all phases to correct for imbalance
I_oc_avg=mean(I_oc);

X_sc=3*sqrt((V_sc_avg/I_sc_avg)^2-(P_sc_avg/I_sc_avg^2)^2);
X_sc_pu=X_sc/Z_base1 %short circuit reactance in per unit

P_oc_total=P_oc(1)+P_oc(2)+P_oc(3);
P_oc_avg=P_oc_total/3;
P_oc_totalpu=P_oc_total/S_base %eddy current losses in per unit

I_c=P_oc_avg/(3*V_oc_avg);
I_noload=I_oc_avg/3; %divide by three because of delta connection
I_m=sqrt(I_noload^2-I_c^2);
I_m_pu=I_m/I_base2;
I_m_percent=I_m_pu*100
```