



HAL
open science

Using IEC 61850 and CIM (Common Information Model) for the incremental and distributed management of an electrical distribution network in presence of DERs

Djibril Diop

► To cite this version:

Djibril Diop. Using IEC 61850 and CIM (Common Information Model) for the incremental and distributed management of an electrical distribution network in presence of DERs. Electric power. Université Grenoble Alpes [2020-..], 2022. English. NNT : 2022GRALT045 . tel-03828420

HAL Id: tel-03828420

<https://theses.hal.science/tel-03828420>

Submitted on 25 Oct 2022

HAL is a multi-disciplinary open access archive for the deposit and dissemination of scientific research documents, whether they are published or not. The documents may come from teaching and research institutions in France or abroad, or from public or private research centers.

L'archive ouverte pluridisciplinaire **HAL**, est destinée au dépôt et à la diffusion de documents scientifiques de niveau recherche, publiés ou non, émanant des établissements d'enseignement et de recherche français ou étrangers, des laboratoires publics ou privés.



THÈSE

Pour obtenir le grade de

DOCTEUR DE L'UNIVERSITÉ GRENOBLE ALPES

Spécialité : GENIE ELECTRIQUE

Arrêté ministériel : 25 mai 2016

Présentée par

Djibril DIOP

Thèse dirigée par **Raphael CAIRE**, Enseignant Chercheur,
Université Grenoble Alpes
et codirigée par **Nouredine HADJSAID**, G-INP

préparée au sein du **Laboratoire Laboratoire de Génie
Electrique**
dans l'**École Doctorale Electronique, Electrotechnique,
Automatique, Traitement du Signal (EEATS)**

Using IEC 61850 and CIM (Common Information Model) for the incremental and distributed management of an electrical distribution network in presence of DERs.

Thèse soutenue publiquement le **10 juin 2022**,
devant le jury composé de :

Monsieur Nouredine Hadjsaid

PROFESSEUR DES UNIVERSITES, Grenoble INP, Co-directeur de
thèse

Monsieur Désiré Dauphin Rasolomampionona

PROFESSEUR, Warsaw University of Technology, Rapporteur

Monsieur Kimmo Kauhaniemi

PROFESSEUR, University of Vaasa, Rapporteur

Monsieur Bertrand Raison

PROFESSEUR DES UNIVERSITES. Université Grenoble Alpes,
Président

Monsieur Raphaël Caire

MAITRE DE CONFERENCES, Université Grenoble Alpes, Directeur de
thèse

Monsieur Thomas Rudolph

INGENIEUR, Schneider Electric, Invité

Monsieur Laurent Guise

INGENIEUR, Energy Semantic, Invité

Monsieur Thierry Coste

INGENIEUR, EDF Lab - Paris Saclay, Invité

*To my late father,
To my mother,
To my wife,
To my brothers and sisters.*

Table of contents

Table of contents.....	3
Acknowledgements.....	7
List of figures.....	9
List of figures (continued).....	10
List of tables:.....	11
List of abbreviations:.....	12
General introduction.....	13
Chapter I: Description of the power system.....	18
I.1. Introduction.....	20
I.2. The change of energy paradigm.....	20
I.3. The power system.....	21
I.3.1. The power generation system.....	21
I.3.2 The transmission system.....	21
I.3.3. The distribution system.....	22
I.4. The distribution system.....	22
I.4.1. Main parts of the distribution system.....	23
I.4.2. The components of a distribution network.....	26
I.4.3. The distribution network – Traditional context.....	29
I.4.4. Distributed Energy Resources (DERs).....	31
I.4.5. The distribution network in presence of DERs.....	33
I.4.6. Different types of network configuration.....	40
I.4.7. Neutral configurations.....	40
I.4.8. Grid codes.....	45
I.4.9. Problem formulation and research objectives.....	47
Chapter II : Protection of distribution networks.....	52
II.1. Introduction.....	53
II.2. Definitions.....	54
II.3. Basic requirements of a protection system.....	55
II.4. Protection of passive distribution networks.....	56
II.4.1. Overcurrent-based protection coordination technique.....	57
II.4.2. Coordination based on a direction criterion.....	59
II.4.3. Coordination based on a logic selectivity.....	60

II.4.4. Conclusion on protection coordination techniques on passive distribution networks	61
II.5. Protection of active distribution networks	62
II.5.1. Adaptive protection schemes based on overcurrent relays	62
II.5.2. Adaptive protection schemes based on distance relays	63
II.5.3. Fault current limiters.....	64
II.5.4. Logic selectivity-based protection coordination using IEC 61850.....	64
II.5.5. Limitations of protection coordination techniques on active distribution networks	65
II.5.6. Conclusion	65
Chapter III : Harmonization between IEC 61850 and CIM (Common Information Model).....	68
III.1. Introduction.....	69
III.2. IEC 61850 and IEC CIM	70
III.2.1. IEC 61850.....	71
III.2.2. Common Information Model (CIM).....	75
III.3. Harmonization between IEC 61850 and IEC CIM	80
III.3.1. Methodology of harmonization	80
III.3.2. Specificities of unbalanced distribution networks	82
III.3.3. Data models constrains for achieving the transfer of network model	84
III.4. Conclusion	84
Chapter IV : Modeling	86
IV.1. Introduction	88
IV.2. Basic principles of the differential protection.....	91
IV.3. Reference distribution feeder	91
IV.3.1. Definitions	91
IV.3.2. Specificities of distribution feeders.....	94
IV.3.3. Choice of our test distribution feeder.....	94
IV.3.4. Description of the test feeder network	95
IV.3.5. Modifications brought to the test feeder	95
IV.4. Modeling approach	98
IV.4.1. Description of the modeling environment.....	98
IV.4.2. Modeling tools	99
IV.4.3. Modeling principles.....	100
IV.4.4. Modeling assumptions	102
IV.4.5. Constraints	102
IV.5. Modeling of the distribution feeder based on CIM model	103

IV.5.1. Introduction	103
IV.5.2. Modeling of the distribution feeder	104
IV.5.3. Introduction to RDF (Resource Description Framework).....	105
IV.6. Modeling of the distribution feeder IEC 61850 model	106
IV.7. Modeling of the distribution feeder based on graph theory	107
IV.7.1. Distribution feeder abstraction.....	107
IV.7.2. Architecture of zone differential protection	113
IV.8. Modeling of network components according to their behavior	114
IV.8.1. Upstream network	114
IV.8.2. Power transformer	115
IV.8.3. Line and cable segments	116
IV.8.4. Load	119
IV.8.5. Capacitor bank	119
IV.8.6. Synchronous machine	121
IV.9. Modeling of the test feeder into the power system simulation tool (OpenDSS)	121
IV.10. Conclusion	122
Chapter V : Simulations	124
V.1. Introduction.....	126
V.2. Simulation methodology	126
V.2.1. Preliminary checks	127
V.2.2. Network simulations	127
V.2.3. Simulation tools	128
V.2.4. Format of simulation results	129
V.3. Setting of differential protection parameters	129
V.3.1. Differential protection parameters.....	129
V.3.2. Current sign convention	130
V.3.3. Tripping decisions.....	130
V.4. Interpretation of simulation results	131
V.4.1. Simulations in simulation package SP1	131
V.4.2. Simulations in simulation package SP2	143
V.5. Conclusions on simulation results	151
Chapter VI : General Conclusions and Perspectives.....	152
VI.1. Conclusions	153
VI.2. Perspectives	156

Bibliography..... 158

Acknowledgements

This PhD work is the fruit of collaboration between the Grenoble Electrical Engineering Laboratory (G2ELab) and my employer Schneider Electric. It was a good opportunity for me to work on a personal initiative consisting in investigating a new mindset for improving the distribution feeder automation functions through the harmonization between the CIM data model and IEC 61850 data model. Over these years of research, I have had the opportunity to meet many people both at Schneider Electric and at the G2ELab who inspired and helped me producing this thesis.

But first and foremost, I would like to thank the Almighty God for his constant support. May Allah's blessing and salvation be upon our Prophet Mouhammad SAWS.

I would like to express my gratitude to Dr Raphaël Caire, my thesis supervisor for his guidance, his endless enthusiasm and his continuous presence throughout the research work. His comments and corrections have improved a lot the final manuscript. Raphaël gave me the freedom to develop my ideas while being present when I came back to questions that had been already resolved or when my ambitions were not compatible with the remaining time. Thank you also for all the precious advice you provided during the preparation of the defense.

I am also grateful to Prof. Nouredine Hadjsaid, my thesis co-supervisor for his valuable comments on my research work and his precious advice : "Your research time is limited, don't spread yourself. Try to get to the end".

I would like to thank Prof. Bertrand Raison, for accepting the chairman of my thesis jury. My thanks also go to all the members of the jury for accepting the invitation, examining my thesis, providing invaluable comments and corrections. Thank you all for the interest you have shown in this work.

I sincerely thank Dr. Marie-Cecile Alvarez and Prof. Frederic Wurtz, the two members of the thesis follow-up committee at the G2ELab, for their continuous encouragements and the interesting comments, suggestions they have provided.

I am deeply grateful to Mr. Laurent Guise, former Director of standardization at Schneider Electric and now CEO of Energy Semantic company. Laurent has decisively contributed both on Schneider Electric and the G2ELab sides to make this thesis possible. Moreover, despite of his tight schedule, he was available whenever I asked him. He greatly enriched my understanding and treatment of my thesis topic thanks to his extended knowledge on IEC 61850 and Smart Grids.

My special thanks also go to Mr. Thomas Rudolph, my thesis supervisor at Schneider Electric side, CTO of Innovation and Architecture, who has financed the thesis.

Thomas has supported me all along the thesis and his help with proofreading the thesis as well as his expert point of view on many topics was precious.

I would like to thank Mr. Tom Berry and Mario Jardim, Senior SCADA experts at Schneider Electric for all their insights into the world of SCADA. Very early in the thesis, Tom and Mario patiently answered my questions on the CIM model, the network control applications at the Control Center level. It greatly helped me understanding the landscape at the Control Center and the role of the CIM model.

I take this opportunity to thank my colleagues from the Expertise Department at Schneider Electric Lattes, Said Kantas, Rachid Ferroudji, Christophe Sutra and Gregory Meuner for coming very early from Montpellier to attend to the defense. Thank you also to Dr. Olivier Richardot and Francisco Fajardo, two colleagues from Schneider Electric Grenoble for coming.

I am deeply grateful to Schneider Electric for giving me the opportunity to do this research work on my personal initiative.

My thanks also go to the whole administration members of the G2ELab for all the support and the actions they have been able to provide during the thesis. Thank you also to OPLAT members for their help in the organization of the pot de thèse.

I conclude by thanking my parents for their prayers. To my wife Dieyna, special thanks for her constant presence, her patience and all her efforts for supporting me on every single aspect of this thesis. Thank you to Papa Moussa and Gaëlle for attending to the defense and supporting the pot the thèse.

Thank you to all the people who have helped in any way during this work.

List of figures

Fig.I-1	: Example of HV/MV substation	24
Fig.I-2	: Types of decentralized generation according to the primary energy	32
Fig.I-3	: Unnecessary protection tripping	35
Fig.I-4	: Protection blinding	36
Fig.I-5	: Fuse premature blowing	37
Fig.I-6	: Lack of protection coordination in islanded mode	39
Fig.I-7-a	: Directly earthed neutral point configuration	42
Fig.I-7-b	: Isolated neutral point configuration	42
Fig.I-7-c	: Neutral point earthed through a Petersen coil	43
Fig.I-7-d	: Neutral point earthed through an impedance	44
Fig.I-7-e	: Distributed neutral point	44
Fig.I-8	: Different classes of generating sources in Continental Europe	45
Fig.I-9	: Fault ride through capability curve of generators connected below 110kV	46
Fig.II-1	: Basic selectivity principle	58
Fig.II-2	: Logic selectivity principle	61
Fig.III-1	: Harmonization work mapping	71
Fig.III-2	: IEC 61850 data modeling	73
Fig.III-3	: IEC 61850 SCL Object model	75
Fig.III-4	: Package dependencies in CIM	77
Fig.III-5	: Equipment class hierarchy in CIM	78
Fig.III-6	: Three layers architecture in CIM	79
Fig.III-7	: Equipment mapping between IEC61850 and CIM	81
Fig.III-8	: Phase wire data model in CIM	83
Fig.IV-1	: Current flow direction on normal operating conditions	A2
Fig.IV-2	: Current flow direction during fault	A2
Fig.IV-3	: Operating characteristic of a biased differential protection	A2
Fig.IV-4	: Example of a distribution feeder split in zones	92
Fig.IV-5	: Reference network	97
Fig.IV-6	: Modeling environment	99
Fig.IV-7	: Simulation architecture	101
Fig.IV-8	: False differential currents	103
Fig.IV-9	: Equipment container class diagram	A4
Fig.IV-10	: Two terminals conducting equipment and its connectivity	A4
Fig.IV-11	: Class diagram of a circuit breaker	A4
Fig.IV-12	: Modeling of a three phase unbalanced line segment using a linecode defined in matrix format	A4
Fig.IV-13	: Transformer model class diagram	A4
Fig.IV-14	: One terminal conducting equipment and its connectivity	A4
Fig.IV-15	: Example of serialization of the 'EnergySource' Object in CIM RDF XML	106
Fig.IV-16	: Reference network split in zones	109
Fig.IV-17	: Zone abstraction	110
Fig.IV-18	: Data exchange between central and peripheral units	113

List of figures (continued)

Fig.IV-19	: Power transformer electrical model	115
Fig.IV-20	: Pi model of a line segment	116
Fig.IV-21	: Example of operating profile of a capacitor bank	120
Fig.V-1	: Graph representation of the reference network connectivity	134
Fig.V-2	: Graph representation of zone 1	135
Fig.V-3	: ZDP operating points of zone 1 – Normal power flow – Simulation step 1 – SP1	139
Fig.V-4	: ZDP operating points of zone 1 – Short-circuit simulations – AB fault on bus 35 in zone 3 – Fault resistance = 0	142
Fig.V-5	: ZDP operating points of zone 1 – Normal power flow – Simulation step 1 – SP2	146
Fig.V-6	: Graph representation of zone 3	147
Fig.V-7a	: ZDP operating points of zone 1 for a BN fault, bus 251, zone 3	149
Fig.V-7b	: ZDP operating points of zone 3 for an in-zone BN fault, bus 251, zone 3	150

List of tables:

Table I-1	: Accuracy class as per IEC 61869-2	28
Table III-1	: Equipment type codes as per IEC 61850-6	A1
Table III-2	: Correspondence between IEC 61850 logical nodes and CIM classes	A1
Table III-3	: Equipment name mapping between IEC 61850 and CIM	A1
Table III-4	: Geographic position mapping between IEC 61850 and CIM	A1
Table III-5	: Connectivity elements mapping between IEC 61850 and CIM	A1
Table III-6	: Equipment container mapping between IEC 61850 and CIM	A1
Table V-1	: ZDP operating time obtained for faults on zones 3, 6 and 4	143

List of abbreviations:

CIM	: Common Information Model
CT	: Current Transformer
CU	: Central Unit
DER	: Distributed Energy Resources
DG	: Distributed Generation
HV	: High voltage
IEC	: International Electrotechnical Commission
MV	: Medium voltage
PU	: Peripheral Unit
ZDP	: Zone Differential Protection

General introduction

For very long time, the electric power grid has been fed by a centralized power generation system. In this paradigm, the produced was largely based on non-renewable primary energy sources. The energy is injected, in a top-down architecture, into transmission and distribution systems to supply respectively HV, MV and LV customers. Several network management functions such as voltage control, frequency control, protection coordination, mandatory to create cost effective Power Systems (as large, stable and resilient as possible), were based on this model. [1]

Nowadays, the energy demand keeps on increasing and is expected to double by 2030 with its consequences on the pollution of the environment. At the same time, the development of the electrical system is very slow due to investment budget constraints. In this context, the electrical system assets are exposed to large pressure due to network congestions. The advent of DGs (Distributed generation) into the previous passive distribution network has increased this pressure. In addition, the presence of Distributed generation has introduced several technical challenges [1] on network operation and protection system. Bi-directional power flows, modification of short-circuit currents, amongst others, due to the presence of DERs, has created new concerns on existing protection coordination strategies, resulting in maloperations on the protection system: unnecessary protection tripping, protection relay blinding, fuse premature blowing, amongst others.

