ILLUSTRATION OF DISTRIBUTED GENERATION EFFECTS ON PROTECTION SYSTEM COORDINATION

BY

HUSSAIN ADNAN ALAWAMI

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This thesis, written by **Hussain Adnan M. Al-Awami**, under the direction of his Thesis Advisor and approved by his Thesis Committee, has been presented to and accepted by the Dean of College of Graduate Studies, in partial fulfillment of the requirements of the degree of **MASTER OF SCIENCE IN ELECTRICAL ENGINEERING.**

Thesis Committee

Prof. Ibrahim M. El-Amin (Chairman)

M.M. Mansour

Prof. Mohammed M. Mansour (Co-Chairman)

Prof. Mohammed A. Abido (Member)

Dr. Samir H. Abdul-Jauwad

Department Chairmen

Dr. Salam A. Zummo

Dean of Graduate Studies

Date: 17/3/10

To my beloved parents, wife, brothers and sisters

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TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

ABBREVIATIONS

DG	Distributed Generation
OC	Overcurrent
Inst	Instantaneous
Imp	Impedance
PF	Power Flow
SC	Short Circuit
E1L	Electrical One Line
TCC	Time Characteristics Curve
Trans	Transformer
GEN	Generator
REC	Recloser
RLY	Relay
CO-GEN	CO-Generation plant

THESIS ABSTRACT

Name: **Hussain Adnan Al-Awami**

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Environmental concerns, market forces, and emergence of new technologies have recently resulted in restructuring electric utility from vertically integrated networks to competitive deregulated entities. Distributed generation (DG) is playing a major role in such deregulated markets. When they are installed in small amounts and small sizes, their impacts on the system may be negligible. When their penetration levels increase as well as their sizes, however, they may start affecting the system performance from more than one aspect. Power system protection needs to be re-assessed after the emergence of DG.

This thesis attempts to illustrate the impact of DG on the power system protection coordination. It will study the operation of the impedance relays, fuses, reclosers and overcurrent relays when a DG is added to the distribution network. Different DG sizes, distances from the network and locations within the distribution system will be considered. Power system protection coordination is very sensitive to the DG size where it is not for the DG distance. DG location has direct impact on the operation of the protective devices especially when it is inserted in the middle point of the distribution system.

Key Words,

Distributed Generation, Impedance relay, fuses, reclosers, overcurrent relays, power system protection coordination

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ملخص الرسالة

اسم الطالب: **حسين عدنان العوامي**

عنوان الرسالة: **تاثير وحدات توليد الطاقة الكهربائية الموزعة على تنسيق وحدات حماية النظام الكهربائي**

التخصص: **هندسة كهربائية**

تاريخ التخرج: **يونيو 2010م**

نظرا للظروق البيئية والضغوط الاقتصادية ودخول كثير من التقنيات الحديثة في مجال توليد الطاقة الكهربائية مما ادى الى إعادة هيكلة خدمات الطاقة من الشبكات الرأسية الى وحدات صغيرة تنافسية . توليد الطاقة الكهربائية الموزعة يلعب دورا رئيسيا في مثل هذه البيئة . إن تأثير هذه الوحدات قد يكون ضئيلا عندما تدرج في الشبكات الكهربائية بنسب صغيرة الا أن تأثيرها على تنسيق وحدات حماية النظام الكه ربائي يتفاقم مع دخولها الشبكة بنسب وحجم عالية . وبالتالي فإن تنسيق وحدات حماية النظام الكهربائي بحاجة الى إعادة تقييم ودراسة مع وجود وحدات توليد الطاقة الكهربائية الموزعة.

هذه الدراسة بصدد دراسة مدى تاثير وحدات توليد الطاقة الكهربائية الموزعة على تنسيق وحد ات حماية النظام الكهربائي. سوف يكون هناك احجام مختلفة لوحدات توليد الطاقة الكهربائية الموزعة بالاضافة الى مقاومات مختلفة بالنسبة الى الخط الكهربائي الواصل بين وحدة التوزيع والشبكة الكهربائية بالاضافة الى مواقع مختلفة لوحدة التوزيع بالنسبة الى الشبكة الكهربائية ووحدات حماية النظام الكهربائي . هناك علاقة بين حجم وحدة توليد الطاقة الكهربائية الموزعة ووحدات حماية النظام الكهربائي . فكلما زاد حجم وحدة توليد الطاقة الكهربائية الموزعة زاد التاثير على وحدات حماية الطاقة الكهربائية بينما لا توجد علاقة واضحة بين مقاومة الخط الكهربائي الواصل بين وحدة التوزيع والشبكة الكهربائية. بالنسبة الى موقع وحدة توليد الطاقة الكهربائية، فهناك تاثير واضح على وحدات حماية النظام الكهربائي خاصة عندما يكون موقع الوحدة في منتصف الشبكة الكهربائية .

المصطلحات الاساسية:

وحدات تولبد الطاقة الكهربائية الموزعة، تنسيق وحدات حماية النظام الكهربائي ، قاطع التيار الكهربائي، صمامات التيار الكهربائي، مرحلات التيار الكهربائي

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CHAPTER 1

INTRODUCTION

1.1. Overview

Environmental concerns, market forces, and emergence of new technologies have recently resulted in restructuring electric utility from vertically integrated networks to competitive deregulated entities. In a typical deregulated environment, the electrical utility will not be thought of central generation units located at remote places, delivering power to end users' loads via long and high voltage transmission lines in a unidirectional power flow. Rather, it will become an open market offering competition in the generation, transmission, distribution and delivering of electrical energy. It may include various technological power generation facilities that could be sited near or at load centers. These generation facilities are termed distributed generators [1].

1.2. Definitions

Distributed generation (DG) is defined in many ways. These are based on generation capacity, unit rating, and based on voltage levels to which it is connected, the technologies it is utilizing, and technical and non-technical values it is adding to the system. Figure 1.1 depicts these bases.

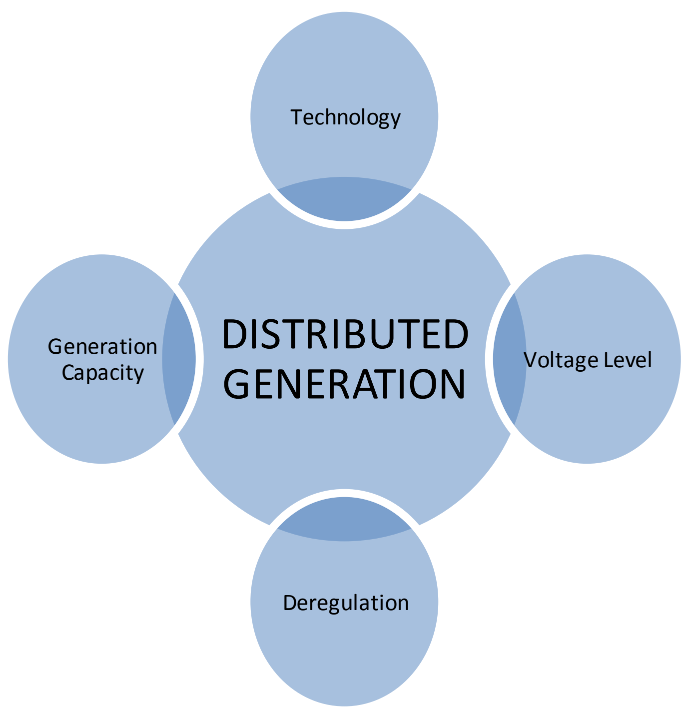

Figure 1.1 Interpretations of DG from Different Aspects

When based on its generation capacity, DG cannot be clearly and consistently defined as there is no certain maximum generation capacity based on which DG could be defined worldwide. For example, DG in Sweden is any generation unit up to 1500kW while in England, the term DG is used for power units with less than 100 MW capacities. In the Australian States of Victoria and New South Wales, a DG is often defined as power generation with capacity of less than 30 MW [1].

Authors generally agree on that DG's are connected near load centers at distribution voltage levels. However, the distribution voltages are not well defined and vary among different utilities. In many cases, there is no separation between voltage levels of distribution and transmission systems. Therefore, the definition of DG based on the voltage levels to which it is connected is not considered an appropriate criterion [1].

The definition of DG is sometimes thought of only those generation units utilizing renewable resources such as wind, ocean waves, solar, and so on excluding those running on fossil fuel gas, nuclear reaction or coal [2]. A DG is also defined based on the tendency toward a competitive environment and changing the way generation companies are doing business. Independent companies are now entering the market running the generation utilities, transmission lines, or distribution networks.

In summary, the term DG is a wide umbrella covering many unlike definitions. Generally, DG is defined as more of the following:

- Facilities located at or near a load center.

- Relatively, small-scale generation units from few kilowatts to few megawatts.
- Generation units based on renewable resources.
- Facilities providing enhanced value other than energy and capacity.
- Residential or commercial back-up generators.

1.3. Advantages

Having understood the principles of a DG and how it is perceived from different angles, one may analyze the potential impacts that a DG has on the grid. Provided that they are carefully selected and investigated, DG units' type of technology, size, location, and operation mode could result in invaluable benefits in system operation. In many cases, it has been concluded that a DG can improve system voltage profile with unit's generation capacity and location playing a vital role in this improvement [3-5]. Moreover, the operation modes of the DG units within the network are also important.

Another important benefit DG is offering is the reduction in line losses. This is due to the fact that a DG participates in relieving transmission lines by delivering active power to loads directly through distribution network [6]. Nevertheless, this is not always true since reverse power flows from larger generation units can increase line losses [5].

Conventional power plants emit many pollutants such as Co_x, NO_x and SO_2, which are directly proportional to the total active power generated. These emissions are contributing

in the global warming and world-wide climate change or what is usually known as "Greenhouse Effect". DG units connected into grid will minimize the dependence on power outputs from conventional generation units and hence reducing emissions. Besides, DG units utilizing *Renewable Resources* will further contribute in emissions reduction [6-7]. A DG has, in contrast, some negative impacts on the environment as well when some technologies, wind turbines and photo-voltaic for instance, need larger area for construction than the conventional plants [5].

1.4. Distributed Generation Technologies

The objectives of this section are to give a quick background on some of existing DG technologies available in the industry and shows comparisons in terms of generation capacities, installation and operation costs of each. The technologies will be discussed separately in individual sub-sections.

1.4.1. Solar Cells or Photo-Voltaic:

Solar cells or Photo- (PV), invented in 1950s, produce electricity from sun light by converting the light beams of the sun into flow of electrons and producing current. Although the current produced is not very high and one needs to install many of these cells together in order to produce enough power, solar cells are very reliable, have no moving parts, and are emission free [8]. Yet, they are very expensive in both capital and installation cost. The power generation costs per kilowatt of PV, for example, could be up to ten times the generation costs by other technologies as shown in Table 1.1 [9].

Table 1.1. Guideline Electricity Generation Costs (cents/kwh) [9]

Combined cycle gas turbine	3-5
Wind	4-7
Biomass gasification	7-9
Remote diesel generation	20-40
Solar PV central station	20-30
Solar PV distributed	20-50

1.4.2. Wind Energy Conversion Systems:

Wind Energy Conversion Systems (WECS) generate electrical power by converting the kinetic energy from the wind into a mechanical energy to drive a generator. WECS, which are normally consisting of two or three blades turbines arranged either vertically or horizontally, are sited at the top of *Wind Towers*. They are constructed and controlled in a way so that maximum power could be extracted from wind taking into account height of the tower, blades radius, aerodynamic characteristics of the blades, and at last the site and topology arrangement of wind turbines inside a *Wind Fam*. Wind farms, sometimes referred to as *Wind Park*, is a tem given for a set of wind turbines grouped together in a specific manner to enlarge size of power generation.

Since the last two decades and power generated from wind is maintaining a rapid increase. According to the American Wind Energy Association (AWEA), an amount of over 180,000 MW generation capacities was installed by end of 2010.

Figure 1.2 demonstrates the growth in wind power generation capacities in USA, Europe and the rest of the world [10].

This increment is a result of the developments in Wind Turbine Generation unit size in term of wind tower height and blades diameter which magnify power extraction. Secondly, the size of installations projects deploying wind turbines as a generation technology is also increasing [11]. Instead of having individual wind turbines, wind farms

with multi tens or even hundreds of wind turbines are erected all over the world delivering power at a wide range of its running capacity.

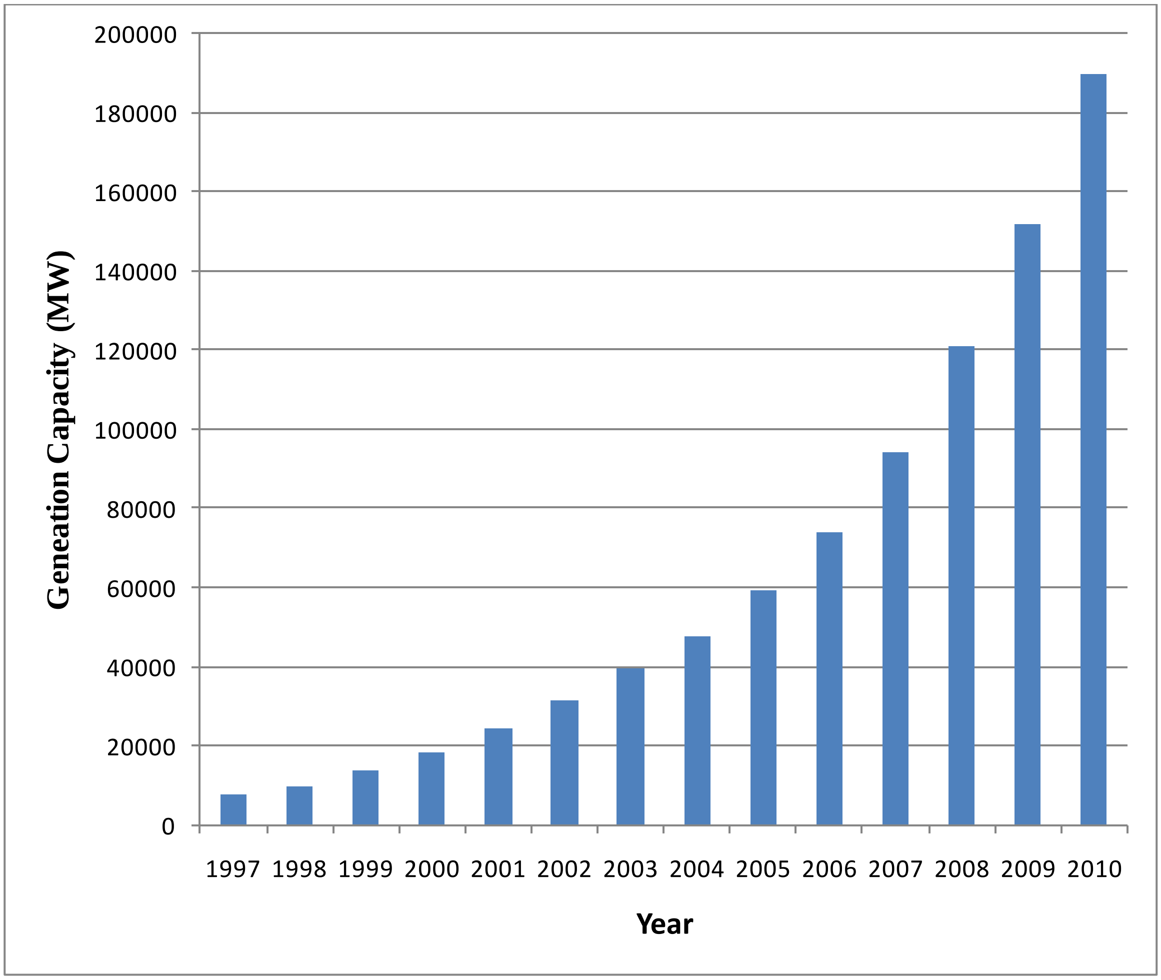

Figure 1.2. World Total Wind Generation Installed Capacity (MW) [10]

1.4.3. Combined Heat and Power Technology (CHP):

In Combined Heat and Power (CHP), the by-product heat that is radiated into atmosphere and wasted in conventional power plants is positively utilized. Additional to being a fuel-efficient energy technology converting around 90% of fuel into energy, CHP offers variety of extra benefits. One of the benefits CHP is offering is the reduction in carbon emissions. It is found that if manufacturers in 1994 had generated steam and electric needs with the existing CHP technology, they would have reduced carbon emissions by around 20% [12]. The wide range sizes of CHP, from few kilowatts to multi-tens of megawatts, is considered another benefit that provides various applications of such technology from small installations at homes up to large industrial plants projects [13].

The installation of CHP in Saudi Arabia is evolving. Saudi Aramco for example has already four CHP plants in operation. The production capacity of these plants is 1,083MW. These plants provide power and steam to Saudi Aramco facilities. Additional co-generation projects are also planned.

Besides PV, CHP and WECS, other possible DG technologies include Internal Combustion Engines, Micro-turbines, Fuel Cells, Hydro-Power Generators, and Geothermal Energy. Details about these technologies could be found in [7-16]. Table 1.2 highlights major characteristics of some of DG technologies.

Table 1.2. Summary of Present Costs and Uses of Distributed Generation Technologies

Characteristics	Internal Combustion Engine	Wind Turbine	Microturbines	Fuel Cell	Photo-Voltaic
Size Range (kW)	50-5000	50-2000	25-75	2000-5	1-100
Current Installed Cost ($/kWh)	200-500	1000 -1500	1000 -1500	3000-4000	1500-6500
Electricity Cost (/kWh)	5.5-10	5.5-15	7.5-10	15-20	15-20
Applications	Back-up Power, Peak Reduction	Green Power, Remote Locations	Back-up Power, Peak Reduction	Power Quality, Base Load	Stock Watering, Grid Independence

1.5. Thesis Motivations

As a result of increasing environmental concerns, the impact of conventional electricity generation on the environment is being minimized and efforts are made to generate electricity from renewable sources. The main advantages of electricity generation from renewable sources are the absence of hazardous emissions and the infinite availability of the prime mover that is converted into electricity. Renewable sources might be from wind Turbines and Photo-Voltaic, for example.

This increase in the application of the DG has prompted researchers to look into the role of the DG's into the power system. Researchers have addressed several issues related to the DG's. This thesis is concerned with the impact of the DG on system protection.

The analysis of the impact of Distributed Generators distances, sizes, and locations on the protection of electrical power system is warranted as it effects the overall system operation. It will provide guidelines and procedures to integrate DG's into the power system without adverse effect.

1.6. Thesis Objectives

The objectives of the thesis would be;

- Apply a complete protection coordination of typical industrial power system.
- Study the effects on the coordination of the protection system when a co-generation plant is added to this network and comes up with corrective actions if any.
- Study the effects on the coordination of the protection system when a distribution generation is added to this industrial power system network.
- Study the role of different sizes, locations, and the distance of the DG from the network on the system protection.
- Document the role of the DG on the system protection.

1.7. Thesis Organization

This thesis is organized as follows. First, a literature survey in chapter 2 will present previous work related to DG impacts on protection system coordination.

In chapter 3, a complete coordination study will be conducted on an industrial power system all the way from the receiving substation (230kV) to the 13.2kV loads. Chapter 4 will consider the addition of a Co-Generation plant connected to the receiving substation and the coordination study will be assessed.

In chapter 5, a distribution generation will be connected to this industrial power system. The effects of adding this DG on the protection system will be studied.

Chapter 6 will consider the impact of the different sizes of this DG as well as the distance of this DG from the network. Also, different location of DG with respect to the network will be analyzed. Finally, chapter 7 will have the conclusions and the future work.

CHAPTER 2

LITERATURE SURVEY

2.1. Power System Protection

Basic power system protection principles are documented. The primary purpose of power system protection is to ensure safe operation of power systems, thus to care for the safety of people, personnel and equipment. Furthermore, the task is to minimize the impact of unavoidable faults in the system. From an electrical point of view, dangerous situations can occur from overcurrents and overvoltages.

For example, an asynchronous coupling of networks results in high currents. Earth faults can cause high touch voltages and therefore endanger people. Hence, the aim is to avoid overcurrents and overvoltages to guarantee secure operation of power systems.

For the safety of the components, it is also necessary to consider device specific concerns, for example oil temperature in transformers, gas pressure in gas insulated components etc. These points are not directly related to electrical values, but, as mentioned, they always come from or lead to unacceptable high voltages or currents.

Another issue is mechanical stress. An example is mechanical resonance of steam turbines due to underfrequency.

Nowadays, electromechanical protection devices are replaced by microprocessor based relays with a number of integrated features. Currents and voltages are suitably transformed and isolated from the line quantities by instrument transformers and converted into digital form. These values are inputs for several algorithms which then reach tripping decisions.

For the design and coordination of protective relays in a network, some overall terms have become widely accepted [17]:

Selectivity: A protection system should disconnect only the faulted part (or the smallest possible part containing the fault) of the system in order to minimize fault consequences.

Redundancy: A protection system has to care for redundant function of relays in order to improve reliability. Redundant functionalities are planned and referred to as backup protection. Moreover, redundancy is reached by combining different protection principles, for example, distance and differential protection for transmission lines.

Grading: For the purpose of clear selectivity and redundancy, relay characteristics are graded. This measure helps to achieve high redundancy whereas selectivity is not desirable.

Security: The security of a relay protection system is the ability to reject all power system events and transients that are not faults so that healthy parts of the power system are not unnecessarily disconnected.

Dependability: The dependability of a relay protection system is the ability to detect and disconnect all faults within the protected zone.

Different network topologies require different protection schemes. In the following paragraphs some typical system is described briefly. The simplest network structure to protect are radial systems, therefore simple relays are used. Normally, time-dependent, graded overcurrent protection is installed regarding redundancy (backup protection). More sophisticated relays are used for the protection of rings and meshed grids. Impedance relays trip due to a low voltage-current quotient. Since these relays allow determining the position of the fault on the line, they are also called distance relays. A very common principle for the protection of generators, transformers, busbars and lines is differential protection. The triggering criteria is a certain difference between input and output current. Furthermore, a number of other techniques are used also device-specific ones [17].

2.2. Preliminary Design

The designer of an electrical power system should first determine the load requirement, including the sizes and types of loads, and any special requirements. The designer should also determine the available short circuit current at the point of delivery, the time-current curves and settings of the nearest utility protective devices, and any contract restrictions on ratings and settings of the protective relays or other overcurrent protective devices in the user's system.

Figure 2.1 shows the sequence of steps in system protection and coordination [18].

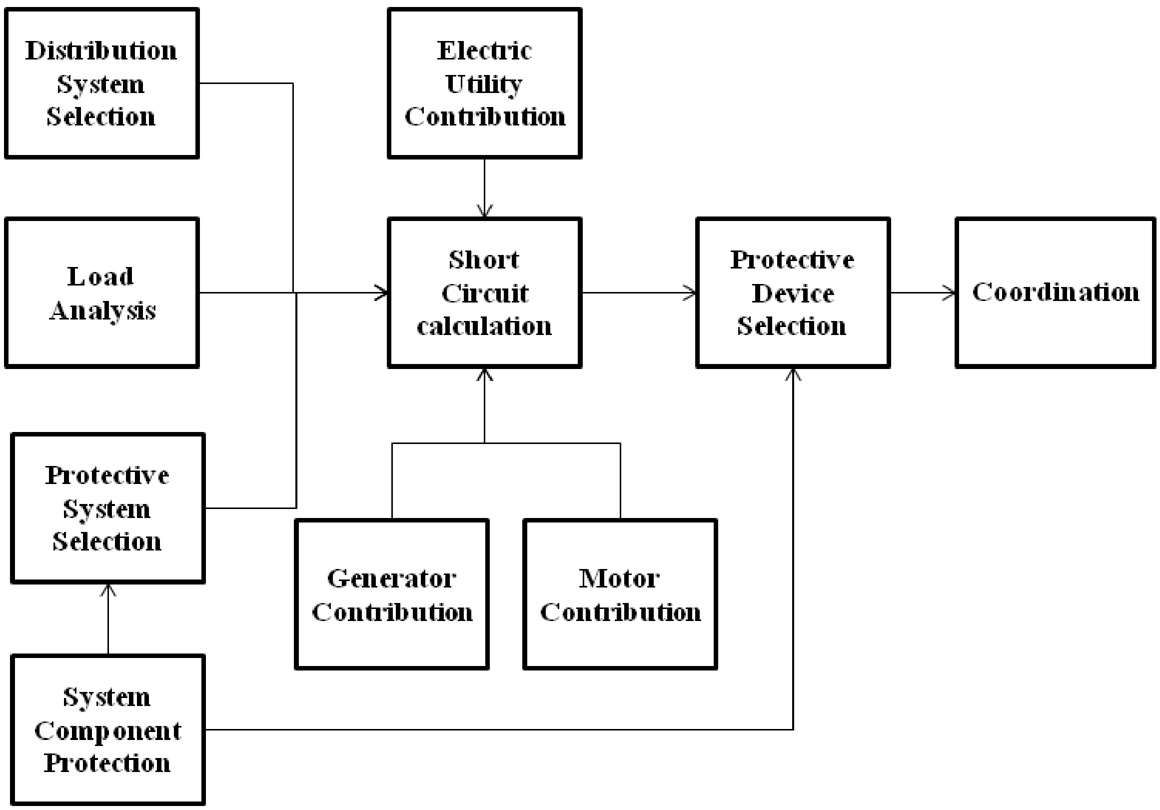

Figure 2.1. Sequence of Steps in System Protection and Coordination

2.3. Basic Protective Equipment

The isolation of short circuits and overloads requires the application of protective equipment that senses when an abnormal current flow exists and then removes the affected portion from the system. The three primary protective equipment components used in the isolation of short circuits and overloads are fuses, circuit breakers, and protective relays.

A fuse is both a sensing and interrupting device, but not a switching device. It is connected in series with the circuit and responds to thermal effects produced by the current flowing through it. The fusible element is designed to open at a predetermined time depending upon the amount of current that flows. Different types of fuses are available having time-current characteristics required for the proper protection of the circuit components. Fuses may be noncurrent-limiting or current-limiting, depending upon their design and construction. Fuses are not resetable because their fusible elements are consumed in the process of interrupting the current flow.

Circuit breakers are interrupting and switching devices that require overcurrent elements to fulfill the detection function. In the case of medium-voltage (1–72.5 kV) circuit breakers, the sensing devices are separate current transformers (CTs) and protective relays or combinations of relays [18].

2.4. Challenges to Protection of Distribution Networks to Distribution Generation

Widespread distributed generation may be incompatible with conventional distribution system protection approaches. Some of the most commonly mentioned challenges to adding DG's to the distribution network are the following [19]:

- Unintentional islanding with concerns about reliability, safety and power quality. Especially when automatic reclosing is applied, even momentary islanding can be very detrimental. Anti-islanding protection is regarded as one of the most challenging question to be solved in the field of distributed generation.
- The operation of DG units can cause failure of the protection system. Fault current produced by DG units may reduce the current seen by a feeder relay. This is referred to as protection under-reach.
- Distributed generation may cause unwanted operation of protection. DG units may cause tripping of healthy feeders in adjacent feeder faults.
- Distributed generation may require upgrading the primary substation busbar protection. In a busbar fault, it is no longer adequate to trip only the infeed from the HV/MV transformer, because there are fault current sources also in the feeders. The existence of DG may also require changes in protection interlocking.
- Nuisance tripping of production units.
- Fault level of networks changes. There may be significant variations in fault level of a certain part of the network, depending on the number and type of generators operating. An increase of fault level may require an upgrade of switchgear; on the other hand, a decrease of fault level may cause problems to overcurrent protection.

- Voltage problems may arise. Overvoltage caused by reverse power is a typical problem. Undervoltage may arise because of common mode tripping of DG or by delayed fault clearing[19].

2.5. Distribution Generation and Automatic Reclosing

One challenge for adding the distribution generation is where there is automatic reclosing in the system protection. In medium voltage overhead networks, automatic reclosing is widely used and a very effective method of fault clearing. Figure 2.2 illustrates the importance of automatic reclosing according to a Finnish study. Most of cleared faults are temporary faults. The best way to clear such faults are by using high speed autoreclosers [19].

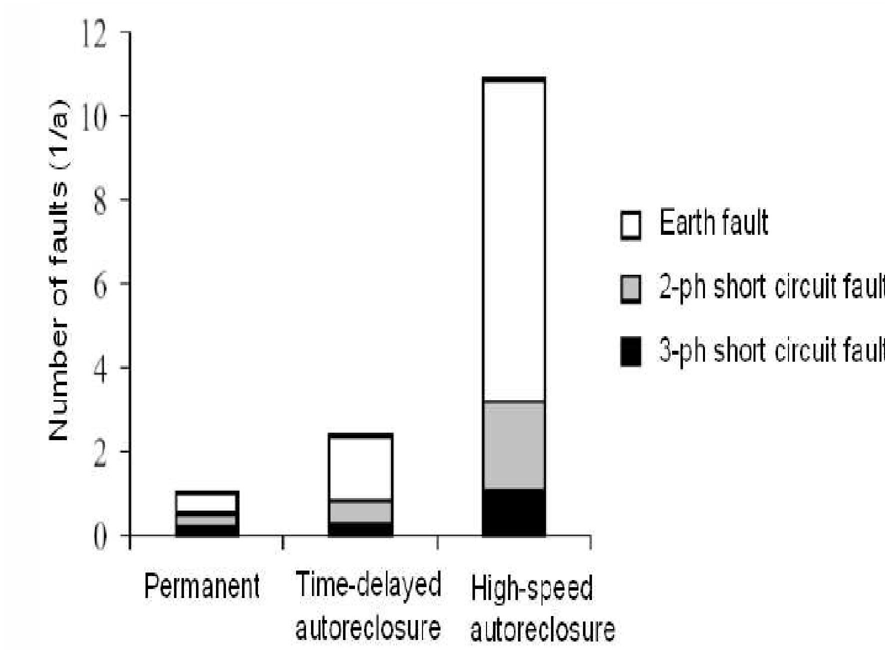

Figure 2.2. Share of Different Faults and Fault Clearing by Automatic Reclosing in Finish Overhead Networks [19].

Figure 2.3 illustrates the principle of reclosing by showing fault current and the autoreclose open time, and after the successful reclosing attempt, the normal load current of the feeder. The purpose of the dead time is to stop the current so that the fault arc can extinguish and the arc path can de-ionize. If sufficient time is not allowed for the gas to disperse, the ionized-gas path will start conducting again after the autoreclose [19].

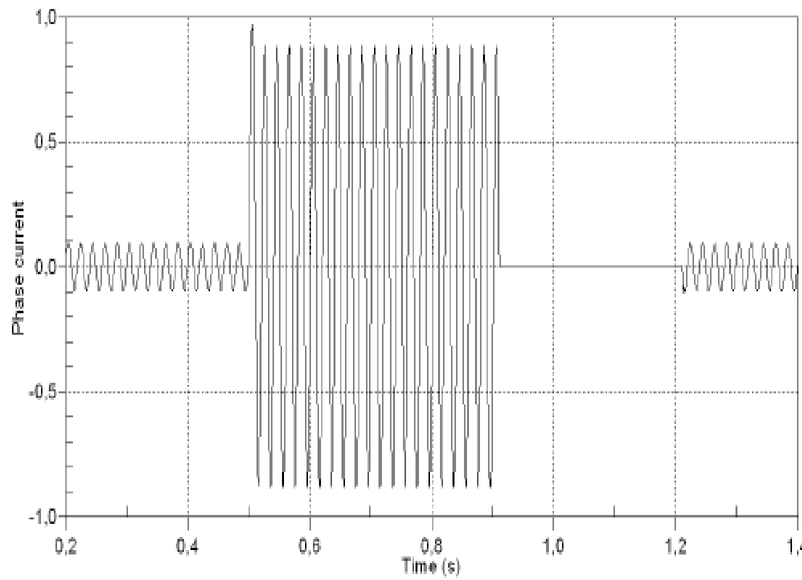

Figure 2.3. **Principle of Automatic High Speed Reclosing [19].**

2.5.1. Automatic Reclosing and Anti-Islanding Requirements

Different countries and network companies have their own standards defining allowed operating times for anti-islanding protection. In most cases there is a separate strict requirement for systems using automatic reclosing. Although IEEE Standard 1547 allows 2 seconds for islanding detection and distributed resources (DR) disconnection, there is a special requirement: “The DR shall cease to energize the Area electrical power system (EPS) circuit to which it is connected prior to reclosure by the Area EPS”. In the USA, the autoreclose open time can be as short as 0.2s but it can be several seconds as well. In the Nordic Countries the open time in high-speed autoreclosing is typically 0.3 seconds. This requires that the anti-islanding protection must operate very rapidly if it is going to disconnect DG units clearly before the reclosure. The speed requirement makes reclosing coordination and anti-islanding protection very challenging [19].

2.5.2. Main Impacts of Distributed Generation on Automatic Reclosing

Automatic reclosing is easily implemented in radially fed networks. The presence of distributed generation units in the feeder means that there are several sources of fault current, and reclosing can lose its effect. The DG units may sustain feeding fault current during the autoreclose open time prohibiting the intended arc extinction. The fault that would have been temporary becomes permanent. The quality of supply deteriorates, and utility equipment will experience prolonged arcing which can lead to shortened life and expensive repairs. The voltage level necessary to sustain the arc is small.

In addition to prevention of successful reclosing, the existence of DG may lead to out-of-phase reclosing. During the autoreclose open time the DG generators may accelerate or slow down so that at the moment of reclosing, in the worst case there is phase opposition between the islanded part of the network and the feeding grid. This can lead to serious current, voltage or torque transients. Damage to both DG units and network components are possible. Although there is little documentation of actual damage to turbine-generators, cumulative impact of these stresses must be taken into account [19].

2.6. Distributed Generation and Under-Reaching/ Over-Reaching of Relays

Each relay in a protection system has a set of settings that will determine the primary and backup protection schemes. The settings for each relay are calculated so that the relay fulfils the primary and backup requirements of the network. Calculations are based on the maximum load current, the maximum and minimum fault currents and/or the impedance of feeders that the relay is protecting. Connecting distributed generation to a distribution network can affect the local protection system [20].

2.6.1. Under-Reaching of Relays

Depending on the distribution generation location, its capacity and the strength of the network to which it is connected to, it may cause some relays to under-reach. To illustrate this consider the following example which is based on the model 38kV radial network shown in the Figure 2.4, where [20]:

Source Impedance + Impedance of the line from A to B:

$$Zsource = 6.499+13.89j\Omega$$

Embedded Generation Impedance:

$$Z_{Gen} = 1.591+37.305j\Omega$$

Impedance of Line from B to C:

$$Z_{BC} = 4.347 + 4.42j\Omega$$

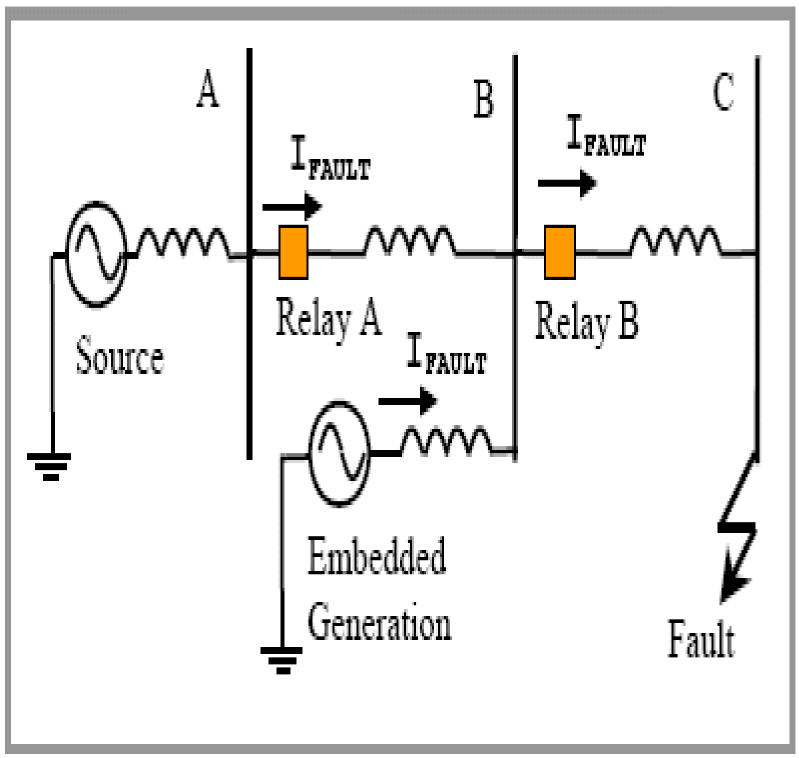

Figure 2.4. Model 38kV Radial Network with Distributed Generation **[20].**

Before the distributed generation is connected to 38kV feeder at busbar B, the fault current for a fault at busbar C, assuming a 1.07 p.. pre-fault voltage, is :

$$I_{Fault} = \frac{System\ Voltage\ 1.07}{\sqrt{3}.(Z_{Source} + Z_{BC})} \approx 1102\angle 59^{o}\ A/\ phase \tag{2.1}$$

where system voltage is 38kV

Therefore, the relay at busbar A can be set to provide backup protection for the relay at busbar B by setting the relay to trip for faults above 1102 Amps.

Adding the distributed generation at busbar B means the total fault current for a fault at busbar C is now:

$$I_{Fault} = \frac{System\ Voltage\ 1.07}{\sqrt{3}.(Z_{Parallel} + Z_{BC})} \approx 1393\angle 62^{o}\ A/\ phase \tag{2.2}$$

Where, Parallel is the impedance of the parallel combination of Z_{Source} and Z_{Gen}.

The total fault current is composed of the following contributions from both the source and the distributed generation:

$$I_{Fault} \approx 1004\angle 56^{o}\ A/\ phase \tag{2.3}$$

$$I_{Generation} \approx 412\angle 78^{o}\ A/\ phase \tag{2.4}$$

This example shows that, while the addition of the distributed generation has increased the total fault current, the current contribution from the source has decreased from 1102Amps to 1004Amps. As a result of the decrease in fault current, the relay at busbar A may not trip in the required time. The connection of distributed generation causes a protection relay to under-reach and as such the required fault clearance time for the backup protection is no longer provided [20].

2.6.2. Over-Reaching of Relays

The previous 38kV radial network can also be used to demonstrate how the presence of distributed generation can cause a relay to over-reach. Before the connection of the distributed generation, the fault current for a fault at busbar C is $1102\angle 62^{o}$ A/phase. Therefore, if the protection relay at busbar B is an overcurrent relay or an overcurrent started impedance relay, the distributed generation could cause the relay to over-reach [20].

2.7. Distributed Generation Islanding Protection

DG units are typically not designed for feeding the public network alone. Thereby, a DG unit maintaining the voltage in a part of the networks results in severe consequences. First of all, it may result in safety hazards to the network personnel as the network is assumed to be de-energized after disconnecting the feeder breaker at the substation [21].

More generally, the DG unit is not capable of maintaining an acceptable level of power quality in the network, which may result in disturbances and equipment damages. The islanding protection is also essential for the DG unit itself, as the returning voltage after the reclosing or islanding results in out-of-step reconnection which stresses the mechanical structure of the unit. Circuit breaker equipment may also be damaged during out-of-step reconnection [21].

For these reasons, it is essential to disconnect DG units rapidly during islanding. DG must also remain disconnected until the connection to the main grid is restored. Distribution network operator (DNO) is responsible for the safety of the network. Thereby DNO should also be able to require proper protection devices and protection settings from the power producer. However, the operation of DG protection is, in many cases, difficult to assess from the DNO's point of view. The increasing amount of DG is complicating the islanding protection as the systems become more capable of operating islanded. Modern DG unit may also be more capable of maintaining the island by means of their efficient control methods [21].

It must be noted that whereas unintended islanding are not allowed, a planned islanding represents a totally new possibility for the power system reliability. New methods are needed to utilize the DG units during longer interruptions in the future. Currently, there are four islanding detection methods as coming in the followings sections.

2.7.1. The Problematic Nature of Islanding Detection

Detection of islanding situation is a difficult issue to estimate in forehand. The possibilities of reliable detection are determined by the circumstances under which the formation of island occurs. In the most typical case, the DG unit is not able to feed the islanded part of the network alone, voltage and frequency collapse and the situation is detected easily. Similarly, DG unit may also feed too much power resulting in overvoltage which can be easily detected. Generally, as long as the generation does not match the momentary loading too precisely, an island can be detected.

The fundamental problem can be deduced from the previous phrase. If the load of the island matches the generation of the DG unit(s), voltage and frequency may remain in their limits. Thus the network may remain islanded. In a distribution network with varying loads, the perfect load-generation balance is theoretically possible in most cases. As the DG output also varies according to the energy resource, the possibility of balance

is difficult to assess. Depending on the variation of loading and generation and on the dynamical behavior of the generator, the island may be formed only momentarily or for a longer period. However, even a momentary islanding can be easily result in failed reclosing and out-of-step switching as mentioned earlier [21], [22].

A mismatch in active power balance is manifested as frequency variation. Similarly, reactive power imbalance results in voltage deviations. Thus, frequency and voltage relays form the traditional form of islanding detection. In most situations, this is adequate also in present installations. However, the no-detection zone (NDZ) of these relays is significant and may thus allow islanding at least momentarily. Figure 2.5 shows the non-detection zone of typical voltage and frequency protection.

As a solution to problems described, dedicated islanding detection techniques have been developed. They offer at least smaller NDZs making undetected islanding even less probable however; the theoretical case of perfect load-generation balance remains unsolved at the moment. These modern islanding detection techniques can be divided to passive and active methods.

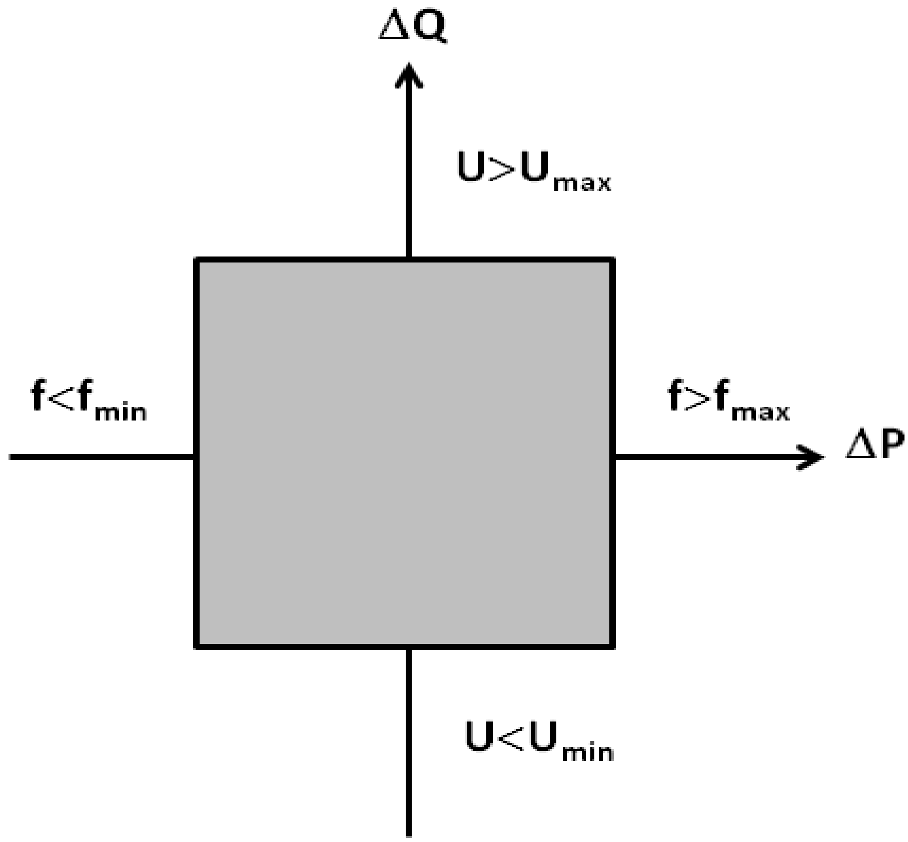

Figure 2.5. The None-Detection Zone of Typical Voltage and Frequency Protection

2.7.2. Passive Methods

Passive methods refer to simply measuring different electrical values at the DG unit's point of common coupling (PCC). These values are used – further processed or as –such – to recognize the formation to the islanded operation. Practically passive methods mean protection relays installed in the PCC. Under-/overvoltage and under-/overfrequency are the most traditional examples[21].

Probably the widely used method is called ROCOF (rate of change of frequency), which is based on continuously calculating the gradient of frequency. The gradient is calculated over few cycles and compared with its defined threshold. ROCOF is able to respond to smaller frequency deviations according to their steepness. Typical operation settings for ROCOF are between 0.1-1.0 Hz/s with an operation time of 0.2-0.5 s [21].

Another new methods is called vector surge or vector shift (VS). VS relay based on measuring the an comparing the cycle durations. By comparing the measured duration with the previous one, the islanding situation can be detected. The difference depends on the balance of active power in the PCC. It can be seen that VS operation reminds frequency protection as it actually measures frequency. However, the essential difference is that whereas frequency is compared to predefined reference value, VS relay uses the previous cycle as a reference. Thereby VS relays are able to detect islandings very fast, within a cycle. Hence there are often operated without time delays. Typically VS settings are between 8^o-12^o [21].

2.7.3. Active Methods

Active methods are called "active" as they are based on making continuously small changes in the state of the PCC and observing the response of the system. The measured response is used to deduce whether the DG units is operating in island or not. The idea is that the protection tries to force the DG unit outside its operation thresholds, which contrives when the DG unit is disconnected from the public network [23][24].

Active methods are typically implemented in inverter applications, as the inverter is suitable for introducing small changes e.g. in the current waveform fed to the network. Typical active methods include for instance impedance measurement, in which the voltage of the PCC is observed for small current changes. Active methods are not allowed in all networks as they are thought to disturb the network and to result in reduced power quality of the system [21], [25].

2.7.4. Systems Based on Communication

As a third type of islanding detection methods, communication systems are frequently highlighted. As the island is practically always formed through the operation of breakers in the network, it would be reasonable to control the DG unit to disconnect simultaneously. This would require a fast and reliable communication between he DG unit and the operating relays. SCADA system could be used to provide this connection. Permanent Internet Protocol (IP) connection that are used for measurements and condition monitoring could be utilized where available. Wireless connection based on GPRS, radio links or equivalent systems might be used [21].

A novel approach for arranging the communication is the usage of carrier-signal on distribution lines. The idea is based on feeding a contiguous high frequency carrier signal to the substation's busbar. This signal will then propagate on all feeders fed by the substation. The DG unit located in the network considers the signal as a guard signal which enables the generation. As the feeder breaker opens, the connection to the substation is lost and the signal will also disappear. The system requires a transmitter at the substation and receivers at the DG units. In the case of longer lines, repeaters may also be needed [21].

The most challenge regarding the communication methods is the operating relays of data transfer. The reliability and robustness also needs to be assessed. For carrier-signal systems, the challenge lies in managing other network disturbances and long lines [21].

CHAPTER 3

COORDINATION STUDY OF INDUSTRIAL POWER SYSTEM

3.1. System Overview

In this chapter, a complete coordination study will be conducted on an industrial power system fed by two 230kV utility lines. The length of each line is approximately 6km. Line 1 and line 2 supply bus1 and bus2 respectively. These two buses are connected through normally closed (NC) tie breaker to avoid any load interruption if one line is lost.

The main substation consists of six transformers each is 90MVA, 230/13.2kV. The utility is represented by an equivalent 60,000MVA_{SC} and X/R of 66. Every two transformers make up a double ended substation with normally open (NO) tie breaker. In case of losing one transformer, the other transformer would pick up the entire load connected to such substation. The total load of this industrial power system is around 265MVA. Figure 3.1 shows the single line diagram.

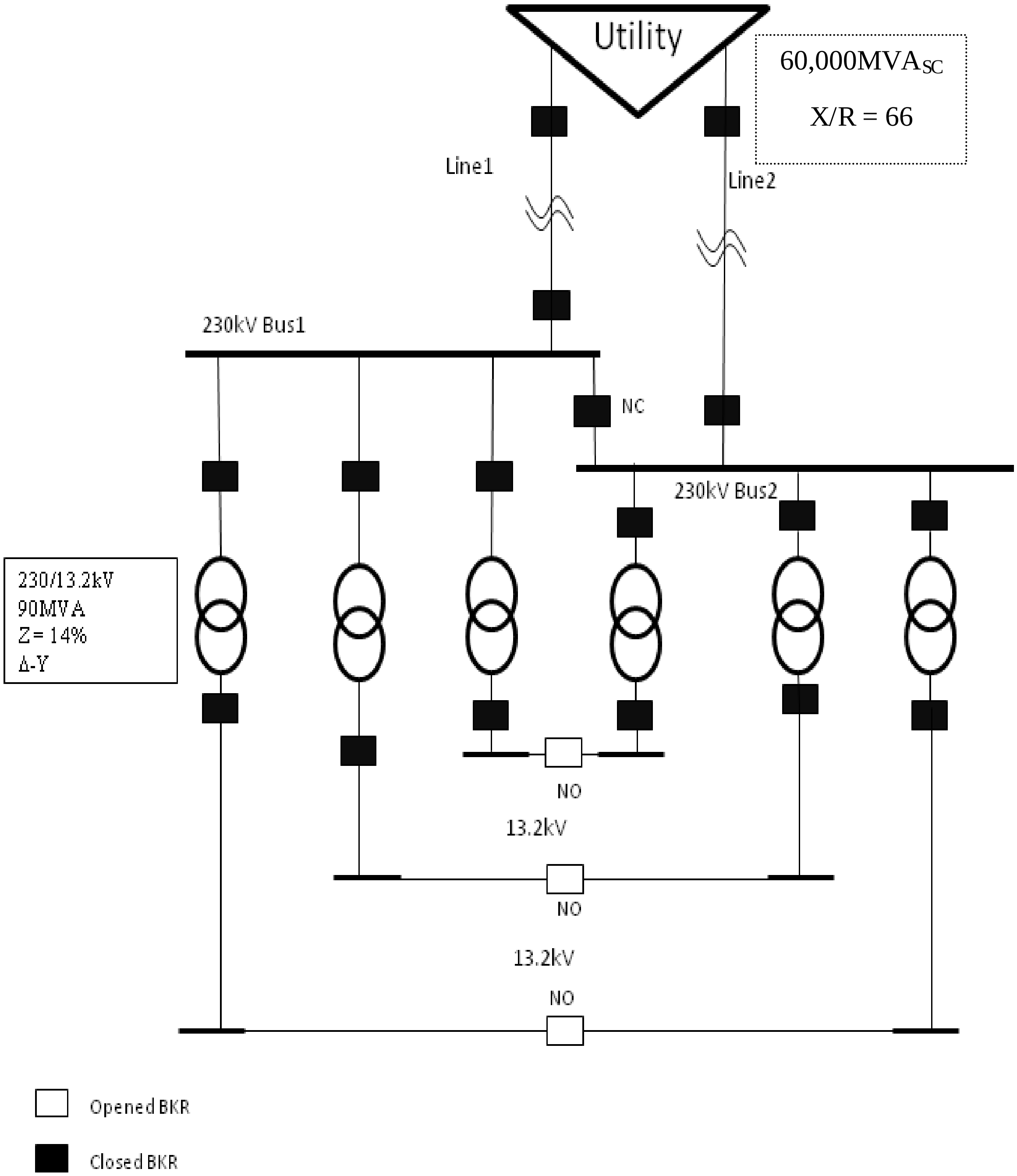

Figure 3.1. Single Line Diagram of the Industrial Power System

The objective here in this section of the thesis is to conduct a complete coordination study of the above system. The following points need to be noted;

- The 13.2kV switchgears are double ended configuration with NO tie breakers. Only one switchgear that includes bus 1 and bus 2 will be considered. The other two switchgears are exactly the same. The loads fed by these substations are assumed to be static loads for simplicity.
- Substation transformers are protected by differential and 50/51 overcurrent relay.
- The 230kV bus 1 and bus 2 are connected by NC tie breaker. Every bus is protected by two bus differential relays (87B); primary and secondary protection. Only the primary differential relay will be shown. Also, there are two overcurrent directional relays on the tie breaker to be coordinated with the feeders connected to that bus.
- The 230kV transmission lines are protected by differential relay (87L) and distance protection relay (21) in addition to the overcurrent relay.
- The coordination time between overcurrent relays protection is 0.35 seconds.
- The ground protection is not considered. Once the phase protection is applied and coordinated, it is easy to apply the ground protection. Also, Δ-Y transformers isolate the ground faults at their secondary from their primary due to their configuration. The ground currents will circulate in the Δ connection of the transformer.
- The software used for this coordination study is ETAP (Electrical Transient Analysis Program) which is produced by Operation Technology Inc (OTI), USA [26].

3.1.1. Modeling the Distance Relay

Since the impedance of a transmission line is proportional to its length, for distance measurement it is appropriate to use a relay capable of measuring the impedance of a line up to a predetermined point (the reach point). Such a relay is described as distance relay and is designed to operate only for faults occurring between the relay location and the selected reach point, thus giving discrimination for faults that may occur in different line sections.

The basic principle of distance protection involves the division of the voltage at the relaying point by the measured current. The apparent impedance so calculated is compared with the reach point impedance. If the measured impedance is less than the reach point impedance, it is assumed that a fault exists on the line between the relay and the reach point. Figure 3.2 shows typical zones settings of the distance relays.

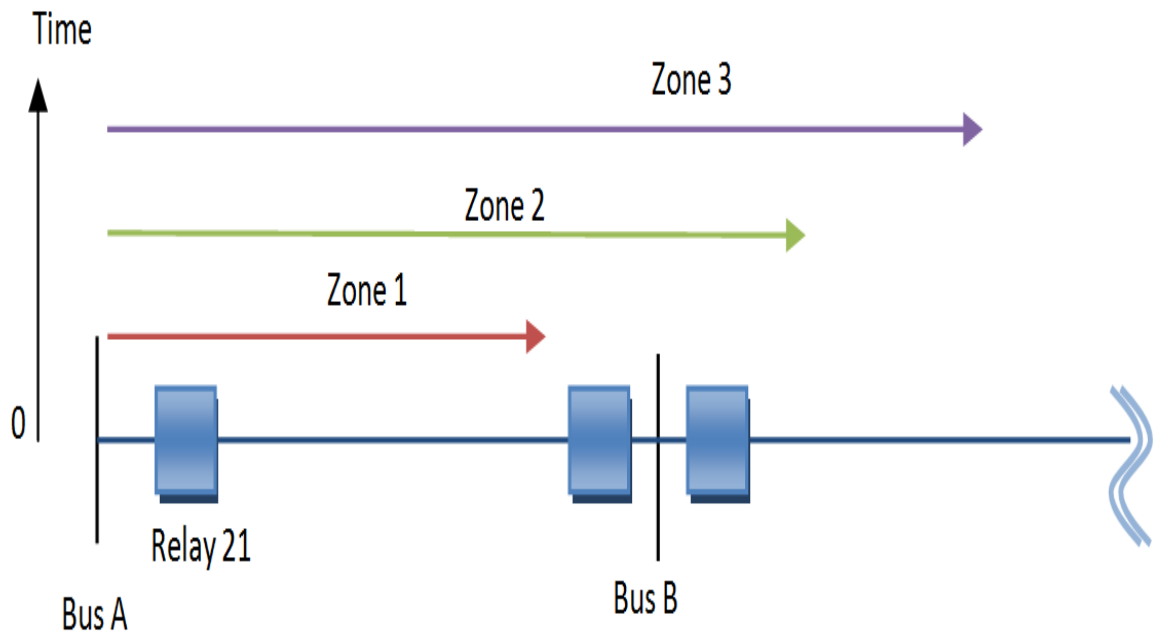

Figure 3.2. Typical Distance Relay Zones Settings

The software used in this thesis (ETAP) does not have a distance relay model in its library. It is therefore essential to create a distance relay model.

Each zone will be modeled by one instantaneous O/C relay by setting the pickup value and the time delay for that zone. For example, zone1 operates usually at 20msec. It is used to protect the line for the faults up to 80% of its length. As the faults is closer to the relay, the fault current increases. Thus, the instantaneous O/C relay could be set to pickup for fault currents more than that value at 20msec operating time. This could be used for the other zones. Figure 3.3 shows the TCC curves generated by the software.

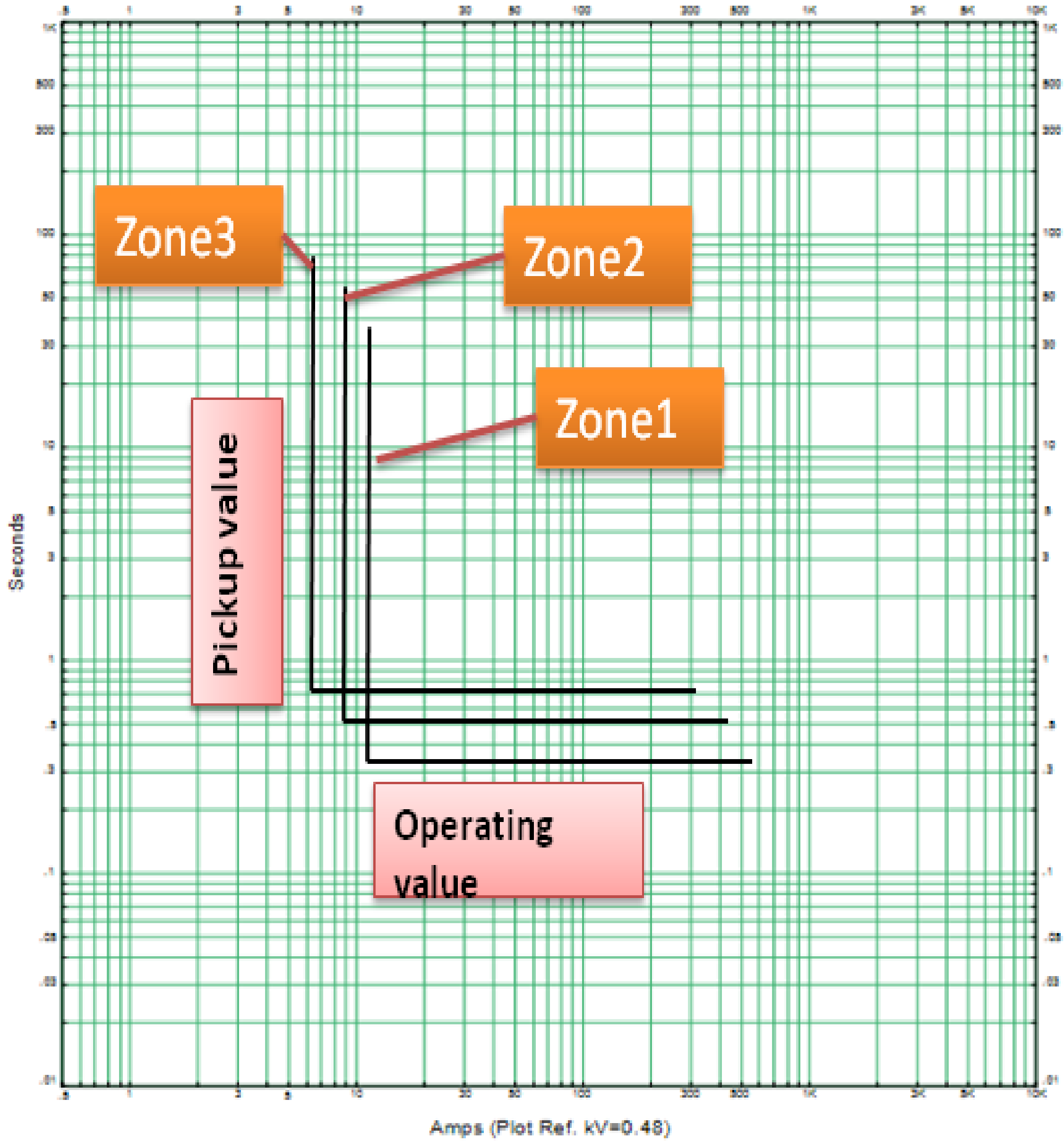

Figure 3.3. Modeling the Zones of the Distance Relay Using Instantaneous Overcurrent Relay in ETAP

3.2. Steady State Analysis

This section will conduct the power flow analysis of the proposed system. The worst scenario will be considered. Only one 230kV transmission line is in service. The load is distributed among three transformers only. Table 3.1 and Figure 3.4 shows the steady state power flow results of the system.

It is worth to mention that the power transformers are auto-tap power transformers. The transformers change their ratios to provide the loads at the secondary buses with the required voltage level. Otherwise, the voltage at the 13.2kV buses would be less than the minimum acceptable value which is 95%. This confirms the validity of the transformers and lines sizes for feeding the industrial loads at acceptable voltage level.

Table 3.1. Steady State Power Flow Results of the Industrial System

Utility Total Power Generation (MVA)	Load Total Power Consumption (MVA)	230kV Voltage Level	Minimum Load Voltage Level
210	200	99.5%	99.7%

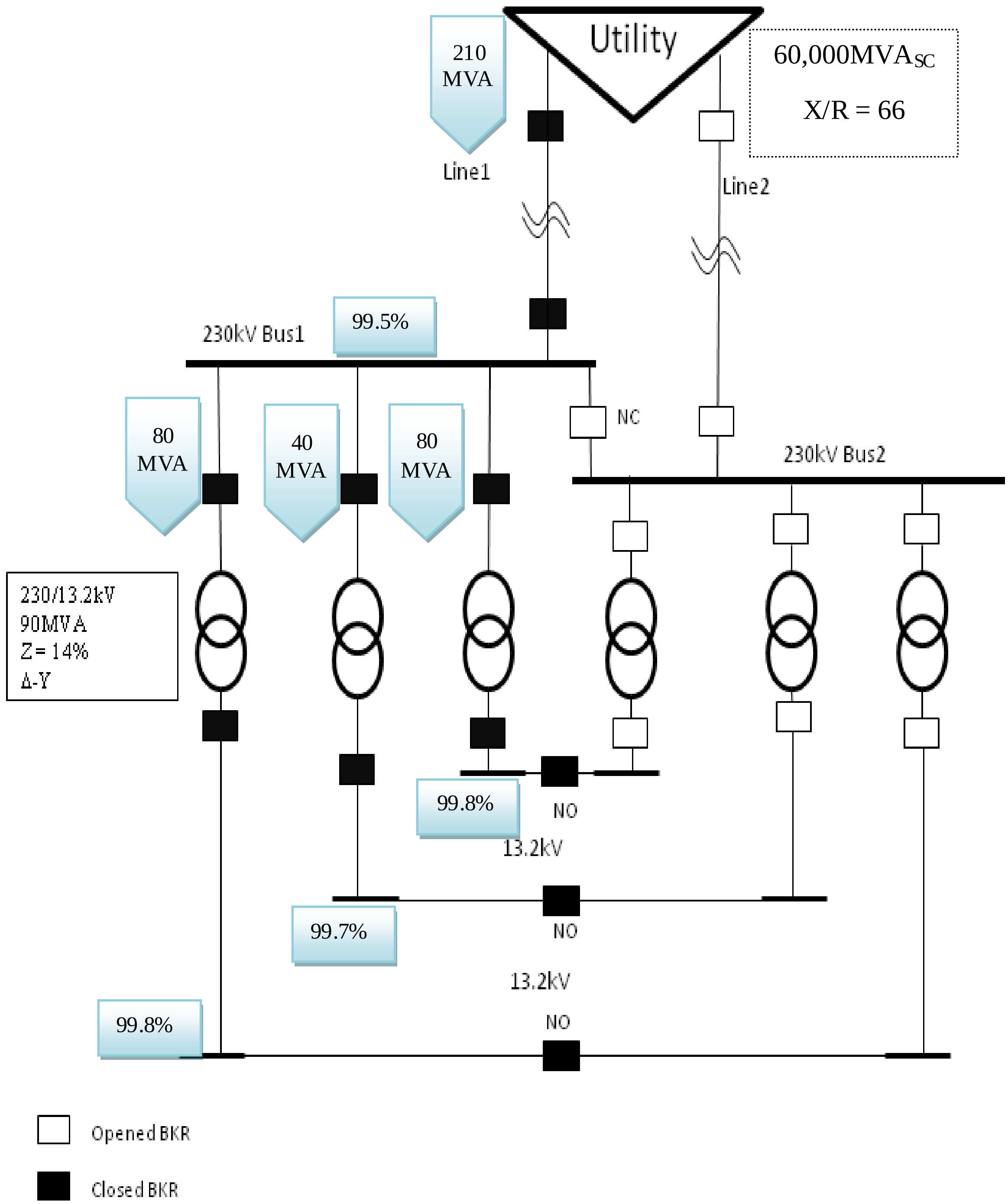

Figure 3.4 Steady State Results

3.3. Short Circuit Analysis

This section will show the available short circuit level at the 230kV and 13.2kV buses. Short circuit studies are used to size the circuit breakers and the switchgears. It is also used by the protection engineers for settings the protection devices in the system. Only three phase faults will be considered. Ground faults on the secondary side of the transformer are not reflected on the primary side of the transformers due to the Δ-Y connection of the power transformers.

For the short circuit study, all sources for short circuit current are assumed to connected to observe the highest short circuit current available in the network. The two utility 230kV lines will be in service during the study. Table 3.2 and Figure 3.5 show the available short circuit current at the 230kV and the 13.2kV buses.

Table 3.2. Available Short Circuit in the Power Industrial Network

Faulted Bus	Fault current (kA)	MVA short circuit
230kV	71.5	16445
13.2kV	30.5	403

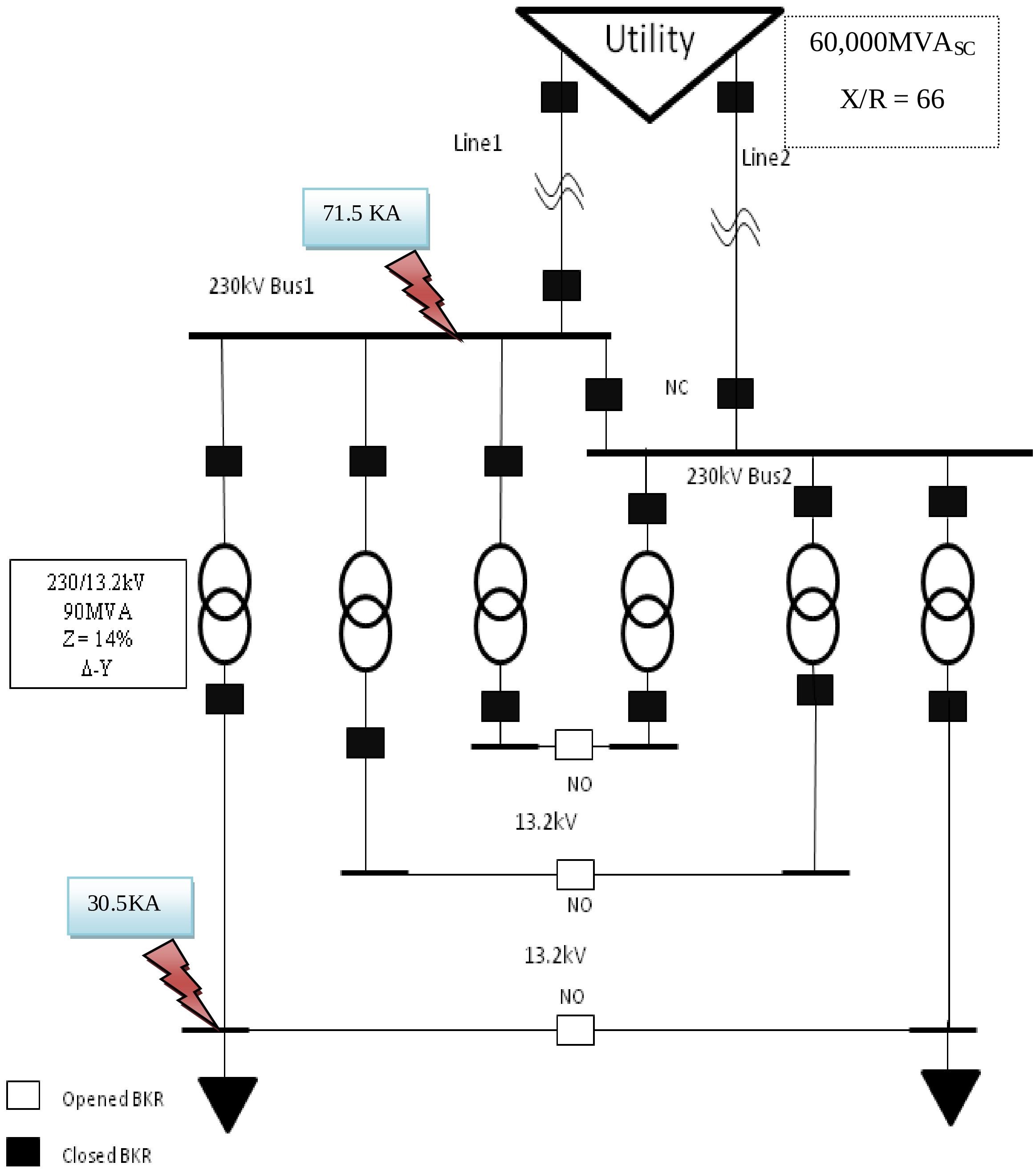

Figure 3.5 Three Phase Short Circuit Current (KA) at the 230kV and 13.2kV Buses

3.4. Coordination Study Analysis

The study starts with the downstream systems. First, the protection system at the load side is set. Then, the upper relay is set to coordinate with the downstream protection. This relay must also clear all faults within its zone. This method is followed all the way to the utility side.

Some equipment in the power system are protected by more than one type of relays. For examples, motors are protected with differential relays, ground relays, and special motor relays that protects the motors against overloading, short circuit, jamming, etc. Also, transformers are protected with differential, ground, overcurrent, pressure relays, and others.

In this thesis, only static loads are considered for simplicity. Also, differential relays are not considered since they are used for local protection and not included in the coordination analysis of the power system.

This section of the thesis will show the sequence of operation of the protective devices when applying faults on some buses. Two three phase faults will be applied; at 13.2kV and the 230kV buses. Only one substation will be studied since it is identical for the rest of the substation. Figure 3.6 shows the part of the system to be studied and Figure 3.6shows the protective devices used.

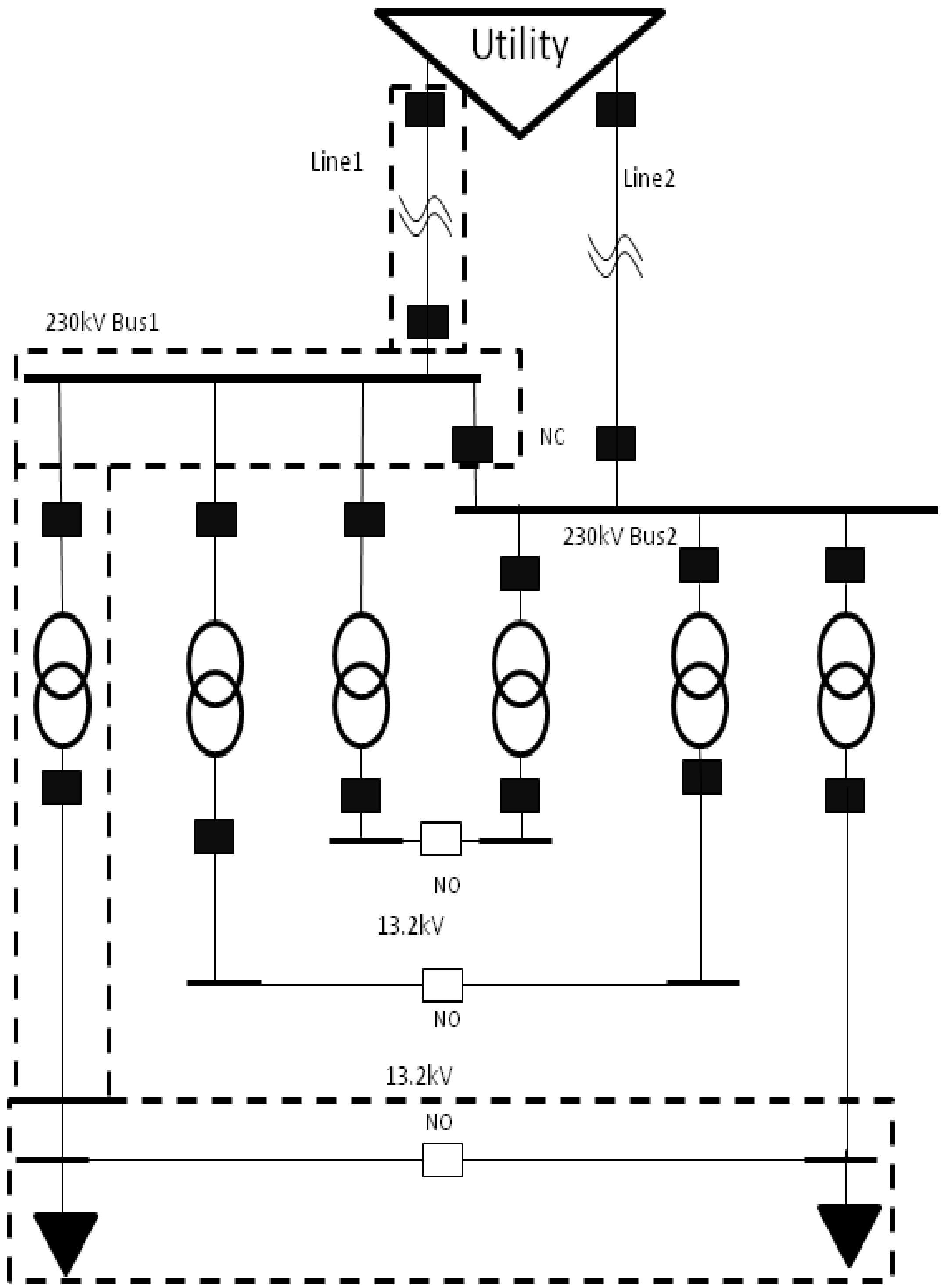

Figure 3.6. Portion of the System to be Protected

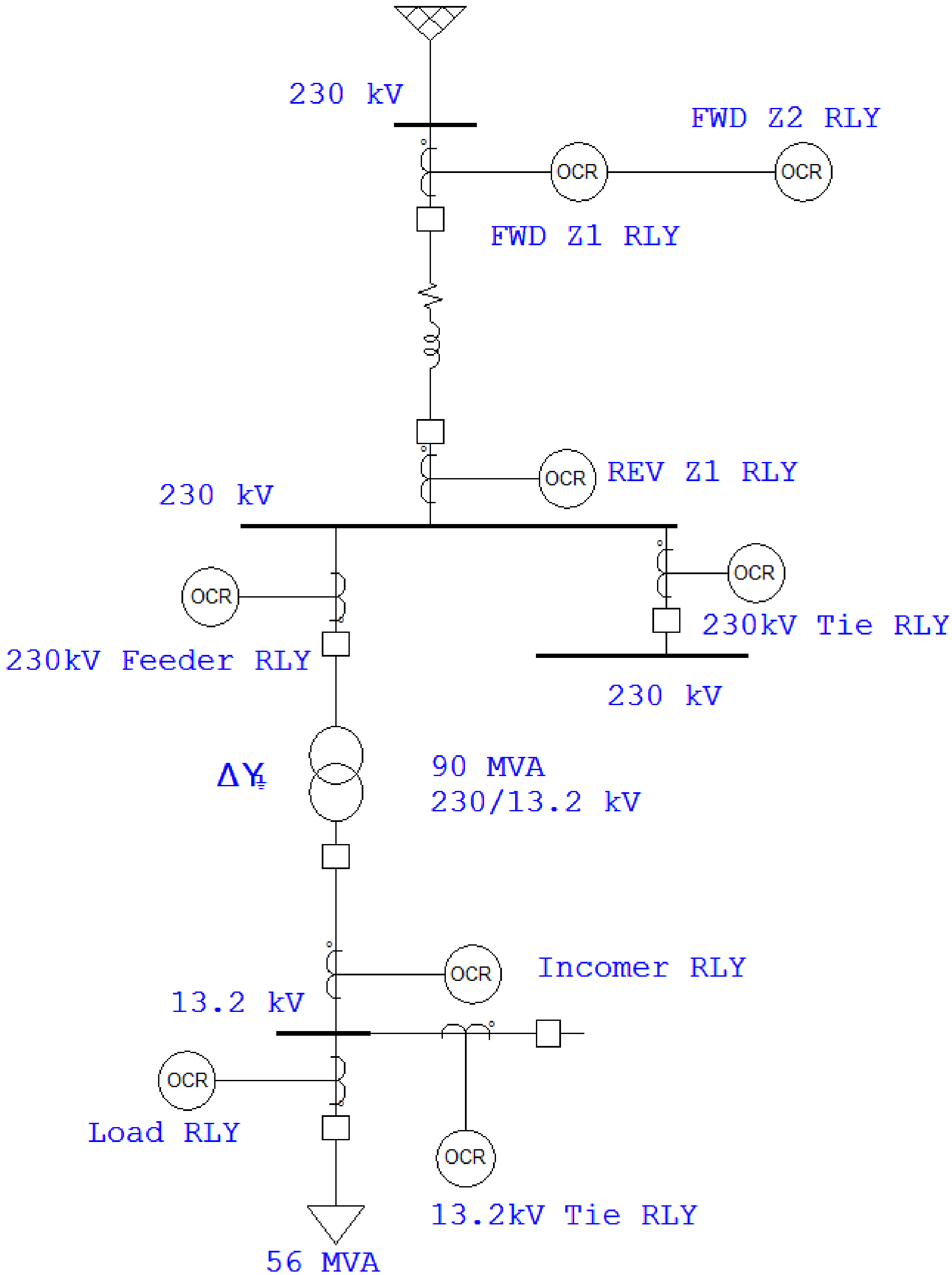

Figure 3.7. Protected Portion Including the Protective Devices

3.5. Relays Settings

In this section, the settings of the overcurrent relays will be applied.

3.5.1. Load Relay Settings

The 13.2kV load is protected by an overcurrent relay (50/51). Table 3.3 shows the load information and relay settings.

Table 3.3. Load Relay Settings

Full Load Current (A)	CT Ratio	Curve Type	Pickup current	Time dial	Instantaneous pickup
2500	3000/5	ANSI-Extremely Inverse	0.9 (2700A)	0.01	1.67 (5010A)

3.5.2. 13.2kV Tie Relay Settings

The 13.2kV tie breaker overcurrent relay (51) is a back up for faults on the load side and the 13.2 bus. Table 3.4 shows the relay settings.

Table 3.4. 13.2kV Tie Relay Settings

CT Ratio	Curve Type	Pickup current	Time dial	Instantaneous pickup
4500/5	IEC-Short Time Inverse	0.65 (2925A)	0.7	None

3.5.3. 13.2kV Incomer Relay Settings

The 13.2kV incomer breaker overcurrent relay (51) is to protect against faults on the bus and act as backup for the tie and load overcurrent relay. Table 3.5 shows the settings of the relay.