It is a fact that the penetration of distributed energy resources will keep on increasing mainly at the distribution network side. To keep the electric network developing and operating more efficiently, the changes in the distribution network call for a new mindset on distribution automation functions and more specifically protection coordination. They also call for extensive real-time interoperable information exchange between Control Center, feeder, DER, plug-in electric vehicles (PEV), storage devices, and so on based on stable and proven international standards.

However, the data exchange is facing nowadays several technological and scientific barriers amongst which:

- The electrical network model modifications require an up to date alignment on both Control Center and distribution feeder single line diagrams. During runtime, the feeder should be able to read the “as-built” network model from the Control Center in a file format, use it to update its single line diagram and integrate it into feeder automation functions. To date, this operation does not exist. However, during planning period, substation engineers configure manually the modifications from a specification in paper format, increasing then the engineering time. One constraint is to make these modifications “on the fly” (pseudo real-time). This aspect raises issues on system management, or how to perform secured distributed automation evolution (i.e. evolutions of each of the components participating to these distributed automation function) on an operating critical system. From a user’s point of view (i.e. Utilities), a large constraint is to guarantee a multivendor architecture, then leading to rely on existing standards such as IEC 61850 at the substation and field levels and CIM (Common Information Model) at enterprise level.
- Different technologies of DERs are connected to the distribution feeder. Their integration to the global network model at the Control Center and network control applications might be easier if all the electrical network components are modeled with the same semantic and syntax. In the meantime, the DER data models defined on IEC 61850-7-420 are not interoperable with the SCADA which is based on CIM (Common Information Model).

Current research works [2], Electricity industry in Europe [3], international standardization committees such as the Technical Committee TC 57 within IEC (International Electrotechnical Committee) [4], [5] and CEN-CENELEC-ETSI [6] have identified very strong requirements for IEC 61850 and CIM (IEC 61968/61970/62325) interoperability on a large variety of domains such as grid operation, grid automation, Distributed Energy Resources (DER) management, industry automation, amongst others.

This research work is part of the so-called “Smart Grid” [7] concept and will use the result of the harmonization between IEC 61850 and IEC CIM for improving the protection coordination on distribution feeders in presence of DERs (also known as active distribution feeders).

The objective is to investigate a new concept of improving the protection coordination on distribution feeders in presence of DERs. The scenario is to transfer to the distribution feeder part of the global knowledge of the Control Center, through a secure incremental management of the power automation systems (including both field and enterprise levels). In fact, the current protection system on the feeder has no knowledge on the electrical network it is protecting. Therefore, by transferring the network model to it, a better protection coordination could be obtained by having all the protection devices exchanging data with each other in real-time.

A new mindset, discussed from chapter 3, consisting in providing knowledge to a distribution feeder controller is presented. This mindset utilizes the harmonization between IEC 61850 and IEC CIM standards to transfer the as-built network connectivity model from the Control Center (model based on IEC CIM) to a feeder controller (model based on IEC 61850). The knowledge provided to the feeder helps it to better perform some automation functions such as protection coordination amongst others. Several decentralized approaches have been proposed in the research literature, but none of them deals with the provision of standardized knowledge from CIM-based operation side down to the IEC 61850-based distribution feeder. This approach enables an incremental management, i.e. an integration “on-the-fly” of network model changes into the distribution feeder automation functions. It also paves the way for the industrialization of the Smart Grid applications based on proven standards such as IEC 61850 and CIM.

A new protection scheme called Zone Differential Protection (ZDP) is also presented from chapter 4 in application of the new mindset. The ZDP, embedded into a distribution feeder controller, uses the network model transferred by the Control Center to perform the protection coordination along the feeder by applying the differential protection principle on a three-phase, unbalanced and node-breaker network model including distributed generation. As its name suggests, the node-breaker network model is the network model with nodes and breaker as opposed to

bus-branch without breakers. The three major components of this scheme are a) the extraction of the incoming network model, b) the creation of network zones between network circuit breakers and c) the application of a reformulated differential protection version to each zone.

This thesis is organized in five chapters.

In the first chapter, a general description of the power system is given with a focus on the distribution network. The motivations of the change of energy paradigm are highlighted. In addition, the technical challenges introduced by DERs on protection coordination along with the grid codes constraints will be covered.

The second chapter focuses on the protection of distribution networks. The protection coordination strategies used in passive distribution networks is discussed. Also, the current state of the art philosophies of protection coordination of active distribution networks is presented.

The harmonization between the CIM and IEC 61850 data models is reviewed in the chapter three.

The chapter four sets the required theoretical basis for the modeling of the proposed “zone differential protection” on an active distribution feeder. Also, an overview on the modeling methodology, the assumptions and the operational requirements of the zone differential protection are developed. This will give an idea on the multi-faceted modeling required to design a zone differential protection for the distribution feeder.

Finally, in the fifth chapter, the previous modeling approaches are applied to a test feeder to achieve steady-state studies (load flow and short-circuit studies) to simulate the behavior of the zone differential protection. The simulation results will be presented. However, due to time constraints, the dynamic studies have not been covered in this thesis which has been done in the half of the regular duration.

This thesis has been partially funded by Schneider Electric in support of my personal initiative to investigate a new mindset consisting of transferring part of the global knowledge of the SCADA to a distribution feeder to better achieve some distributed automation functions such as Volt/VAR control, load shedding optimization,

protection coordination. The thesis is in the framework of the partnership between Grenoble INP and Schneider Electric under the supervision of the G2eLab (Electrical Engineering research Laboratory).

Chapter I: Description of the power system

- Chapter I: Description of the power system 18
 - I.1. Introduction..... 20
 - I.2. The change of energy paradigm 20
 - I.3. The power system 21
 - I.3.1. The power generation system..... 21
 - I.3.2 The transmission system 21
 - I.3.3. The distribution system 22
 - I.4. The distribution system 22
 - I.4.1. Main parts of the distribution system 23
 - I.4.1.1. The HV/MV primary substation(s)..... 23
 - I.4.1.2. The MV network..... 25
 - I.4.1.3. The MV/LV distribution substations..... 25
 - I.4.1.4. The LV network..... 25
 - I.4.2. The components of a distribution network..... 26
 - I.4.2.1. Power transformers 26
 - I.4.2.2. Line voltage regulators 26
 - I.4.2.3. Capacitor banks 26
 - I.4.2.4. Loads..... 27
 - I.4.2.5. Conductors 27
 - I.4.2.6. Circuit breakers 27
 - I.4.2.7. Reclosers..... 27
 - I.4.2.8. Sectionalizers..... 28
 - I.4.2.9. Instrument transformers..... 28
 - I.4.2.10. Fuses..... 29
 - I.4.2.11. Protection relays 29
 - I.4.3. The distribution network – Traditional context 29
 - I.4.3.1. Conceptual architecture 29
 - I.4.3.2. Control of traditional distribution networks 30

I.4.3.3. Protection of traditional distribution networks	30
I.4.4. Distributed Energy Resources (DERs)	31
I.4.4.1. The decentralized generation	31
I.4.5. The distribution network in presence of DERs	33
I.4.5.1. Conceptual architecture	33
I.4.5.2. Control of distribution networks in presence of DERs	33
I.4.5.3. Protection coordination issues in distribution networks in presence of DERs	34
I.4.5.3.1. Unnecessary protection tripping.....	34
I.4.5.3.2. Protection blinding	35
I.4.5.3.3. Fuse premature blowing	36
I.4.5.3.4. Islanding detection concerns.....	37
I.4.5.3.5. Difficulty of reclosing after a fault.....	38
I.4.5.3.6. Lack of coordination in islanded mode	38
I.4.5.3.7. Grounding concerns	39
I.4.6. Different types of network configuration	40
I.4.7. Neutral configurations.....	40
I.4.7.1. Neutral configurations used in Europe	41
I.4.7.2. Neutral configurations used in the US	44
I.4.8. Grid codes.....	45
I.4.9. Problem formulation and research objectives	47
I.4.9.1. Problem formulation	47
I.4.9.2. Research objectives and scientific contributions	49
I.4.9.3. Conclusion	49

I.1. Introduction

To better understand the motivations of this research subject and get an idea on potential constraints, technical choices, the chapter I gives a description of the power system.

The electric system structure, its components and operation are discussed along with the advent of the DERs (Distributed Energy Resources) and the operational requirements imposed to them by the grid codes. In this chapter, the power system will be presented with a special focus on the distribution system.

I.2. The change of energy paradigm

The conventional grid model is a system where large amounts of energy are produced from centralized power generation and injected into the transmission system. The energy is transferred then to the distribution network which supplies, then, the end-users. In this model, the power is produced from large power plants with typically fossil-fuel-based primary energy. For many decades, the power production from fossil and non-renewable energies has been recognized as one of the main causes of the destruction of ozone layer due to the emission of greenhouse gases. Nevertheless, the IPCC (Intergovernmental Panel on Climate Change) experts are still not categoric to say that the power generation is the root cause of the climate change [8]. However, the public opinion has developed new aspirations for environment protection and sustainable development. It is putting increasing pressure to governments to take the right decisions. Then, governments had put in place new policies such as the liberalization of energy markets to raise investment, energy efficiency programs to reduce the energy consumption, the modification of the energy mix with the insertion of renewable energies, the provision of financial support to end-users for the installation of solar PV, among others. This was the advent of DERs (Distributed Energy Resources) in the distribution system which became active. A new energy paradigm emerged where the power is also injected within the distribution system.

The new energy paradigm has introduced technical challenges into the power system that need to be studied to better understand the constraints induced on protection coordination amongst all.

I.3. The power system

The electric system is defined as the global and complex infrastructure extending from the generating power plants down to the remote load centers. It is generally divided into three parts:

- The power generation system
- The transmission system
- The distribution system

I.3.1. The power generation system

Traditionally, the power is supplied in top-down by power generation system to distribution system via the transmission system. To designate the generation part of the power system, the term "bulk generation" was used to insist on the large quantity of energy produced by generators. Power generation is ensured by generators which convert different forms of primary sources into an electric energy. The quantity of electric energy produced can be controlled by modulating the quantity of primary energy at the input.

I.3.2 The transmission system

The load centers are generally located very far from power plants even though part of the load can be connected to the transmission system. However, the transfer of large quantity of energy to remote locations can create significant energy losses.

Therefore, to reduce the power losses to its minimum, a high voltage system also termed "transmission system" is needed. This transmission system is composed of High Voltage (HV) lines which interconnect HV/MV substations considered as the interfaces between the transmission and the distribution systems. The transmission system also allows national and international interconnections by connecting HV substations. A fraction of the energy flowing through the transmission system is used

to supply large industrial loads. The voltage levels used may differ from one country to another, however, the transmission system is generally operated with voltages greater than or equal to 50kV as per the voltage decomposition defined in [9].

I.3.3. The distribution system

Most of the customers are connected in low voltage (LV), some others on the medium voltage (MV). Therefore, to carry the energy to the furthest customers with the adequate voltage level, the distribution system performs successive voltage reduction from HV/MV to MV/LV distribution substations. The voltage levels used may differ from one country to another, however, the distribution system is generally operated with voltages below 50kV as per the voltage decomposition defined in [9].

As discussed in the introduction, the focus of this thesis is on the protection of distribution networks in presence of DER. Therefore, in the rest of the thesis, the emphasis will be put on the distribution system where the distribution network is one component.

I.4. The distribution system

The distribution system is a set of primary radial circuits that a utility uses to deliver power from HV/MV substation(s) to the end customers. During operation, the distribution system can be subject to different types of faults that must be detected and selectively eliminated by a protection system to ensure a good continuity of power supply. Before analyzing the protection system of a distribution system, it is crucial to understand the different parts of this network, its components, structure, organization and control before and after the insertion of DERs (Distributed Energy Resources). To this end, the section I.4.1 gives a description of the distribution system which can be divided into four main parts:

- The HV/MV supplying primary substation(s)
- The MV network
- The MV/LV distribution substations
- The LV network

I.4.1. Main parts of the distribution system

I.4.1.1. The HV/MV primary substation(s)

The HV/MV “primary” substation makes the interface between the transmission system and the distribution system. The HV/MV substation plays an important role in the security and the quality of supply to the distribution network. One or more back-up supplies are found in these substations due to the N-1 requirement which enforces to ensure the continuity of supply whenever a supplying source or equipment is lost. Physically, the substation is generally composed of several HV and MV busbars (based on different voltage levels) to which incoming and outgoing feeders connect through containers called bays. The Fig.I-1 gives an example of a classical HV/MV substation with two HV incoming feeders, one HV bus coupler, two outgoing feeders to HV/MV power transformers with an On-Load Tap Changer (OLTC) for voltage regulation, two MV incoming feeders from HV/MV power transformers, one MV bus coupler and two MV outgoing feeders. Each bay includes primary equipment such as circuit breakers to interrupt the fault current, disconnectors to isolate the circuits for maintenance, current and voltage transformers for current and voltage measurement. The bay also includes secondary devices for power flow measurement, protection and control.