Table 3.5. 13.2kV Incomer Relay Settings

CT Ratio	Curve Type	Pickup current	Time dial	Instantaneous pickup
4500/5	IEC-Short Time Inverse	0.72 (3240A)	0.72	None

3.5.4. 230kV Feeder Relay Settings

The 230kV primary overcurrent relay is to protect against faults on the transformer and act as backup for faults on the secondary side of the transformer. Table 3.6 shows the settings of this relay.

Table 3.6. 230kV Feeder Relay Settings

Transformer Full Load Current	CT Ratio	Curve Type	Pickup current	Time dial	Instantaneous pickup
226A	300/5	IEC-Short Time Inverse	0.99 (297A)	1.59	13.33 (3999A)

3.5.5. 230kV Tie Relay Settings

The 230kV tie breaker overcurrent relay is a backup for the transformer primary overcurrent relay and to any faults on the 230kV bus. Table 3.7 shows the settings of this relay.

Table 3.7. 230kV Tie Relay Settings

CT Ratio	Curve Type	Pickup current	Time dial	Instantaneous pickup
800/5	IEC-Short Time Inverse	0.46 (368A)	1.86	None

3.5.6. REV Zone1 Relay Settings

The reverse distance relay is to protect the 230kV line in the reverse direction. This is to cover the unprotected section of the line by zone 1 of the forward distance relay. Table 3.8 shows the relay settings.

Table 3.8. Reverse Zone1 Relay Settings

CT Ratio	Zone1 Pickup	Clearance Time (sec)
800/5	7.5 (6000A)	0.02

3.5.7. Forward Distance Relay Settings

The forward distance relay is to protect the 230kV line and act as a backup for any faults on the 230kV bus in the receiving substation of the industrial system. Zone 1 of this relay covers upto 80% of the line and zone2 upto the 230kV bus. Table 3.9 shows the relay settings.

Table 3.9. Forward Distance Relay Settings

CT Ratio	Zone1 Pickup	Clearance Time (sec)	Zone2 Pickup	Clearance Time (sec)
1200/5	35.33 (42396A)	0.02	29.33 (35196A)	1.1

3.6. Sequence of Operation

In this section, a three phase fault will be applied on the 13.2kV load bus, 230kV transformer primary bus and in the middle of the 230kV transmission line. In all cases, the Time Current Characteristic (TCC) curve of the sequence of operation of the protective devices will be shown along with the table.

3.6.1. Fault at the 13.2kV bus

A three phase fault will be applied at the 13.2kV load bus. The sequence of operation as results of this fault shall be as follows;

1. Load relay
2. 13.2kV tie relay
3. 13.2kV incomer relay
4. 230kV feeder relay.

The coordination time shall be 0.35 sec to have proper coordination. Table 3.10 shows the sequence of operation of the protective devices and Figure 3.8 shows the TCC curves for this fault.

Table 3.10. Sequence of Operation for a Fault on the 13.2Kv bus

Time (ms)	Protective Device	Fault Current (kA)
0.9	Load relay	30.741
355	13.2kV Tie Relay	30.741
717	13.2kV Incomer Relay	30.741
1072	230kV Feeder Relay	1.775

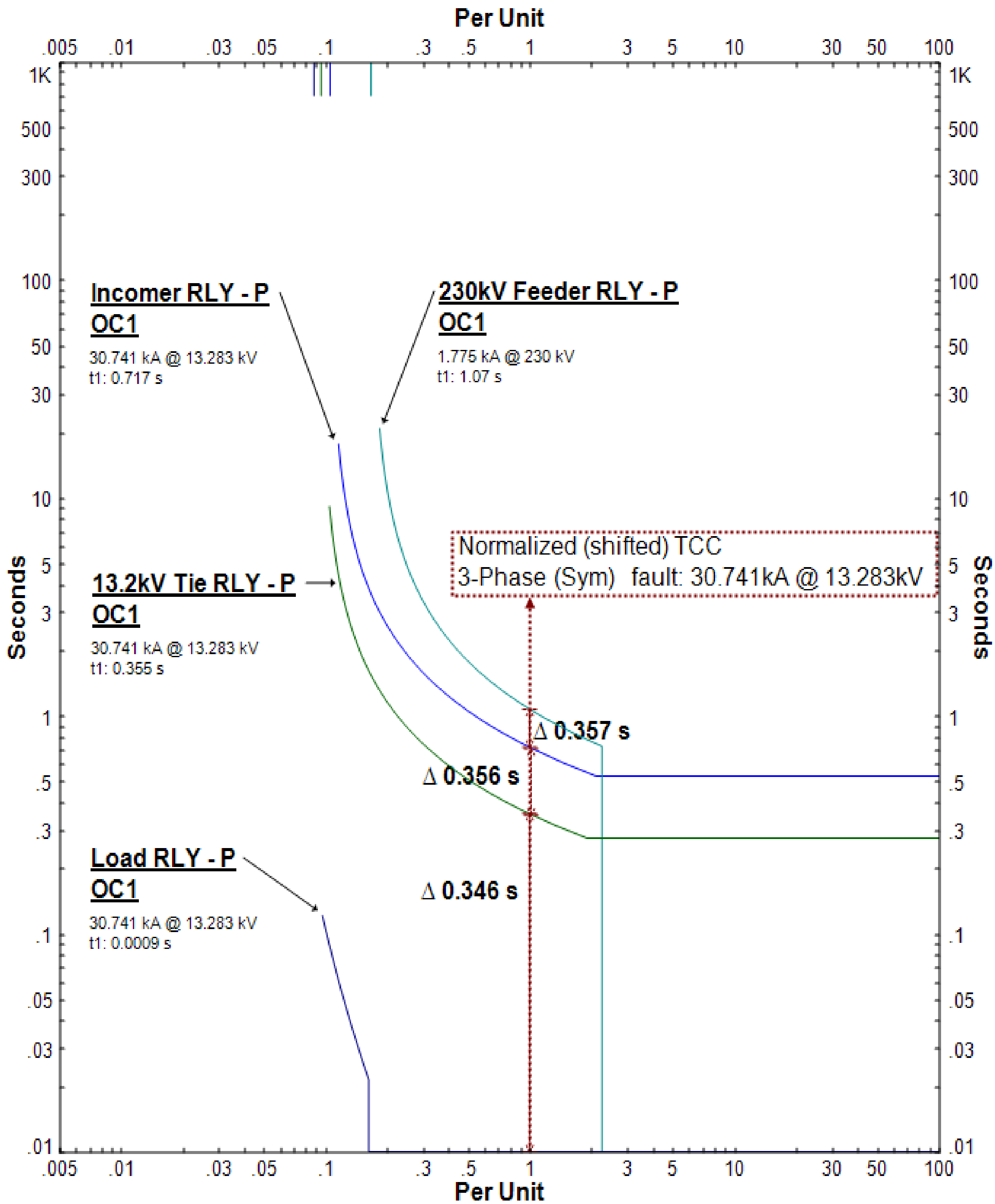

Figure 3.8. Sequence of Operation for Fault at 13.2kV Load Bus

3.6.2. Fault at the 230kV Transformer Primary Bus

A three phase fault will be applied at the 230kV transformer primary bus. The sequence of operation as results of this fault shall be as follows;

1. 230kV feeder relay.
2. 230kV tie relay.
3. 230kV FWD zone2 relay.

The coordination time shall be 0.35 sec to have proper coordination. Table 3.11 confirms the correct operation of the protective devices and Figure 3.9 shows the TCC diagram.

Table 3.11. Sequence of Operation for a Fault at the 230kV Transformer Primary Bus

Time (ms)	Protective Device	Fault Current (kA)
10.0	230kV Feeder Relay	71.458
731	230kV Tie Relay	35.729
1100	FWD Z2 Relay	35.729

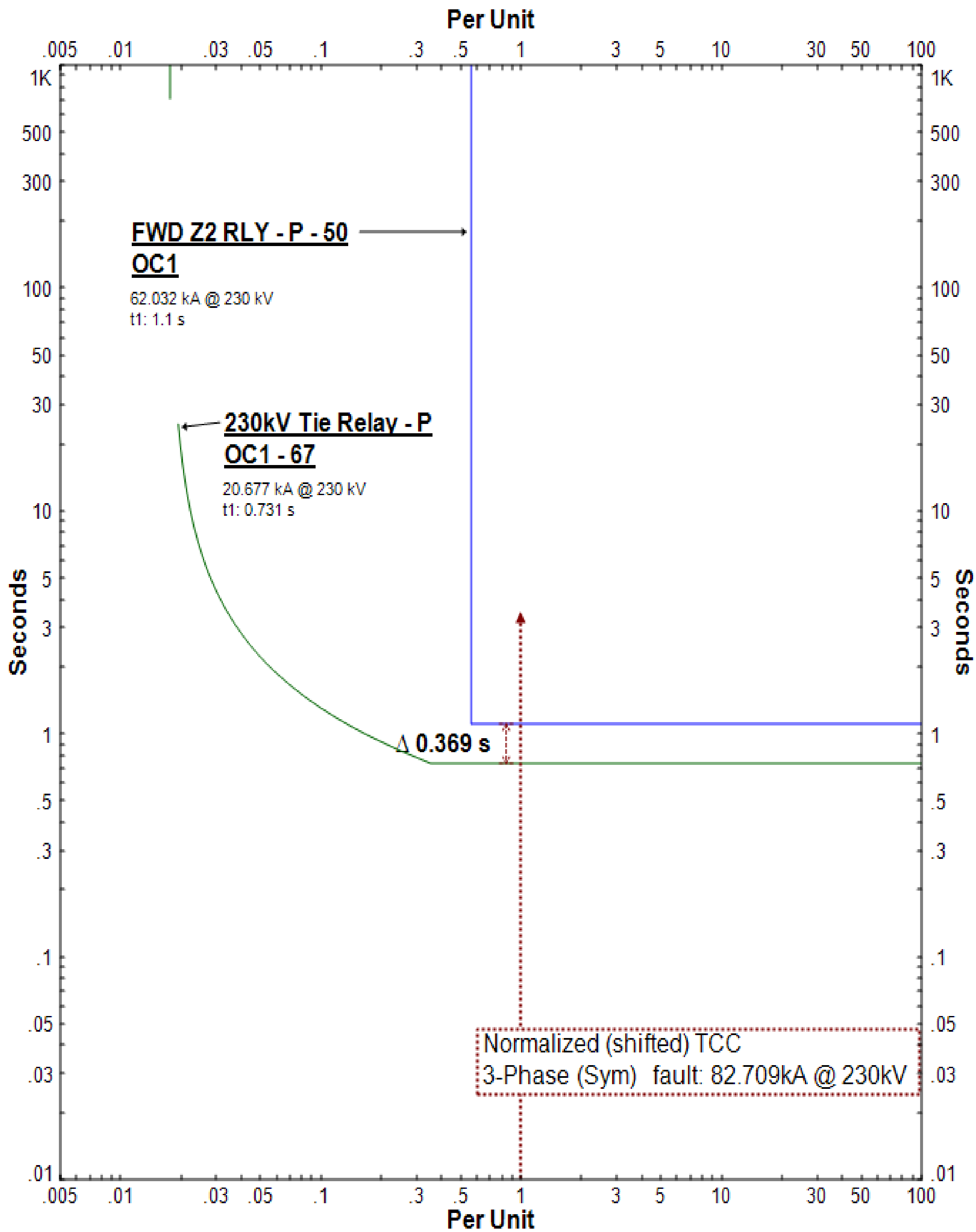

Figure 3.9. Sequence of Operation for a Fault at the 230kV Transformer Primary Bus

3.6.3. Fault at the middle of the 230kV Transmission Line

A three phase fault will be applied at the middle of the 230kV transmission line. The sequence of operation as results of this fault shall be as follows;

1. FWD zone1 relay.
2. REV zone1 relay.
3. 230kV tie relay.
4. FWD zone2 relay.

The coordination time shall be 0.35 sec to have proper coordination. Table 3.12 confirms the correct operation of the protective devices and Figure 3.10shows the TCC diagram.

Table 3.12. Sequence of Operation for a Fault on the Middle of the 230kV Line

Time (ms)	Protective Device	Fault Current (kA)
20.0	FWD Z1 relay	62.032
20.0	REV Z1 relay	20.677
731	230 Tie Relay	20.677
1100	FWD Z2 relay	62.032

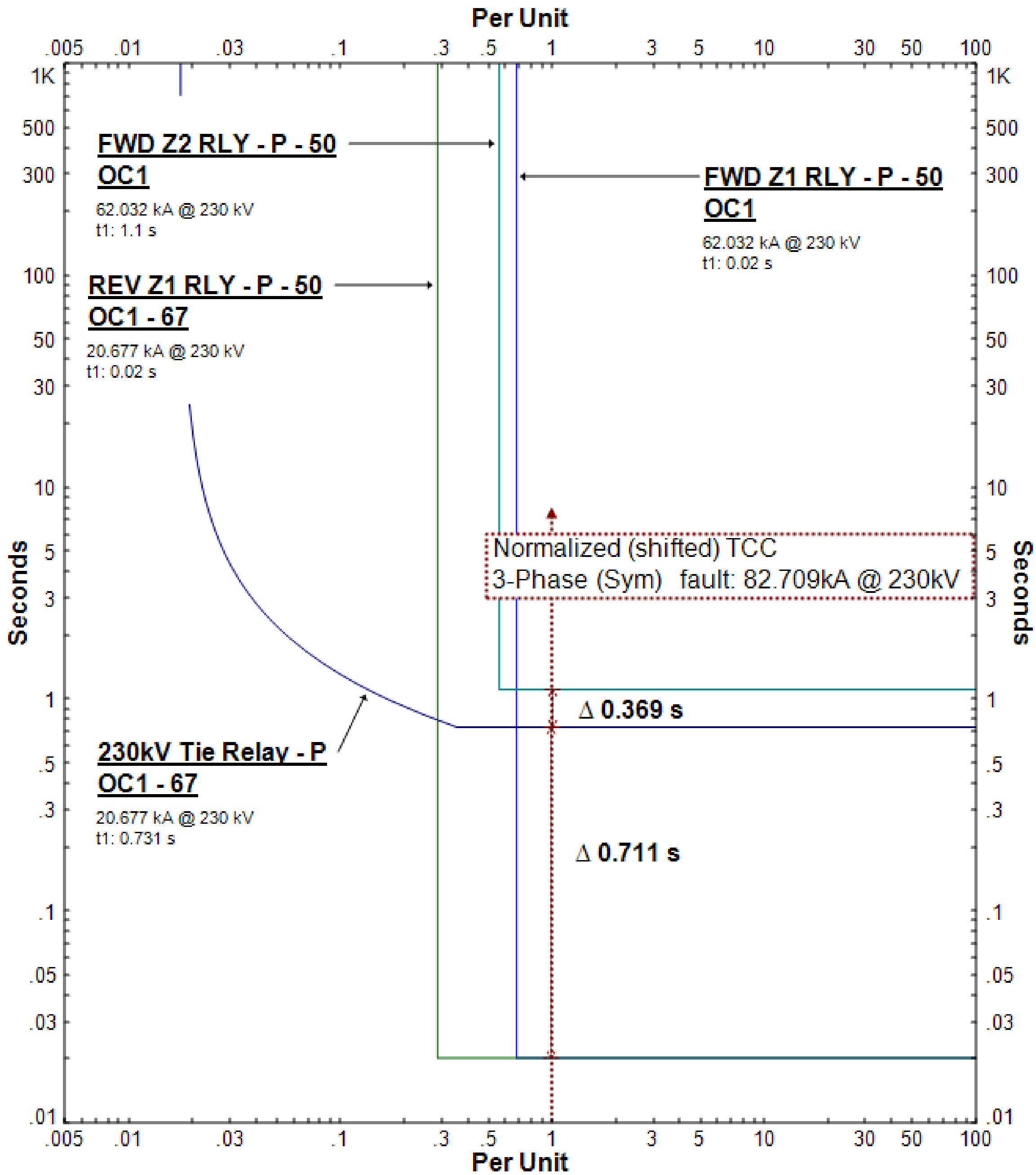

Figure 3.10. Sequence of Operation for a Fault on the Middle of the 230kV Line

CHAPTER 4

COORDINATION STUDY OF INDUSTRIAL POWER SYSTEM INCLUDING CO-GEN

4.1. Overview

Cogeneration, also known as Combined Heat and Power, or CHP, is the production of electricity and heat in one single process for dual output streams. In conventional electricity generation, 35% of the energy potential contained in the fuel is converted on average into electricity, whilst the rest is lost as waste heat.

Cogeneration uses both electricity and heat and therefore can achieve an efficiency of up to 90%, giving energy savings between 15-40% when compared with the separate production of electricity from conventional power stations and of heat from boilers. It is the most efficient way to use fuel. Cogeneration also helps save energy costs, improves energy security of supply, and creates jobs.

In this chapter, a complete coordination study will be conducted on the original system when a Co-Generation plant is connected to the industrial power system 230kV receiving substation. The co-generation plan has two 165MW generators with size of 165MW each.

Each unit is connected to 209MVA, 13.2/230kV transformer. Figure 4.1 shows the single line diagram of the system.

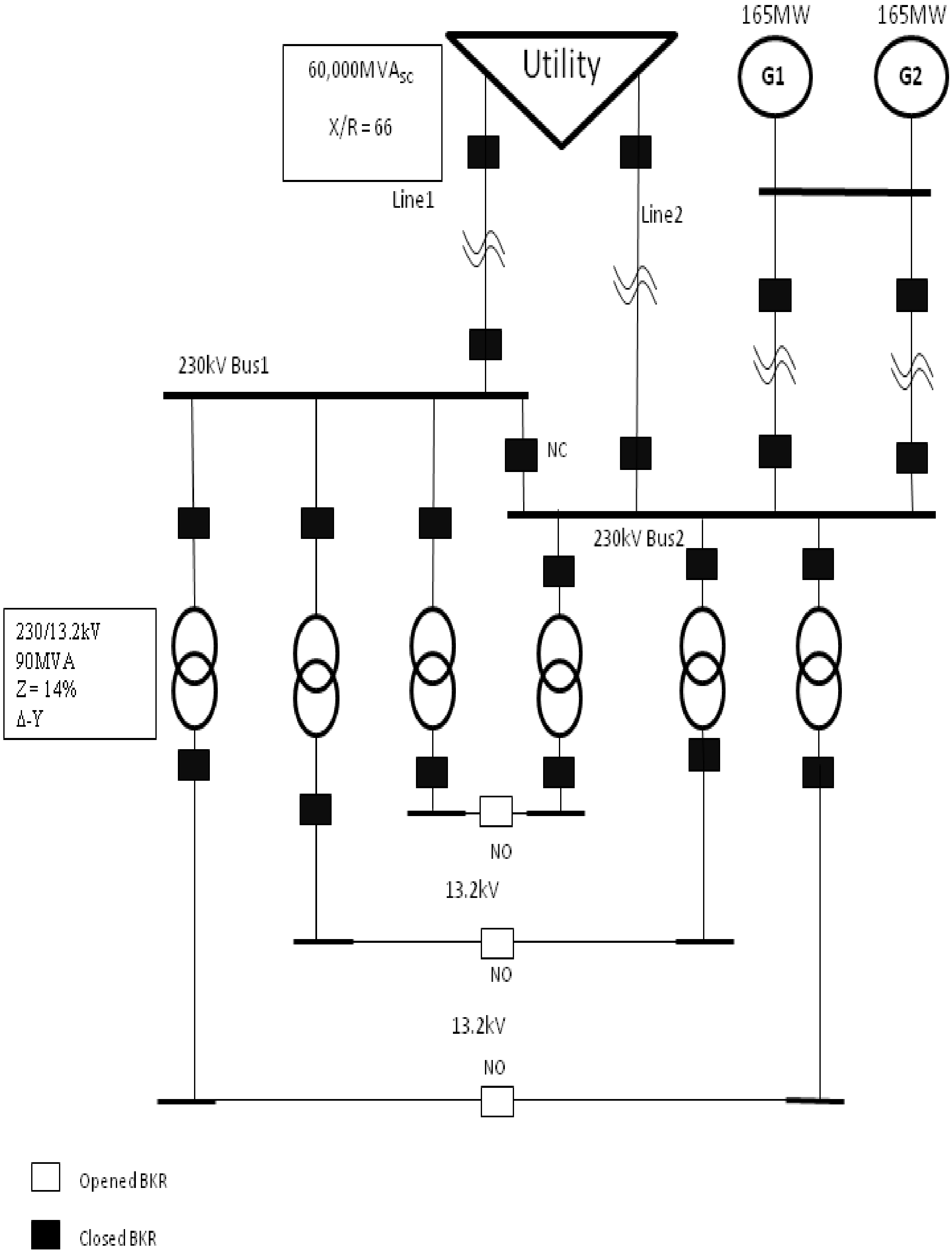

Figure 4.1. Single Line Diagram of the Industrial Power System Including the Co-Gen

4.2. Short Circuit Analysis

This section will show the available short circuit level at the 230kV and 13.2kV buses. Short circuit studies are used to size the circuit breakers and the switchgears. Only three phase faults will be considered as before.

For the short circuit study, all sources for short circuit current are assumed to connected to see the highest short circuit current available in the network including the co-generation plant. All 230kV lines in the proposed system will be in service during the study. Table 4.1 shows the three phase faults level before and after the addition of the co-generation plant. There is a difference of 5KA in the short circuit for a fault on the 230kV bus due to the addition of the Co-Generation where it is only 0.3kA for a fault on the 13.2kV bus. Table 4.1 and Figure 4.2 shows the available short circuit current at the 230kV and the 13.2kV buses.

Table 4.1. Short Circuit Level Comparison Before and After the Adding of Co-Gen

Faulted Bus	**Fault Current (kA)**	
	Without Co-Gen	**With Co-Gen**
230kV	71.5	75.05
13.2kV	30.5	30.78

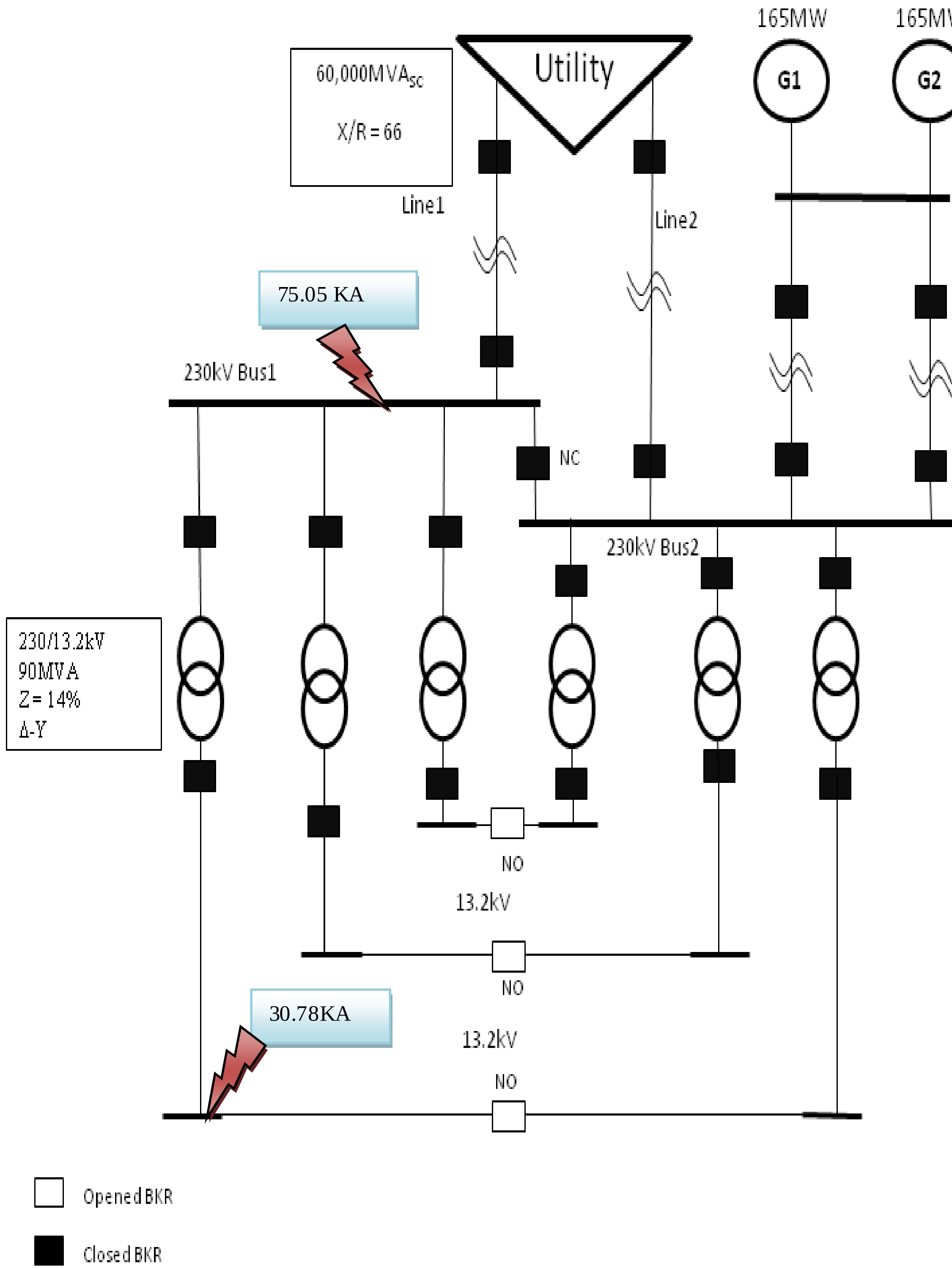

Figure 4.2. Three Phase Short Circuit Current Values

4.3. Modified Coordination Study

There is no modification to the coordination study due to the addition of the cogeneration plant. There are two reasons for this which are;

1. The co-generation plant is connected at high voltage. This means that the current contribution level is not very high.
2. The short circuit current available from the co-generation plant is 3.7kA which is too small compared with that of the utility which is 70kA.

CHAPTER 5

COORDINAITNO STUDY OF THE INDUSTRIAL POWER SYSTEM INCLUDING DG

5.1. Case Study Description

The original industrial power system is fed from utility and new co-generation plant. There are two loads are at distance of 20 and 30 km from the plant and no grid exists nearby. The proposal is to have 34.5kV overhead lines from the industrial power receiving substation to feed these two loads.

Several years later, a local generation plant is to be built to help feeding the two loads or maybe the industrial power system due to increased load in both; the network itself and the loads. Figure 5.1 shows the layout of the proposed system and Figure 5.2 shows the single line diagram. The size of the two loads is 5MVA each.

This chapter will start first with the settings of the protection devices without the DG. Then, a DG of size 15MW will be connected and its effects on the coordination of the power system will be studied.

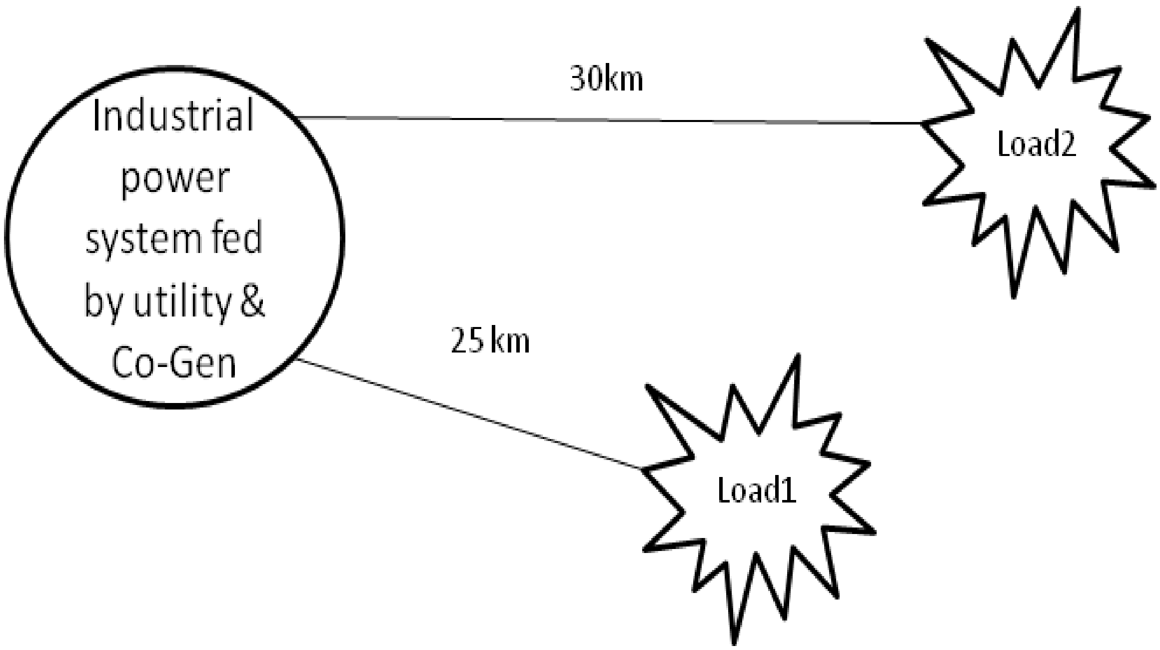

Figure 5.1. Layout of the Loads Fed by the Industrial Power System

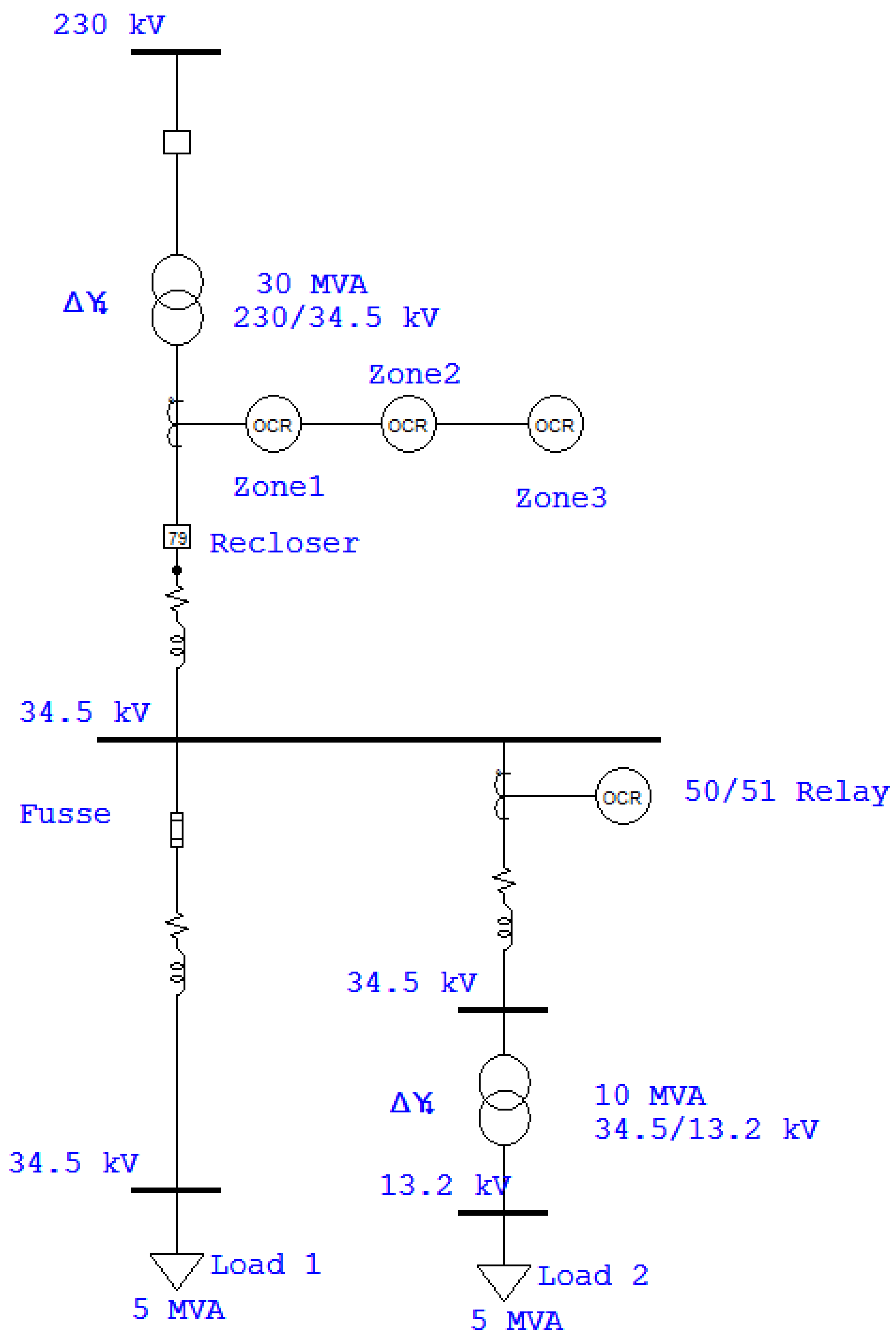

Figure 5.2. Electrical One Line Diagram of the Loads Fed by the Industrial Power System

5.2. Stead State Study

After running the power flow, all buses voltage levels are above the threshold value which is 95%. This confirms the suitable sizes of the transformers and the overhead lines. Table 5.1 shows the obtained results.

Table 5.1. Power Flow Study Results

Bus	Voltage Level (%)	Power (MVA)	Current (A)
Connection Bus (34.5kV)	98.01	9.7	164.9
Load 1 (34.5kV)	97.78	4.8	81.8
Transformer 34.5kV bus	96.77	4.8	83.3
Load 2 (13.8kV)	97.08	4.7	203.1

5.3. Short Circuit Study

This study is to determine the available three phase short circuit current in different location of the previous distribution network. The short circuit currents at different buses are shown in Table 5.2

Table 5.2. Short Circuit Current at Different Locations

Faulted Bus	Voltage (kV)	Fault current (kA)
80% of line 1	34.5	2.0
110% of line 1	34.5	1.83
Transformer Primary bus	34.5	1.53
Load1	34.5	1.73
Load 2	13.8	2.4

5.4. Relays Settings

In this section, the following protection devices will be set;

1. Distance relay (zone1, 2, & 3).
2. 50/51 overcurrent relay.
3. Recloser relay
4. Fuse

5.4.1. Distance Relay Settings

The distance relay is located at the secondary of the 230/34.5kV transformer. Table 5.3 is the settings for the distance relay. Zone1 is used to protect 80% of the 34.5kV overhead line going out of the substation to the connection bus. Zone2 is used as a backup that covers all line1 and 10% of the lines going out of the connection bus. Zone3 is used to be a backup for the protection devices in the downstream.

Table 5.3. Distance Relay Zones Settings

Relay Zones	Reaching Point	Voltage (kV)	Pick up current (kA)	Tripping time (sec)
Zone 1	80% of line1	34.5	2	0.02
Zone 2	10% of line 1	34.5	1.8	0.38
Zone 3	Transformer primary bus	34.5	1.5	0.76

5.4.2. Overcurrent Relay Settings

This relay is located at the beginning of the overhead line going out of the connection bus to load2. This relay is used to protect this portion of the line and gives instantaneous protection all the way to the primary bus of the 34.5/13.2kV transformer. It also gives a backup for the secondary bus of this transformer with time delay. Table 5.4 shows the settings of this relay.

Table 5.4. Overcurrent Relay Settings

Pick up (A)	Time Dial	Curve Type	Instantaneous Pickup (A)	Time (sec)
200	0.35	ANSI-Extremely Inverse	1100	0.01

5.4.3. Recloser Settings

A recloser is located on the secondary side of the 230/34.5kV transformer. This recloser is used to clear transient faults on the overhead lines. This serves two purposes;

1. Minimize the interruption time by fat opening and closing the breaker to re-energize the circuit after clearing transient faults.
2. It saves the fuses in the lateral circuits. It clear the faults before the blown of the fuses for temporary faults.

Reclosers could be set for one shot, two shots, or sometimes for three shots. Table 5.5 shows the settings of the recloser in the study system.

Table 5.5. Recloser Settings

Pick up (A)	Time Dial (sec)	# of shots
280	0.05	1

5.4.4. Fuse Characteristics

A fuse is inserted on the overhead line going out of the connection bus feeding load 1. Fuses are used because it is cheaper than the circuit breaker. This fuse is protected by the recloser for any transient faults. Instead of blowing this fuse for temporary faults, the recloser is designed to clear that fault instead of having long outage and the task of replacing the fuse. Table 5.6 shows the fuse characteristics.

Table 5.6. Fuse Characteristics

Voltage	**Size**	**Curve type**
38kV	125A	Very slow

5.5. Coordination Study

In this section, faults at four buses will be simulated to confirm the proper coordination of the applied settings before. The buses are;

1. Middle of line 1.
2. Load 1 bus.
3. 34.5 transformer primary bus.
4. 13.8kV load bus.

5.5.1. Fault at Middle of Line 1

A fault on the middle line 1 is to test the operation of the distance relay zones. The operation of the three zones will be monitored. Table 5.7, Figure 5.3, and Figure 5.4 show the sequence of operation as a result of such fault and the fault current values.

The fault is cleared by zone1 in 0.02 sec as expected. Zone2 will operate in 0.379 sec to coordinate with zone1. Finally, zone3 will operate in 0.763 sec.

Table 5.7 Sequence of Operation for a Fault on Middle of Line 1

Distance Relay Zones	Fault current (kA)	Operating time (sec)
Zone 1	2.17	0.02
Zone 2	2.17	0.379
Zone 3	2.17	0.763

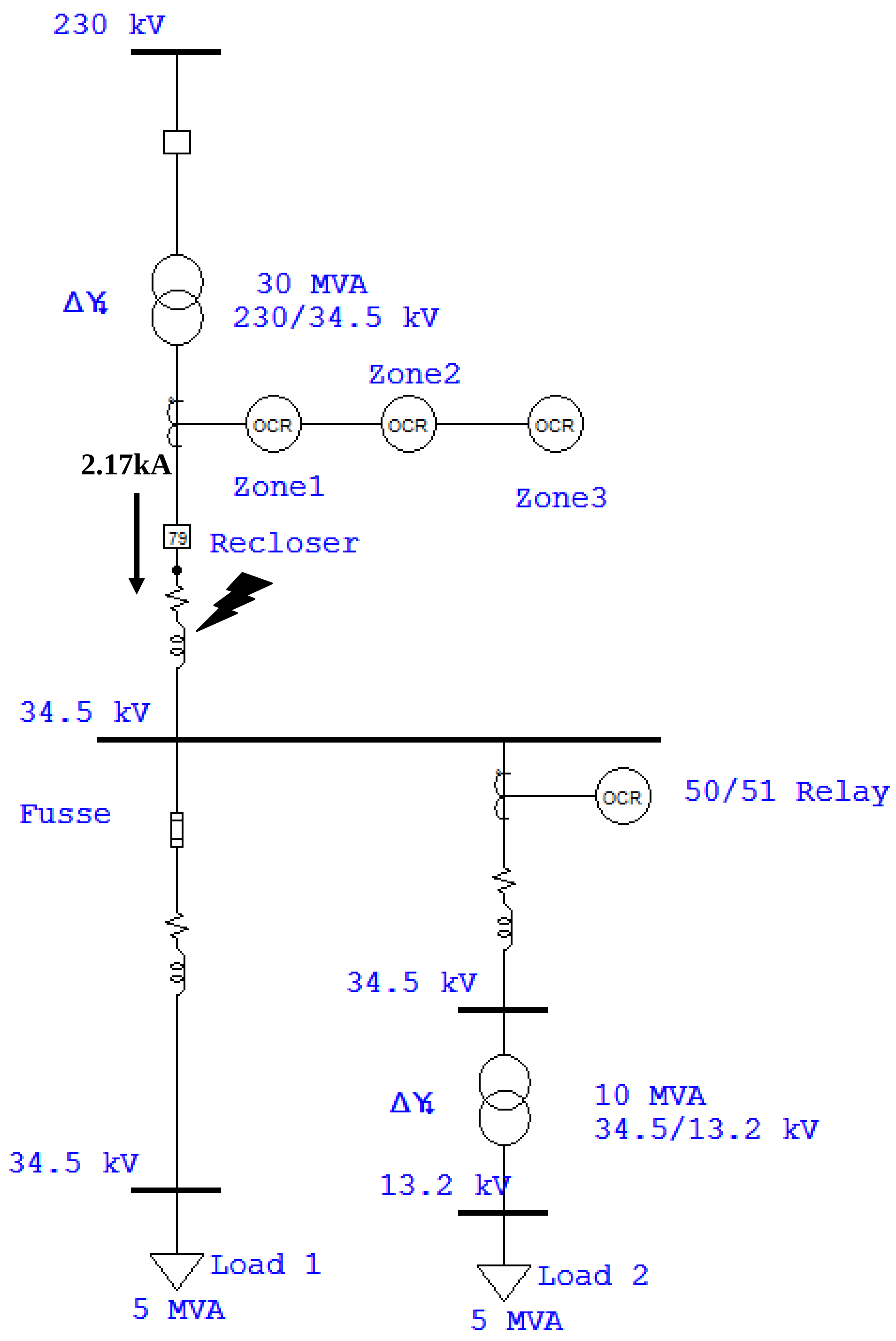

Figure 5.3. Fault at the Middle of the Line.

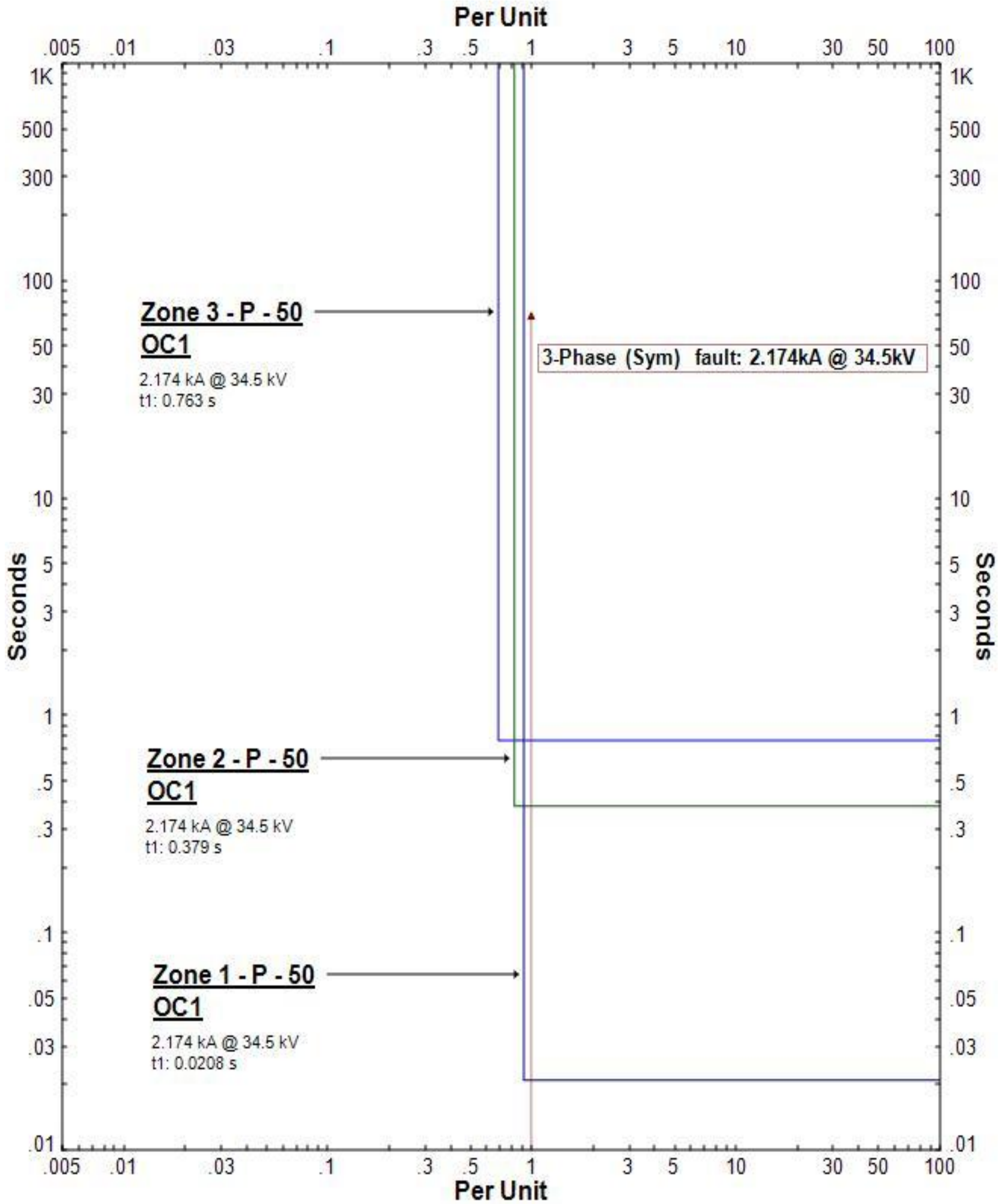

Figure 5.4. Sequence of Operation for a Fault on Middle of Line1

5.5.2. Fault at Load1 Bus

A fault on laod1 bus is to test the coordination between the recloser and the fuse. The coordination will be monitored. Table 5.8, Figure 5.5, and Figure 5.6 show the sequence of operation as a result of such fault and the fault current values.

The fault is cleared first by the recloser in 0.06 sec as expected if it is transient fault. The fuse will be blown in 0.38-0.51sec. The coordination time between the recloser and the fuse is 0.333 sec which is enough to allow the recloser to save the fuse for the transient faults.

Table 5.8 Sequence of Operation for a Fault on Load1 Bus

Operated Protective Device	Fault current (kA)	Operating time (sec)
Recloser	1.779	0.0586
Fuse	1.779	0.375

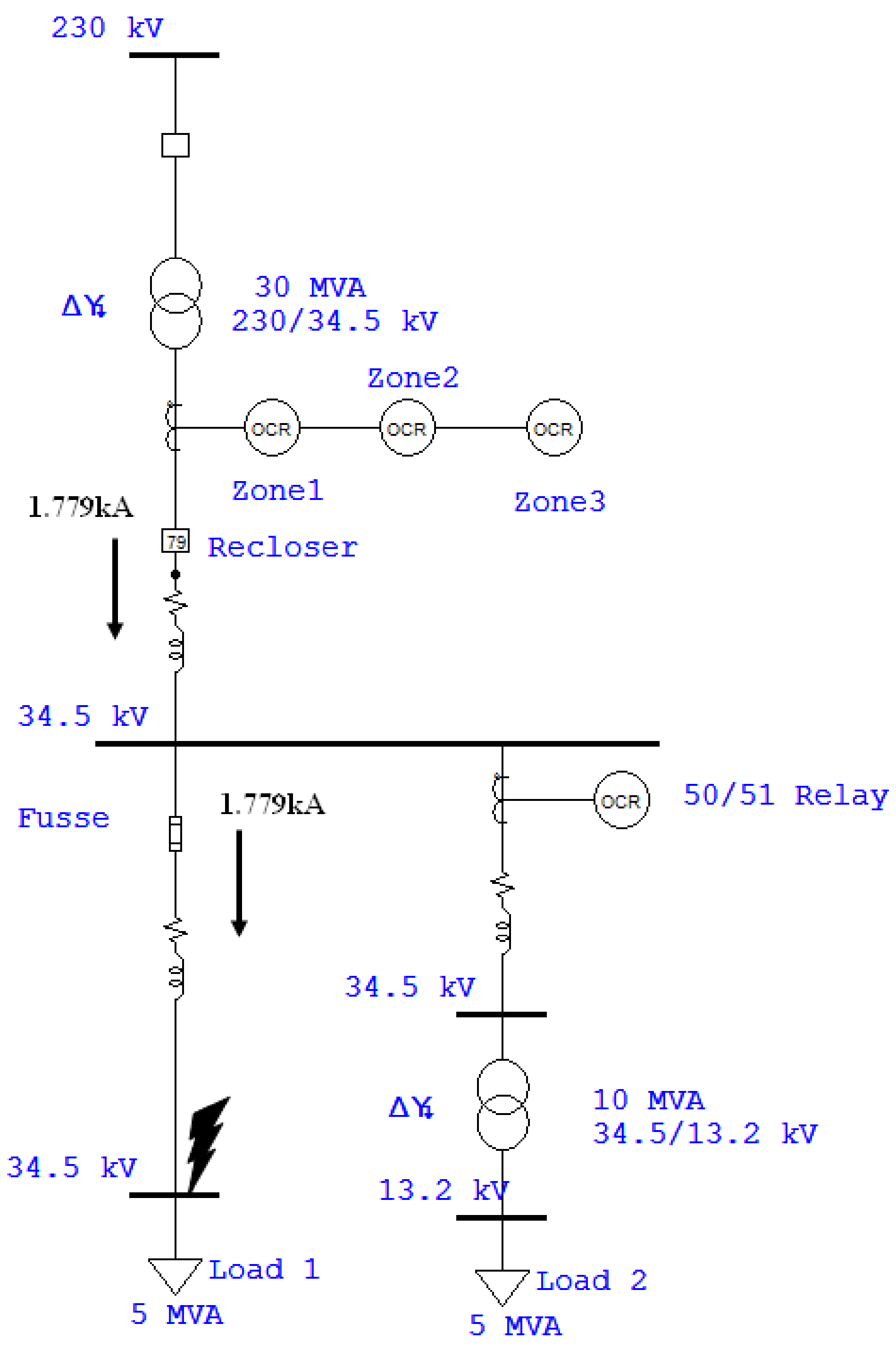

Figure 5.5. Fault at Load1 Bus

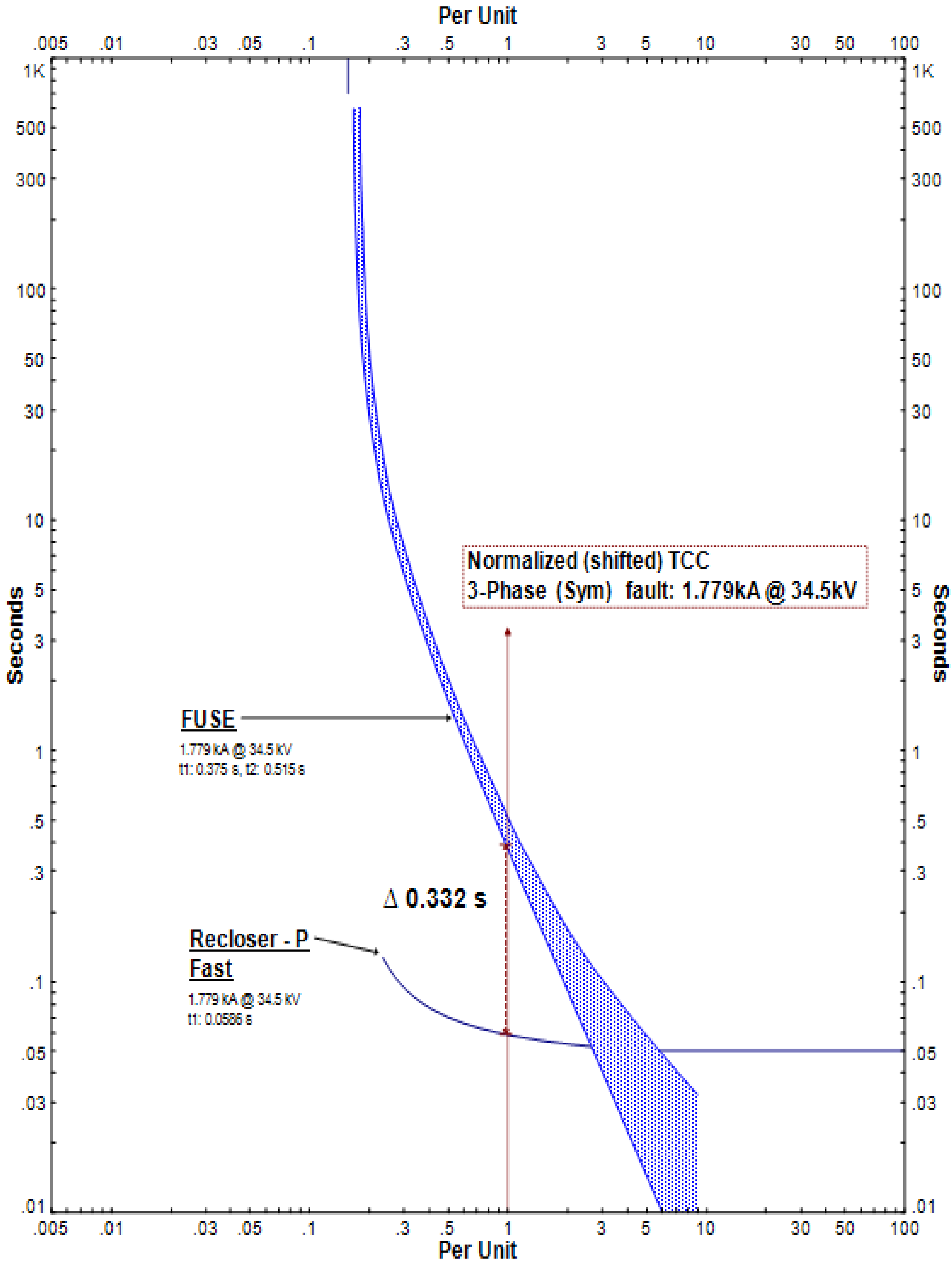

Figure 5.6. Sequence of Operation for a Fault on Load 1 Bus

5.5.3. Fault at the 34.5kV Transformer Primary Bus

A fault on the 34.5kV transformer primary bus is to test the operation of relay 50 and zone3 the distance relay. Table 5.9, Figure 5.7, and Figure 5.8 show the sequence of operation as a result of such fault and the fault current values.

The fault is cleared by relay 50 in 0.01sec as expected. Zone3 will act as a backup protection for this overcurrent relay. it will operate in 0.763sec. Zones 2 & 3 of the distance relay will not operate as the fault is out of their zone.

Table 5.9. Sequence of Operation For A Fault On The 34.5kV Transformer Primary Bus

Operated Protective Device	Fault Current (kA)	Operating Time (sec)
50/51 relay	1.577	0.01
Zone3	1.577	0.763

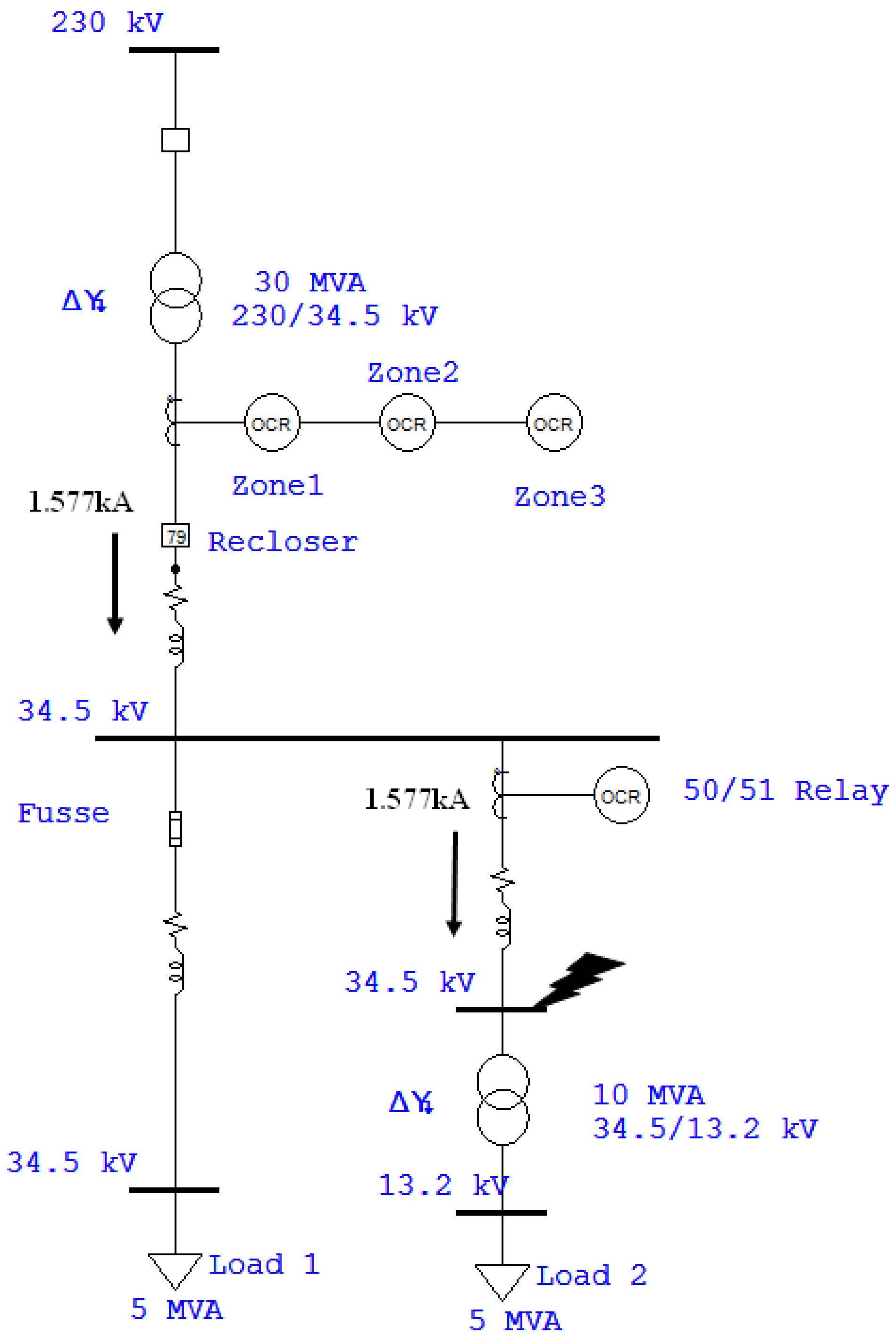

Figure 5.7. Fault at 34.5kV Transformer Primary Bus

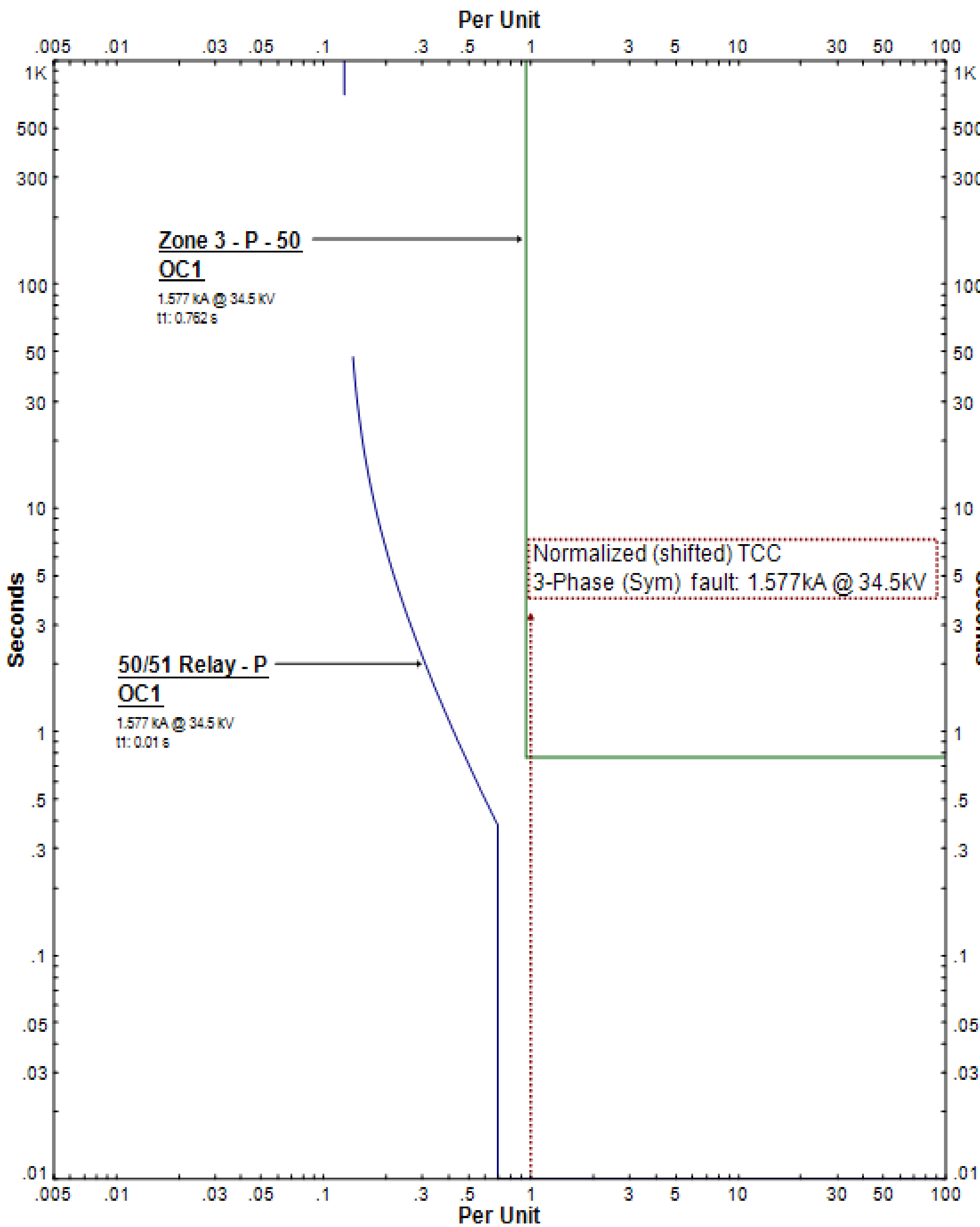

Figure 5.8. Sequence of Operation for a Fault on the 34.5kV Primary Bus

5.5.4. Fault at the 13.8kV Transformer Secondary Bus

A fault on the 13.8kV transformer secondary bus is to test the operation of the overcurrent relay 51. Table 5.10, Figure 5.9, and Figure 5.10 shows the sequence of operation as a result of such fault.

The fault is cleared by the time overcurrent relay 51 in 0.5sec. This delay is to coordinate with protection system on the 13.8kV side.

Table 5.10 Sequence of Operation for a Fault on Load2 Bus

Operated Protective Device	Fault Current (kA)	Operating Time (sec)
Overcurrent relay	0.949	0.501s

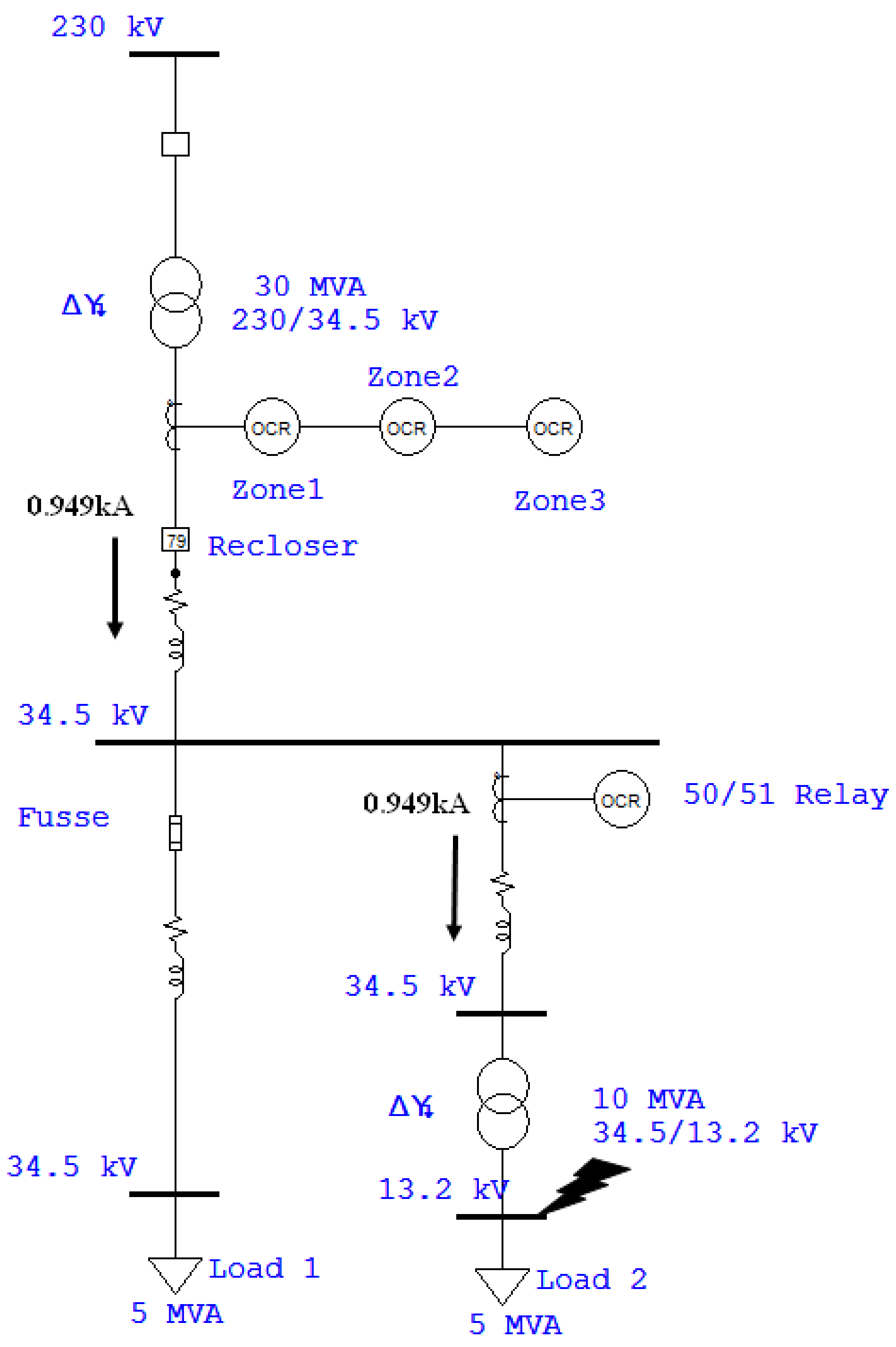

Figure 5.9. Fault at Load2 Bus

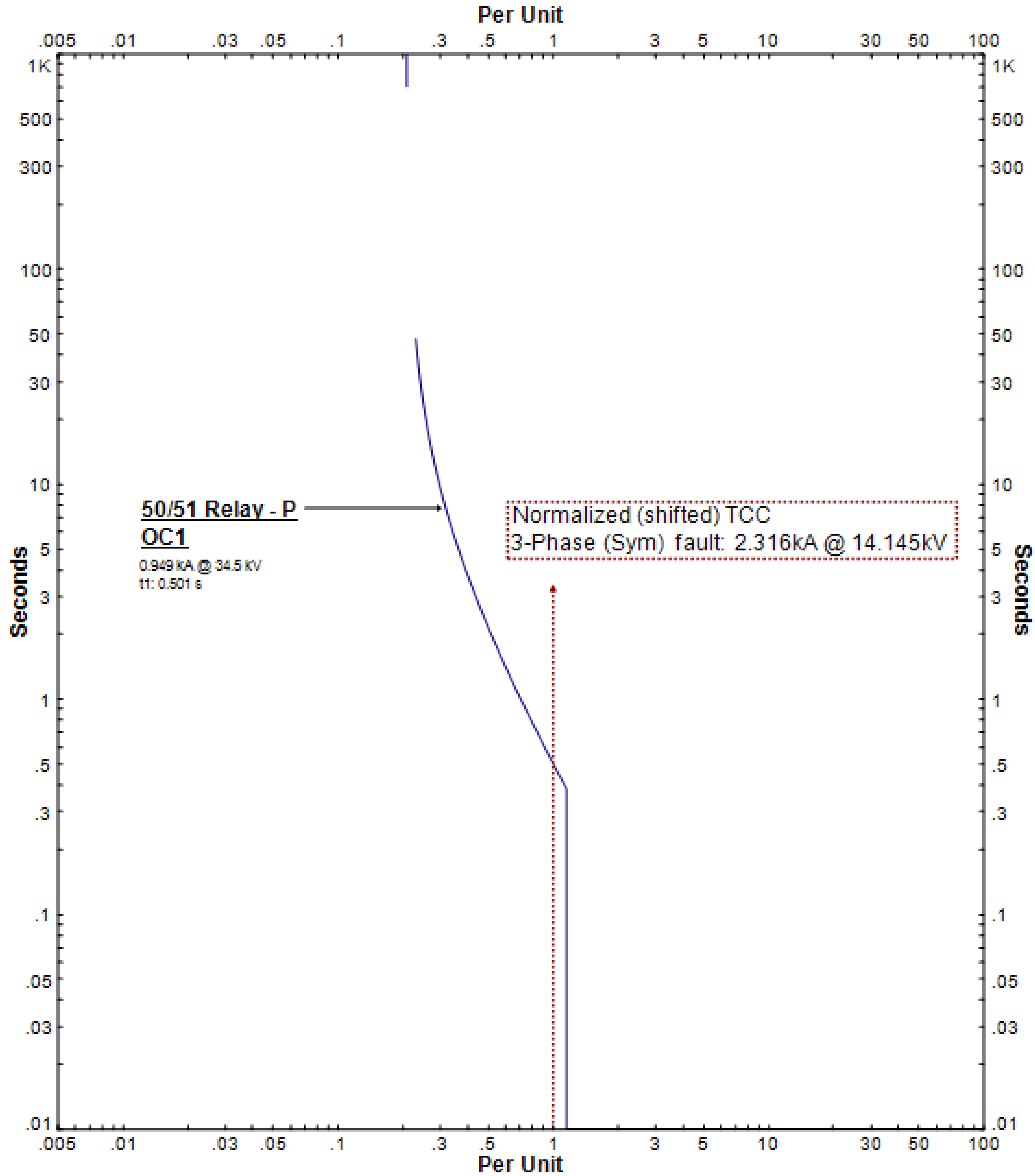

Figure 5.10. Sequence of Operation for a Fault On The 13.8kV Transformer Secondary Bus

5.6. DG Effects on the Protection System Coordination

A 15 MW distributed generation is connected to the 34.5kV distribution network at the connection bus. This DG is located at distance of 5km from the connection bus.

The effects on the coordination system due to the addition of DG will be studied. Specifically, the operation of zone3 of the distance relay, the operation of the instantaneous relay (50/51), and the coordination of the recloser/fuse will be investigated. Figure 5.11 shows the single line diagram of the system under study.

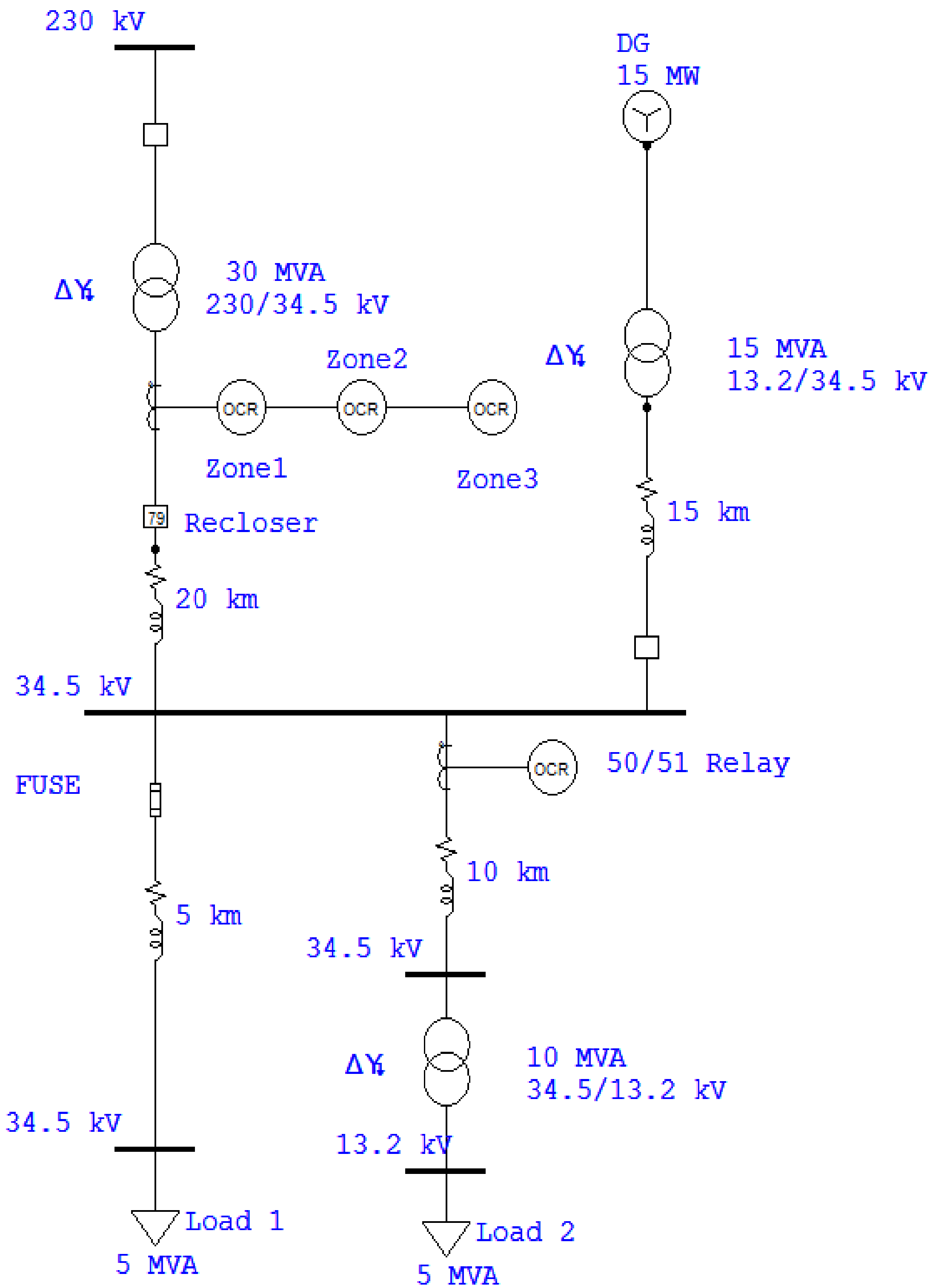

Figure 5.11. Connection of the 15MW DG

5.6.1. Operation of Zone3 of the Distance Relay

The pick up of zone3 in the distance relay is set at 1.5kA as shown in Table 5.3. For any faults current below 1.5kA, zone 3 of this relay will not pick up. Adding this DG caused the fault current to decrease to 1.42kA when the 34.5kV transformer primary bus is faulted. Table 5.11, Figure 5.12 and Figure 5.13 show results for such fault.

In this case, zone3 is the backup protection for the overcurrent relay. Having the DG installed, zone3 is no longer provides a back protection for the O/C relay for any faults at the last 30% of the line. This is because for a fault at the 70% of the line, the fault current is 1.5kA which is the pickup zone3. For faults after the 70% of the line, the fault current would be less than 1.5kA which will cause the zone3 to under-reach.

Table 5.11. Sequence of Operation for a Fault on the 34.5kV Transformer Primary Bus

Protective Device	Pickup Value (kA)	Fault Current (kA)	Operating Time (sec)
Overcurrent (50)	1.1	2.277	0.01
Zone 3	1.5	1.42	∞

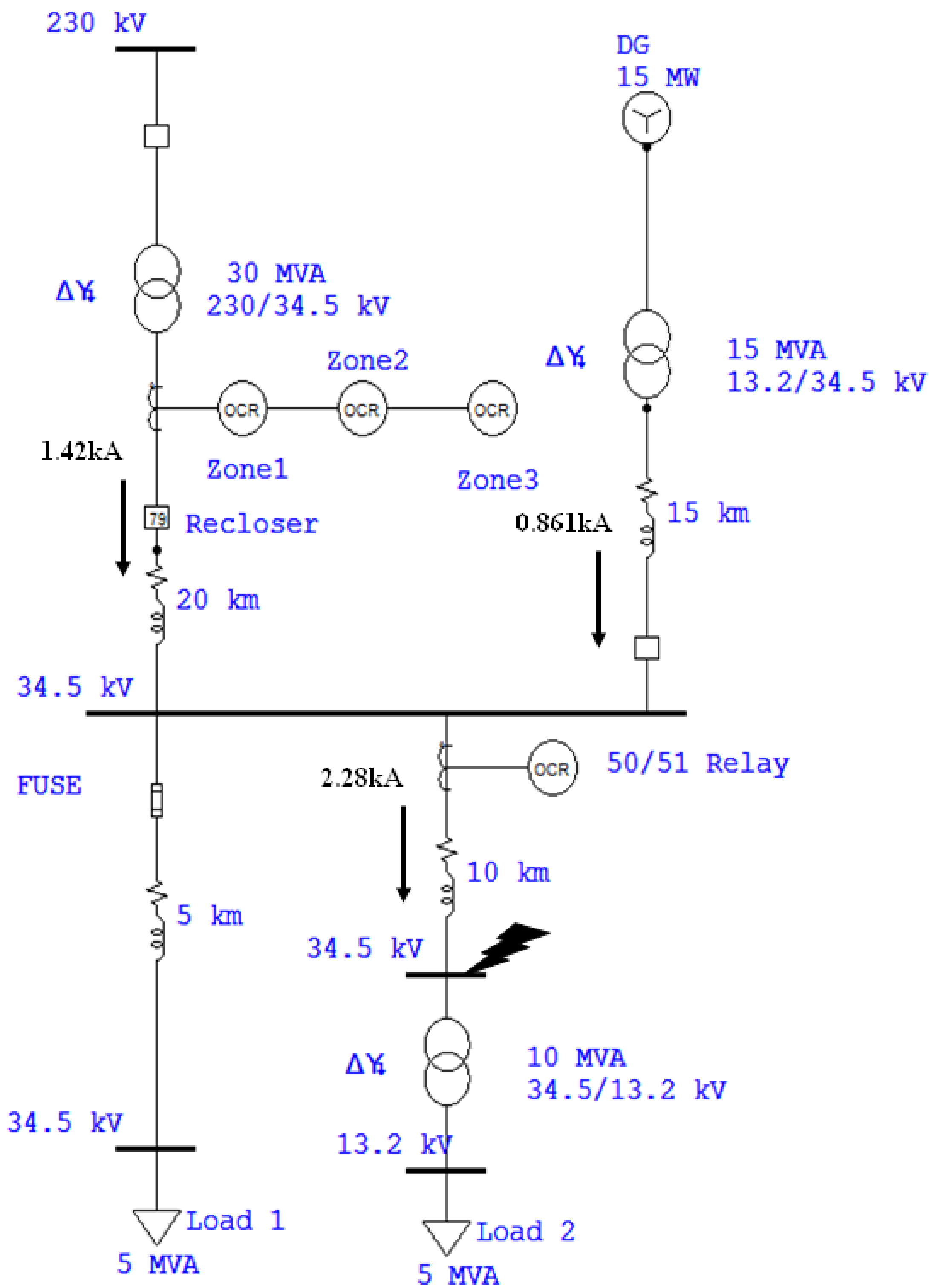

Figure 5.12. Fault Current Values for Fault at the 34.5kV Transformer Primary Bus When DG is Added

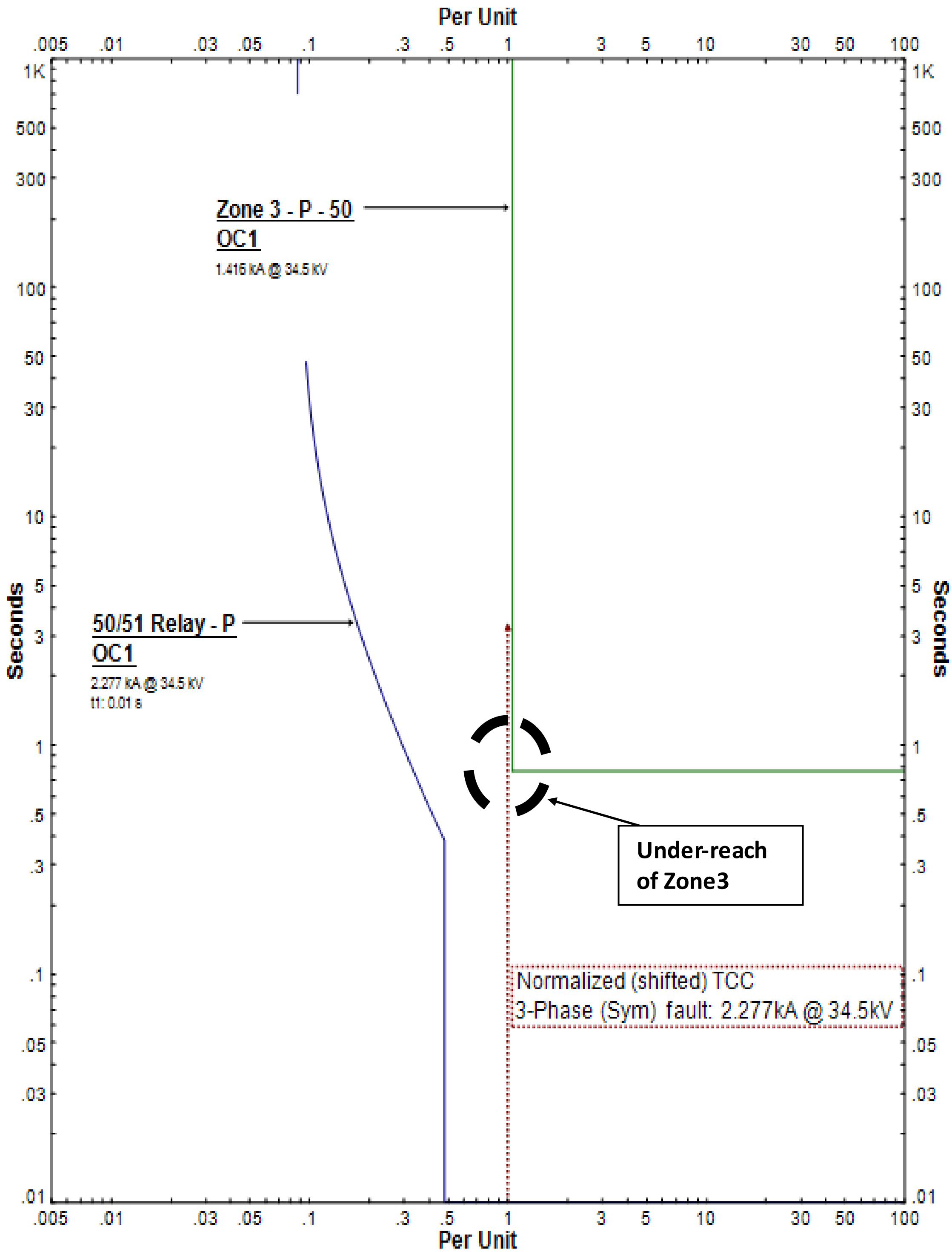

Figure 5.13. Under-reach of Zone3 for a Fault on the 34.5kV Transformer Primary Bus

5.6.2. Operation of 50/51 Overcurrent Relay Instantaneous Protection

This overcurrent relay is set to operate instantaneously for faults within the line going out of the connection bus to load2. For faults at the secondary of this transformer, this relay shall operate with some time delay to coordinate with the downstream protection.