Similarly to the bay, several automation functions are required within the substation to allow for the local and remote control, monitoring of all the primary equipment and running of specific sequences within the substation. The control of the HV/MV substation is done either locally by operators or remotely from a Control Center which sends open/close commands to the motorized switchgear or voltage setpoints for voltage regulation, among others. As for monitoring, current, voltage measurements, switchgear status, information from protection IEDs (Intelligent Electronic Devices) and specific substation data are sent via a gateway to a SCADA (Supervisory Control And Data Acquisition) located at the Control Center. As we will develop later, most Control Centers use now the CIM data model to represent the data whereas the substation uses the IEC 61850 data model. Therefore, a coordination is mandatory between these two data models for a seamless data exchange.

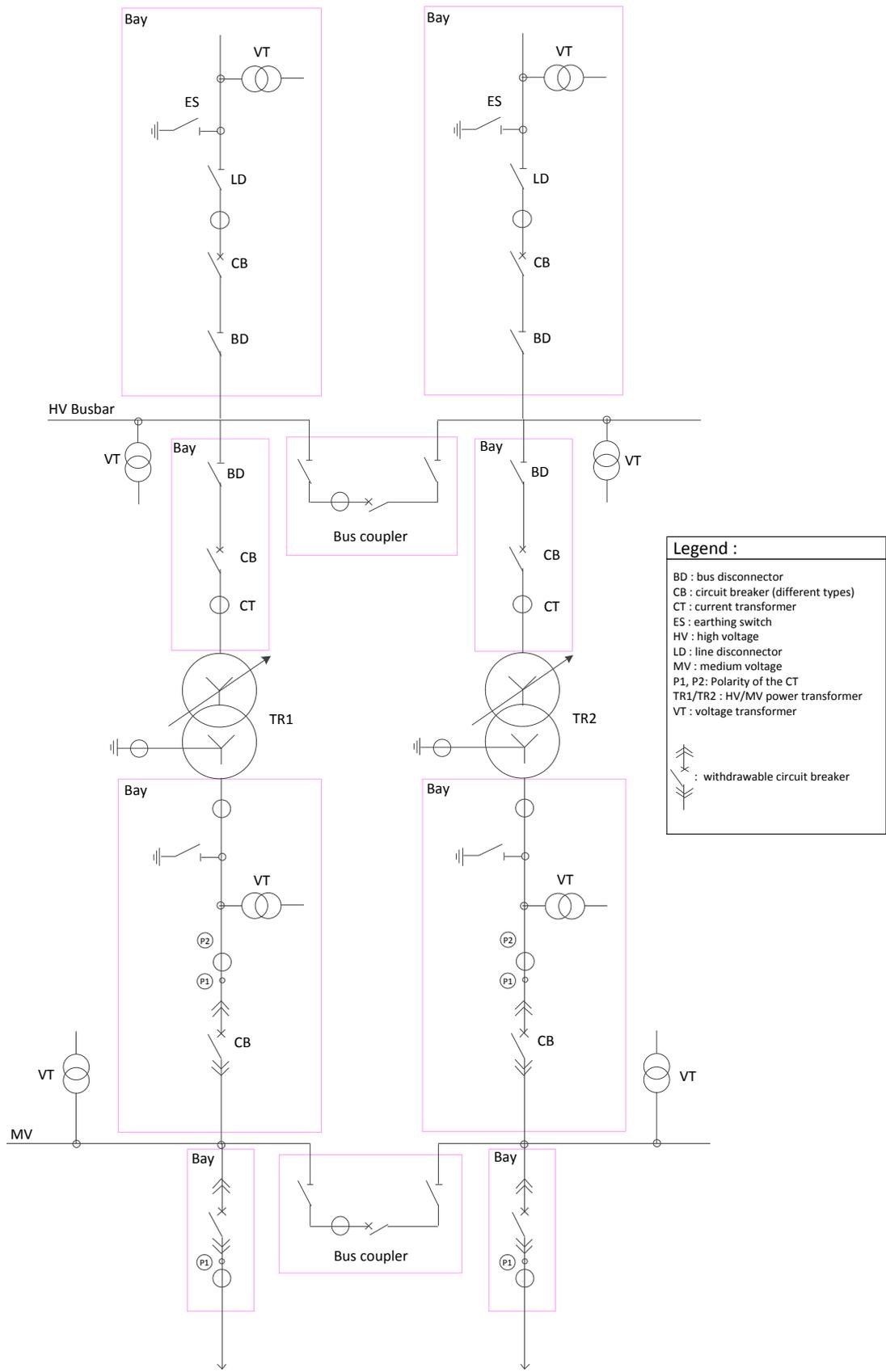


Fig.I-1. Example of HV/MV substation

1.4.1.2. The MV network

The MV network is composed of a set of feeder circuits connected to the MV busbar(s) of the HV/MV substation. Each feeder has a backbone that can carry the circuit many kilometers away from the substation. The backbone has multiple tapped-off laterals and sub-laterals feeding MV loads or MV/LV distribution substations supplying the LV loads. Several distribution schemes can be found with distributed neutral point or not. In rural areas, loads are generally supplied through overhead lines or a mix of cables and overhead lines. As for urban areas, the power supply is generally done through cables. To ensure the continuity of supply, a feeder circuit may have one or more back-up feeders originating from the same or other HV/MV substations. An appropriate circuit reconfiguration is carried out following an outage or to relieve an overloaded circuit. In the US, reclosers are installed on MV feeder backbone or on the main laterals allowing more flexibility during circuit reconfiguration and making possible the isolation of the faulty circuit.

1.4.1.3. The MV/LV distribution substations

The MV/LV distribution “secondary” substation is the interface between the MV and the LV distribution networks. The MV/LV distribution substation is composed of MV incoming feeders, distribution power transformers and LV outgoing feeders. In addition, a set of devices for metering, remote control, measurement and protection can be found.

1.4.1.4. The LV network

The LV (Low Voltage) network is supplied by the MV/LV distribution transformers. In this thesis, the LV network will not be modeled and the LV loads will be considered as “aggregated” loads at the MV level.

I.4.2. The components of a distribution network

The previous section discussed the main parts of a distribution network. In this section, an overview on the distribution network components is given..

I.4.2.1. Power transformers

The purpose of power transformers is to transfer electrical energy from one voltage to another. Power transformers can be found in HV/MV transmission substations where they generally step-down the voltage to supply the distribution network. In this case, they are equipped with an on-load tap changer for voltage regulation to counteract internal voltage drop as well as HV voltage deviations. Power transformers are also found in MV/LV distribution substations. Very often, they can be installed on top of poles (pole-mounted transformers) when serving rural areas. In addition, power transformers can be used as step-up transformers especially when they are connected to decentralized generation located on the LV side of the distribution network.

I.4.2.2. Line voltage regulators

The line voltage regulator is a unit ratio power transformer that is generally installed in series on MV feeders. It is equipped with taps that allows a voltage control on the feeder.

I.4.2.3. Capacitor banks

The purpose of capacitor banks is to supply reactive power to compensate the reactive power needed for example on heavy loads spots. In traditional distribution networks where the power is supplied from the main HV/MV substation, the capacitor bank reduces the reactive power flowing from the upstream which, then, reduces the voltage drop. The capacitor banks can be of fixed type or voltage regulated.

1.4.2.4. Loads

A load can be thought of as a point of electric energy consumption. In the distribution network, the load may be balanced with the same current on the three phases or unbalanced if the load is not evenly distributed on the three phases. In addition, it can be single phase, phase to phase or three phase loads. As for three phase loads, they may be connected in wye or delta. In presence of DER (Distributed Energy Resources), some loads may have different behaviors. For example, an energy storage system may be momentarily charging (in which case it is seen as a load) or discharging (it is then seen as a source).

1.4.2.5. Conductors

A distribution network is made of several conductor sections of different characteristics connected to carry the power towards loads points. The conductor sections can be installed underground (cables) or overhead (lines). The conductors are specified according to several criteria: the rated current to carry, the voltage drop and the maximum short-circuit current at the installation point.

1.4.2.6. Circuit breakers

A circuit breaker is a mechanical switching device that has the capability of making, carrying continuously and breaking electrical current on normal operating conditions, but also the capability of breaking the fault current up to a specified value. It is used in conjunction with a protection relay which sends a command to the tripping coil to open the circuit breaker or a command to the closing coil during a reclosing sequence or a manual close.

1.4.2.7. Reclosers

A recloser is a circuit breaker equipped with a protection relay. It is designed to execute a preset open/close sequence before going to lockout. It is generally placed on MV overhead lines to improve the continuity of supply after a fault occurrence. In addition, it can be used for network protection or circuit reconfiguration.

1.4.2.8. Sectionalizers

A sectionalizer is a disconnecter equipped with a relay that counts the number of operations of an upstream breaker or recloser during a fault sequence and opens when they reach the preset count while the breaker or recloser is still open. It can neither reclose nor break a fault current.

1.4.2.9. Instrument transformers

Instrument transformers are used to transform high primary voltages or currents into smaller values than can be safely handled by secondary equipment (protection devices for example). They have a primary winding which carries the primary voltage or current and a secondary winding to which secondary devices such as protection relays are connected. A transformation ratio is applied between the primary and secondary value of voltage or current. Instrument transformers that modifies the magnitude of current are referred to as “current transformers” (CT) and those transforming the magnitude of the voltage are called “voltage transformers” (VT).

In practice, a transformation error is introduced by the instrument transformer. The table I-1 gives the accuracy for current transformers used in protection applications. For example, during its transformation, a conventional current transformer (CT) with an accuracy class of 5P introduces a maximum error of magnitude 5% of its nominal current for short-current values equal to their accuracy limit factor (ALF) while the current transformer is at its rated accuracy power S_n . On normal operating conditions, the transformation error is $\pm 1\%$ of the nominal current of the CT.

Accuracy class	Current magnitude error at nominal I_n	Angle error δ at nominal I_n	Total error at $n \cdot I_n$ (rated accuracy limit)
5P	$\pm 1\%$	± 60 minutes	5%
10P	$\pm 3\%$		10%

Table I-1- Accuracy class as per IEC 61869-2

Besides these static errors, the instrument transformer has a transient response during fault conditions which may result in core saturation. As a result, a malfunction of the protection relays can follow. As can be seen, instrument transformers are very important in a protection system as they are the interfaces between power system and the protection relays.

1.4.2.10. Fuses

A fuse is a protective device consisting on a metallic element that melts to create a circuit discontinuity in presence of a faulty current that exceeds the fuse rating for a certain time. The fuse melts according to specific inverse time-current curve. However, the fuse should allow normal operating currents and overloads to flow without deteriorating.

1.4.2.11. Protection relays

A protection relay is a device that responds to signals from instruments transformers (current transformers, voltage transformers) and commands a circuit breaker to open under faulty conditions. One of the main challenges of protection relays is to ensure a good stability of the relays during current transformers (CT) saturation as the protection relays face a large current transformation error and the current measured by the relays is altered [10].

1.4.3. The distribution network – Traditional context

1.4.3.1. Conceptual architecture

For many years, the traditional electricity distribution network was passive as the electric power was only supplied in top-down from the transmission network via HV/MV substation. There was no embedded generation. The distribution feeder was radial as there was only one path for the power to flow from the feeding substation to the end users. In the same way, there was only one path for the short-circuit currents to flow from the source (which is the HV/MV substation) to the fault inside the distribution network.

1.4.3.2. Control of traditional distribution networks

The distribution network has been historically controlled and monitored by a SCADA located at a Control Center in a centralized approach where Control Center operators manage the circuit reconfiguration, the switching of capacitor banks, the voltage control, amongst others. Besides this remote control, the substation could be controlled locally through a substation automation system (SAS) or manual commands from operators. Recently, the concept of “feeder automation” has been introduced to perform some automation function under the feeder control.

1.4.3.3. Protection of traditional distribution networks

In the absence of decentralized generation, the distribution network is considered as radial and fed from the main power station. If a fault appears downstream of an MV feeder connected to the main power station, only the main substation is contributing to that fault. Thus, the short circuit current will be flowing from the main substation to the fault (upstream to downstream). To achieve a protection coordination in this context, the basic idea has been, up to now, to create a grading margin between the protection devices in cascade in the fault path to eliminate the fault while restraining the outage to the only affected section.

Traditionally, overcurrent-based protection devices (fuse, recloser and overcurrent protection relay) are used on distribution networks. Several technologies of protection relays (electronic, digital) may be found with or without direction detection functionality. Also, in some distribution networks, sectionalizers are added to the landscape to improve the fault location and isolation in conjunction with reclosers. Basically, the current flowing on the circuit is supervised and should the magnitude of this current exceed a preset threshold for a time delay, the protection device that is the closest to the fault will open to isolate the fault, leaving the rest of the circuit energized. The tripping time delay is according to a preset time-current characteristic. More details are given in chapter II on the philosophies of protection used on both passive and active distribution networks.

I.4.4. Distributed Energy Resources (DERs)

There is no consensus on the definition of DERs but the Institute of Electrical and Electronics Engineers (IEEE) defines the DERs as “sources of electric power that are not connected to a bulk power transmission system. DER include both generators and energy storage technologies” [11]. In Europe, the term DERs includes the decentralized generation, the storage and the controllable loads. The definition of IEEE will be considered as it suits better the application (protection coordination) we will discuss further from chapter 4. The load controllability has no effect on our protection scheme as the loads manipulated in our application are aggregated at the MV level. Also, storage systems are considered as loads during their charging period and sources when they are discharging.

In the rest of the section, the different technologies of decentralized generation will be presented with their current contribution during short-circuits. In addition, the challenges the protection coordination must face in presence of DERs which will be discussed.

1.4.4.1. The decentralized generation

Basically, the decentralized generation covers all the power generation sources recently installed on the distribution network and at the end users' premises following the deregulation of the energy markets. In fact, the deregulation of energy markets has set incentives to promote the power production from renewable energies. The decentralized generation can be classified according several criteria: the primary energy used, the technology of power conversion. According to the primary energy used, there are two categories:

- Renewable energy based decentralized generating sources also known as intermittent generating sources: example of solar PVs and wind generators. Because the input primary energy is based on weather conditions which is not perfectly known, these generating sources have a stochastic behavior;
- Non-renewable energy based decentralized generating sources such as small-scale diesel generators. They have a deterministic behavior causing the energy produced to be dependent on the injected primary energy.

The Fig.I-2 illustrates this classification.

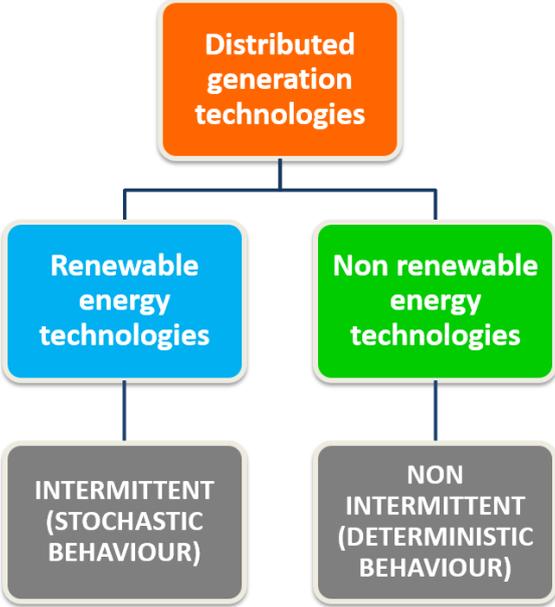


Fig.I-2. Types of decentralized generation according to the primary energy

According to the technology used for the energy conversion, there are three categories of decentralized generators:

- Synchronous machines;
- Induction machines;
- Inverter-based generation sources which are interfaced to the grid through power electronics: case of solar PV installations for example.

Synchronous machines:

The synchronous generator has three impedances [12]: the subtransient positive sequence reactance (X''_d), the transient positive sequence reactance (X'_d) and the synchronous positive sequence reactance (X_d) with $X''_d < X'_d < X_d$. As a result, the short-circuit contribution of the generator differs according to the current reactance of the generator. If a short-circuit is applied at the terminal of a synchronous machine, the current will start out very high and decay to a steady-state value. Synchronous machines generally deliver about six times the rated current for several cycles before decaying to between 400% and 200% of rated current [29].

Induction machines:

If a short-circuit is applied at the terminal of an induction machine, the current will start out very high before decaying rapidly to zero due to the demagnetization of the machine. The induction machines deliver about six times rated current during this very short time (usually from one to three cycles) [13].

Power electronics interfaced generating sources:

On power electronics interfaced decentralized generators, the short-circuit contribution of inverters is less than 200% of the inverter rated current [13].

As we can see, the different types of decentralized generators respond differently during short-circuits. On normal operating conditions, the output power of intermittent generators is dependent on weather conditions.

I.4.5. The distribution network in presence of DERs

As discussed previously, the distribution network operation, planning and protection are impacted by the presence of DERs. In this section, the highlight is only put on aspects related to protection coordination. Before developing the protection issues introduced by DERs, we present the new network architecture. Then, the challenges on control and protection of the distribution system are discussed.

I.4.5.1. Conceptual architecture

In the new paradigm, the network control becomes more complex with the new actors. In addition, the power flow becomes bi-directional and the short-circuit currents have several paths to flow: from the traditional main source (which is the HV/MV substation) to the fault on one hand and from the decentralized generators to the fault on the other hand.

I.4.5.2. Control of distribution networks in presence of DERs

In the traditional control scheme, the centralized control scheme requires several teams of network operators. In addition, the central control scheme becomes more

complex in presence of DERs. Therefore, the question of the relevance of the current centralized control scheme arises. A mechanism for providing an MV feeder with the maximum relevant information to help it better perform critical functions such as protection coordination, voltage profile mitigation, circuit reconfiguration amongst others could be very interesting and could also open new perspectives for feeder automation. The question is not to declare the current centralized control inefficient and useless but to relieve control operators at the Control Center by assigning more tasks to MV feeders in a new control scheme combining the centralized and decentralized schemes.

1.4.5.3. Protection coordination issues in distribution networks in presence of DERs

The protection system must adapt to the presence of DERs. To do so, it is important to understand the challenges introduced by DERs on protection coordination. Amongst these issues, we have the unnecessary protection tripping, the protection blinding, the fuse premature blowing, islanding detection concerns, difficulty of reclosing after a fault, grounding concerns, lack of protection coordination in islanded mode. In this section, these challenges are presented. An MV network consisting of two MV feeders (Feeder 1 and Feeder 2) with distributed generators (DG1-4) on each of the two feeders is used to highlight some protection concerns introduced by the presence of distributed generation.

1.4.5.3.1. Unnecessary protection tripping

The unnecessary protection tripping is explained on Fig.1-3 on which a three-phase fault is placed at point F1. The fault current flows from the main upstream 90kV source and from the decentralized generators (DG). It is important to mention that on feeder 1, the direction of the fault current is from the MV bus to the three-phase fault point while on feeder 2, the direction is towards the MV bus due to the infeed from the generator DG4. If the fault current measured by the protection relay on each feeder exceeds the preset overcurrent thresholds, the two relays will trip should the relays are not fitted with the directionality. As a result, an undesired tripping will occur on the adjacent sound feeder (feeder 2) for a fault on feeder 1.

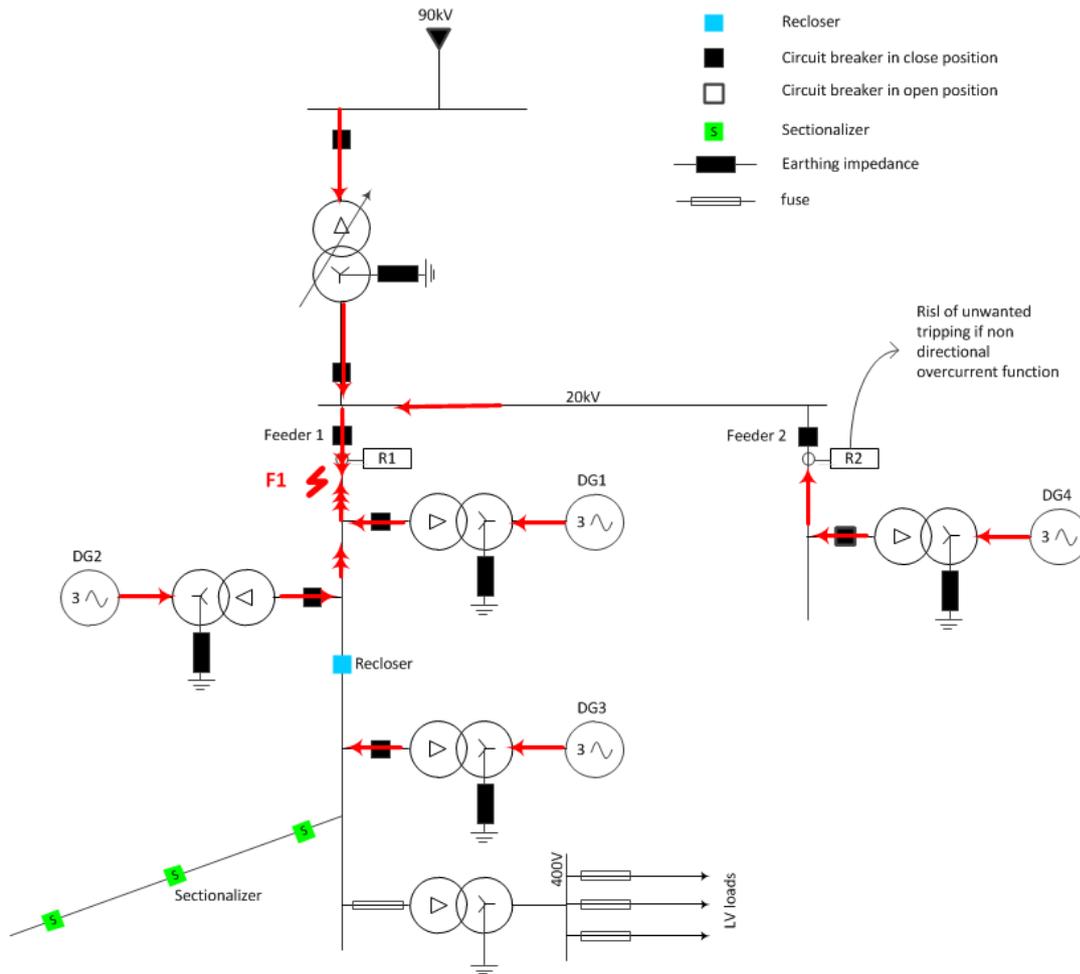


Fig.I-3. Unnecessary protection tripping

I.4.5.3.2. Protection blinding

Fig.I-4 below illustrates the protection blinding phenomenon with a fault placed at F2, after the connection point of DG1. The presence of the generator DG1 creates an intermediate current infeed which reduces the short-circuit contribution from feeder 1 to the downstream short circuit current compared to the case without decentralized generation. This results in a reduction of sensitivity on feeder 1 and possibly a protection blinding preventing the protection relay at feeder 1 to see the fault at F2.

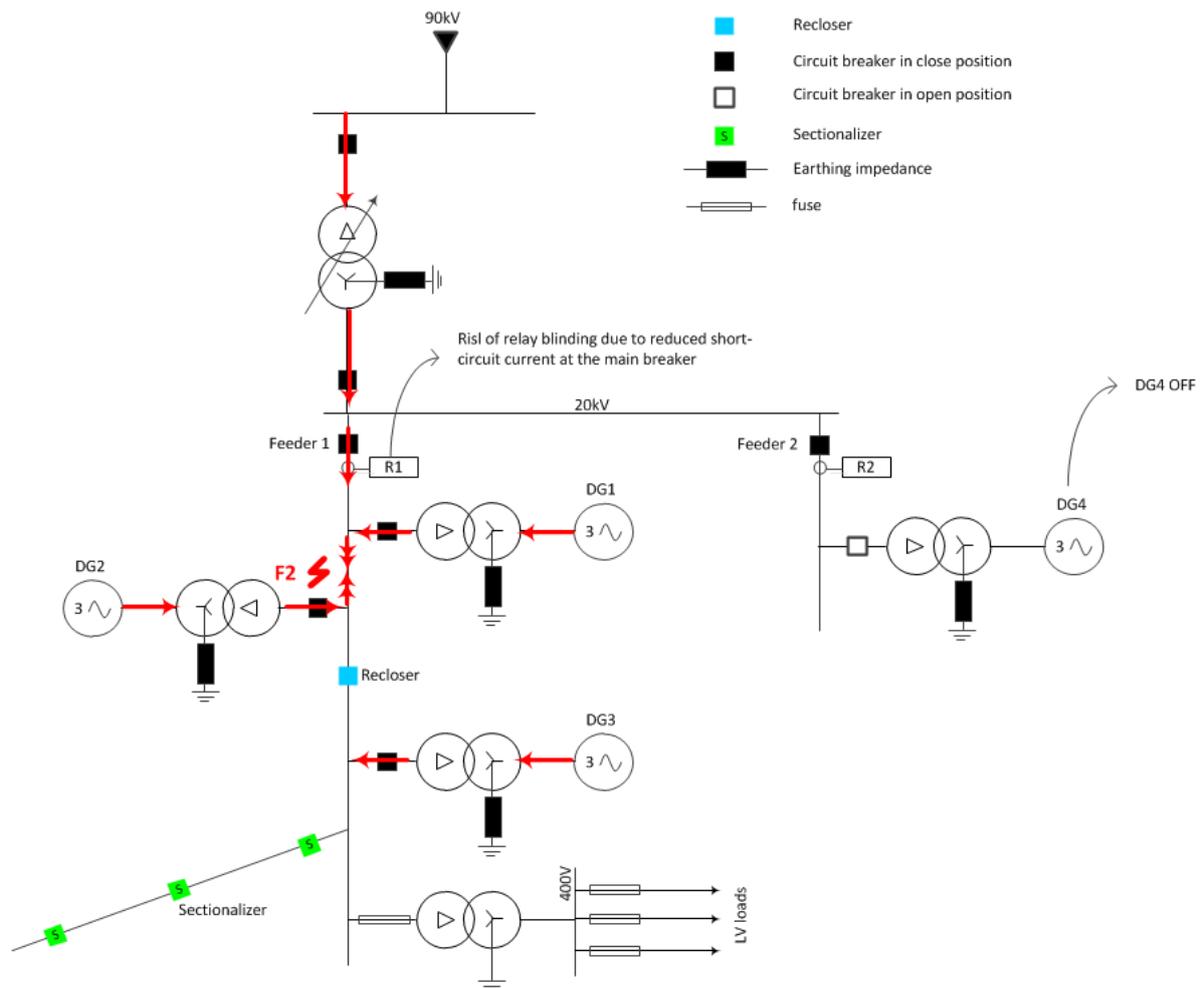


Fig.I.4 Protection blinding

I.4.5.3.3. Fuse premature blowing

The presence of decentralized generation into the electricity distribution network also affects the fuses. Specifically, a fuse is selected based on a maximum load on the feeder and a short circuit current on the protected circuit. But, due to the contribution of decentralized generation, the total short circuit current crossing the fuse is increased in such a way that a premature fuse blowing could be experienced as mentioned on Fig.I-5. The common practice would recommend, for a fugitive fault, to enable a high-speed reclosing to save a downstream fuse from blowing. Consequently, to improve the selectivity in presence of decentralized generation, it is

important to allow the fuse blowing only if the fault located on the downstream side of the fuse is assumed permanent.