Adding this DG, caused this O/C relay to operate instantaneously even for faults at the 13.8kV load side (over-reach). Table 5.12, Figure 5.14, and Figure 5.15 show the results for such fault.

Table 5.12. Sequence of Operation for a Fault on Load2 Bus

Protective Device	Pickup Value (kA)	Fault Current (kA)	Time (sec)
Overcurrent (50)	1.1	1.17	0.01

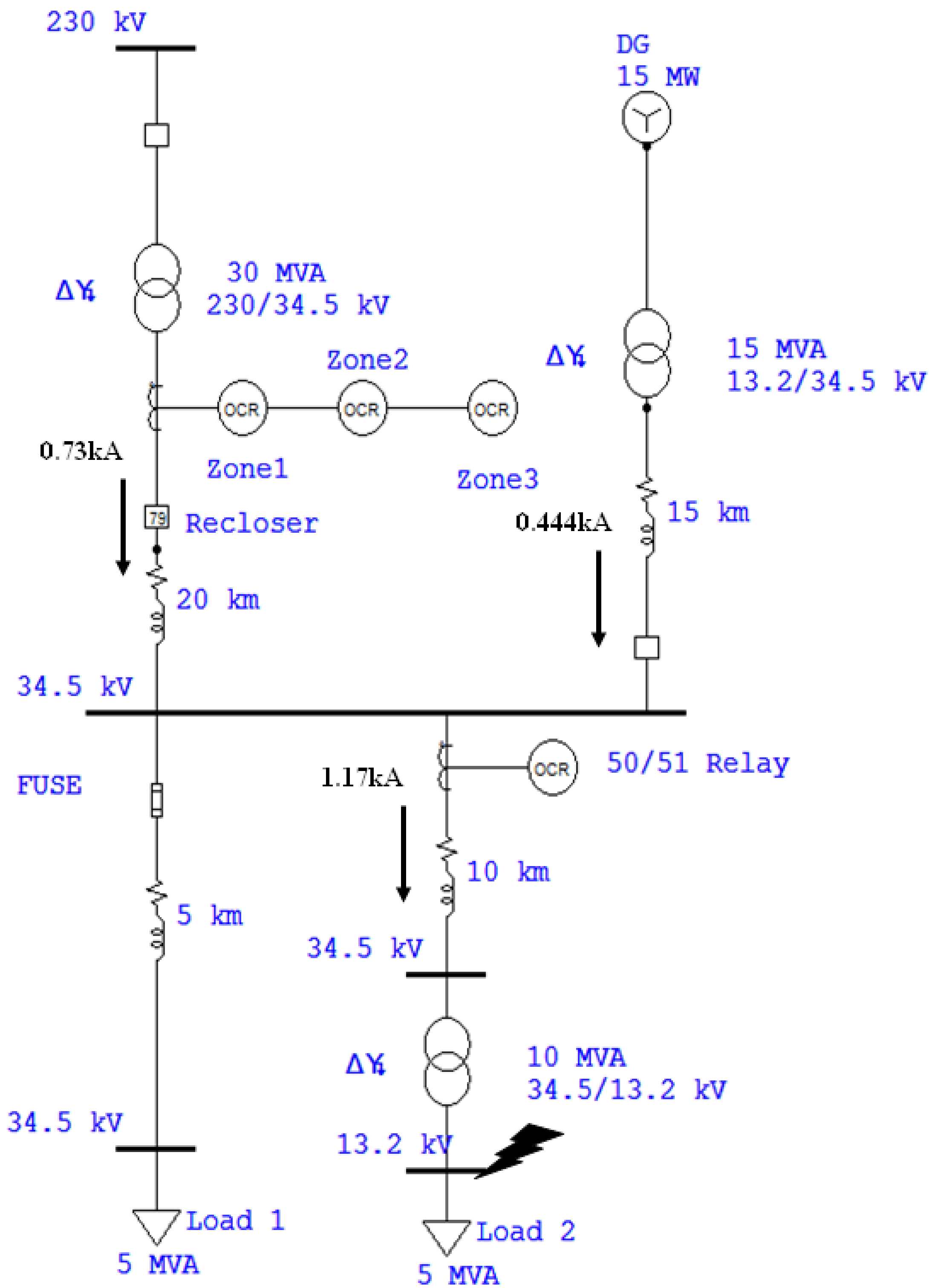

Figure 5.14. Fault Current Values for a Fault on Load2 Bus When DG is Added

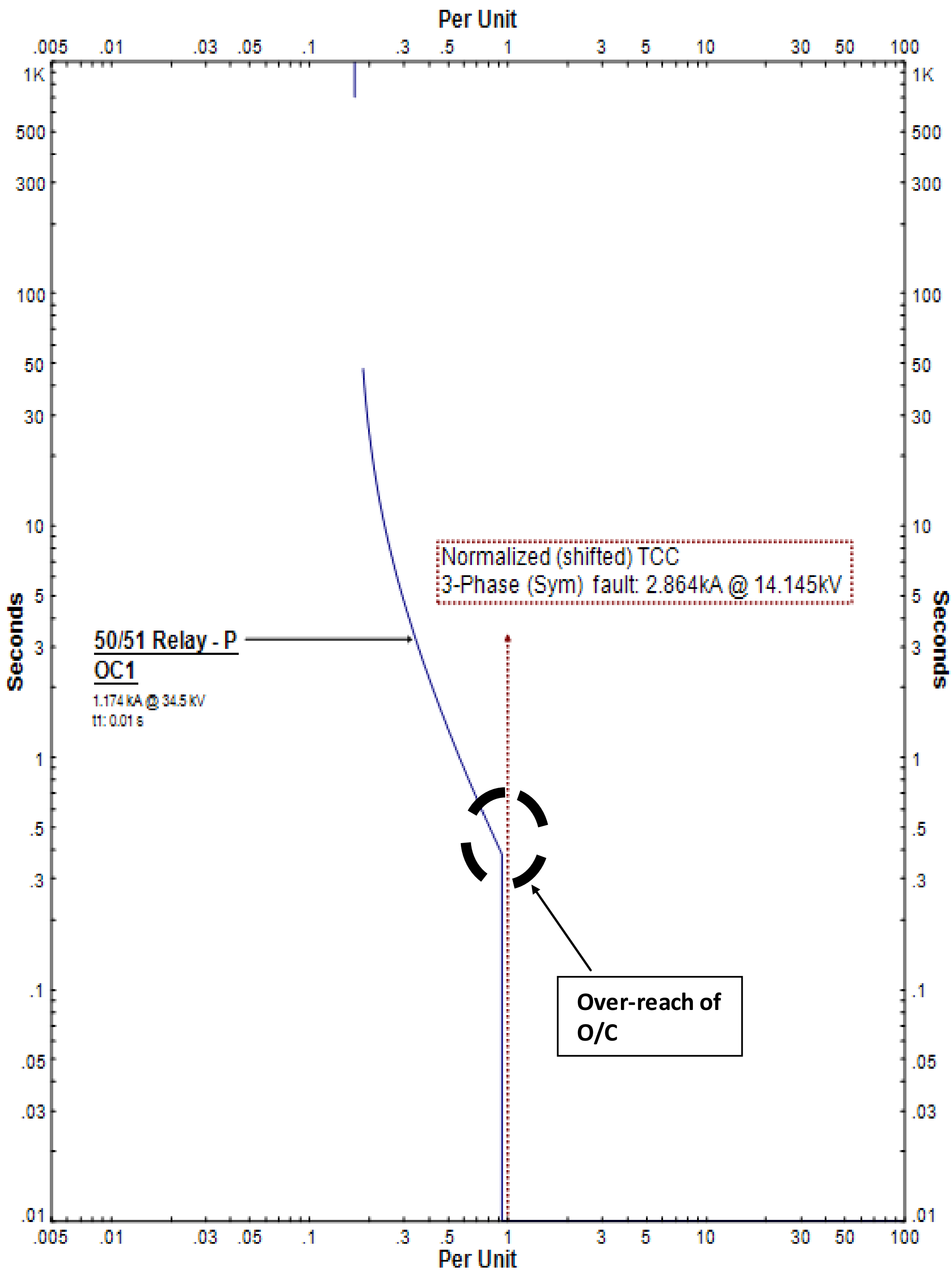

Figure 5.15. Over-reach of O/C Relay for a Fault at Load2 Bus

5.6.3. Recloser/ Fuse Coordination

The recloser is set to operate faster than the fuse to clear transient faults on the circuit the fuse is protecting as explained before. Adding such DG caused the coordination time between the fuse and the recloser to go down from 0.333 sec (Figure 5.6) to 0.06 sec as shown in Figure 5.17.

The reason for this mis-coordination is that the fault current seen by the recloser decreased from 1.78kA to 1.67kA and the fault current read by the fuse increased from 1.78kA to 3.06kA due to the addition of the DG. In other words, the recloser is seeing less current and the fuse is experiencing more current. This results on slower operation of the recloser and faster operation of the fuse. Table 5.13, Figure 5.16, and Figure 5.17 show the results for such fault.

Table 5.13. Sequence of Operation for a Fault on Load1 Bus

Protective Device	Fault Current (kA)	Time (sec)
Recloser	1.701	0.059
Fuse	2.734	0.2035

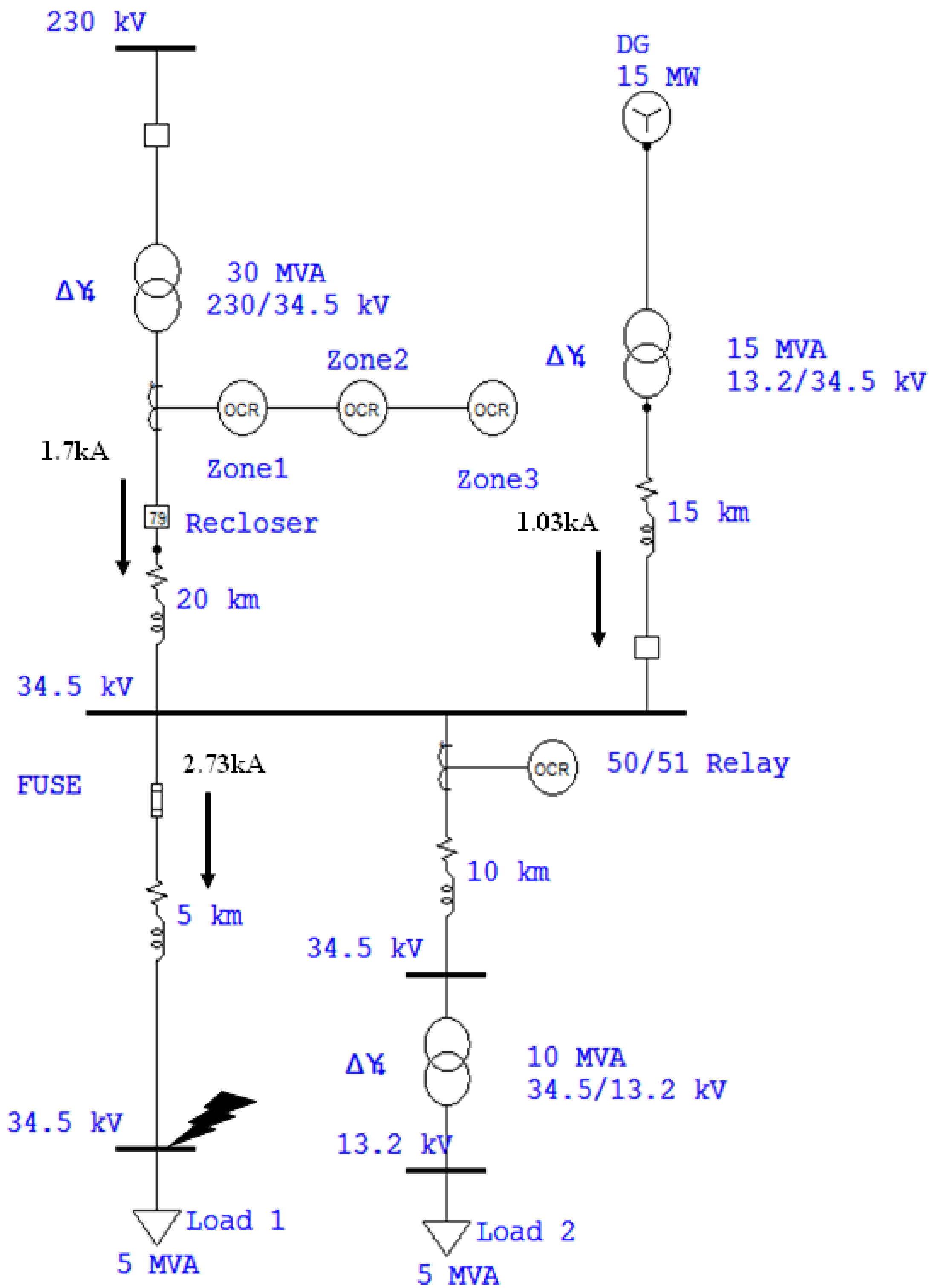

Figure 5.16. Fault Current Values for a Fault on Load1 Bus When DG is Added

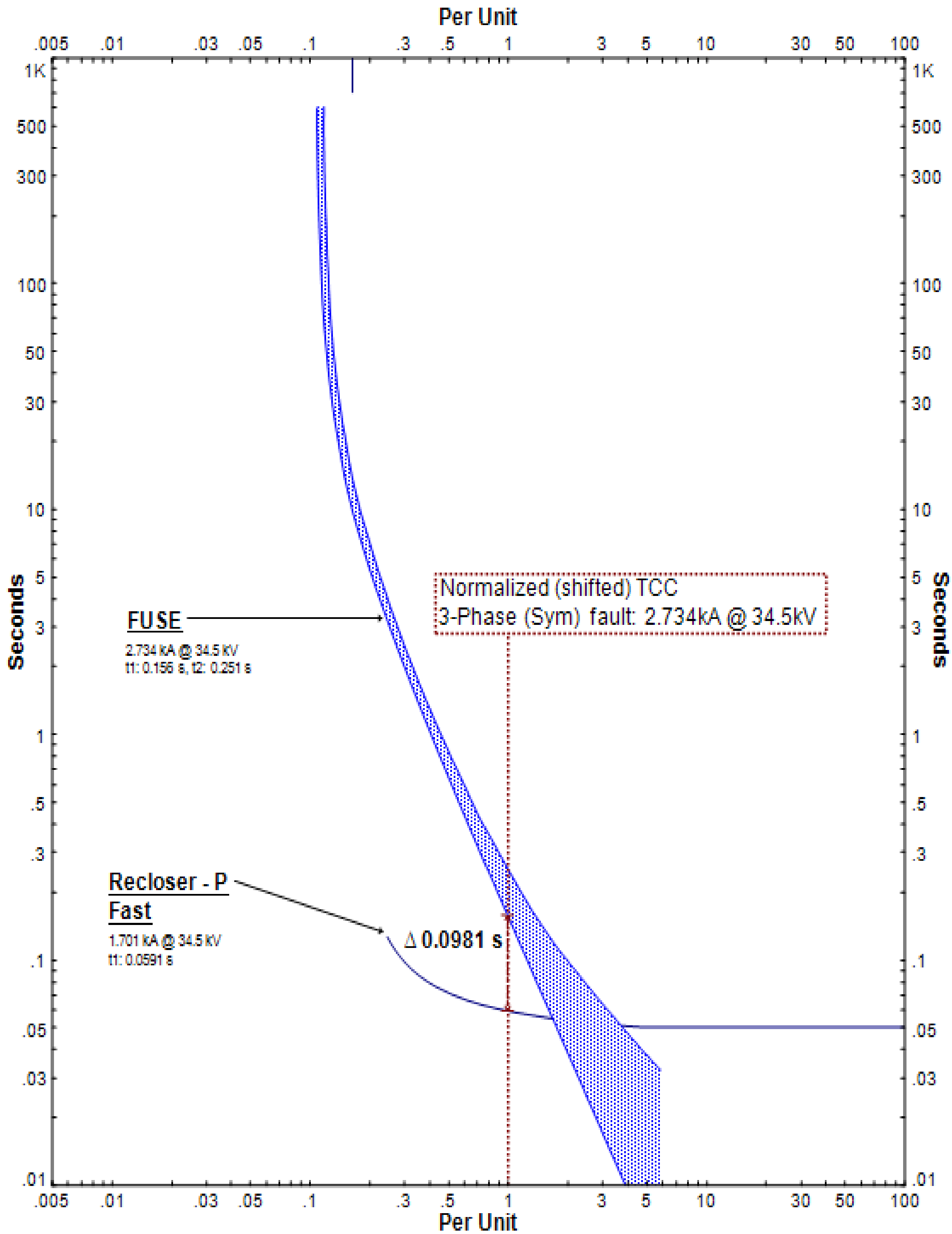

Figure 5.17. Recloser/ Fuse Mis-Coordination for a Fault on Load2 Bus

CHAPTER 6

IMPACT OF THE DG SIZE AND LOCATION ON THE SYSTEM PROTECTION

6.1. Overview

In chapter 5, the size of the DG was 15 MW and the overhead line connecting this DG to the network was 5km long. The DG was connected in between the industrial system and the loads at the connection bus. In this chapter, different scenarios will be studied. It will the impact of different DG sizes, DG distances from the network, and locations of the DG within the network.

In each case, the effect of the DG on the coordination system will be investigated considering the followings as in chapter 6;

1. Operation of Zone3 of the distance relay (fault at the 34.5kV primary bus).
2. Operation of the 50/51 relay (fault at load2 bus).
3. Recloser/ Fuse coordination (fault at load 1 bus).

6.2. Different DG Sizes

DG sizes will be changed between 0 to 15MW and line length between the DG and the connection bus will be kept at 5km distance. Three buses will be faulted for this study. These buses are; 34.5kV transformer primary bus, load1 bus, and load2 bus.

6.2.1. Fault at 34.5kV Transformer Primary Bus

A fault on this bus is to test the operation of zone3 of the distance relay. The DG size will be changed. The pickup value of the zone 3 is 1.5kA. Before the DG is connected, the fault current seen by the relay is 1.58kA.

Once the DG is connected, this fault current is decreased. Table 6.1 shows the value of the fault current seen by the relay as the DG size is changed from 0 to 15MW. Zone3 of the distance relay will under-reach once the size of the DG is more than 5MW. This is due to the decrease of the fault current seen by the distance relay below its pickup value. Figure 6.1 shows the total fault current at the faulted bus, the fault current seen by the relay and the pickup value of zone3.

Table 6.1. Short Circuit Values at the 34.5kV Transformer Primary Bus for Different DG Sizes

DG Size (MW)	Faulted bus Total Fault Current (kA)	Fault Current Through the Impedance Relay (kA)	Zone3 Pickup (kA)	Correct Operation
0	1.58	1.58	1.5	YES
2.5	1.74	1.54	1.5	YES
3	1.77	1.53	1.5	YES
5	1.88	1.51	1.5	YES
7.5	2	1.48	1.5	NO
10	2.11	1.46	1.5	NO
12.5	2.2	1.44	1.5	NO
15	2.28	1.42	1.5	NO

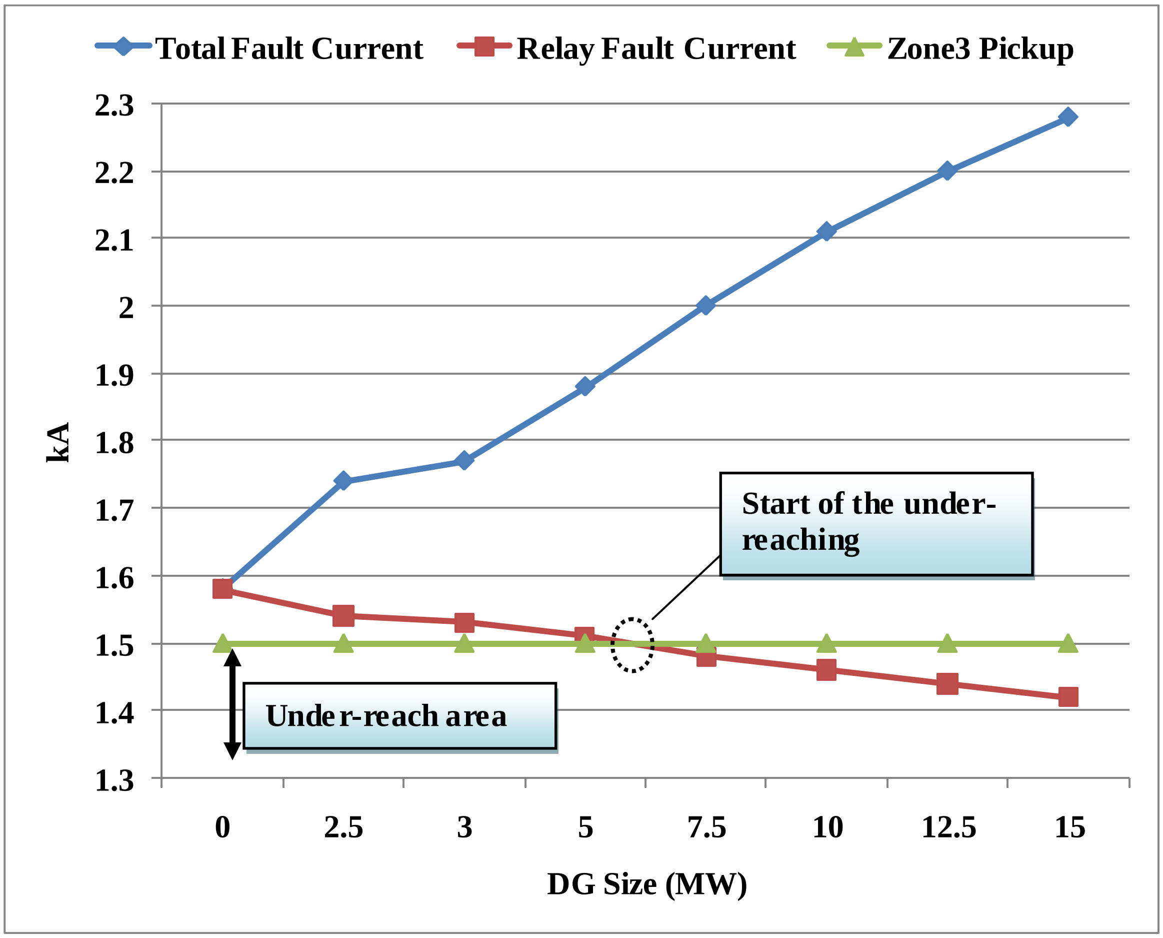

Figure 6.1. DG Sizes and Under-Reaching of Zone3 of Distance Relay

6.2.2. Fault at Load 2 Bus

A fault on this bus is to test the operation of the instantaneous protection of the overcurrent relay. The DG size will be changed. The pickup value of the instantaneous relay 50 is 1.1kA. Before the DG is connected, the fault current seen by the relay is 0.949kA.

Once the DG is connected, the fault current seen by the overcurrent relay is increased. Table 6.2 shows the value of the fault current seen by the relay as the DG size is increased from 0 to 15MW. The instantaneous protection of the 50/51 relay will over-reach once the DG size is more than 7.5MW. Figure 6.2 shows the fault current seen by the relay and pickup value of the instantaneous protection (50).

Table 6.2. Short Circuit Values at the Load2 Bus for Different DG Sizes

DG size (MW)	50/51 Relay fault current (kA)	Instantaneous pickup (kA)	correct operation
0	0.949	1.1	YES
2.5	1.01	1.1	YES
5	1.06	1.1	YES
7.5	1.09	1.1	YES
10	1.13	1.1	NO
12.5	1.15	1.1	NO
15	1.17	1.1	NO

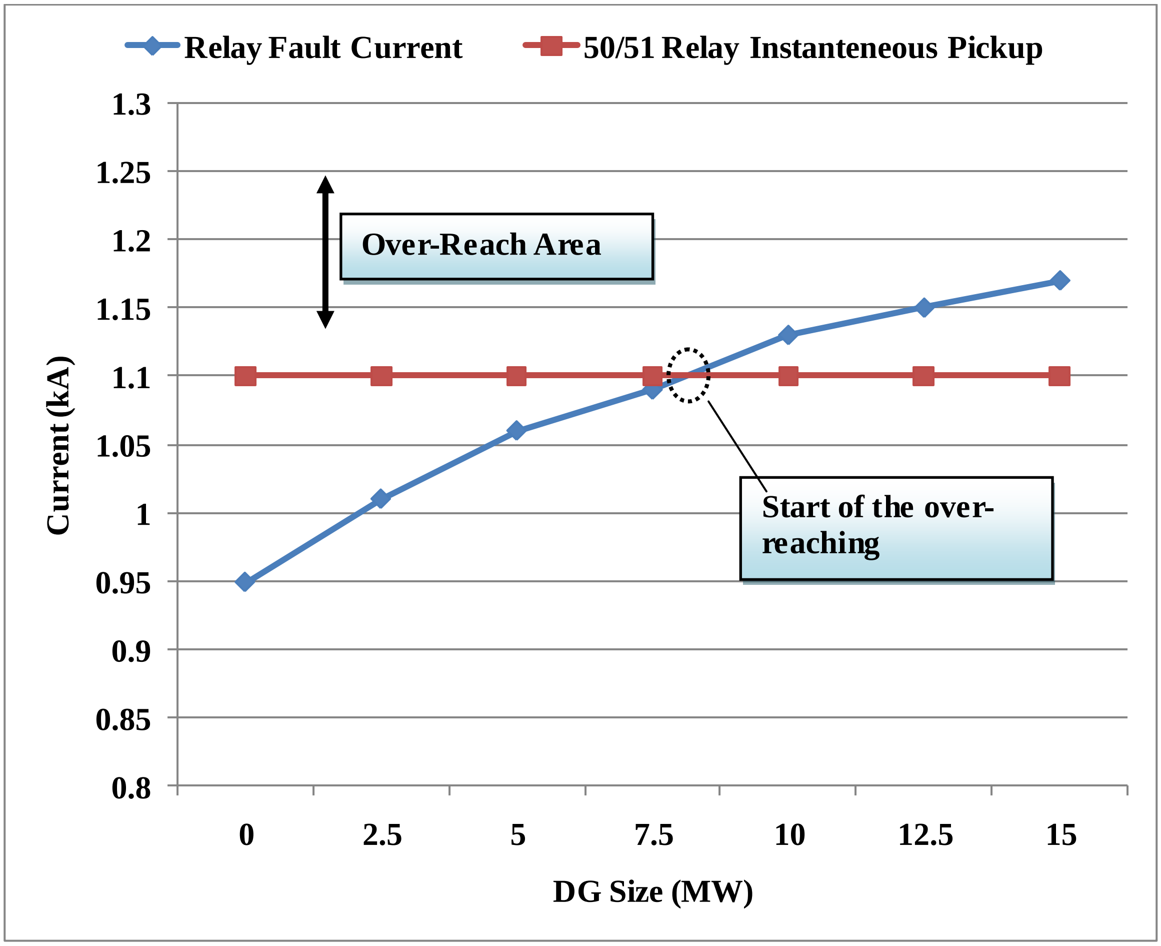

Figure 6.2. DG Sizes and Over-Reaching of the Instantaneous Protection of the 50/51 O/C Relay

6.2.3. Fault at Load 1 Bus

A fault on this bus is to test the coordination between the recloser and the fuse. The DG size will be changed. Before the DG is connected, the coordination time between the recloser and the fuse is 0.333sec. once the DG is connected, the fault current seen by the recloser is decreased where the fault current seen by the fuse is increased.

Table 6.3 shows the value of the fault current seen by the fuse and the recloser as the DG size is changed from 0 to 15MW. If the threshold value of the coordination time between the fuse and the recloser is set to be 0.25 sec, the coordination time is lost at DG size of 5MW. Figure 6.3 shows the fault current seen by the fuse and the recloser and the coordination time between them.

Table 6.3. DG Size Effects on Recloser/Fuse Coordination

DG Size (MW)	Recloser fault current(kA)	Clearance Time (sec)	Fuse fault current (kA)	Clearance Time (sec)	Coordination time ($T_{fuse} - T_{REC}$)
0	1.779	0.0586	1.779	0.445	0.3864
2	1.764	0.0587	1.953	0.370	0.3113
5	1.746	0.0588	2.181	0.303	0.2442
7.5	1.733	0.0589	2.345	0.2665	0.2076
10	1.721	0.0589	2.49	0.2395	0.1806
12.5	1.71	0.059	2.619	0.2195	0.1605
15	1.701	0.0591	2.734	0.2035	0.1444

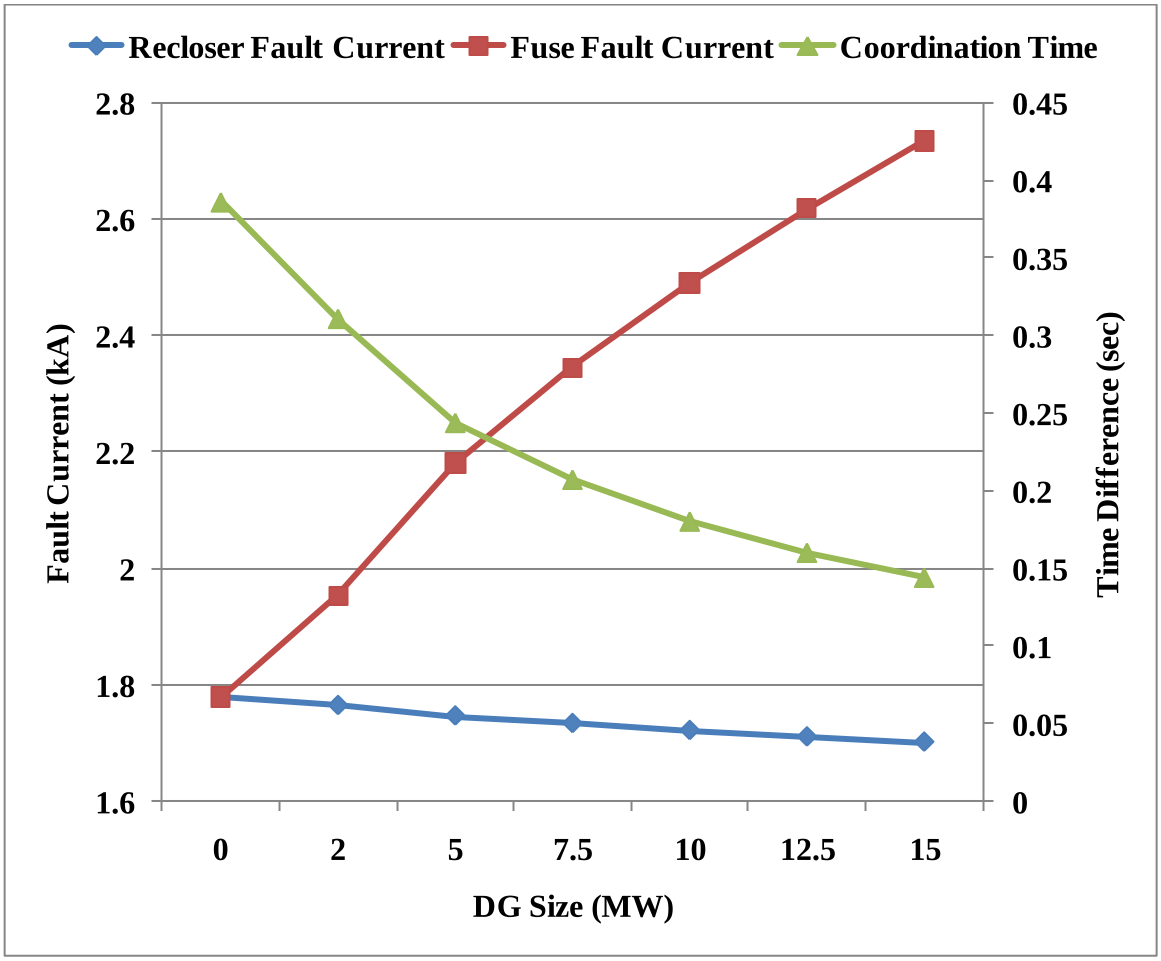

Figure 6.3. DG Size Effects on Recloser/Fuse Coordination

6.3. Distribution Line Lengths

In this section, the effect of the line length between the DG and the network on the coordination system will be studied. The length of the DG feeder will be changed from 0 to 5km. The size of DG will be kept at 15MW. The same procedure in section 6.2 will be followed.

6.3.1. Fault at 34.5kV Transformer Primary Bus

A fault on this bus is to test the operation of zone3 of the distance relay. The line length will be changed. The pickup value of zone3 is 1.5kA. Before the DG is connected, the fault current seen by the relay is 1.58kA.

Once the DG is connected, the fault current seen by the relay is decreased. Table 6.4 shows the value of the fault current seen by the relay as the DG distance will be changed. Zone3 of the distance relay will always under-reach until the line length between the DG and the network reaches 130km. Figure 6.4 shows the fault current seen by the relay, total fault current at the faulted bus and the pickup value of zone3

Table 6.4. Short Circuit Values at the 34.5kV Transformer Primary Bus for Different Line Length

Line Length (km)	Faulted bus Total Fault Current (kA)	Impedance Relay Fault Current (kA)	Zone3 Pickup (kA)	Correct Operation
0	2.31	1.41	1.5	No
5	2.28	1.42	1.5	No
10	2.25	1.42	1.5	No
20	2.19	1.44	1.5	No
30	2.15	1.45	1.5	No
40	2.11	1.45	1.5	No
50	2.08	1.46	1.5	No
100	1.96	1.49	1.5	No
130	1.91	1.5	1.5	Yes

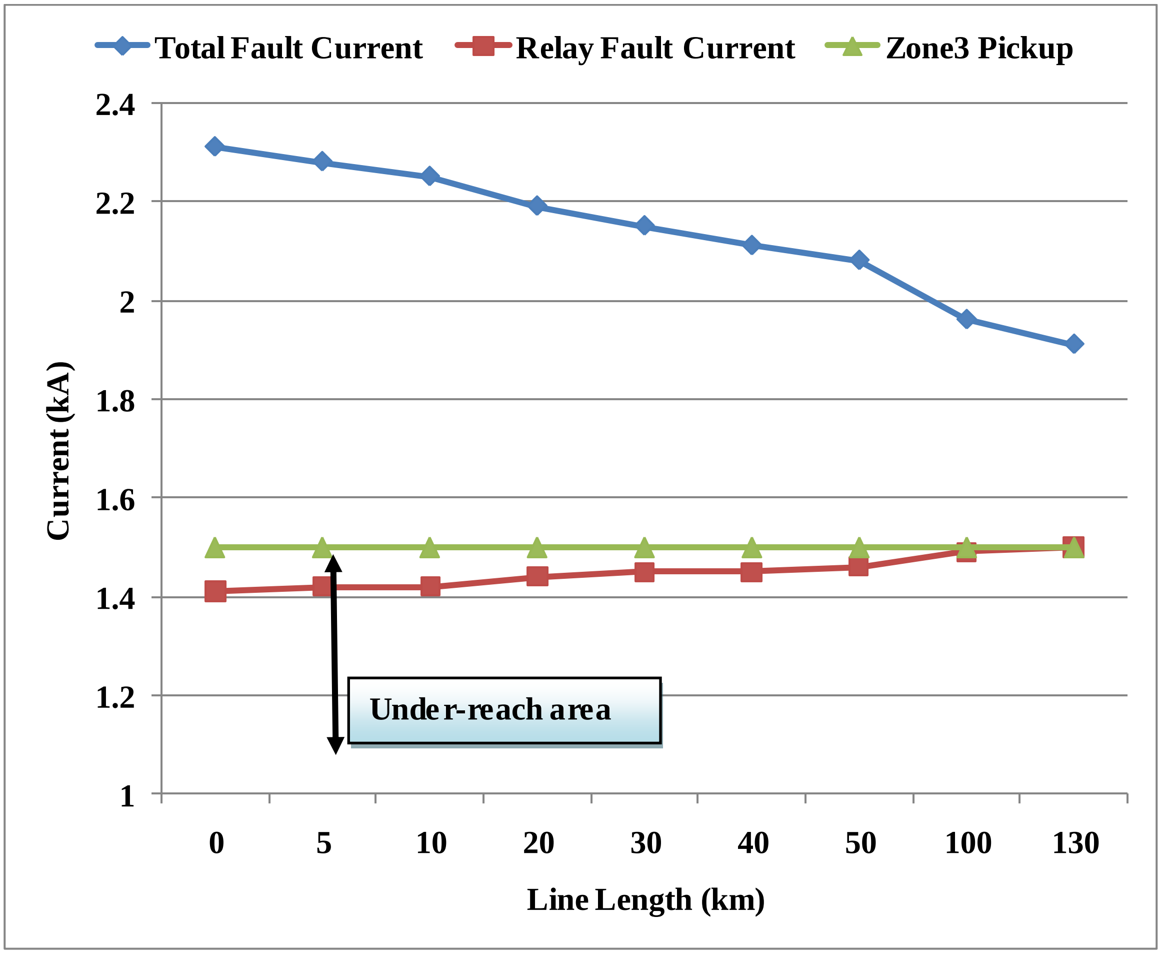

Figure 6.4. Short Circuit Values at the 34.5kV Transformer Primary Bus for Different Line Length

6.3.2. Fault at Load 2 Bus

A fault on this bus is to test the operation of the instantaneous protection of the 50/51 overcurrent relay. The line length will be changed. The pickup value of the instantaneous relay 50 is 1.1kA. Before the DG is connected, the fault current seen by the relay is 0.949kA.