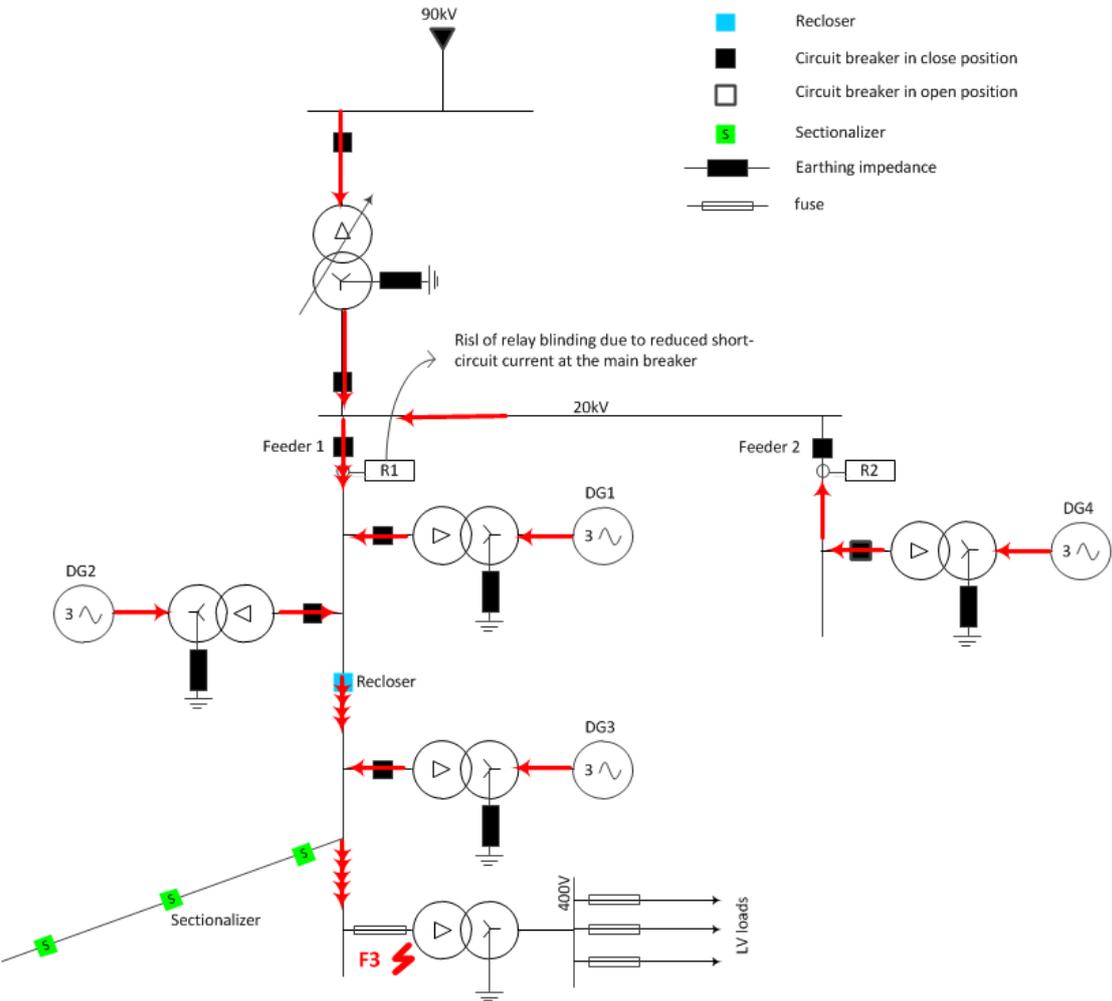


Fig.I-5. Fuse premature blowing

I.4.5.3.4. Islanding detection concerns

Decentralized generation (DG) is normally supposed to stop energizing a portion of the network that has been separated from the main power distribution grid. In other words, to avoid the continuous energization of a fault for example, the DG should be decoupled by a loss of mains protection. Generally, the loss of mains protection is not an efficient means to detect the absence of the main power supply especially in presence of DG. This point is of importance mainly for security reasons but also for the service restoration.

I.4.5.3.5. Difficulty of reclosing after a fault

In the traditional passive distribution network, an auto recloser could decide to reclose after a fault without taking care of what is happening downstream. Indeed, traditionally, there was no other source except the main power source at the HV/MV substation. But, in presence of DG, care should be taken to coordinate the reclosing with the neighboring sources for two reasons:

- situations could arise such as closing a circuit breaker out of synchronism (main power supply and the DG not necessarily synchronized);
- in passive distribution network, the typical dead time value for high speed reclosing is between 100 to 500ms. This dead time must be reconsidered in presence of DG otherwise if the reclosing order comes too fast, there may not be enough time to extinguish the arc.

I.4.5.3.6. Lack of coordination in islanded mode

In islanded mode, the protection settings in grid connected mode are not necessarily valid and may need to be updated due to the reduction of the short circuit current. Moreover, a coordination is required between overcurrent and under voltage thresholds on the generating sources (example of DG4) as depicted in the Fig.I-6.

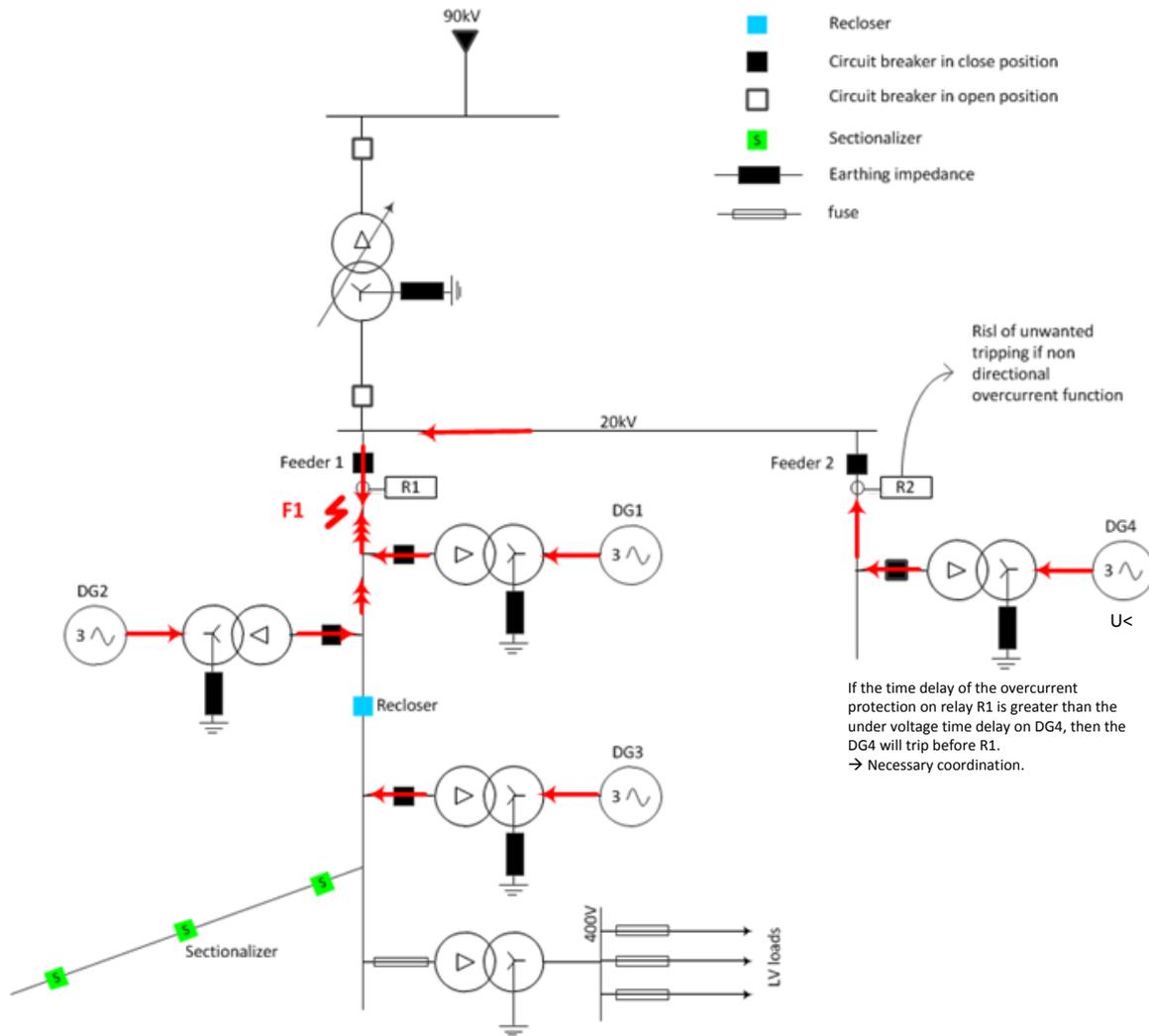


Fig.I-6. Lack of protection coordination in islanded mode

I.4.5.3.7. Grounding concerns

The presence of Distributed Generators (DG) can create different neutral point arrangements. On one hand, when the secondary side of the power transformer connecting a DG (call it TR-DG) to the main power supply is coupled in wye and earthed, then in case of earth fault on the MV network, both neutral point at the main power supply side and the neutral point of TR-DG will be contributing to the fault current. On the other hand, during the islanded mode, two situations may arise: a neutral point fixed by TR-DG or an isolated neutral point. As a result, these situations will influence the protection against earth faults and the network security.

In the light of the previous sections, it clearly appears that the introduction of DG in the initial traditional passive network has created several concerns on protection coordination that must be addressed carefully. The protection strategies will be discussed in the chapter 2.

I.4.6. Different types of network configuration

The design of the zone differential protection we want to investigate in this thesis requires the knowledge of the network connectivity of the distribution feeder including the loads, the capacitor banks, line voltage regulators, generators, circuit breakers, reclosers, etc. and the connectivity between them. There are several network configurations on distribution networks amongst which:

- the radial configuration where the loads are supplied via individual circuits from the HV/MV substation without interconnection to any back-up HV/MV substation. In this configuration, the protection coordination is generally based on simple overcurrent protection relays with a time/current grading between them. However, the radial configuration may be more sophisticated in presence of reclosers;
- the open loop configuration where the one supplying HV/MV substation is interconnected to at least another neighboring HV/MV substation via switches. On normal operating conditions, by opening switches at appropriate points, the network can be operated as a radial circuit;
- the looped configuration which are more complex and where basic overcurrent protection relays cannot ensure a good protection coordination. Distance or directional protection are required in this configuration.

Whatever the configuration, an important and determinant element is the knowledge of the position of circuit breakers and reclosers as it is used for the creation of zones of protection.

I.4.7. Neutral configurations

The study of the neutral configuration is very important as it determines how the earth is connected (grounding) on the source side, hence the earth current flow according

to the grounding method. The main purposes of grounding are to minimize potential transient over voltages to comply with local, state, national codes for personnel safety requirements and to assist in the rapid detection and isolation of the trouble or fault areas [14]. The MV neutral configuration is defined at the HV/MV power transformers located at HM/MV substations and is very important when dealing with protection aspects because each neutral arrangement dictates a different protection scheme. In this section, two main MV networks are presented: three phase MV networks with 3 wires as in Europe and three phase MV networks with 4 wires as in the US.

1.4.7.1. Neutral configurations used in Europe

In Europe, the MV distribution networks are composed of 3 wires for the three phases. Four different neutral arrangements can be found as described below:

- directly earthed neutral point where the MV neutral point of the HV/MV power transformer at the main substation is directly connected to the earth (Fig.I-7-a). In this case, the earth fault current is important and can exceed the three phase fault current.
- isolated neutral point where there is no direct link between the system neutral point and the earth (Fig.I-7-b). So, no earth current will be flowing from the MV neutral point of the HV/MV power transformer. The only flowing earth fault current corresponds to the contribution of capacitances between phases and earth of the lines connected to the supplying bus. That means, the earth current is weak and even smaller than the nominal current. The earth fault current is approximately the same whatever is the fault location, which complicates the earth fault protection coordination. As for the overvoltage between healthy phase and earth, an increase of $\sqrt{3}$ of the system nominal voltage can be reached during an earth fault.