Once the DG is connected, the fault current seen by the 50/51 overcurrent relay is increased. Table 6.5 shows the value of the fault current seen by the relay as the line length is changed. The instantaneous protection of the 50/51 relay will not over-reach once the line length reaches 80km. Figure 6.5 shows the fault current seen by the relay and the pickup value of the instantaneous protection of the 50/51 relay.

Table 6.5. Short Circuit Values at the Load2 Bus for Different Line Lengths

Line Length (km)	50/51 Relay fault current (kA)	Instantaneous pickup (kA)	correct operation
0	1.18	1.1	No
10	1.17	1.1	No
20	1.15	1.1	No
50	1.12	1.1	No
70	1.1	1.1	No
80	1.09	1.1	Yes

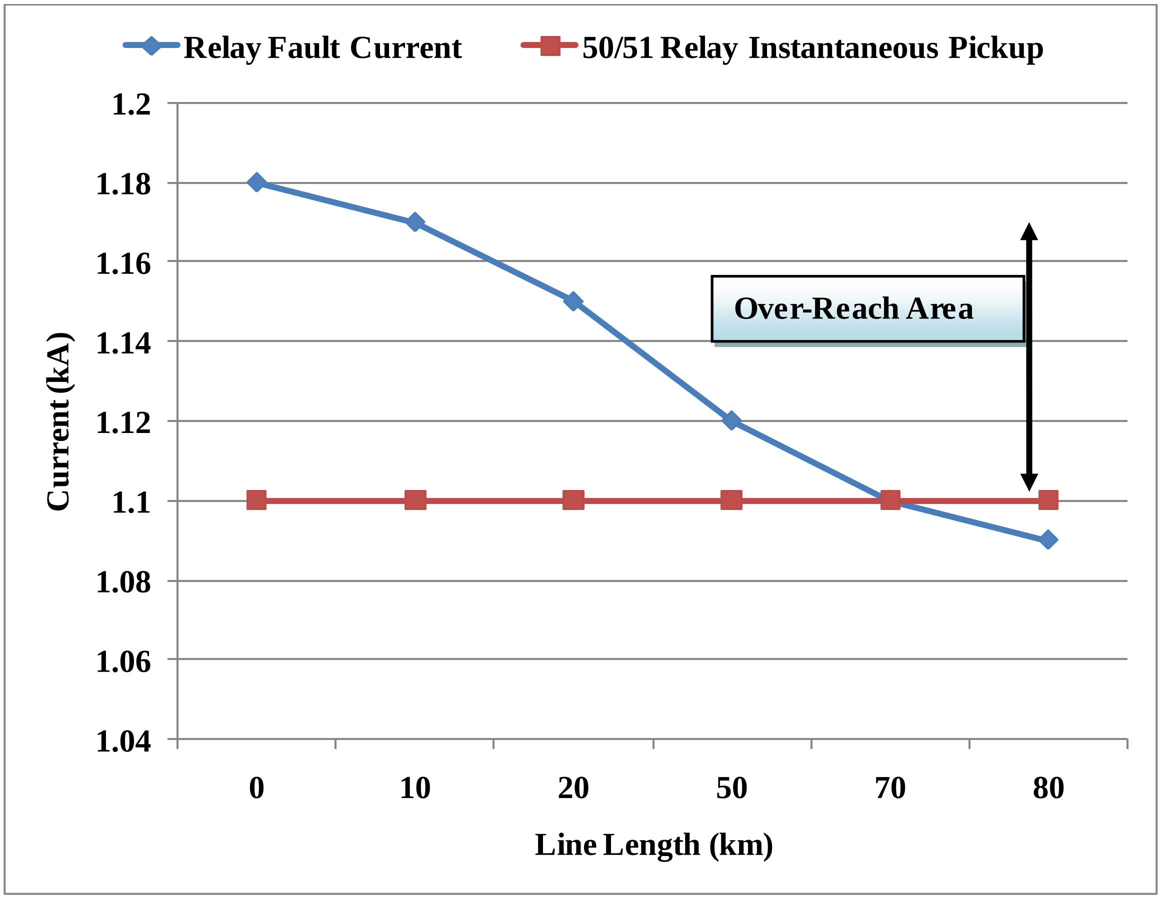

Figure 6.5 Line Lengths and Over-Reaching of the Instantaneous Protection of 50/51 O/C Relay

6.3.3. Fault at Load 1 Bus

A fault on this bus is to test the coordination between the recloser and the fuse. The line length will be changed. Before the DG is connected, the coordination time between the recloser and the fuse is 0.333 sec.

Once the DG is connected, the fault current seen by the recloser is decreased where the fault current seen by the fuse is increased. Table 6.6 shows the value of the fault current seen by the fuse and the recloser as the line length are changed. If the threshold value of the coordination time between the fuse and the recloser is set to be 0.25 sec, the coordination time will always be lost. Figure 6.6 shows the fault current seen by the fuse and the recloser and the coordination time between them.

Table 6.6. Line Length Effects on the Fuse/Recloser Coordination Time

Line Length (km)	Recloser I_F (kA)	Recloser Clearance Time (sec)	Fuse I_F (kA)	Fuse Clearance Time (sec)			T_{DIF} (sec) $T_{fuse} - T_{REC}$
				T1	T2	T_{AVG}	
0	1.698	0.0591	2.781	0.15	0.245	0.1975	0.1384
5	1.701	0.0591	2.734	0.156	0.251	0.2035	0.1444
10	1.704	0.059	2.691	0.161	0.258	0.2095	0.1505
20	1.711	0.059	2.615	0.17	0.269	0.2195	0.1605
30	1.716	0.059	2.551	0.179	0.28	0.2295	0.1705
40	1.72	0.0589	2.497	0.187	0.29	0.2385	0.1796
50	1.724	0.0589	2.490	0.194	0.299	0.2465	0.1876

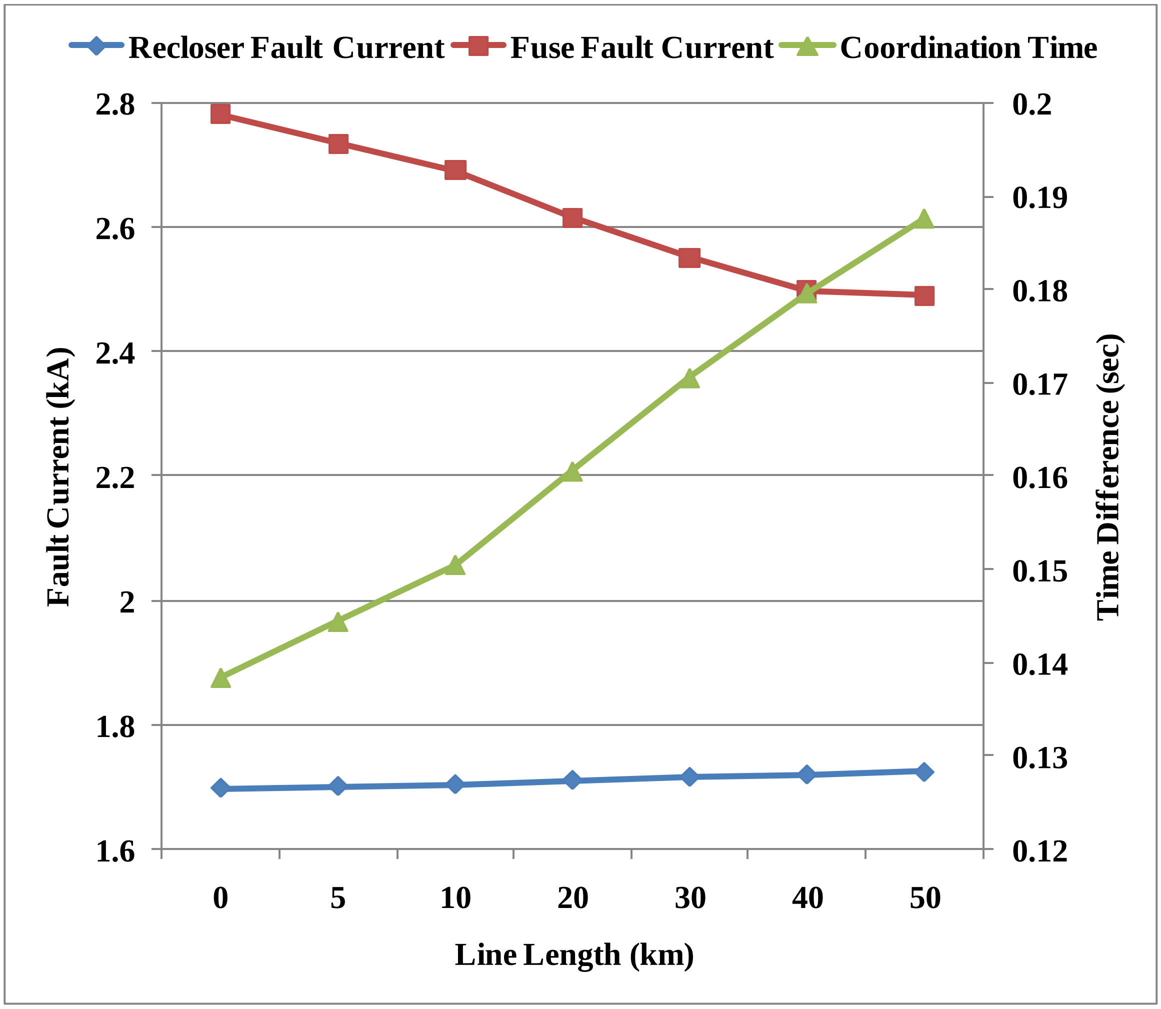

Figure 6.6. Line Length Effects on the Fuse/Recloser Coordination Time

6.4. Different DG locations within the Network

In this section, the connection point of the DG to the network will be changed. Three locations more will be studied as follows;

1. Load1 side (location 1 in Figure 6.7)
2. Load2 side (location 2 in Figure 6.7)
3. Transformer secondary side (location 3 in Figure 6.7)

For every location, the same three buses will be faulted and the effects on the coordination will be studied. As before, it will consider the operation of the impedance relay, operation of the instantaneous 50/51 overcurrent relay, and the fuse/recloser coordination time. The size of the DG will be kept at 15MW and the line length will be kept at 5km.

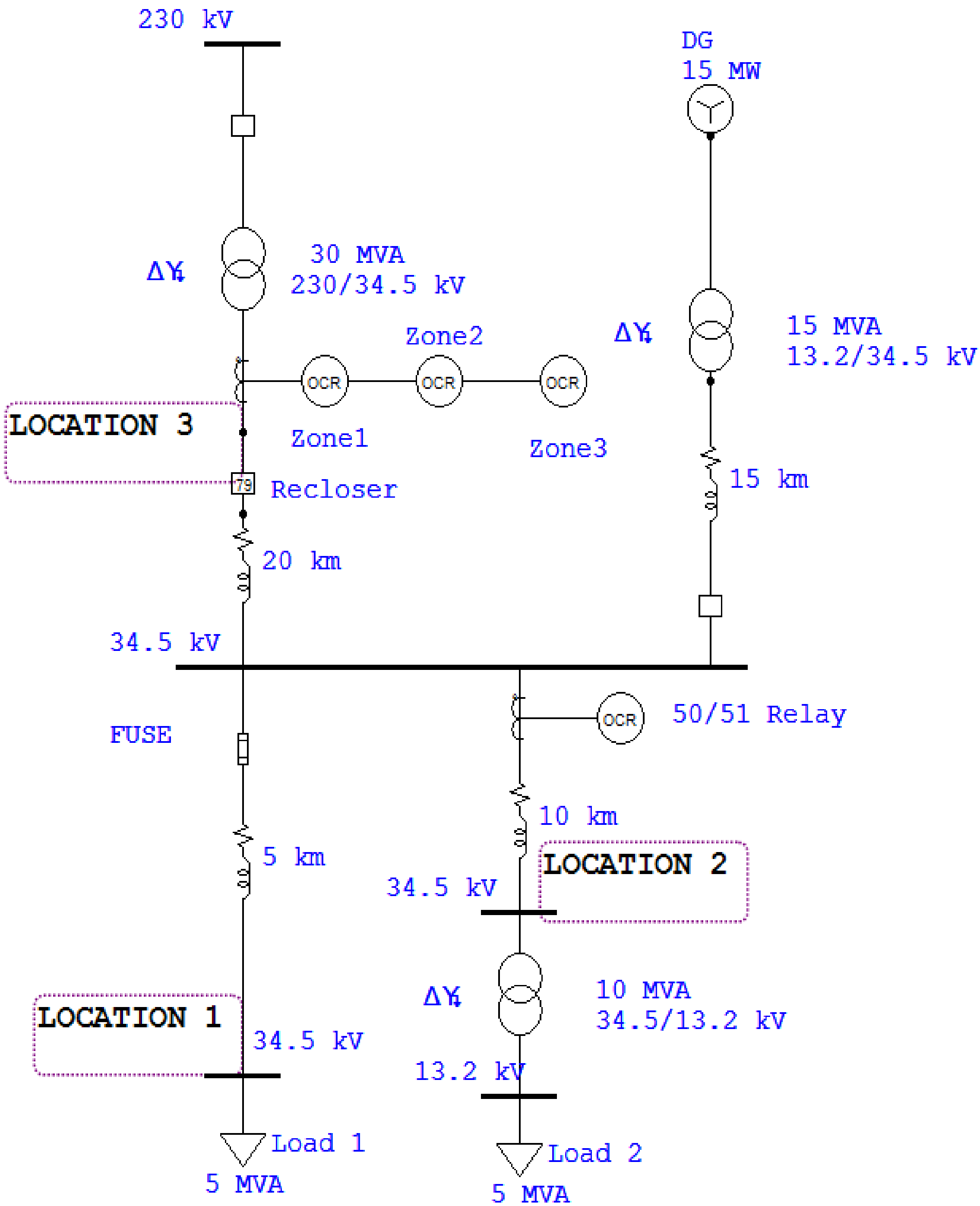

Figure 6.7. Different DG Locations within the Distribution Network

6.5. DG at Load 1 Side (Location 1)

For this location, the operation of the zone3 of the distance relay, the operation of 50/51 relay, and the coordination time between the recloser and fuse will be investigated.

6.5.1. Fault at 34.5kV Transformer Primary Bus

A fault on this bus is to test the operation of the 50/51 overcurrent relay and zone 3 of the distance relay. Table 6.7, Figure 6.8, and Figure 6.9 show the fault current values and the protective devices operation time as a result of such fault.

Zone3 of the distance relay did not operate for a fault on the 34.5kV transformer primary bus (under-reached) when the DG was connected. The fault current seen by the distance relay is 1.42kA which is less than its pickup value (1.5kA). Another mis-operation was experienced. The fuse was blown for a fault out of its zone. This is due to the DG fault current seen by the fuse. For the overcurrent relay, it operated instantaneously as expected.

Having the DG connected on load1 bus side, it will cause the fuse to be blown and zone 3 of the distance relay to under-reach.

Table 6.7. Sequence of Operation for a Fault on 34.5kV Transformer Primary Bus

Protective Device	Pickup Value (kA)	Fault Current (kA)	Time (sec)
Overcurrent (50)	1.1	2.24	0.01
Fuse	-	0.825	1.984
Zone3	1.5	1.42	∞

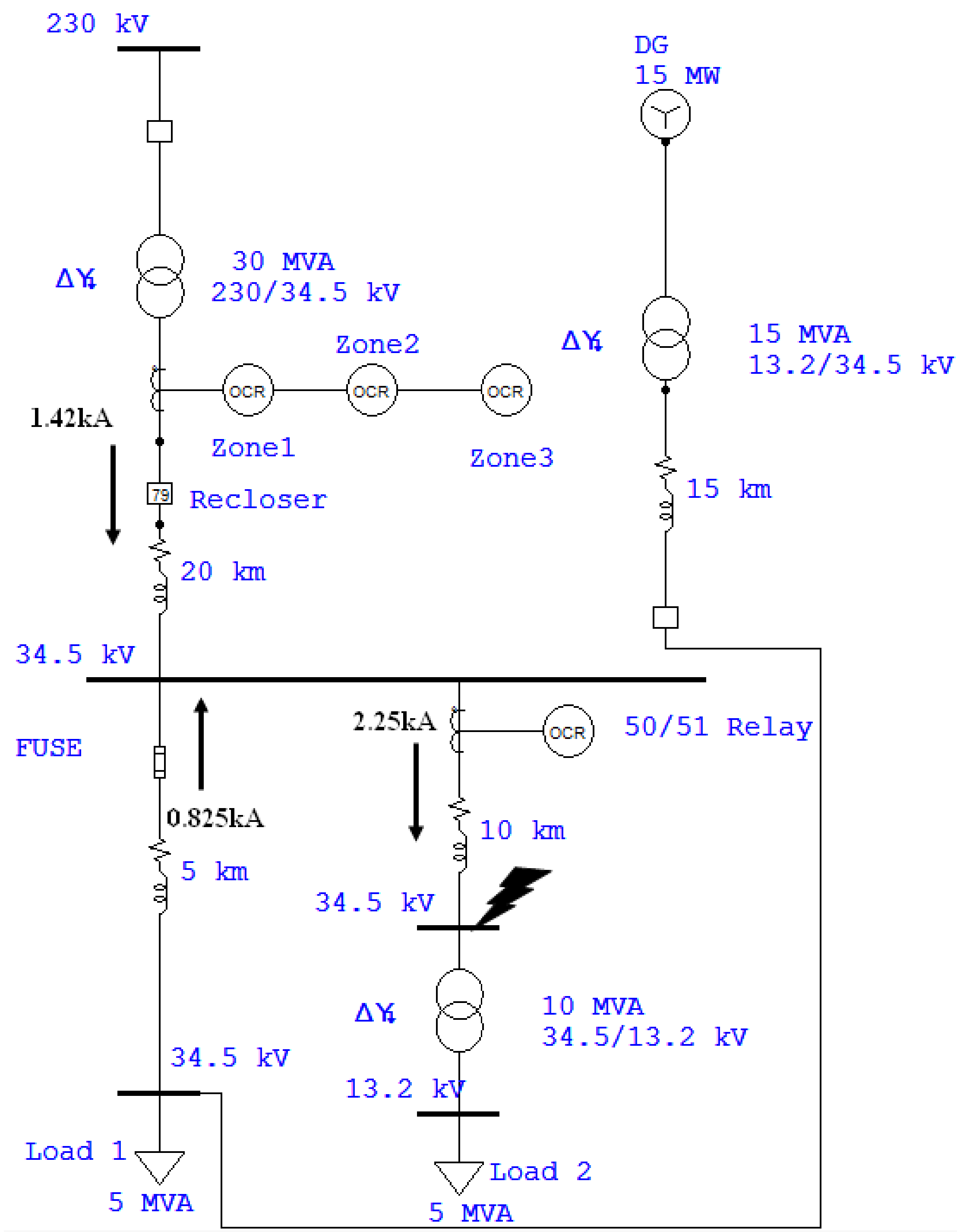

Figure 6.8. Fault Current Values for a Fault on the 34.5kV Transformer Primary Bus When a DG on Location1

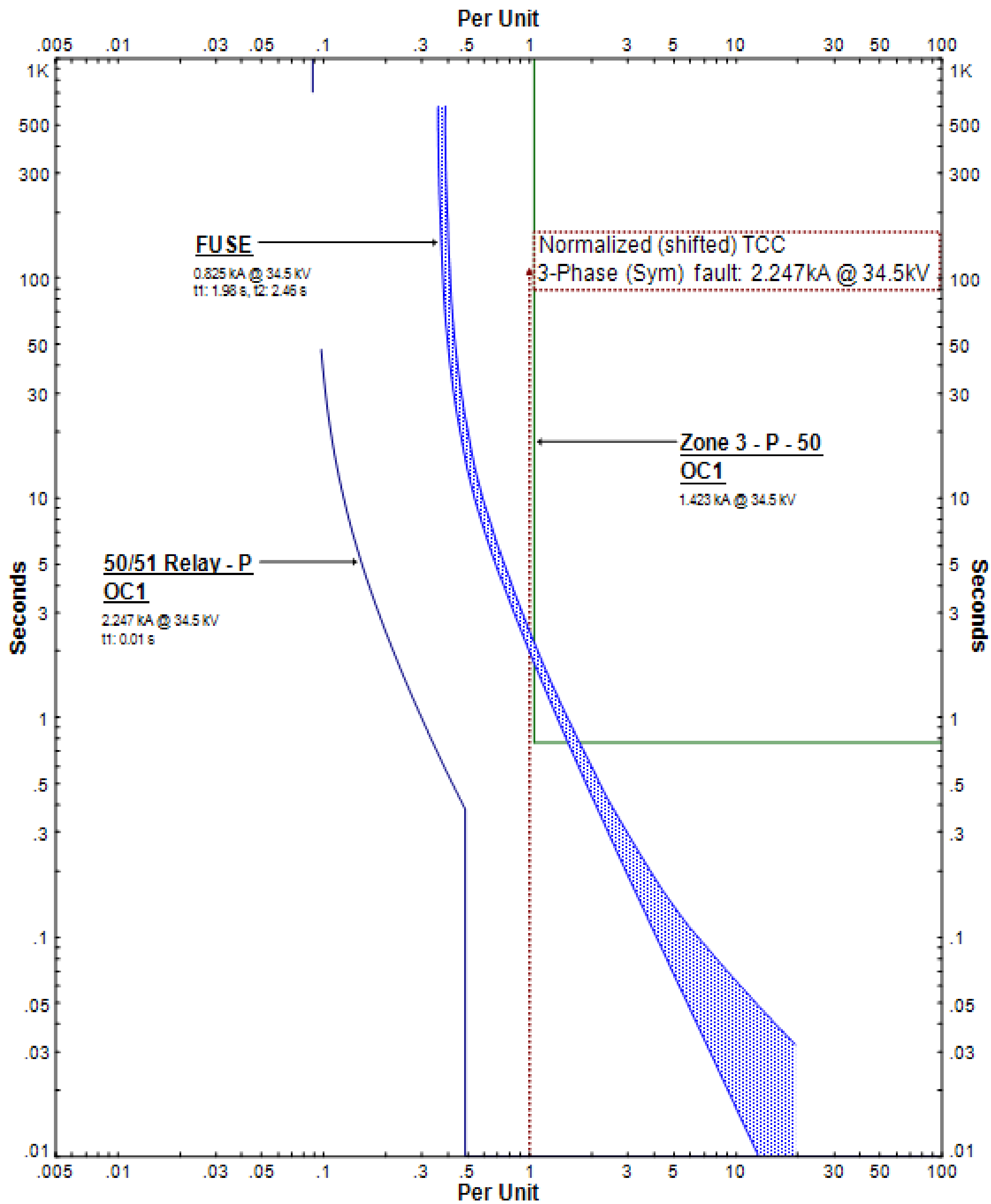

Figure 6.9. Operation of the Protective Devices for Fault on the 34.5kV Primary Bus

6.5.2. Fault at Load 2 Bus

A fault on this bus is to test the operation of the overcurrent relay. Table 6.8, Figure 6.10 and Figure 6.11 show the results.

The overcurrent over-reached for this fault on load2 bus. The fault current seen by the overcurrent relay is 1.17kA which is above its pick up value (1.1kA). The fuse on the other circuit was blown as well. This is due to the DG fault current seen by the fuse.

Having the DG connected at load1 bus side causes the fuse to operate for faults outside its zone. Furthermore, the overcurrent relay over-reach fault faults on the 13.8kV transformer secondary bus.

Table 6.8. Sequence of Operation for a Fault on Load2 Bus

Protective Device	**Pickup (kA)**	**Fault Current (kA)**	**Time (sec)**
50/51 Relay	1.1	1.166	0.01
Fuse	-	0.428	14.55

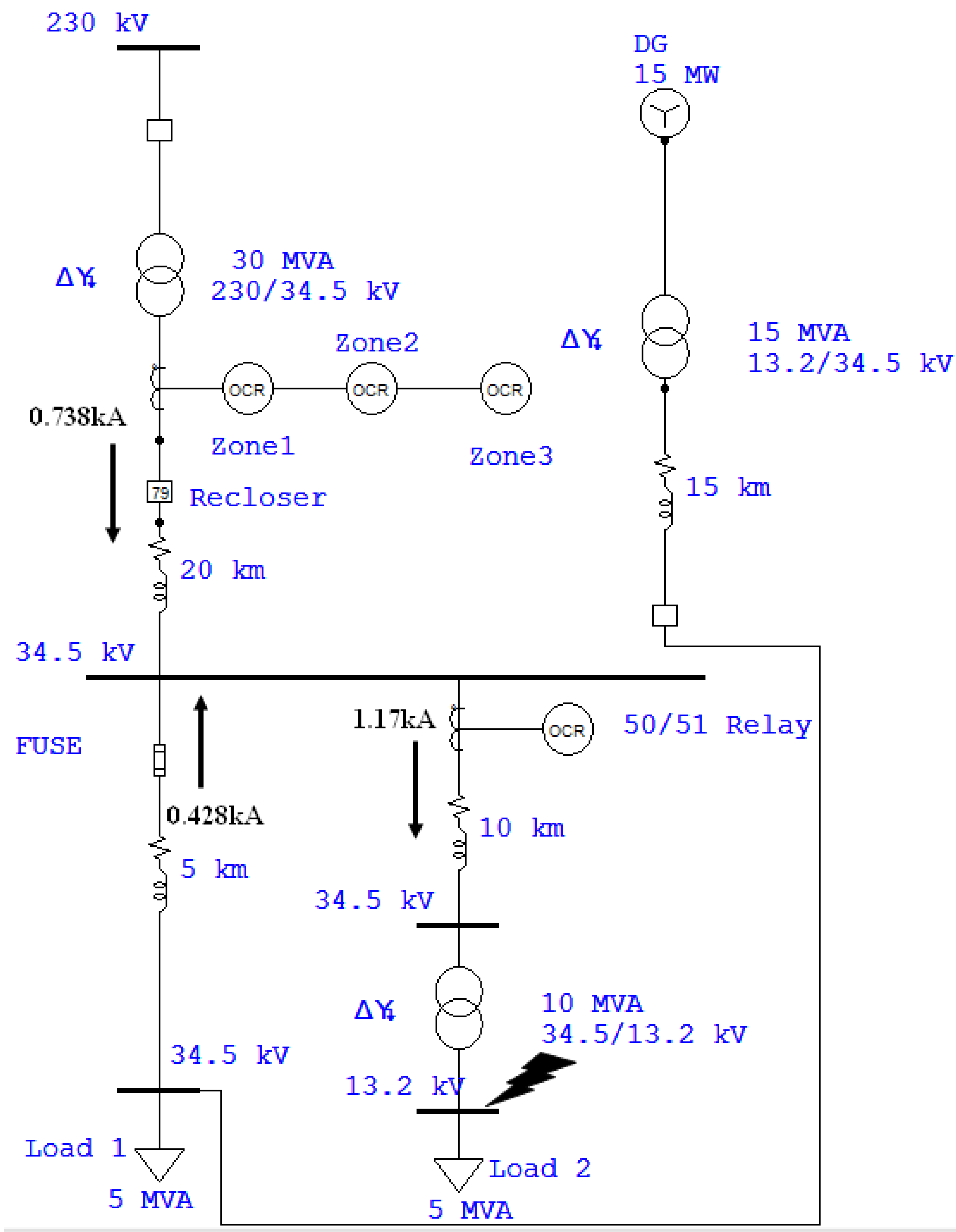

Figure 6.10. Fault Current Values for a Fault on Load2 Bus When a DG is on Location 1

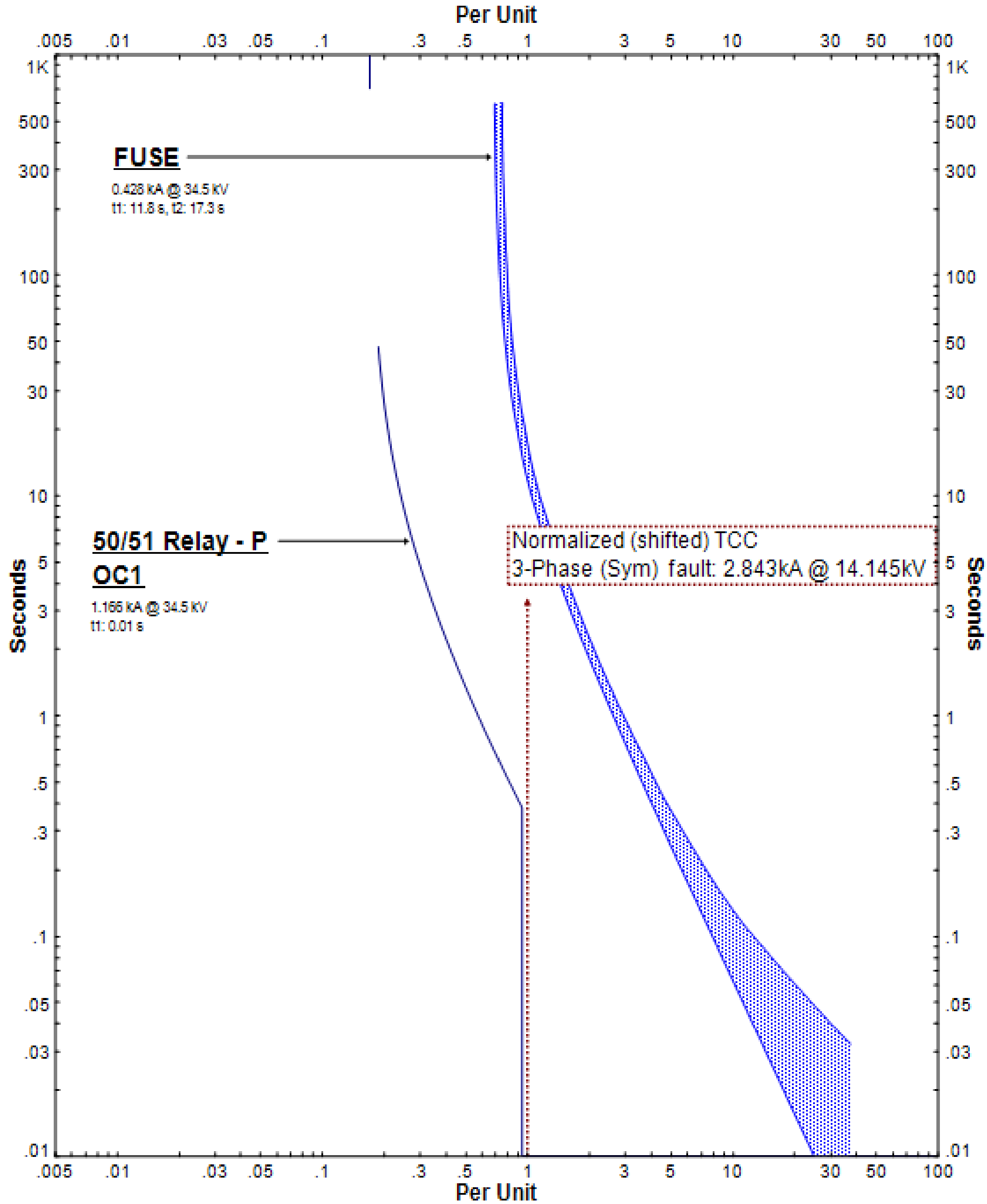

Figure 6.11. Operation of Protective Devices for Faults on Load2 Bus

6.5.3. Fault at Load 1 Bus

A fault on this bus is to test the coordination between the fuse and the recloser. Table 6.9, Figure 6.12, and Figure 6.13 show the results.

The coordination between the recloser and fuse was not lost. The reason for this is that the same fault current is going through both; recloser and the fuse. Also, this fault current is reduced due to the addition of the DG.

Table 6.9. Sequence of Operation for a Fault on Load1 Bus

Protective Device	**Fault Current (kA)**	**Time (sec)**
Recloser	1.779	0.0186
Fuse	1.779	0.445

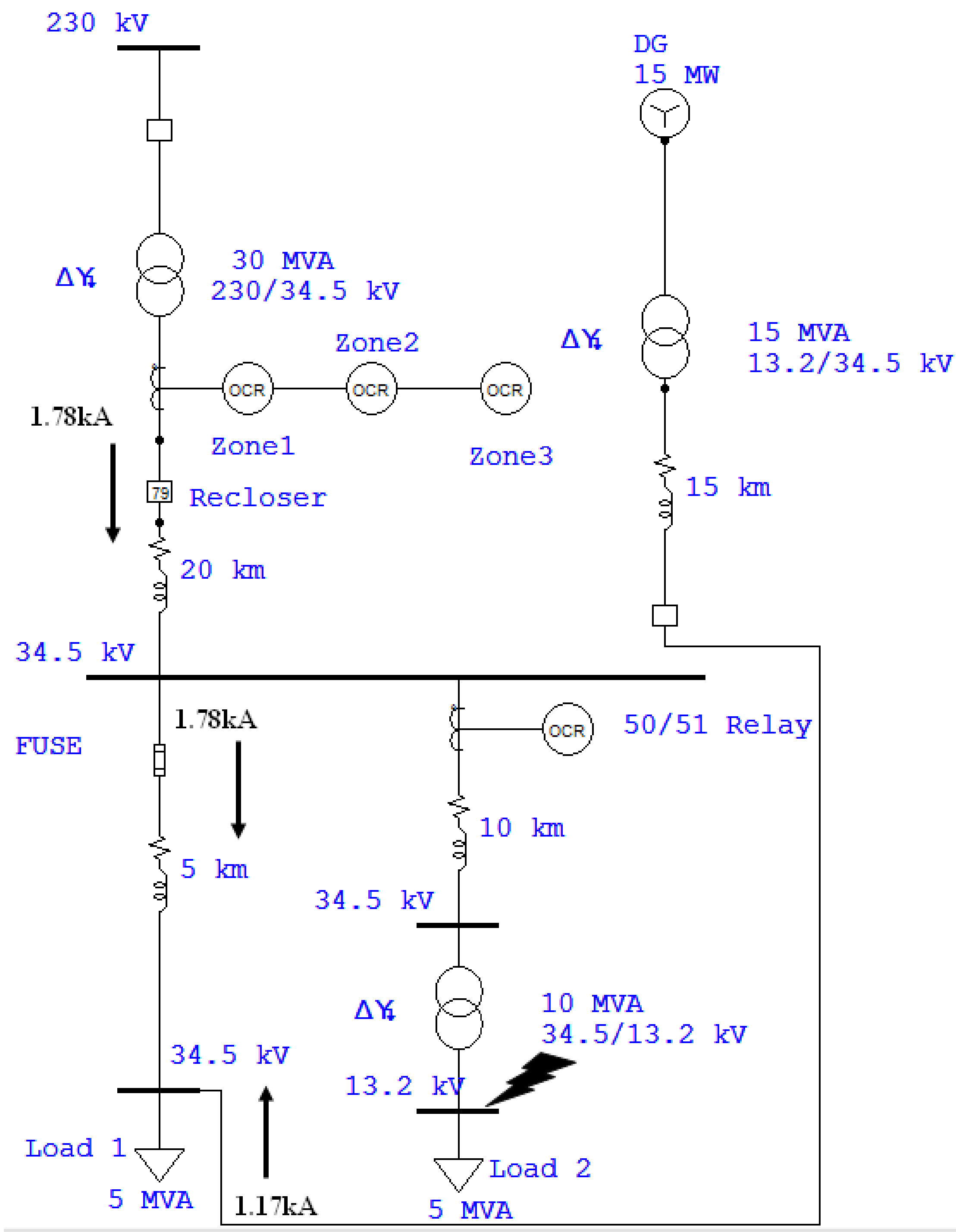

Figure 6.12. Fault Current Values for a Fault on Load1 Bus When DG is on Location1

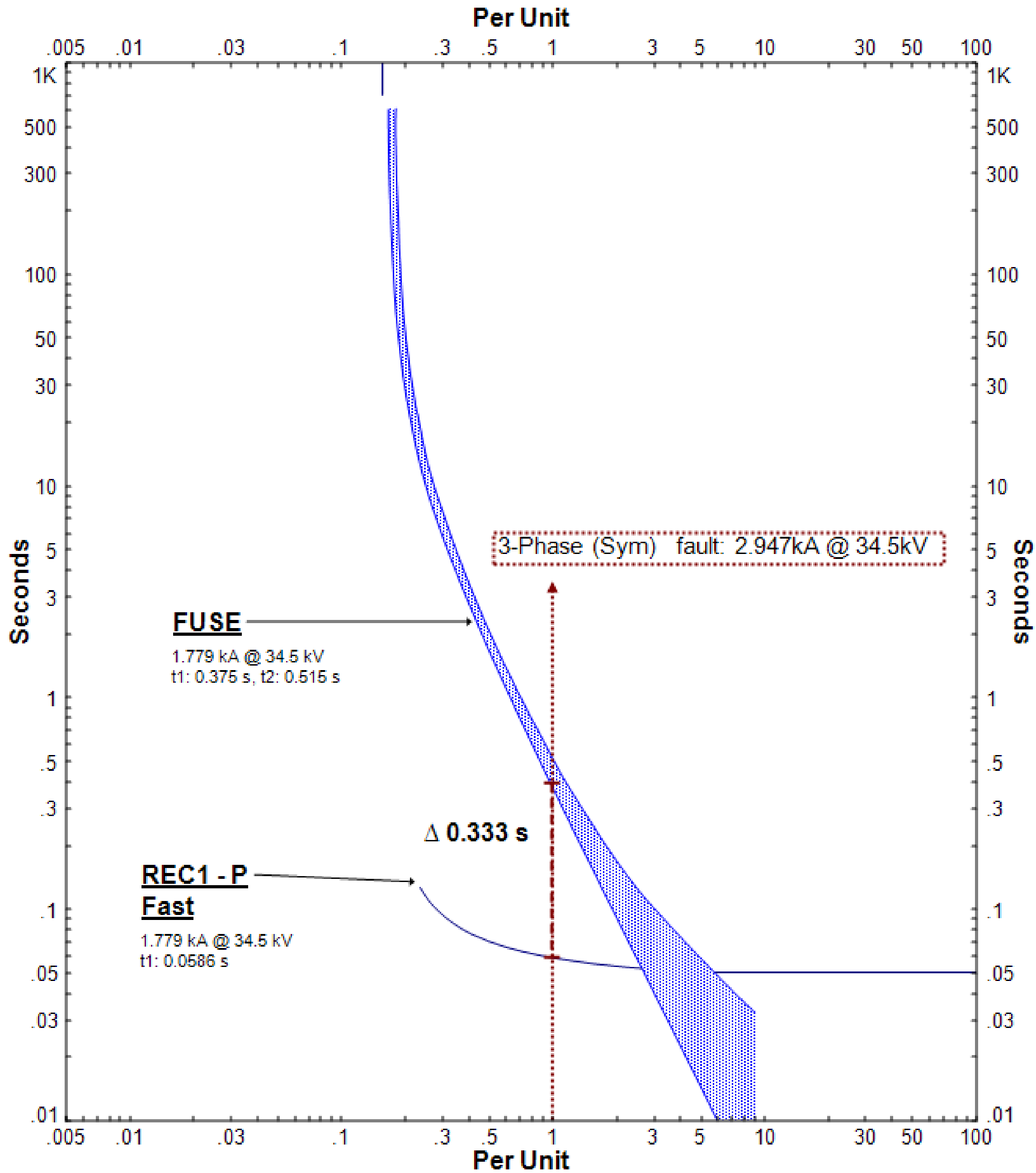

Figure 6.13. Coordination Time between Fuse and the Recloser for Fault on Load1 Bus

6.6. DG at Load 2 (location 2)

For this location, the operation of the protective devices will be tested for the faults on the three buses as explained before.

6.6.1. Fault at 34.5kV Transformer Primary Bus

A fault on this bus is to test the operation of the overcurrent relay and zone 3 of the distance relay. Table 6.10, Figure 6.14, and Figure 6.15 show the results of such fault.

Zone3 of the distance relay did not under-reach when the DG was connected. Also, the overcurrent relay operated instantaneously as expected. The fault current seen by the distance relay and the overcurrent relay is 1.58kA. This value is above the pickup value of distance relay zone3 and the instantaneous overcurrent settings.

Having the DG connected on load2 34.5kV bus side did not cause zone 3 to under-reach. This is because the system is kept at radial configuration. The utility feeds the system at one side and the DG feeds the system at the end side.

Table 6.10. Sequence of Operation for a Fault on 34.5kV Transformer Primary Bus

Protective Device	Pickup Value (kA)	Fault Current (kA)	Time (sec)
(50) overcurrent Relay	1.1	1.577	0.01
Zone3	1.5	1.577	0.763

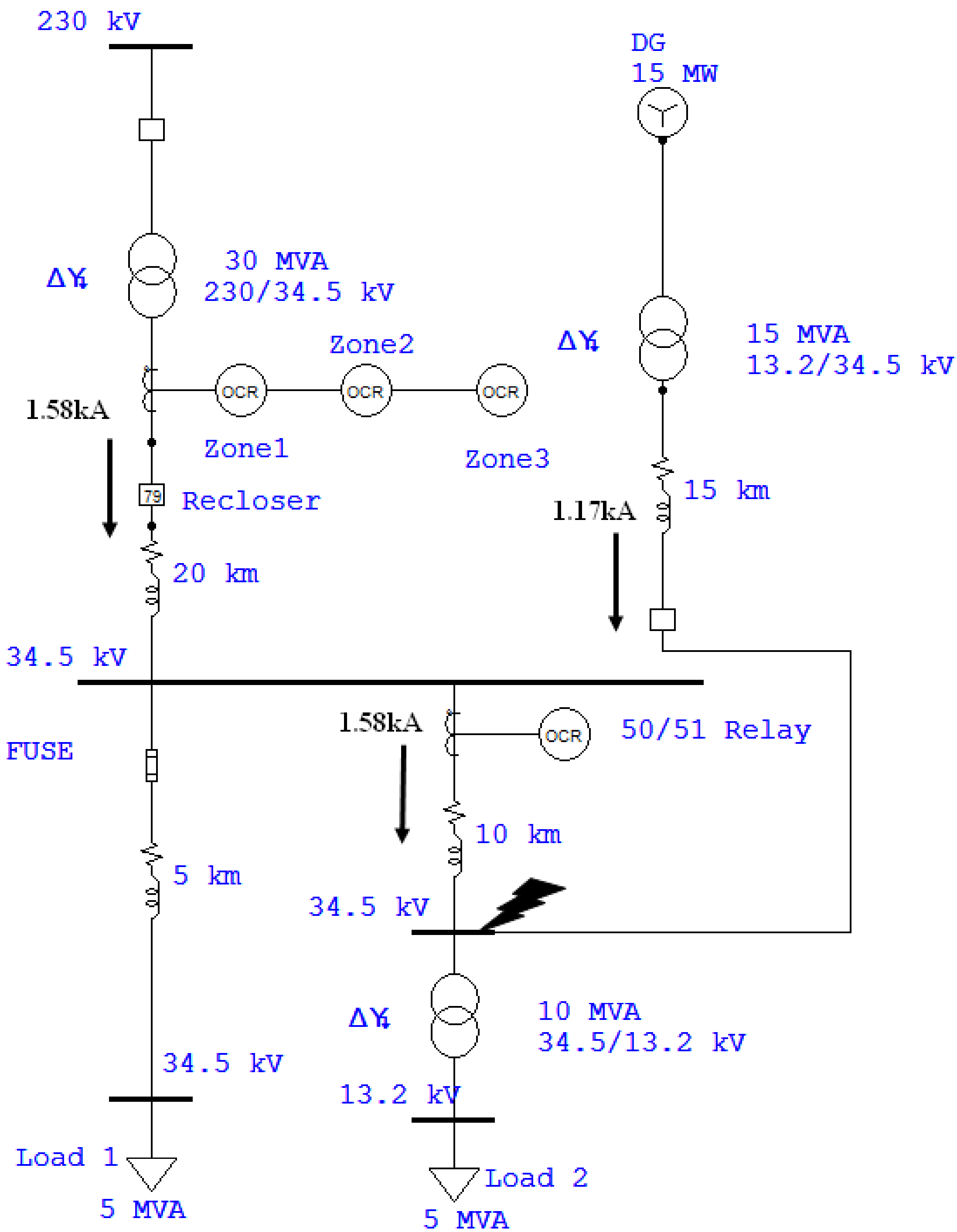

Figure 6.14. Fault Current Values When for a Fault on 34.5kV Transformer Primary Bus When a DG is on Location2

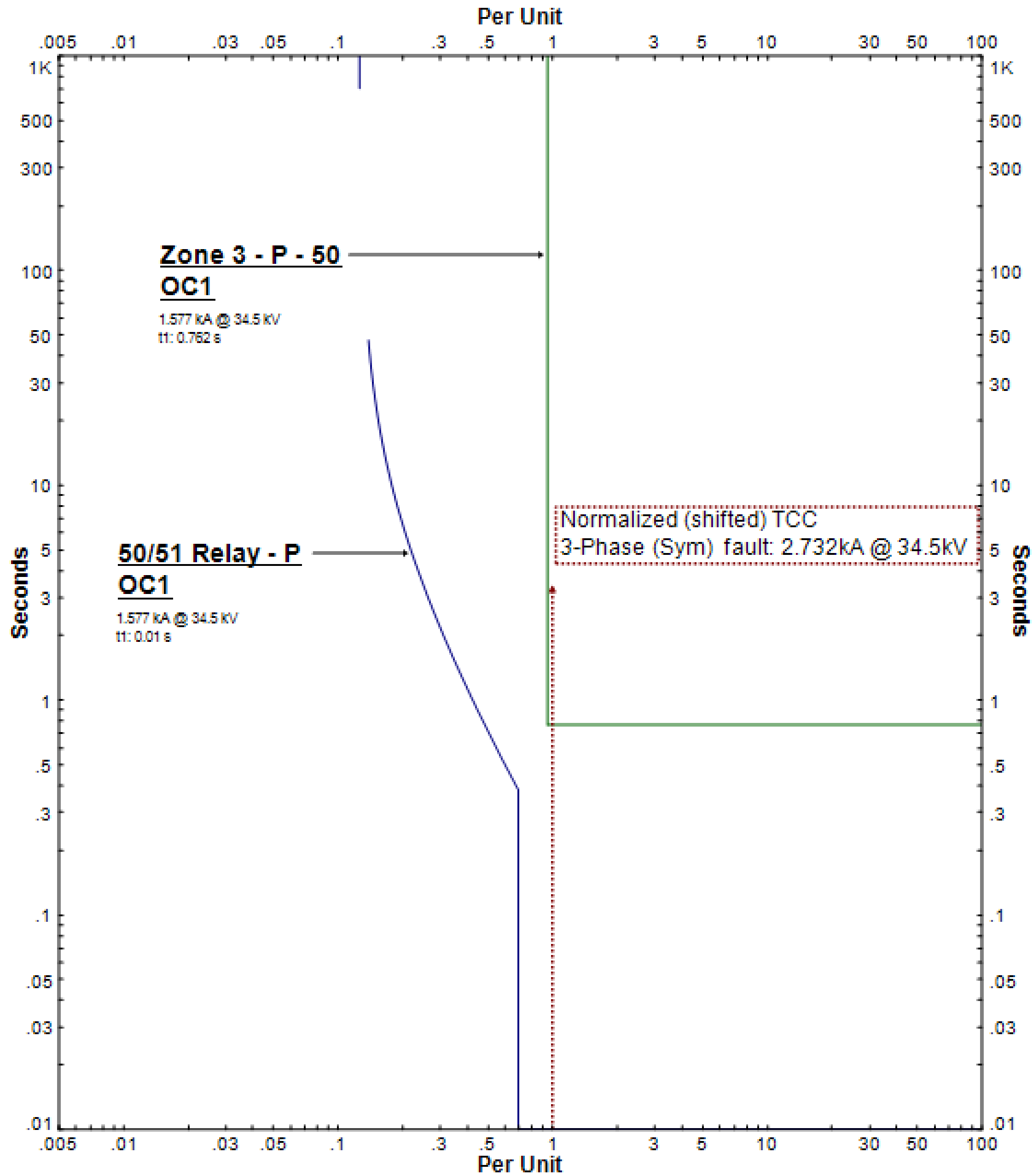

Figure 6.15. Operation of the Protective Devices for a Fault on The 34.5kV Transformer Primary Bus for a DG in Location 2

6.6.2. Fault at Load 2 Bus

A fault on this bus is to test the operation of the O/C relay 51. Table 6.11, Figure 6.16 and Figure 6.17 show the results obtained.

Having the DG connected on the 34.5kV transformer primary bus did not cause the overcurrent to over-reach. The reason for this is that the fault current contribution from the DG did not go through the overcurrent relay. Only the utility fault current was seen by this O/C which was not high enough to operate relay 50.

Table 6.11. Fault Currents for Faulting Load2 Bus.

Protective Device	50/51 Relay Fault Current (kA)	Clearance Time (sec)
Overcurrent (51)	0.738	0.825

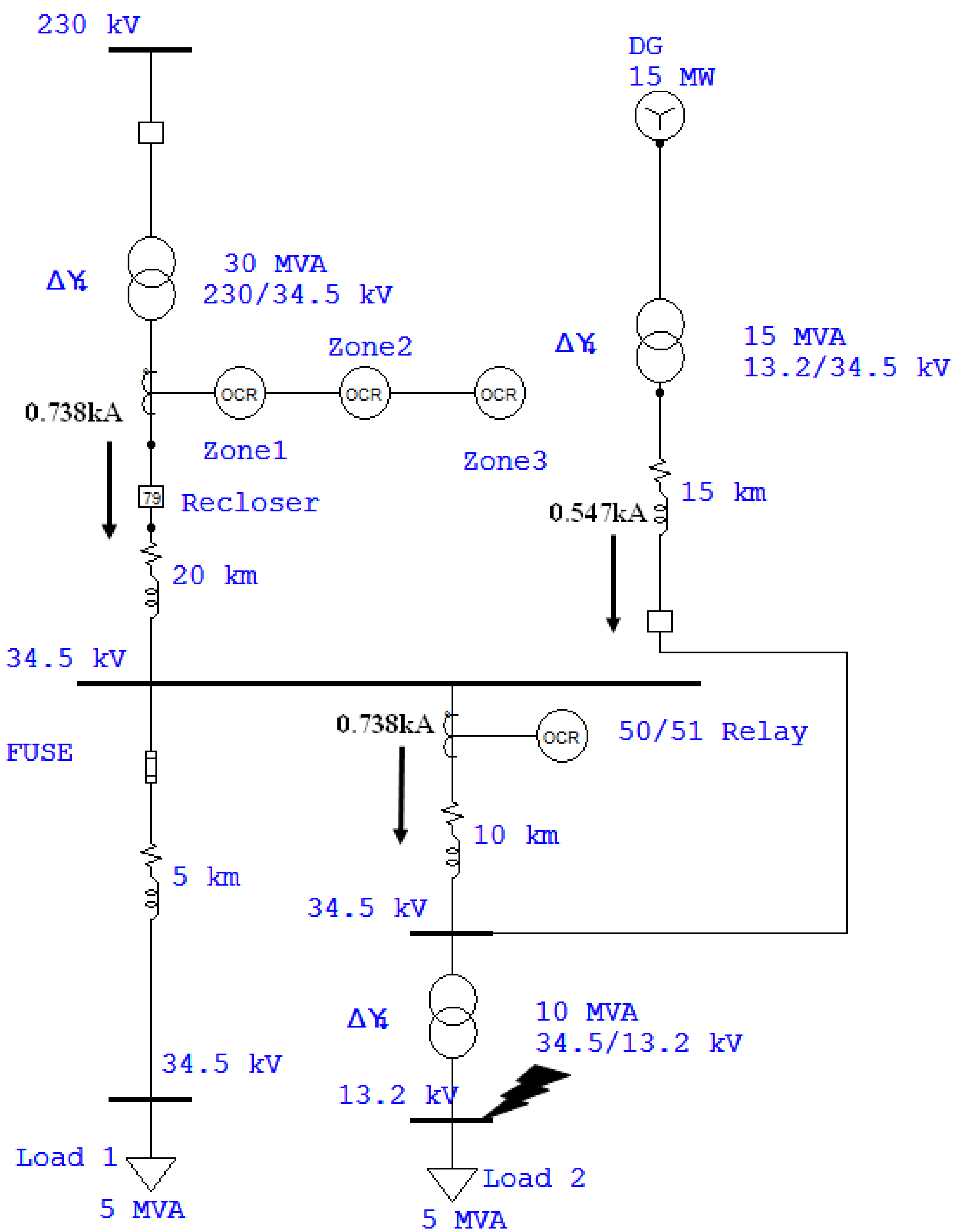

Figure 6.16. Fault Current Values for a Fault on Load2 Bus When a DG is on Location2

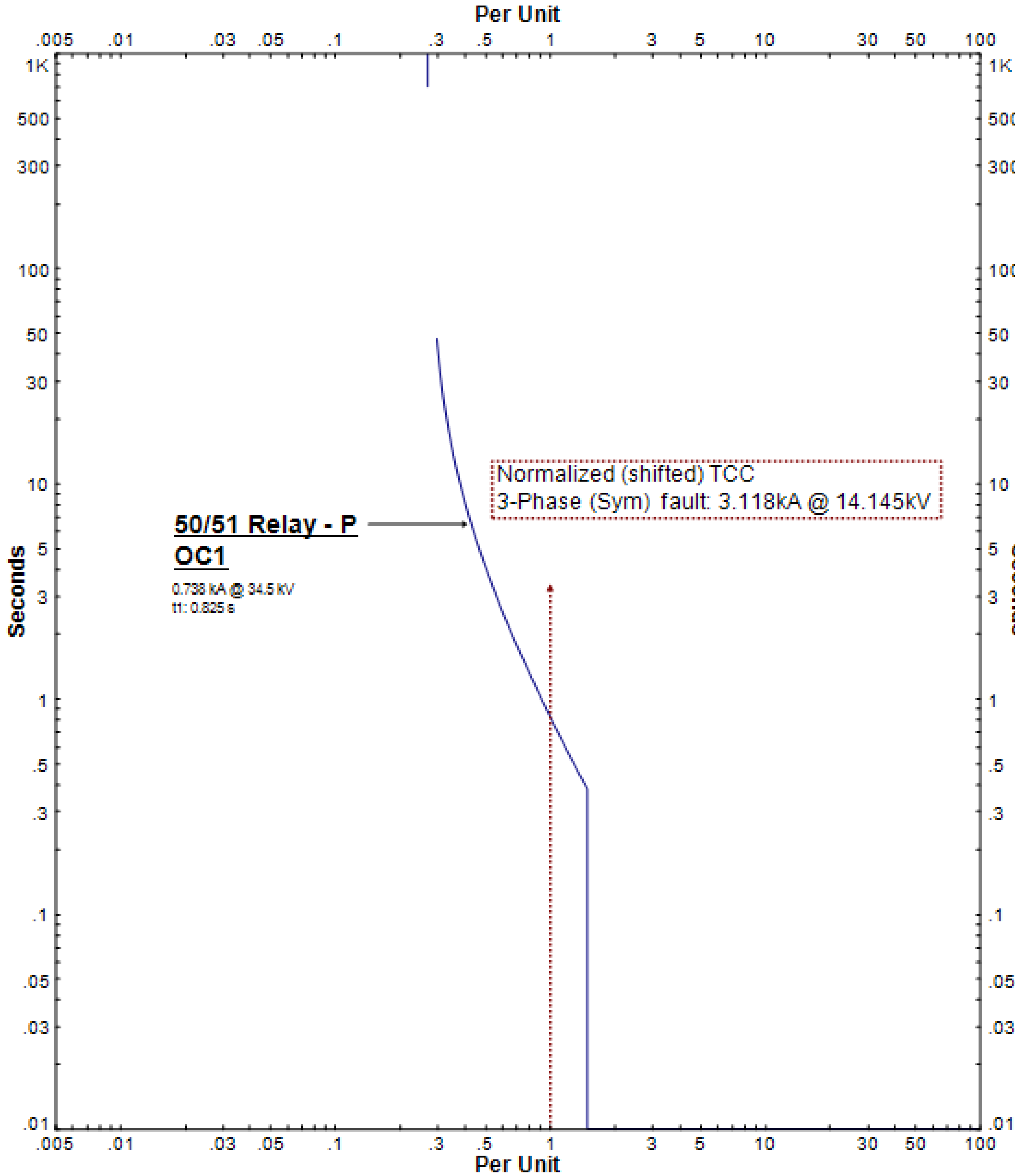

Figure 6.17. Operation of Protective Devices for Faults on Load2 Bus

6.6.3. Fault at Load 1 Bus

A fault on this bus is to test the coordination time between the fuse and the recloser. Table 6.12, Figure 6.18 and Figure 6.19 show the results obtained.

Having the DG connected to the 34.5kV transformer primary bus effected the coordination time between the fuse and the recloser. This is due to the total fault current from the DG and the utility seen by the fuse. On the other hand, only the utility fault current was seen by the recloser. The higher the current that is going through the fuse, the faster the fuse will blow. This results on reducing the coordination time between the fuse and the recloser.

Table 6.12. Fault Currents and Clearance Time for Load1 Fault

Protective Device	Fault Current (kA)	Clearance Time (sec)
Recloser	1.709	0.059
Fuse	2.633	0.2175
Overcurrent (51)	0.924	0.527

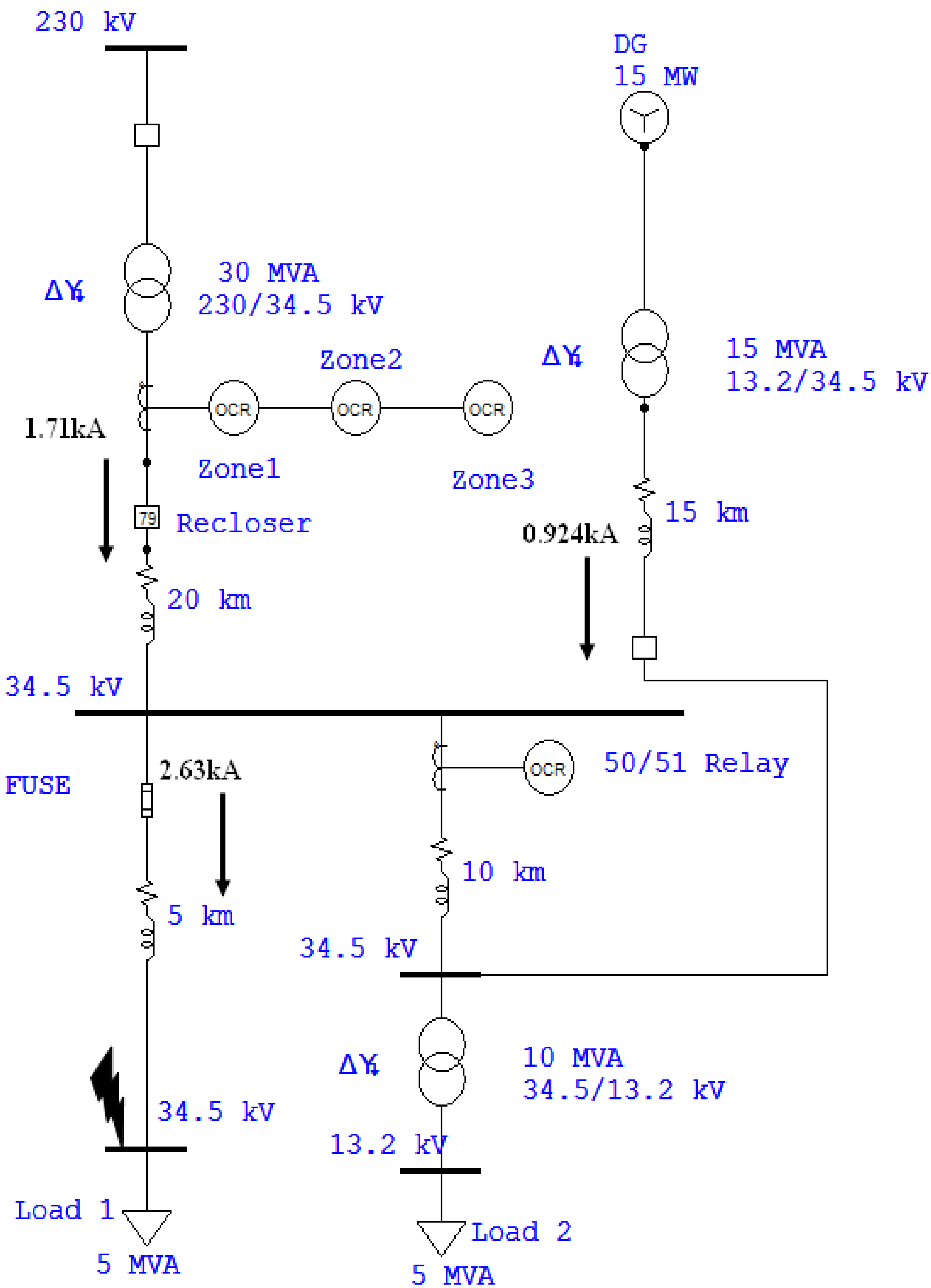

Figure 6.18. Fault Current Values for a Fault on Load1 Bus When DG is on Location2

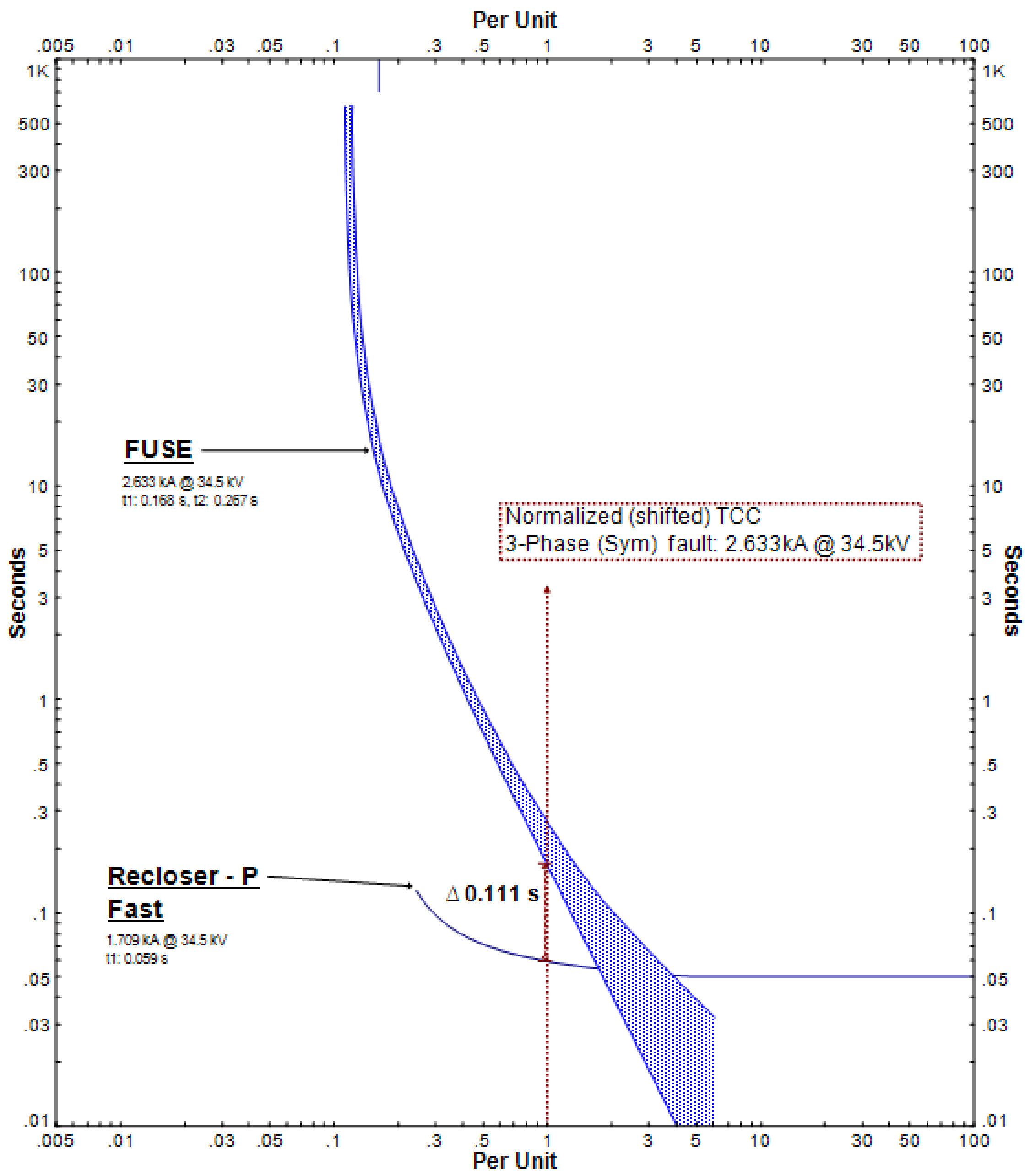

Figure 6.19. Coordination Time between Fuse and the Recloser for Fault on Load 1 Bus

6.7. DG at the Transformer 34.5kV Secondary Bus (Location 3)

In this section, the DG will be connected to the 34.5kV bus of the industrial power system transformer as it is shown in Figure 6.7. As in previous sections, the same three buses will be faulted to test the operation of the protective devices.

6.7.1. Fault at 34.5kV Transformer Primary Bus

A fault on this bus is to test the over-reaching of distance relay zone3 and the operation of the overcurrent relay 50. Table 6.13 and Figure 6.21 show the results obtained.

Having the DG connected to the transformer 34.5kV secondary bus caused the correction operation of the overcurrent relay 50. Furthermore, zone3 of the distance relay did not under-reach. However, zone2 of the distance relay operated for faults outside its zone (over-reached). Also, zone1 was about to operate.

The fault current was 1.978kA. Before the DG was connected, the fault current is 1.58kA. When the DG is connected directly the connection point with the utility, the fault current increased from 1.58 to 1.978kA. This increase caused zone2 to over-reach. Also, the new value is very close to zone1 pickup value (2kA).

Table 6.13. Sequence of Operation for a Fault on the 34.5kV Transformer Primary Bus

Protective Device	**Pickup (kA)**	**Fault Current (kA)**	**Time (sec)**
Overcurrent Relay 50	1.1	1.978	0.01
Distance Relay (Zone 1)	2		N/A
Distance Relay (Zone 2)	1.8		0.379
Distance Relay (Zone 3)	1.5		0.763

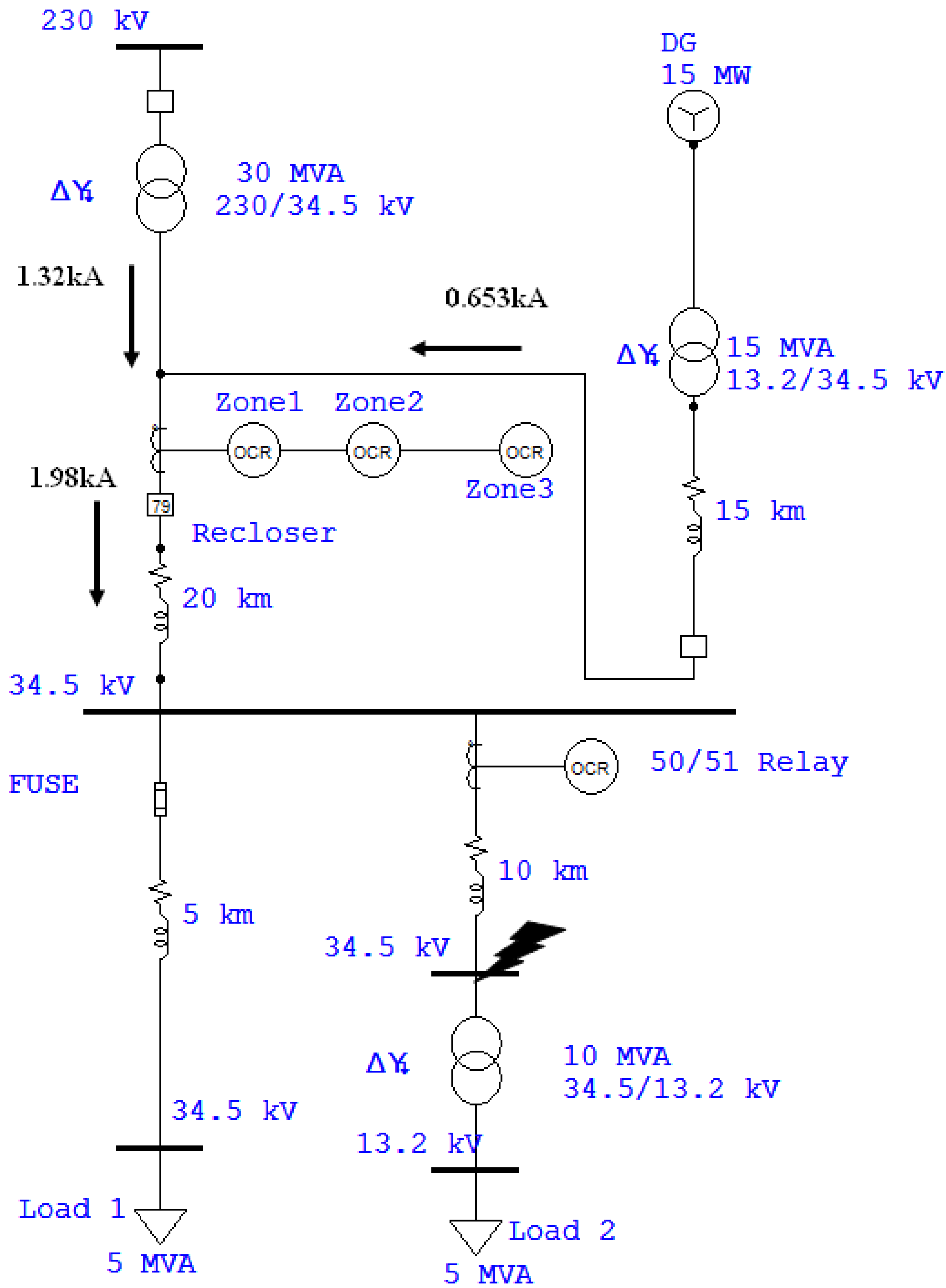

Figure 6.20. Fault Current Values for a Fault on 34.5kV Transformer Primary Bus When a DG is on Location3

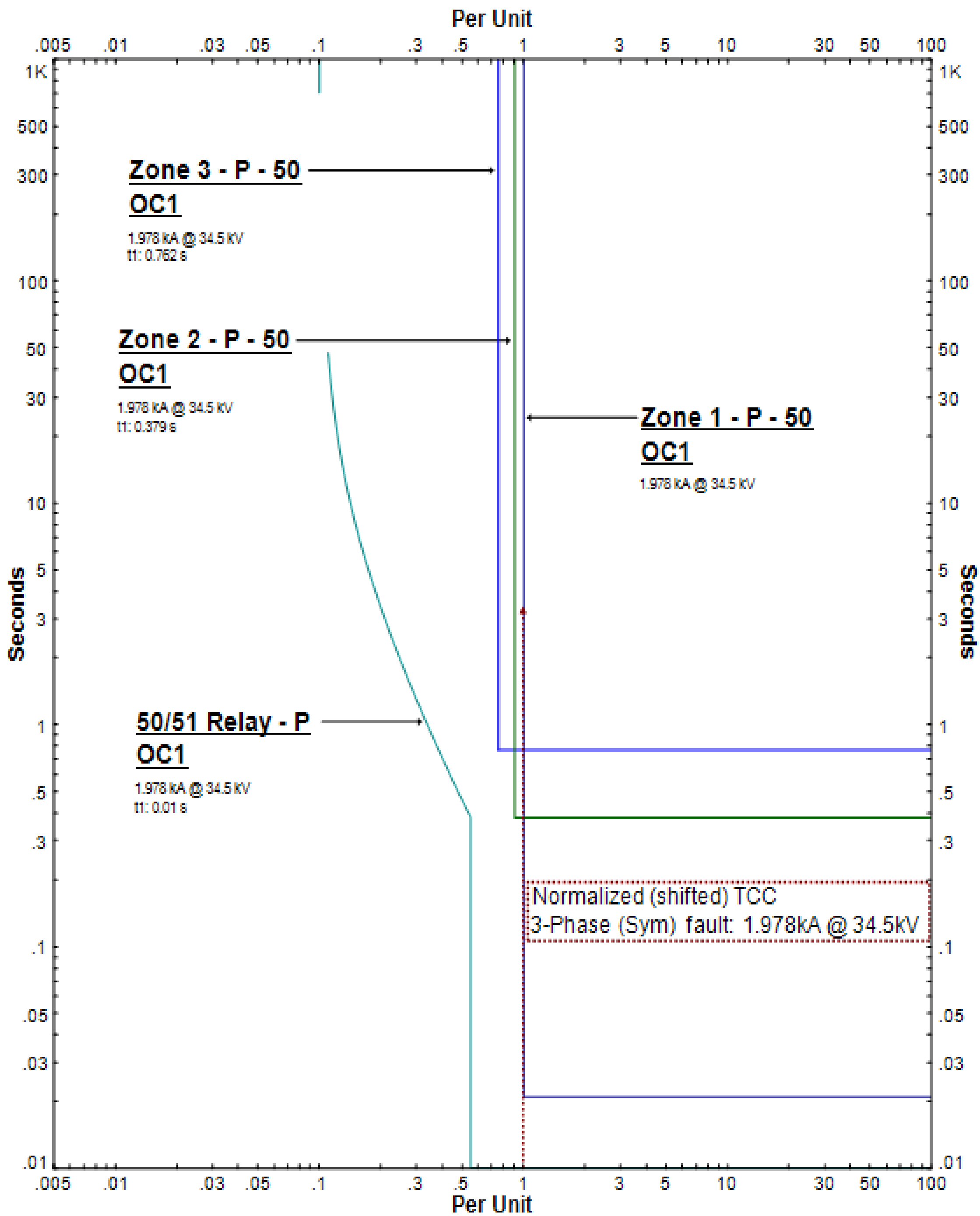

Figure 6.21. TCC Curves for a Fault on the 34.5kV Transformer Primary Bus

6.7.2. Fault at Load 2 Bus

A fault on this bus is to test the operation of the overcurrent relay 51. Table 6.14 shows the sequence of operation for such fault.

Table 6.14. Sequence of Operation for a Fault at Load2 Bus

Protective Device	50/51 Relay Fault Current (kA)	Clearance Time (sec)
Overcurrent (51)	1.09	0.5

It worths to mention that the fault current is very much close to 1.1kA which is the pickup of the instantaneous protection. If the settings were less than 1.1kA or the transformer impedance is less, this relay would definitely over-reach.

6.7.3. Fault at Load 1 Bus

A fault on this bus is to test the coordination between the recloser and fuse. Table 6.15, Figure 6.22 and Figure 6.23 show the results obtained.

Both the fuse and recloser are reading the same fault current. However, the coordination time is reduced between them. This is because the fault current increased from 1.78kA to 2.323kA when the DG was connected. Increasing in the fault current causes both the fuse and recloser to clear the fault faster. The increase in the fuse clearance time is much more significant than that of the recloser which effected the coordination time.