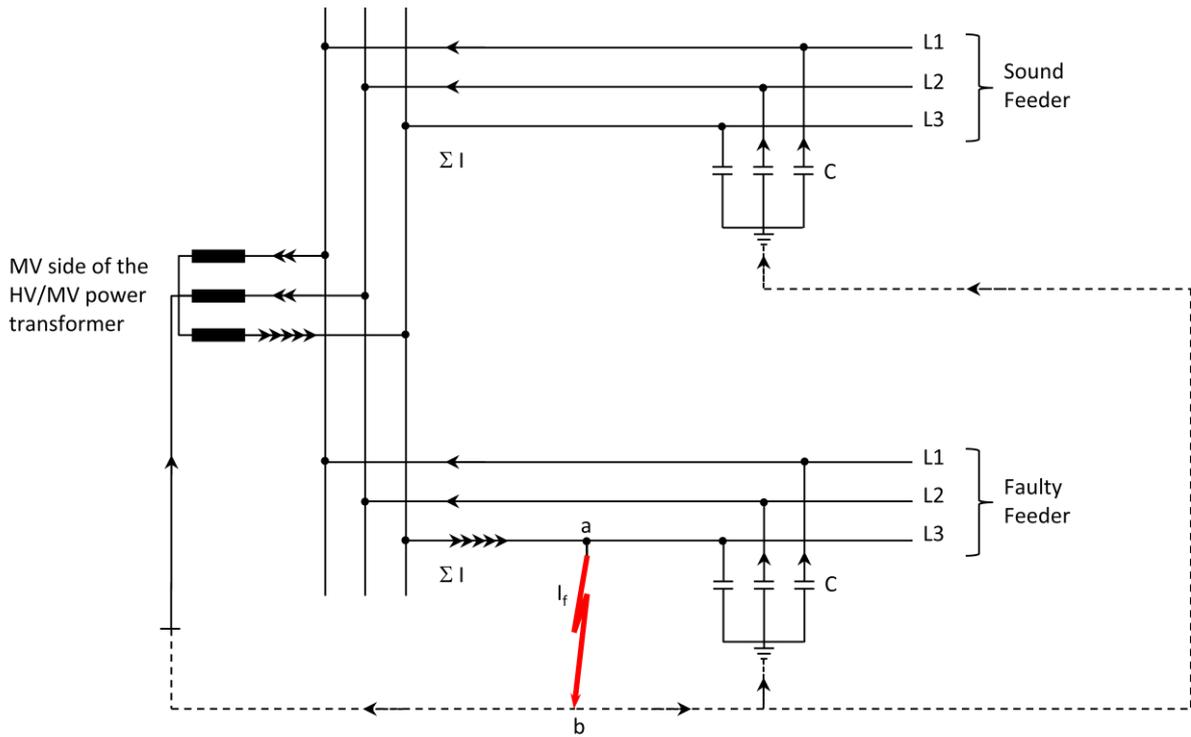


Fig.I-7-a – Directly earthed neutral configuration

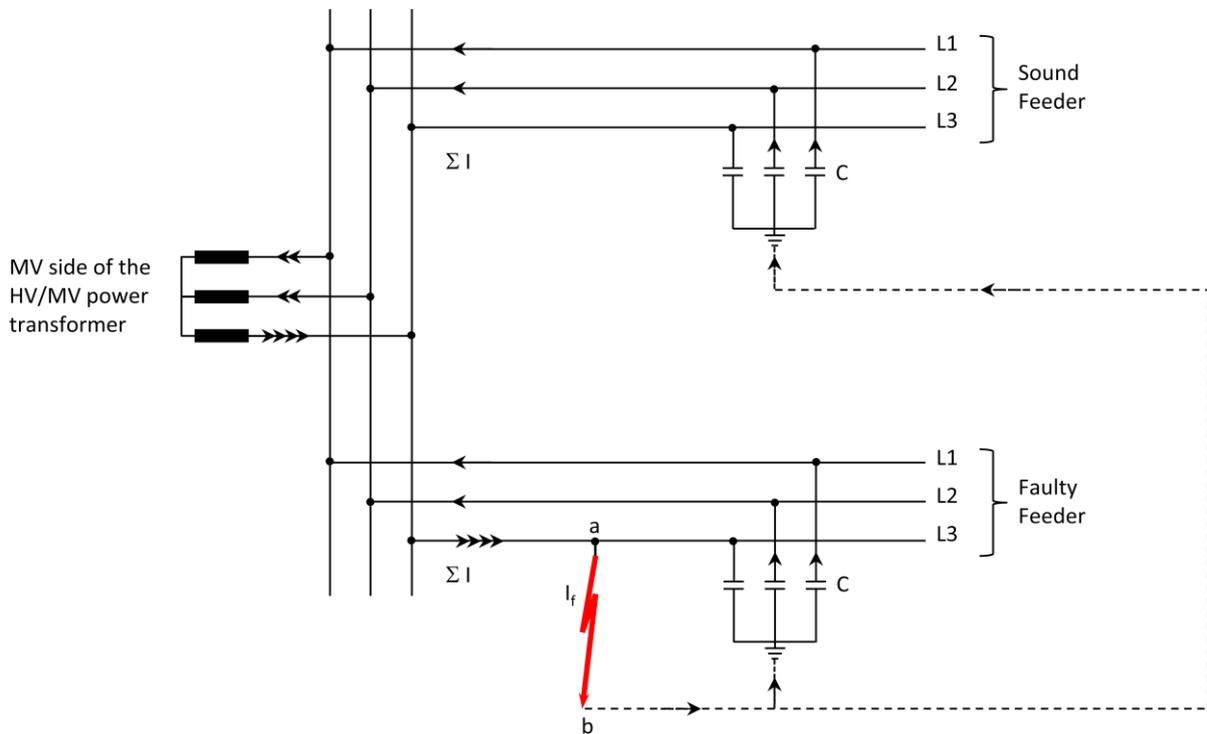


Fig.I-7-b – Isolated neutral configuration

- neutral point earthed through a Petersen coil as shown on Fig.I-7-c: The idea is to try to extinguish the fault current on a feeder by tuning the inductance on the neutral point so that the generated inductive current equals the capacitive current value from neighboring feeders.

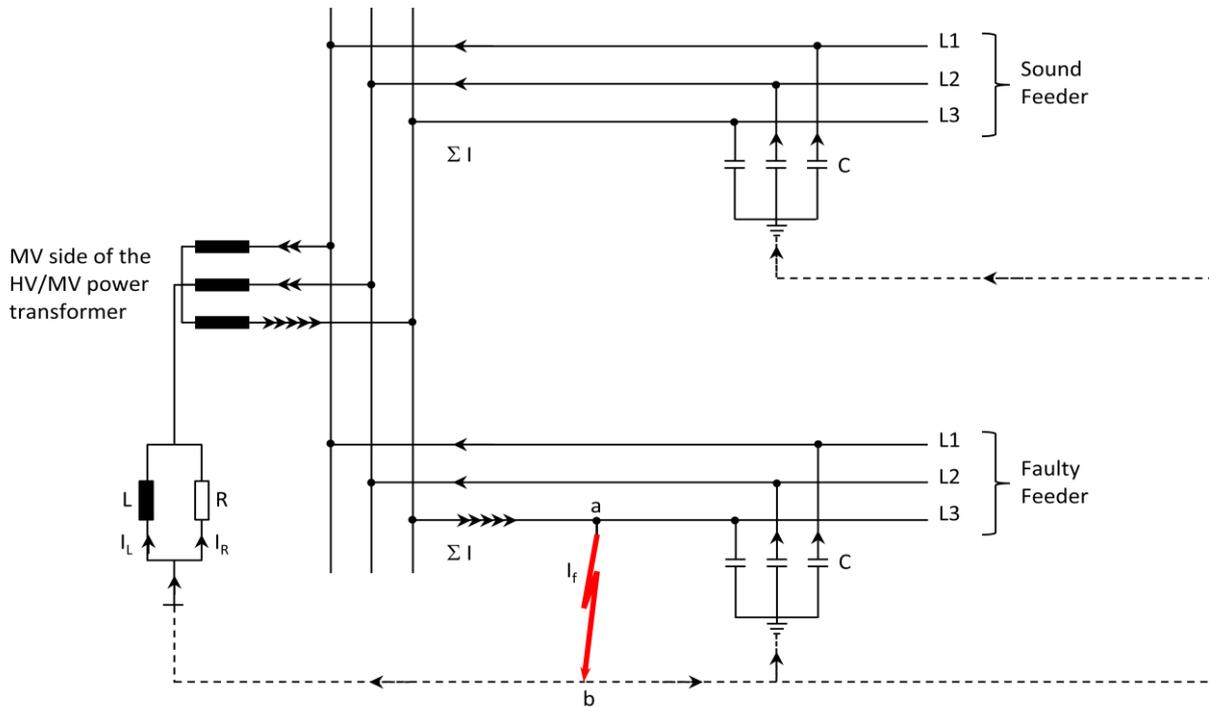


Fig.I-7-c – Neutral point earthed through a Petersen coil

- neutral point earthed through an impedance as illustrated on Fig.I-7-d: In this case, the neutral point of the HV/MV power transformer is connected to the earth via a resistance or a reactance which limits the earth current. In French MV distribution networks, a maximum earth current value (300A for MV overhead networks and 1000A for MV underground networks) has been agreed as a compromise to avoid high stresses on equipment, to reduce the disturbances on telephone networks, while taking full advantage of the protection system performance, especially the sensitivity [15].

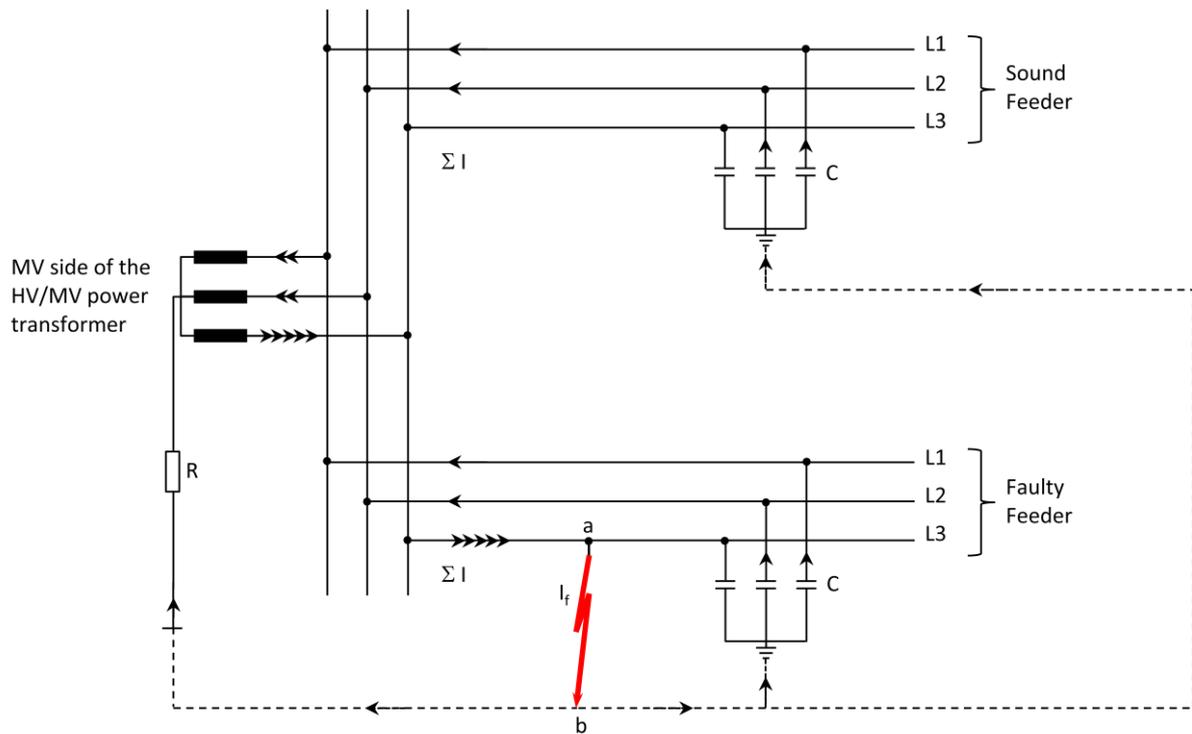


Fig.I-7-d – Neutral point earthed through a resistance

1.4.7.2. Neutral configurations used in the US

In the US, the MV distribution networks are in 4 wires as the neutral point is directly earthed and distributed at several points (Fig.I-7-e). For a single line to ground fault, this arrangement limits the voltage rise on unfaultry phases to about 125 to 135% of the pre fault condition [16].

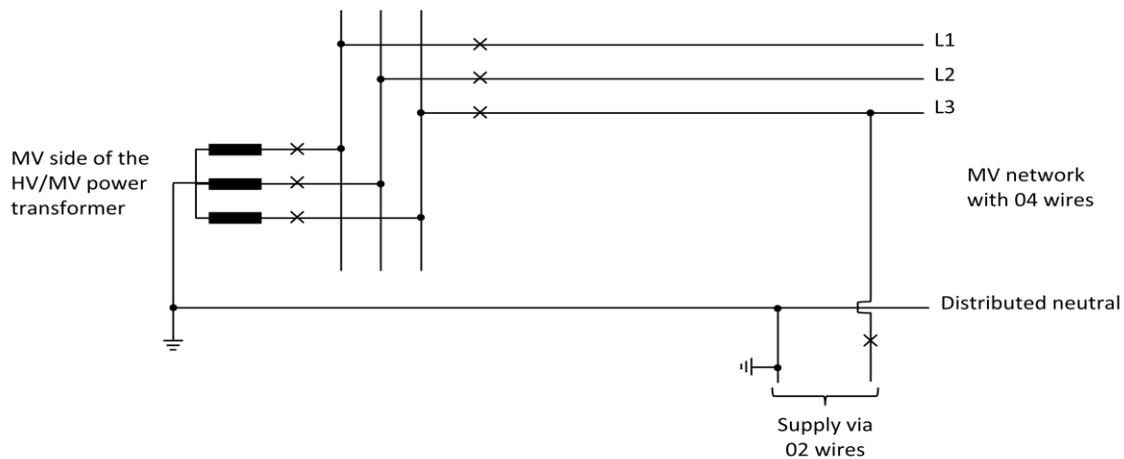


Fig.I-7-e – Distributed neutral point on MV networks with four wires

I.4.8. Grid codes

The massive penetration of DERs on the electricity network may create severe risks on electrical system security if specific requirements are not defined concerning their behavior during fault conditions, the fault clearance time, the connection requirements, etc. A grid code is a technical document containing the rules for operation, maintenance, planning of the grid. There are several common specifications of grid code from one country to another. But due to some specificities, local requirements can be defined. In Europe, grid operators found that standard requirements could improve the reliability of the global interconnected network. Therefore, European Union has tasked ENTSOe (European Network Transmission System Operators - Electricity) to write a harmonized grid code. At European level, five synchronous areas (UCTE for Continental Europe, NORDEL for Nordic countries, BALTSO for Baltic countries, UKTSOA for Great Britain, ATSOI for Ireland and North Ireland) have been created with specific rules for each of them [17]. For example, Fig.I-8 depicts the categorization of generating sources into four classes with the rated power and voltage level requirements defined within Continental Europe.

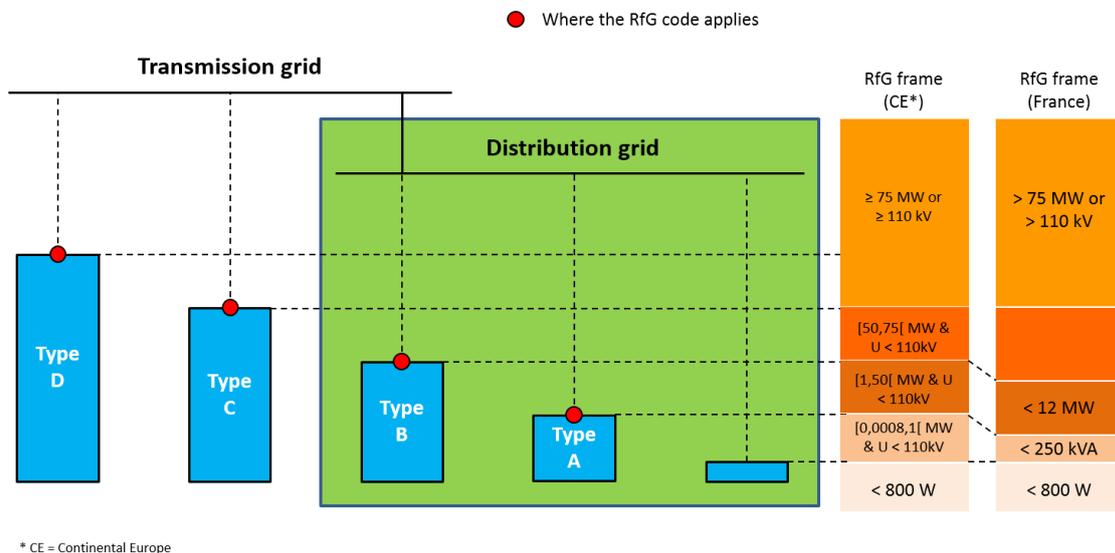


Fig.I-8. Different classes of generating sources in Continental Europe – adapted from [18]

Then, for each class, a set of technical requirements have been defined on several domains such as the requirements for generators (Rfg), grid connection, operational security, among others.