Table 6.15. Sequence of Operation for a Fault on Load1 Bus

Protective Device	Fault Current (kA)	Clearance Time (sec)
Recloser	2.323	0.0208
Fuse	2.323	0.2705

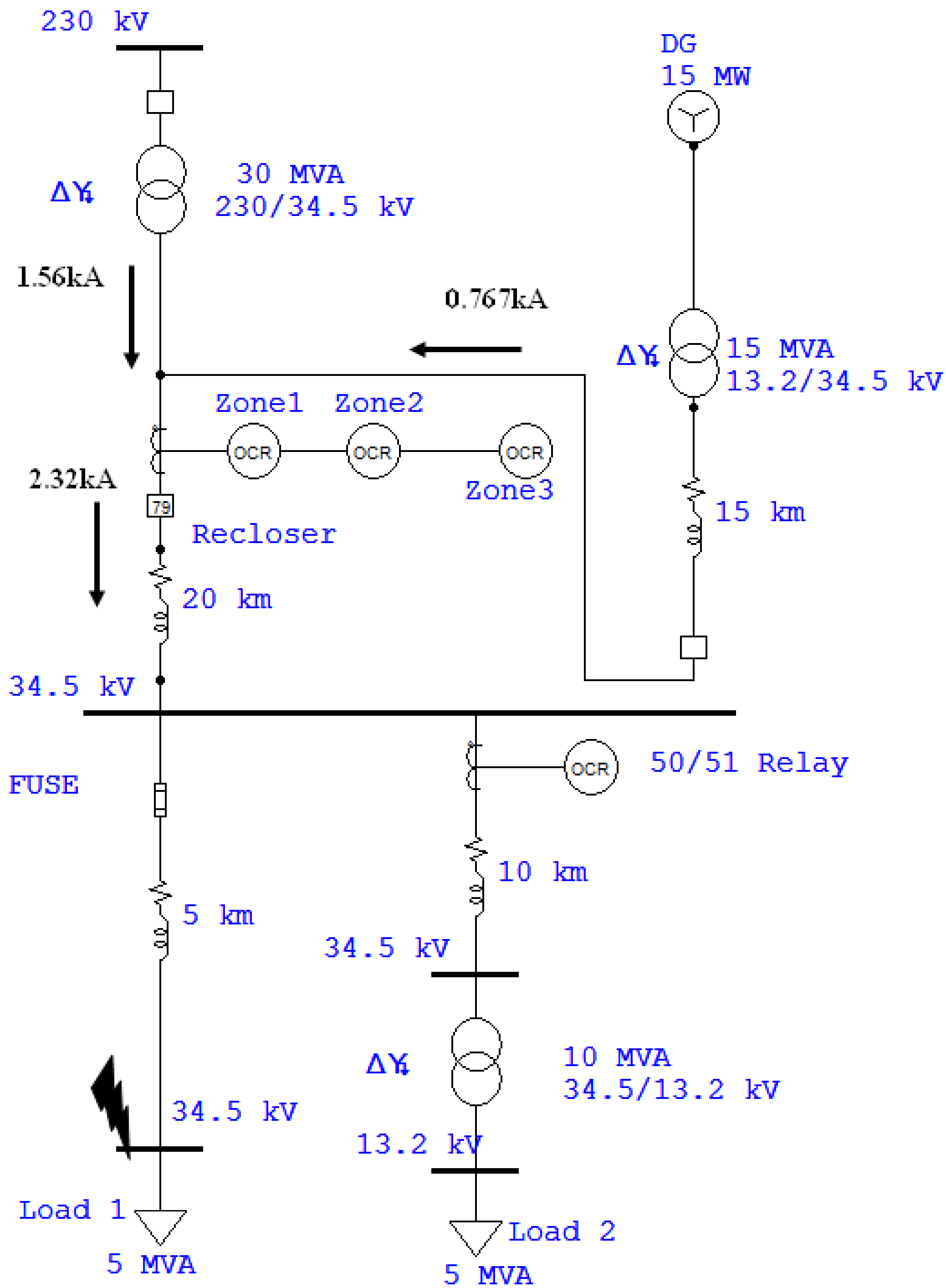

Figure 6.22. Fault Current for a Fault on Load1 Bus When the DG is on Location3

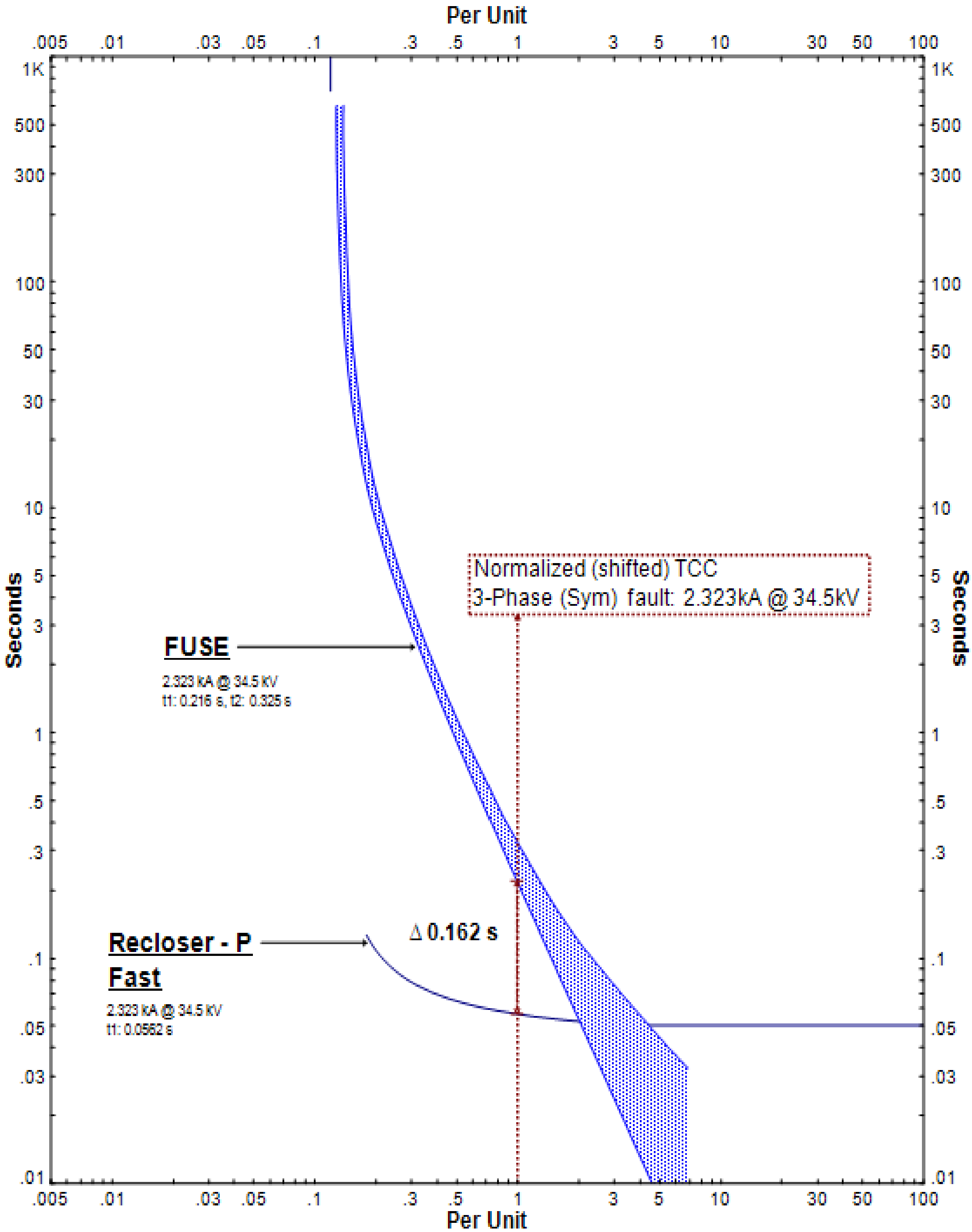

Figure 6.23. Coordination Time between the Recloser and the Fuse for a Fault on Load1 Bus

6.8. Final DG System

In the previous sections, different DG sizes, distances from the network, and different locations within the system have been considered. It is found that the maximum DG size for this system is 5MW and the best location is in location 1.

The DG distance from the network has very minor effects on the coordination system. However, it is kept at 15km distance as in the previous studies. Figure 6.24 shows the single line of the system. The following sections will study coordination of the final system.

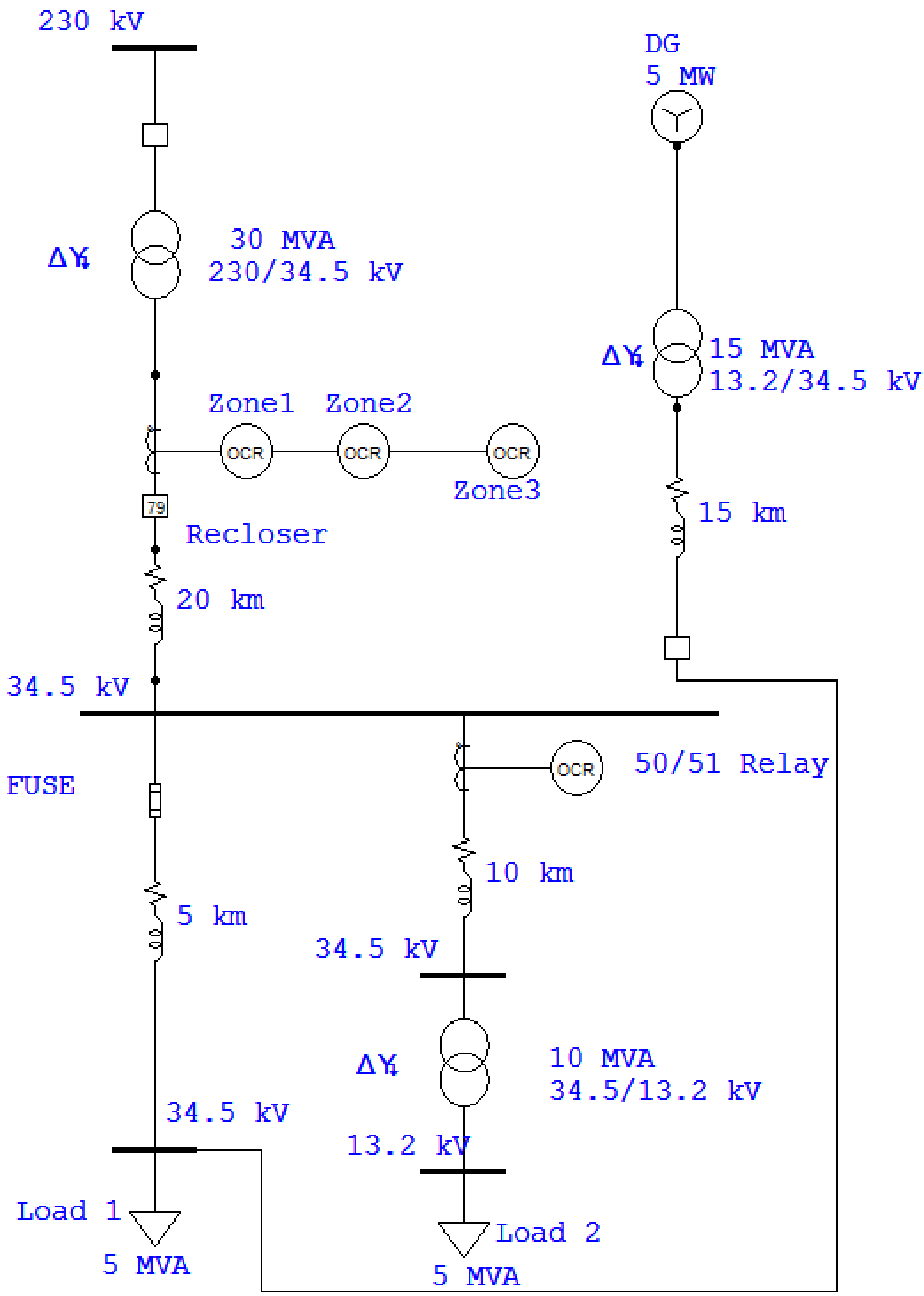

Figure 6.24. Electrical One Line of the Final System

6.8.1. Fault at Load1 Bus

A fault on this bus is to test the coordination between the fuse and the recloser. Table 6.16, Figure 6.25, and Figure 6.26 show the sequence of operation of the protective devices and the fault current values.

The coordination between the recloser and fuse was not lost. The reason for this is that the same fault current is going through both; recloser and the fuse. Also, this fault current is reduced due to the addition of the DG.

Table 6.16. Sequence of Operation for a Fault on Load1 Bus

Protective Device	Fault Current (kA)	Clearance Time (sec)
Recloser	1.779	0.0186
Fuse	1.779	0.375

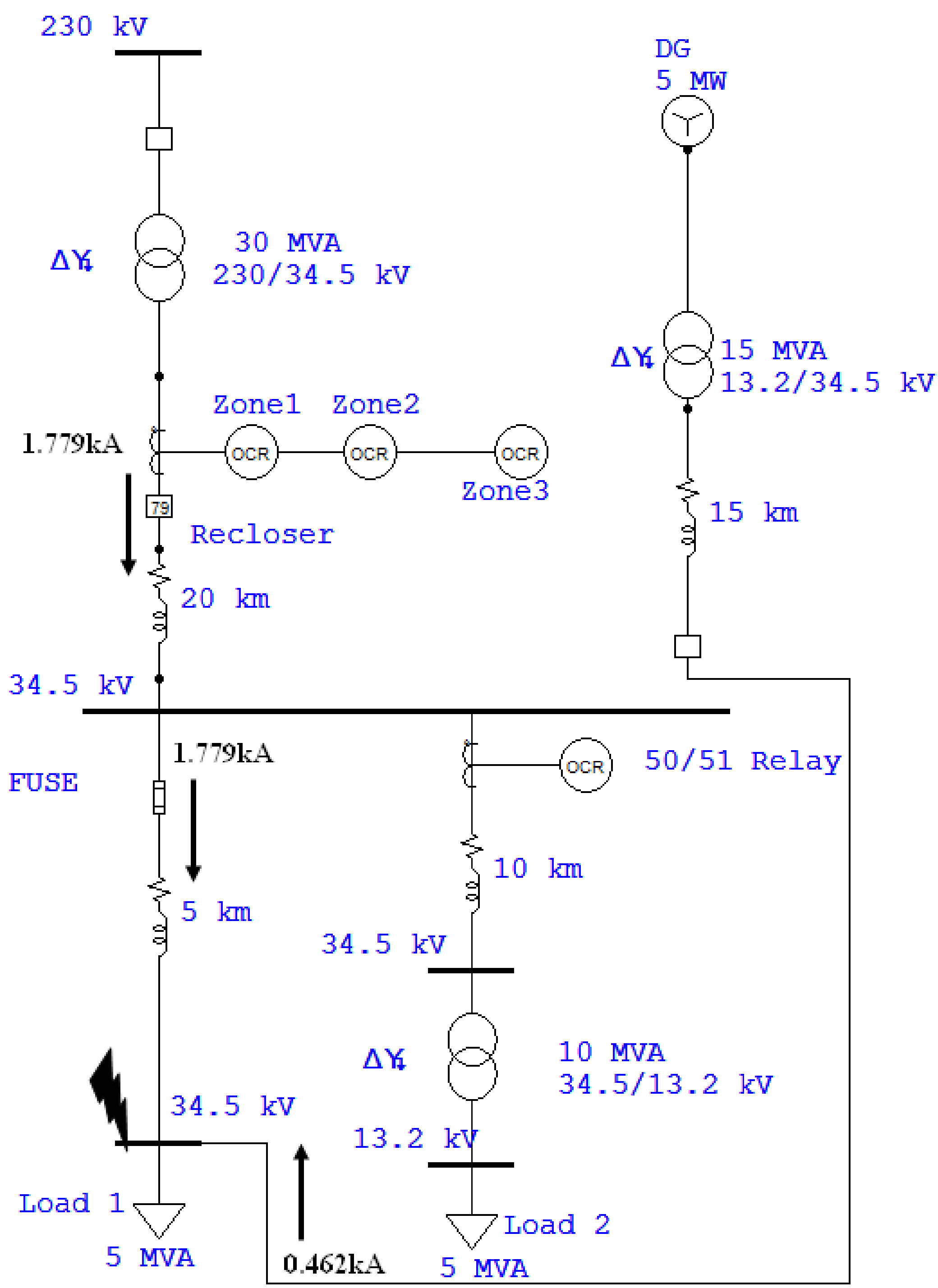

Figure 6.25. Fault Current Values for a Fault on Load1 Bus

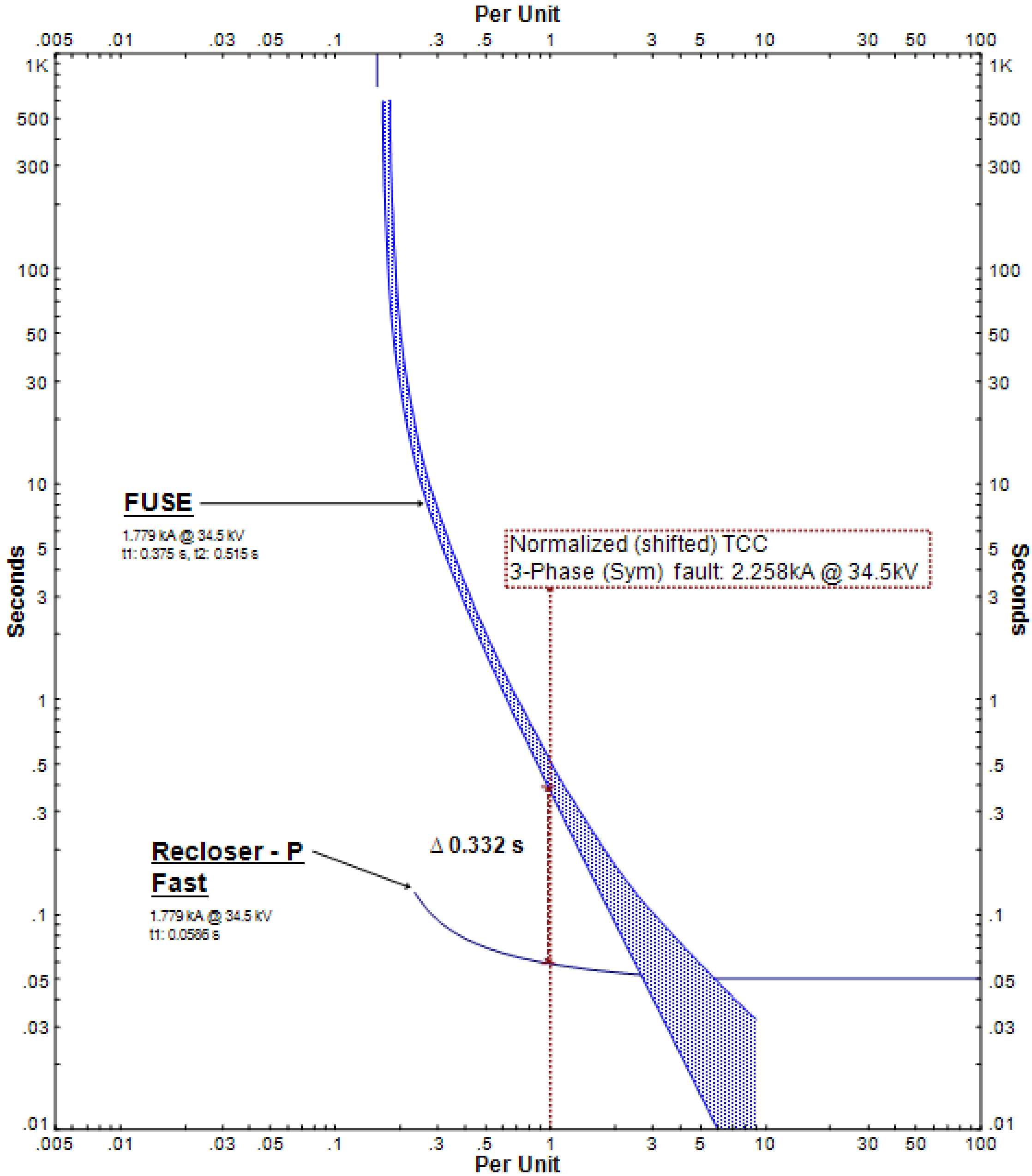

Figure 6.26. TCC Curve for a Fault On Load1 Bus

6.8.2. Fault at 34.5kV Transformer Primary Bus

A fault on this bus is to test the operation of the overcurrent (50) and zone 3 of the distance relay. Table 6.17, Figure 6.27, and Figure 6.28 show the results of such fault.

The overcurrent relay (50) operated as expected. Zone3 of the distance relay did not under-reach when the DG was connected on location 1 with size of 5MW. The fault current seen by the distance relay is 1.51kA which is above its pickup value (1.5kA).

The fuse was blown for a fault out of its zone. However, it took 30 sec to blow. This time is very long where the other protective devices will operate first to clear fault. Also, the fuse will not de-rated for external faults due to small fault current going through the fuse.

Having the DG connected on load1 bus side with size of 5MW did not effect the coordination of the power system coordination.

Table 6.17. Sequence of Operation for a Fault on 34.5kV Transformer Primary Bus

Protective Device	Fault Current (kA)	Clearance Time (sec)
Overcurrent (50)	1.867	0.01
Zone 3	1.152	0.763
Fuse	0.356	26.605

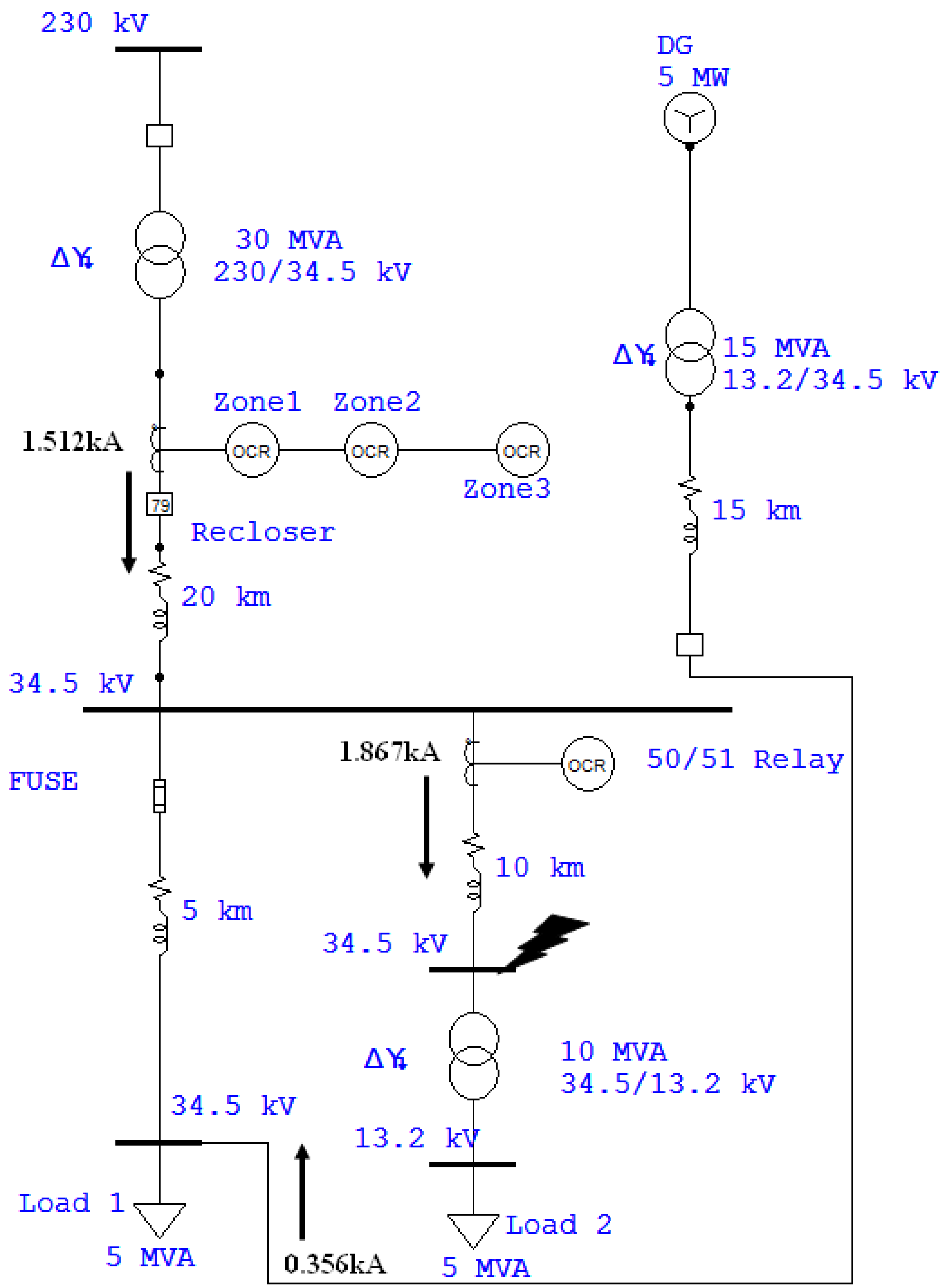

Figure 6.27. Fault Current Values for a Fault on the 34.5kV Transformer Primary Bus

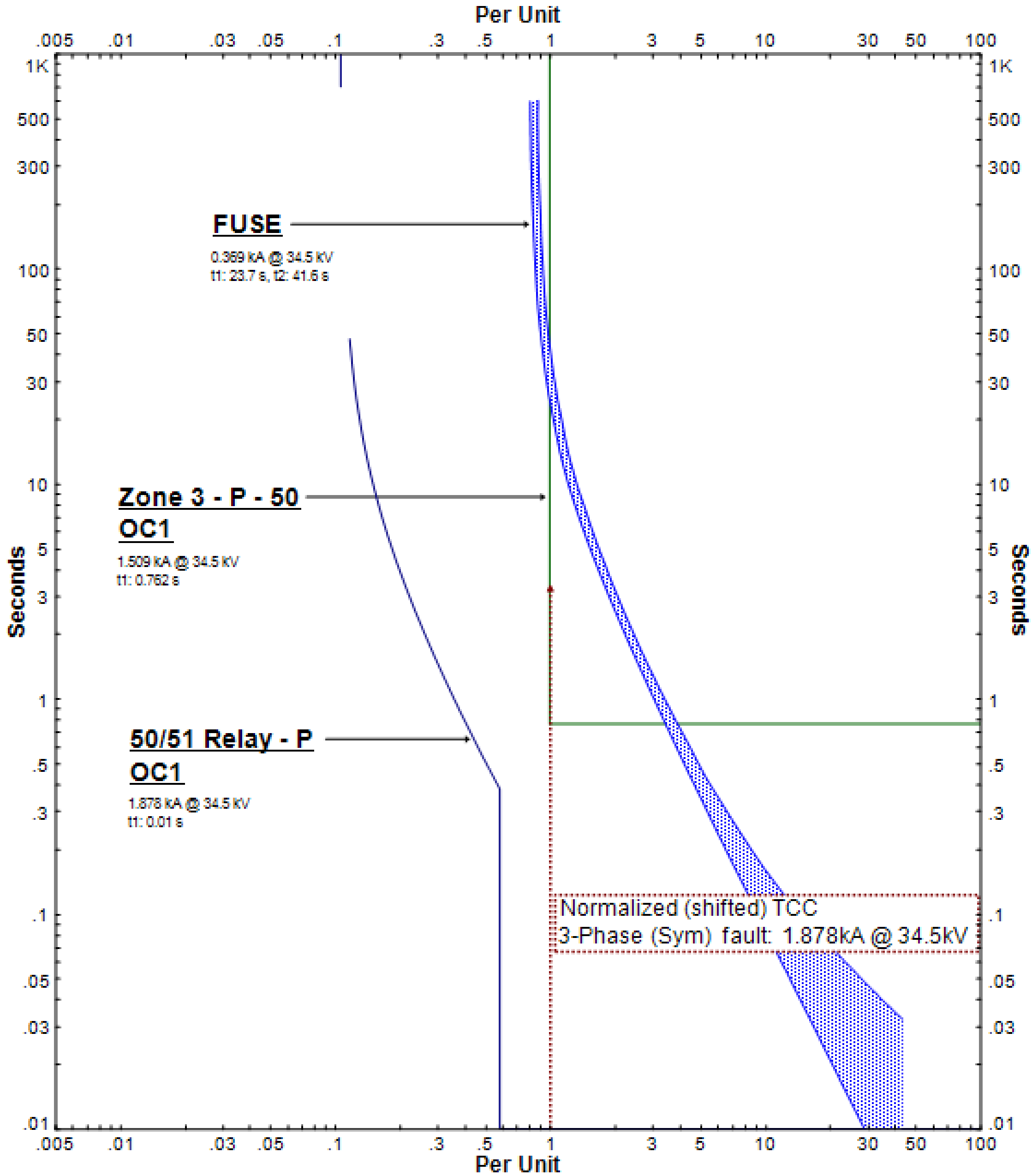

Figure 6.28. TCC Curve for a Fault on the 34.5kV Transformer Primary Bus

6.8.3. Fault at Load 2 Bus

A fault on this bus is to test the operation of the O/C relay 51. Table 6.18 and Figure 6.29 show the results obtained.

Having the DG connected on load1 bus with size of 5MW did not cause the overcurrent to over-reach. The reason for this is that the fault current contribution from the DG is not high enough to increase the total fault current going through this relay to the instantaneous pickup. Also, the fuse was not blown due to small amount of fault current coming from the DG (0.2kA)

Table 6.18. Sequence of Operation for a Fault on Load2 Bus

Protective Device	Fault Current (kA)	Clearance Time (sec)
Overcurrent relay (51)	1.051	0.414

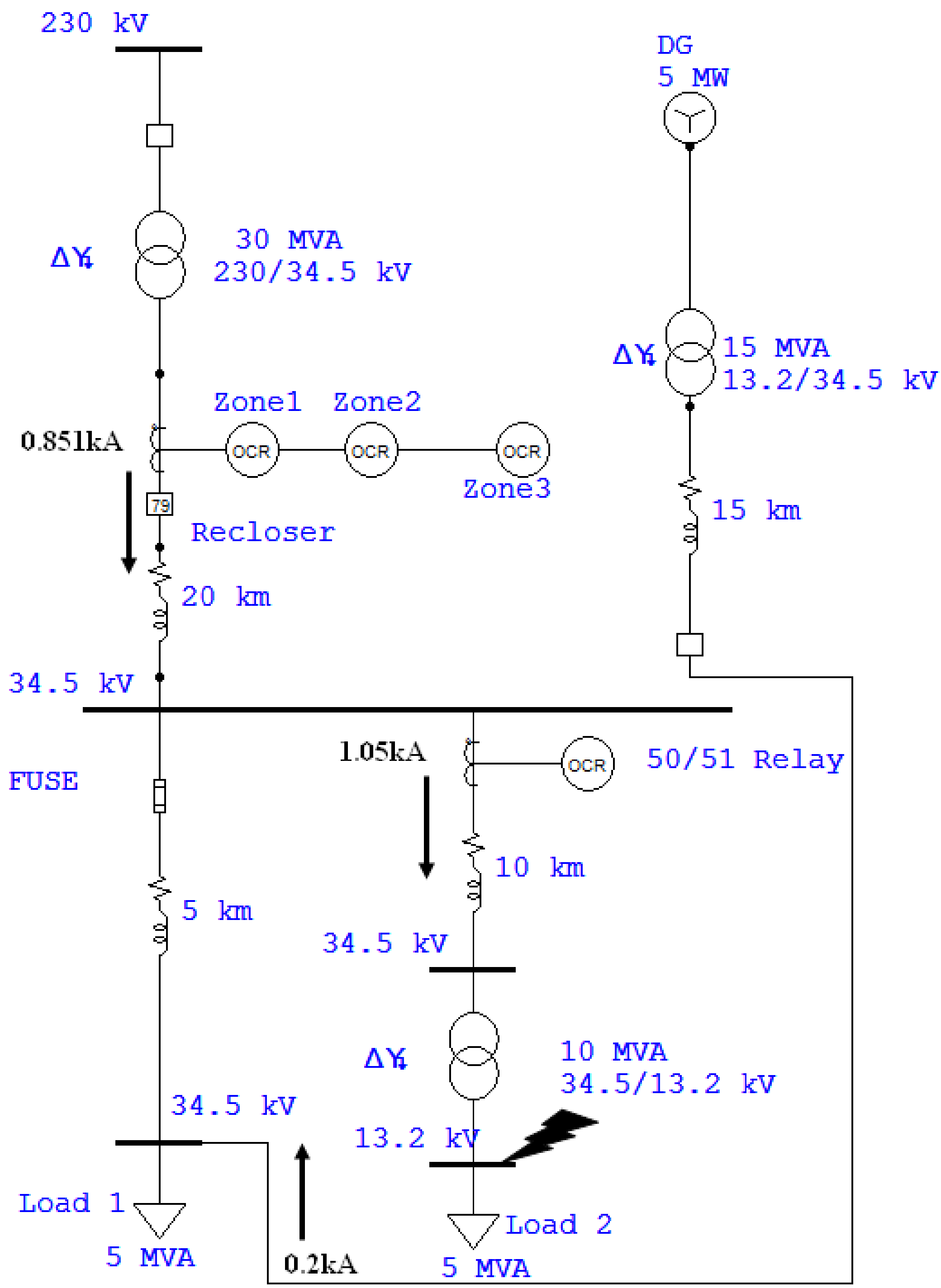

Figure 6.29. Fault Current Values for a Fault on Load2 Bus

CHAPTER 7

CONCLUSION AND FUTURE WORK

7.1. Conclusions

In this work, a study is performed to assess the impacts of the Co-Generation and Distributed Generation has on the coordination of electrical power system protection. For the Co-Generation, it is concluded that it has no effects on the coordination of the protection devices in the system for the following two reasons;

1. The short circuit current of the Co-Generation is too small compared with that of the utility. The short circuit current of the utility is 72kA where for the co-generation is 3.7kA.
2. Co-Generation is connected to the electrical system at transmission voltage level (230kV) which means less current contribution. If it was connected at distribution voltage level (69kV, 34.5kV,..), it would make a difference as the case for distribution generation.

However, the distribution generation does effect the power system coordination despite its low megawatts size. This is because it is connected at the distribution voltage level.

In this thesis, the DG effects on the distance relay, overcurrent relay, and the recloser/fuse coordination were studied. It considered different DG sizes, different DG connection points to the network, and different distances between the DG and the network.

The distance between the DG and the distribution network does not have serious impact on the coordination of the power system. On the other hand, the DG size has a significant impact on the coordination system. As the DG increases, the fault current increases that causes the relays to over-reach. Furthermore, the fault current contribution from the utility is reduced which causes the distance relay to under-reach. This change in the fault current at different parts of the system causes zone3 of the distance relay to under-reach and the overcurrent relay (50) to over-reach. This change in the current also effects the coordination time between the protection devices as it was shown for the fuse/ recloser case.

DG location within the network has direct impact on the protection coordination. It causes the operation of some protective devices due to the backfeed of this DG. Also, some relays might under-reach due to the decrease in the fault current or over-reach due to the increase in the fault current going through this protective device. This change in the current effects the coordination between the protective devices.

Before connecting DG's, it is recommended to consider the followings;

1. If the DG size is large, it will have serious impact.
2. A proper connection point of the DG to the distribution network. Even for small DG, the distribution network is not anymore radial system due to this connection.
3. Under-reaching and over-reaching of the relay can be solved by changing the settings by having two groups of settings. One group is when the DG is not connected and the other group is used when the DG is connected to the distribution network. For the recloser/fuse coordination, changing the clearance time cannot be achieved. One solution is to replace the fuse with a breaker that could have group of settings. This will cause more money since the breaker is more expensive than the fuse.

7.2. Future Work

As interesting area of research, I recommend the followings;

1. Consider different type of distribution generation. Every kind of distribution generation has some characteristics in contribution in short circuit current.
2. Consider more than one DG in the network system and study the effects on the coordination system.
3. Consider different voltages where the DG to be connected to the distribution network.
4. Adding such DG might have some effects on the current transformer (CT) saturations. CT's saturation need to be studied to confirm the proper size for the protection.

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APPENDIX A

ANSI DEVICE NUMBERS

List of ANSI Device Numbers [27]

Device #	Description
1	Master Element
2	Time Delay Starting or Closing Relay
3	Checking or Interlocking Relay
4	Master Contactor
5	Stopping Device
6	Starting Circuit Breaker
7	Rate of Change Relay
8	Control Power Disconnecting Device
9	Reversing Device
10	Unit Sequence Switch
11	Multifunction Device
12	Over speed Device
13	Synchronous speed Device
14	Under speed Device
15	Speed or Frequency, Matching Device
16	Data Communications Device (see note)
17	Shunting or Discharge Switch
18	Accelerating or Decelerating Device
19	Starting to Running Transition Contactor
20	Electrically Operated Valve
21	Distance Relay
22	Equalizer Circuit Breaker
23	Temperature Control Device
24	Volts Per Hertz Relay
25	Synchronizing or Synchronism Check Device
26	Apparatus Thermal Device
27	Undervoltage Relay

28	Flame Detector
29	Isolating Contactor or Switch
30	Annunciator Relay
31	Separate Excitation Device
32	Directional Power Relay
33	Position Switch
34	Master Sequence Device
35	Brush Operating or Slip Ring Short Circuiting Device
36	Polarity or Polarizing Voltage Devices
37	Undercurrent or Under power Relay
38	Bearing Protective Device
39	Mechanical Condition Monitor
40	Field (over/under excitation) Relay
41	Field Circuit Breaker
42	Running Circuit Breaker
43	Manual Transfer or Selector Device
44	Unit Sequence Starting Relay
45	Abnormal Atmospheric Condition Monitor
46	Reverse phase or Phase Balance Current Relay
47	Phase Sequence or Phase Balance Voltage Relay
48	Incomplete Sequence Relay
49	Machine or Transformer, Thermal Relay
50	Instantaneous Overcurrent Relay
51	AC Inverse Time Overcurrent Relay
52	AC Circuit Breaker
53	Exciter or DC Generator Relay
54	Turning Gear Engaging Device
55	Power Factor Relay
56	Field Application Relay
57	Short Circuiting or Grounding (Earthing) Device

58	Rectification Failure Relay
59	Overvoltage Relay
60	Voltage or Current Balance Relay
61	Density Switch or Sensor
62	Time Delay Stopping or Opening Relay
63	Pressure Switch
64	Ground (Earth) Detector Relay
65	Governor
66	Notching or Jogging Device
67	AC Directional Overcurrent Relay
68	Blocking or "Out of Step" Relay
69	Permissive Control Device
70	Rheostat
71	Liquid Level Switch
72	DC Circuit Breaker
73	Load Resistor Contactor
74	Alarm Relay
75	Position Changing Mechanism
76	DC Overcurrent Relay
77	Telemetering Device
78	Phase Angle Measuring Relay
79	AC Reclosing Relay
80	Flow Switch
81	Frequency Relay
82	DC Reclosing Relay
83	Automatic Selective Control or Transfer Relay
84	Operating Mechanism
85	Communications, Carrier or Pilot Wire Relay
86	Lockout Relay
87	Differential Protective Relay

88	Auxiliary Motor or Motor Generator
89	Line Switch
90	Regulating Device
91	Voltage Directional Relay
92	Voltage and Power Directional Relay
93	Field Changing Contactor
94	Tripping or Trip Free Relay

APPENDIX B

DEFINITION OF STANDARD RELAY CHARACTERISTICS

Relay Characteristics according to IEC 60255 [28]

Relay characteristic	Equation (IEC 60255)
Standard Inverse (SI)	$t = TMS \times \frac{0.14}{I_r^{0.02} - 1}$
Very Inverse (VI)	$t = TMS \times \frac{13.5}{I_r \quad - 1}$
Extremely Inverse (EI)	$t = TMS \times \frac{80}{I_r^2 - 1}$
Long Time Standard Earth Fault	$t = TMS \times \frac{120}{I_r \quad - 1}$

I_r = (I/I_s), where I_s = relay setting current

TMS = Time Multiplier Setting

TD = Time Dial Settings

North American IDMT Relay Characteristics [28]

Relay characteristic	Equation (IEC 60255)
IEEE Moderately Inverse	$\mathrm{t} = \frac{TD}{7}\left\{\frac{0.0515}{I_r^{0.02}-1}+0.114\right\}$
IEEE Very Inverse	$\mathrm{t} = \frac{TD}{7}\left\{\frac{19.61}{I_r^{2}-1}+0.491\right\}$
Extremely Inverse (EI)	$\mathrm{t} = \frac{TD}{7}\left\{\frac{28.2}{I_r^{2}-1}+0.1217\right\}$
US CO8 Inverse	$\mathrm{t} = \frac{TD}{7}\left\{\frac{5.95}{I_r^{2}-1}+0.18\right\}$
US CO2 Short Time Inverse	$\mathrm{t} = \frac{TD}{7}\left\{\frac{0.02394}{I_r^{0.02}-1}+0.01694\right\}$

I_r = (I/I_s), where I_s = relay setting current

TMS = Time Multiplier Setting

TD = Time Dial Settings

VITA

Name: Hussain Adnan Al-Awami

Date of Birth: June 08, 1981

Place of Birth: Al-Khober

Nationality: Saudi

Address: P.O.Box 5504, Dhahran 31311, Saudi Aramco, Saudi Arabia

E-mail: awamihsn@yahoo.com

Education: Bachelor of Science in Electrical Engineering from KFUPM, January 2004.

Master of Science in Electrical Engineering from KFUPM, June 2010.