As for the Rfg, constraints on frequency withstand and Fault Ride-Through (FRT) are set for each class of generator. Fig.I.9 gives an example of a fault ride-through capability curve for generators below 110kV [17]

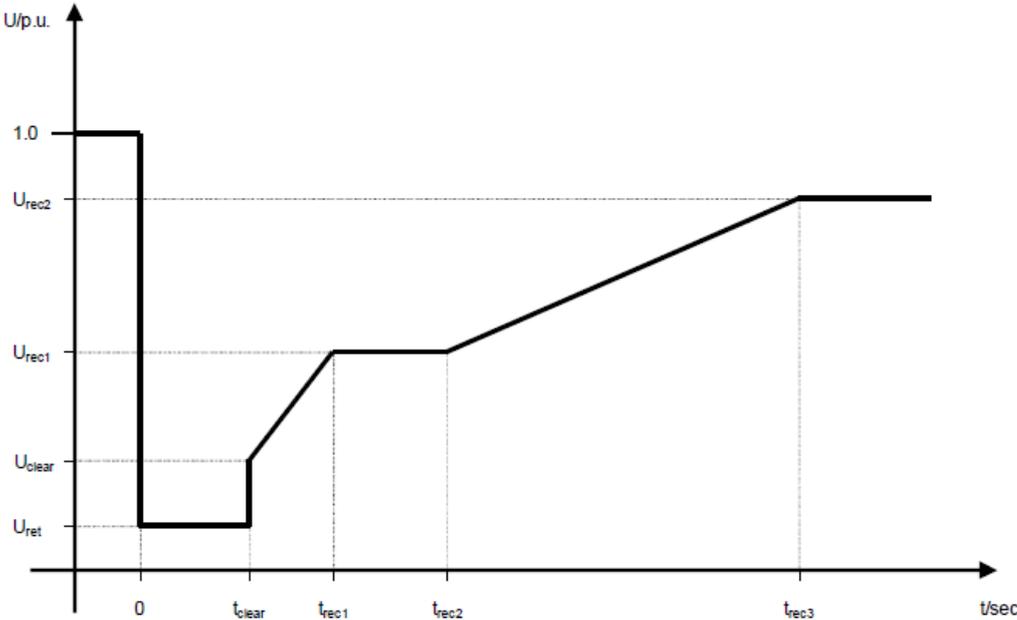


Fig.I-9. Fault ride through capability curve of generators connected below 110kV [18]

In this example, a generator below 110kV must disconnect during a fault when the associated voltage drop reaches U_{ret} for a duration of t_{clear} (time to clear). As we can see, the protection system must adapt to the constraints defined by the grid code as it is crucial to coordinate the time to clear required on generators with zone differential protection where there are in-zone generating sources, etc.

In the US, the IEEE 1547 set of standards define the interconnection technical specifications and functional requirements for DERs.

I.4.9. Problem formulation and research objectives

The objective of a protection coordination system is to protect electrical assets against the impacts of short-circuits, but also ensure the continuity of the power supply by disconnecting the faulty part from the rest of the electrical system. The protection coordination consists in arranging the settings on protective devices installed on the network to detect and eliminate the fault on the affected part of the network. This function is critical and should be ensured in any case including in presence of DERs.

I.4.9.1. Problem formulation

To ensure the protection coordination, several philosophies based on distance protection [19], [20], fault current limiters [21], [20], IEC 61850-based logic selectivity [22], overcurrent-based adaptive protection with change of setting groups [23], overcurrent-based adaptive protection with dynamic change of settings have been proposed [24]. Unfortunately, while these approaches have the advantage of somehow improving the protection coordination, there is still room for improvements.

Firstly, for distance or overcurrent-based protection schemes, the impact of the intermediate infeed may create an under-reaching phenomenon [19] (for distance relays) and loss of sensitivity or relay blinding.

Secondly, the data exchange between the MV feeder and the Control Center is not fully used due to the difference between their data models, CIM (Common Information Model) at the Control Center and IEC 61850 at the MV feeder level. Therefore, the gaps between these two data models need to be studied.

Thirdly, in the current protection coordination strategies, the evolution on the feeder network connectivity model (addition of a new customer or substation or generating source, decommissioning of equipment) is not dynamically integrated into the protection scheme in operation time. In addition, the modification of the electrical characteristics of an equipment is not known by the protection system itself except by protection engineers who are obliged to make a coordination study to check the validity of current settings. The protection system has no means to integrate the

changes on assets by itself. Introducing a new process of change management could enhance the protection system and more globally other distribution automation functions such as voltage control, load shedding optimization, etc. Each function would be tied to the feeder network connectivity model.

Fourthly, an MV feeder may momentarily extend to a back-up feeder following a circuit reconfiguration for instance. In this case, it is important for the feeder to integrate to its control the network components that were initially connected to a back-up feeder for example. For several resources, this may be viewed as a change of “jurisdiction”. The protection scheme could be more intelligent to adapt to these changes.

Besides the previous aspects related to protection coordination, the network control architecture should also adapt. Historically, the distribution network has been monitored from the Control Center in a centralized architecture. All the substations and field devices were controlled from the Control Center, leading to consequent data flows between substations and Control Center on one hand, and between the field devices and Control Center on the other hand. The current centralized control model will be more and more inefficient and unrealistic in some point of view due to the need of increased controllability and observability, the geographically large scale of distribution networks, the necessity of active control with DER introduction, the need to monitor the Electric Vehicles (EV) and the Demand Side Management (DSM), among others. Therefore, a centralized control architecture becomes extremely complex and communication-intensive in such a way that questions arise about the relevance of this control architecture. One of the main questions today is how to design a control system that combines both centralized and decentralized control architectures avoiding being in an “all centralized” or “all decentralized” control architecture?

However, the decentralized control at a distribution feeder controller level would require an interaction between, on one hand, the Control Center which uses the CIM (Common Information Model) data model and the feeder which uses the IEC 61850 and, between the electric components on the feeder circuit and the feeder controller on the other hand which both use the IEC 61850. As a result, a harmonization of

these two data models is necessary. This decentralized control would pave the way for the transfer of network model from the Control Center to the MV feeder.

Addressing these hindrances could give many possibilities to feeder automation and increase the resiliency of the control system while relieving the network operators.

1.4.9.2. Research objectives and scientific contributions

This research work was intended with one objective in mind: to create an added value on protection coordination on active distribution networks by providing the MV feeder with its matrimonial base. Basically, the distribution feeder does not have any knowledge about the downstream network it is supplying. So, the scenario is to use the fruit of the harmonization between the CIM and IEC 61850 data models to provide a distribution feeder with the network connectivity model of the downstream circuit it controls to help it better perform some automation functions such as the protection coordination. A controller located at the head of the distribution feeder will analyze the incoming network model and split it into zones on which a so-called “Zone Differential Protection” will be applied in collaboration with protection relays located at zone boundaries. The protection relays at the zone boundaries will send their instantaneous electric currents to the feeder controller to check the current balance in each zone. The instantaneous currents from all the components (intermittent and non- intermittent generating sources, the load currents at MV/LV substations, capacitor banks, the current injection at the boundaries, etc.) within each zone are assessed to check the current balance in the zone. In addition, the status of circuit breakers or reclosers are sent to the controller. The fact that the differential protection is self-selective and fast makes it a good candidate for the protection of distribution networks in presence of Distributed Generation (DG).

1.4.9.3. Conclusion

The protection coordination on distribution networks becomes more complex in presence of Distributed Generation. Nevertheless, it should be ensured without degrading the reliability indicators. Many strategies have been proposed to continue to ensure a good protection coordination in presence of Distributed Generation. In this thesis, we investigate a new concept of Zone Differential Protection (ZDP)

applied to a distribution feeder based on the transfer of its network connectivity model from the Control Center. To understand the technical challenges in this thesis, we have described previously the power system and more specifically the distribution system both in its traditional model and in the new paradigm. The protection coordination concerns introduced by DG have been exposed. In the next chapter, we present the state of the art in protection coordination on active distribution networks.

Chapter II : Protection of distribution networks

- Chapter II : Protection of distribution networks 52
 - II.1. Introduction..... 53
 - II.2. Definitions 54
 - II.3. Basic requirements of a protection system..... 55
 - II.4. Protection of passive distribution networks 56
 - II.4.1. Overcurrent-based protection coordination technique 57
 - II.4.2. Coordination based on a direction criterion 59
 - II.4.3. Coordination based on a logic selectivity..... 60
 - II.4.4. Conclusion on protection coordination techniques on passive distribution networks 61
 - II.5. Protection of active distribution networks 62
 - II.5.1. Adaptive protection schemes based on overcurrent relays 62
 - II.5.2. Adaptive protection schemes based on distance relays 63
 - II.5.3. Fault current limiters..... 64
 - II.5.4. Logic selectivity-based protection coordination using IEC 61850..... 64
 - II.5.5. Limitations of protection coordination techniques on active distribution networks 65
 - II.5.6. Conclusion 65

II.1. Introduction

The objective of a distribution system operator is to deliver electric power to its customers with a good quality of supply under the constraint of optimal capital and operational costs. The electric power is supplied from substations connected to customers via distribution feeders. Basically, a good quality of supply is a good continuity of supply while ensuring that the voltage and the frequency of the supplied energy stays within predetermined limits. Keeping the voltage and the frequency in certain limits is the task of voltage and frequency regulation systems which are out of the scope of this thesis. In this section, we will focus on the protection system as an essential function for improving the continuity of supply on the distribution network. In fact, the power system is subject to disturbances originating from either endogenously (example of a grid operator error or an ageing of the insulators) or exogenously due to lightning strikes, animals, growing trees, grid operator error among others. Whatever the origin, these disturbances may produce short-circuit currents flowing from the different generating sources to the fault location. The protection of distribution networks consists of installing protection devices at specific points of the distribution network and arranging their settings for efficiently protecting both electrical equipment and people against the dangerous effects of faults. This activity is referred to as protection coordination.

A properly coordinated protection system is vital to ensure that an electricity distribution network can operate within preset requirements for safety for individual items of equipment, staff and public, and the network overall [25]. To achieve this coordination, different protection schemes exist. In this section, the emphasis will be put only on the protection of the MV distribution networks. The objective of this section is to present the protection coordination techniques traditionally used on passive distribution networks. Then, the protection coordination philosophies on active distribution networks are analyzed with their advantages and drawbacks from which a zone differential protection scheme is proposed.

II.2. Definitions

Before reviewing the protection coordination strategies, a few definitions along with the basic requirements of a protection scheme are given for a better understanding of the further sections.

Current grading: difference of current magnitude setting between two consecutive protection relays.

Minimum short-circuit current: minimum current magnitude measured by a protection device during a fault.

Overcurrent relay: a protection relay whose decision is related to the degree by which the measured current exceeds a set value [26].

Protection system: a combination of protection equipment designed to secure, under predetermined conditions, usually abnormal, the disconnection of an element of a power system, or to give an alarm signal, or both [26].

Relay operating time: time delay that elapses between the detection of the fault by the relay and the instant where the relay issues a trip command.

Relay pick-up: a relay is said to “pick-up” when it changes from the de-energized position to the energized position [26]. For example, when the electric current measured by the relay exceeds a preset threshold, the relay will pick-up.

Selectivity path: path defined by the set of all protective devices involved in a fault from one source to the fault location.

Setting: preset value of the ‘energizing’ quantity (voltage, or current or a combination of them) over/under which the relay is expected to operate.

Setting group change: to adapt the protection settings to different network contexts, modern relays have several setting groups containing each, the same set of protection functions but with possibly different settings.

Time grading: the time interval that must be allowed between the operation of two adjacent relays to achieve correct discrimination between them [26].

II.3. Basic requirements of a protection system

A distribution network is subject to different types of faults which may appear on any part of the network. These faults may be shunt faults or series faults. Shunt faults involve one phase with the ground, two phases with or without ground, three phases with or without ground. A series fault is typically a broken conductor for example. But, whatever the type, the faulty part should be disconnected from the network. However, in Petersen coil grounded networks, a phase to ground fault could be treated as temporarily operational. In this case, the first fault is tolerated while the second gives place to a trip. The objective of the protection system is to detect the fault and open the faulty circuit (exclusion of the electrical network operated with a fault) either by sending a trip order to the appropriate circuit breakers/reclosers or via a fuse blowing. To perform its tasks, the protection system must ensure some basic requirements:

- **Selectivity:** the protection system should disconnect the smallest portion of the power system affected by a fault to minimize the impact of the outage on customer supply. The selectivity can be ensured via basic current magnitude, time criteria, directional criteria; hence, unnecessary customer shortages can be avoided;
- **Operating speed:** when we are dealing with protection topics, one important thing to have in mind is that protection belongs to the so-called "critical applications". As such, the notion of speed is critical because the effects of faults can be very dangerous for electric equipment (damages on insulation, electrodynamic stresses, fire, among others) and for people and animals (high touch voltage). In addition, the fault clearance time which is the sum of the protection and the circuit breaker operating times counted from the fault occurrence, has a decisive impact on network stability. Moreover, some types of loads cannot withstand for a long time the under voltage induced by a fault. Consequently, the fault clearance time is a key parameter on a protection system:
- **Sensitivity:** it is the ability of protection system to detect the smallest possible fault current: the smaller is the current, the more sensitive is the protection. This

sensitivity will be affected by the measuring devices in charge of the current acquisition (current transformers) but also by the level of the short circuit power;

- Reliability: the protection system must fulfil its function in its whole operational lifetime. [27] considers that relays, in contrast with most other equipment, have two alternative ways in which they can be unreliable: they may fail to operate when they are expected to, or they may operate when they are not expected to. In this respect, [27] decomposes reliability into two branches: dependability which is the measure of the certainty that the relay will operate correctly for all faults which they are designed to operate and security which is the measure of the certainty that the relay will not operate incorrectly for any fault.

The equations below, giving the expressions of dependability, security and reliability [27], will be used later to assess the performance of our proposed protection coordination solution.

$$Dependability = \frac{\textit{number of correct trips}}{\textit{number of desired trips}} \quad \text{Equation II.1}$$

$$Security = \frac{\textit{number of correct trips}}{\textit{number of trips}} \quad \text{Equation II.2}$$

$$Reliability = \frac{\textit{number of correct trips}}{\textit{number of desired trips} + \textit{number of incorrect trips}} \quad \text{Equation II.3}$$

Any protection scheme should have the target to maximize the previous objectives.

II.4. Protection of passive distribution networks

In historical electricity distribution networks, MV feeders were generally operated in radial configuration. The power was flowing in one direction, from the source (main HV/MV substation) to the load. The protection coordination was designed by considering no embedded generation in the distribution network. As a matter of fact,

such a network was referred to as a “passive” network. The main protection devices in a traditional distribution network are the protection relays, reclosers and fuses. These devices are arranged to ensure the selectivity using the different coordination techniques presented below.

II.4.1. Overcurrent-based protection coordination technique

In traditional electricity distribution networks, the MV feeder is in general protected by overcurrent protection devices which use overcurrent as a criterion for detecting faults. The protection device operates should an electric current value is exceeded. The basic idea is that, during a fault, the short-circuit current increases as the fault is close to the source. Thus, this behavior is utilized to create a discrimination between protective devices in cascade. As illustrated in Fig.II-1-a, the short-circuit current measured by the protection relay PR1 is higher for a fault at F1 than for faults at F2 and F3. So, the selectivity can be done based on the fault current variation along the circuit.

For the fault F3, the selectivity path is between the fuse F, the recloser R and the upstream protection relays PR1, PR2 and PR3. There are two approaches to ensure the selectivity between the fuse and the recloser (direct upstream protection device):

- the fuse blowing scheme where the fuse blows during the fault downstream;
- the fuse saving scheme in which the upstream recloser de-energizes the circuit at the fault occurrence to avoid the fuse blowing for fugitive fault. The fuse blowing is allowed only should the fault be permanent.

Therefore, the criterion for protection operation is that the flowing current exceeds the preset threshold (I_s) during a preset time delay (t_s). The operating time of the protection device may have a constant or inverse characteristic. With a constant characteristic, the operating time is constant for any current magnitude above a preset overcurrent setting I_s whereas in an inverse characteristic, the operating time decreases as soon as the measured current increases above I_s . Fig.II-1-b and Fig.II-1-c show the operating characteristics of two protection devices in cascade respectively with constant and inverse characteristics. On Fig.II-1, the overcurrent-based coordination technique between the protection devices PR3, PR2, PR1 and R(recloser) is achieved by grading the settings of current pick-up and operating time

delays. However, the coordination between the fuse F and the upstream protection devices (PR3, PR2 and PR1) is ensured by assigning to them an operating characteristic similar to the one of the fuse (typically an extremely inverse curve similar to the I^2t characteristic of the fuse) or a constant characteristic. In addition, as the nearest upstream protection device backs-up the fuse, its operating characteristic must be placed above the one of the fuse with a sufficient grading margin to ensure selectivity.

The criteria for setting the overcurrent protection were determined based on:

- Minimum short circuit current
- Maximum load
- Cold load pick-up

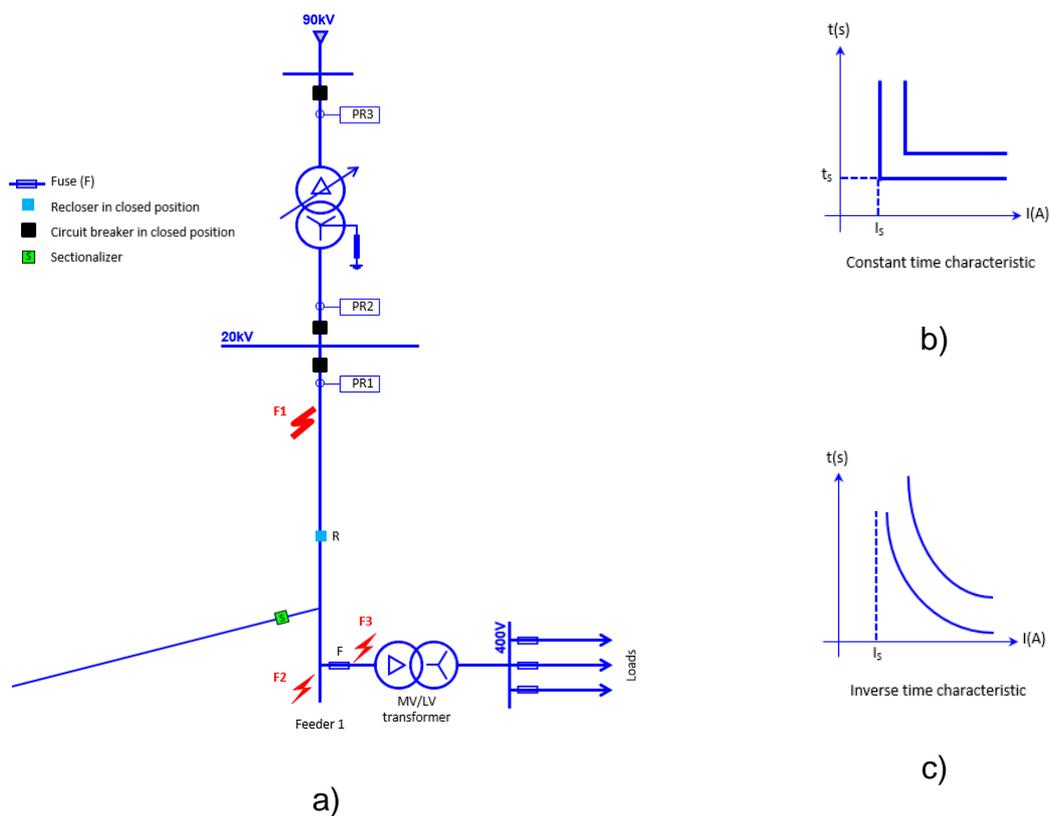


Fig.II-1. Basic selectivity principle

In this protection coordination technique, there is no data exchange between protection devices. The overcurrent-base coordination technique has two main drawbacks:

- the operating time setting increases as we move towards the main source (MV bus of the HV/MV supplying substation);
- the overcurrent settings are generally non-directional. In this case, the upstream capacitive current flowing from sound feeders towards the faulty feeder during an earth fault may create the so-called “sympathetic” tripping on these sound feeders should the flowing current exceed the non-directional earth settings. The “sympathetic” tripping may also be created by the short-circuit current contribution from one or more distributed generator(s) connected to an adjacent feeder and feeding a fault on a faulty feeder.

II.4.2. Coordination based on a direction criterion

To tackle the issue of “sympathetic” tripping on these sound feeders, a voltage input is added, where appropriate, to the simple overcurrent measurement to define a current flow directionality.

In the principle, the phase shift between the voltage and current is used to define an operation area and a restraining area. The overcurrent protection relay operates as soon as the operating point falls within the operating area and restrains otherwise.

The two main criteria for the operation of the overcurrent protection relay are:

- the short-circuit current and voltage magnitudes should be above respectively the overcurrent and voltage settings and
- the phase angle between the voltage and current should be within the pre-defined angle operating range

In this technique, data exchange between directional elements of different protection devices is not a ‘must’ in general. However, it may be required to ensure selectivity under drastic time constraints.

It is important to note that the direction criterion is also used on distribution networks operated in loop or when the main feeder is supplied in back-up by a neighboring feeder from the same supplying substation as the main feeder or from another HV/MV substation. In fact, when the supply is from a back-up source, there may be an inversion of the power flow and short-circuit current. The selectivity paths may also be inverted.

II.4.3. Coordination based on a logic selectivity

Even with directional overcurrent protection relays, the fault clearance time increases as we move towards the main supplying substation, which increases the stress on equipment. The logic selectivity has been patented by Schneider Electric (formerly Merlin Gerin) to reduce the fault clearance time while maintaining the protection coordination. As described in [28], the basic principle of logic selectivity is that any protection device affected by the fault will send:

- a logic wait signal (LWS) to the upstream protection stage;
- a tripping signal to the circuit breaker to which it is associated.

As shown on Fig.II-2, the protection relay PR1 sends a logic wait signal to the relay PR2 whenever a fault appears on the downstream side of PR1.

The basic idea is to temporary block the fast threshold of the upstream overcurrent protection following a pick-up on the neighboring downstream protection. However, a second threshold (time delayed) is available at the upstream level in case the downstream protection fails to trip its associated circuit breaker.

In this technique, enough short-circuit current is necessary to create a relay pick-up. Then, the relay will be able to send the logic wait signal upstream. Therefore, there is a data exchange between the different stages of protection devices involved in the selectivity path.

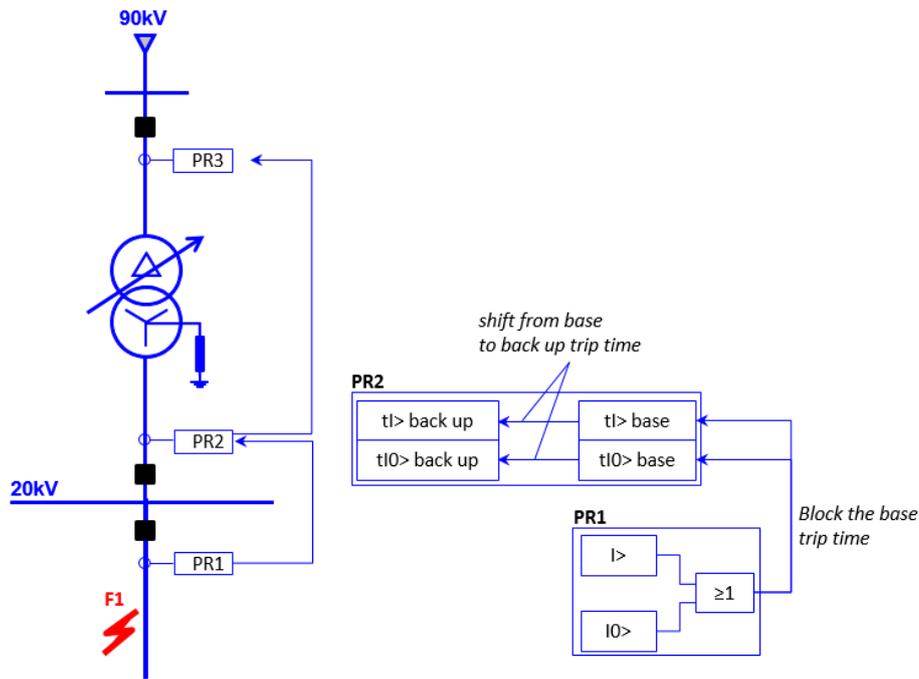


Fig.II-2. Logic selectivity principle

II.4.4. Conclusion on protection coordination techniques on passive distribution networks

The previous protection coordination techniques have been used for long time in traditional passive distribution networks and have proven to be effective most of the time. In addition, a single setting of protection devices was enough to establish the protection coordination even though, in some cases, a change of setting group may be used. But unfortunately, these techniques will not be efficient in presence of distributed generation due to bi-directional short-circuit current and power flow and other concerns mentioned in the chapter 1 such as the risk of fuse premature blowing, relay blinding, among others. Therefore, a lot of researchers have investigated new protection schemes that adapt to network changing conditions particularly in active distribution networks. In the literature, the term “adaptive protection” is used to characterize this new protection philosophy. Adaptive protection is an automatic procedure that monitors and amends protection relay settings to make them better attuned to prevailing system operating conditions [29].

II.5. Protection of active distribution networks

So long as the distribution network was passive and radially operated, the protection coordination techniques described previously worked correctly. But, the insertion of distributed energy resources (DER) into the initially passive distribution network has introduced many challenges on the protection coordination. Some of these difficulties have been discussed in the chapter 1. In the following section, we will present and analyze the state of the art in protection coordination strategies used on distribution networks in presence of DERs.

II.5.1. Adaptive protection schemes based on overcurrent relays

In [23], the author discussed an IEC 61850-based protection coordination approach implemented in Hailuoto island pilot project. In his approach, the author suggested to automatically adapt the protection settings to the changes in network conditions via a setting group change. The scheme uses a communication-assisted concept with an IEC 61850-based data exchange between field protective relays and the protection relay at the main feeder. To note that, in the proposed solution, the setting group change required on the protective relays along the feeder is managed by a centralized grid automation controller (playing also the role of gateway for communications between substation and control center) located at the HV/MV substation. In [24], a combination of a local adaptive and communication assisted central protection is proposed, whereby the relay settings are dynamically updated based on online identification of the network topologies and status of DERs. Particularly, the local adaptive protection updates relay settings based on DERs status ON/OFF employing locally acquired information, whereas the centralized protection updates the relay settings during major changes in grid topologies: network reconfiguration and switching between islanded and grid connected modes. Two phase overcurrent thresholds are used (for multi-phase faults): the low threshold have an inverse time characteristic used to monitor the overloads whereas the high thresholds have a definite time characteristic set at the same time delay with different current settings. The TMS (Time multiplier setting) of low overcurrent threshold is dynamically adjusted on changing network conditions. In these approaches, the first drawback is the risk of protection blinding could be a real issue on distribution

networks with a significant penetration level of DER. Another drawback of this solution is that the protection settings in each setting group is tied to the network configuration. So, anytime there is a new network configuration, it is necessary to check the validity of the settings in the new context.

II.5.2. Adaptive protection schemes based on distance relays

Basically, a distance protection uses the voltage and current measured locally to compute the total impedance between the relay position to a fault. This total impedance is correlated to the impedance per unit of length to give the distance to the fault. [19] proposed a solution based on a mix of traditional overcurrent protection and distance elements. In the principle, two overcurrent protection thresholds are used in combination with distance elements. The zone 1 of the distance protection is used to trip very rapidly for fault very close to the feeder source. It is coordinated with a fuse saving scheme allowing then to save the fuse for transient faults. The reaches on other distance forward zones (zones 2 and 3) act as a back-up to overcurrent protection depending on the presence or not of a midline recloser.

But, while this solution compensates for many limitations of overcurrent relays, provides an adaptive adjustment of the zone reach for both phase-to-phase and for phase to earth faults together with an adaptation to heavy load situations, it has some disadvantages. Firstly, the proposed solution may be weakened on some network conditions such as an insertion of distributed generator is the zone 1 reach. In this case, the fault current infeed from decentralized generations creates an underreaching phenomenon that may prevent the distance protection from seeing the fault in the right zone and, in some cases, not tripping. This is mainly the case when the DG is connected between the distance relay (at the main MV feeder) and the fault point. A distance protection relay is said to underreach when the apparent impedance measured by the relay is greater than the real impedance to the fault [26]. Another situation is the connection of MV/LV transformers (of rated power greater than 2500kVA) close to the main MV feeder could be conflicting with the zone 1 reach. Secondly, the decentralized generators may create some issues in the direction determination as reported in [30]. Therefore, a forward fault could be seen in reverse.

II.5.3. Fault current limiters

To reduce the contributions of distributed energy resources to the short-circuit current measured by the protection relays to avoid an update of the protection plan, authors such as [6], proposed an approach based on fault current limiters. A fault current limiter is a low impedance device that has no action during normal operation.

However, during fault it takes fast action by inserting high impedance in series with a DG (in general, the fault current limiting device is in series with the source that is likely to impact a protection coordination with its contribution to short-circuit). In the same vein, [16] discussed a protection coordination scheme based on distance relay and fault current limiter to suppress the underreaching phenomenon introduced by the DG.

As we can see, this solution requires the installation of a fault current limiter in series with each decentralized generation. Also, the behavior of distributed generators with a fault current limiter in series is not covered in the light of the grid code requirements for generators during fault.

II.5.4. Logic selectivity-based protection coordination using IEC 61850

The principle of logic selectivity has already been presented previously in the protection of traditional distribution networks. This technique has proven to be effective in passive distribution networks where it was applied in radial, open loop and closed loop configuration (in combination with directional overcurrent functions) to reduce the fault clearance time while ensuring a good protection selectivity. [31] applied this technique and combined it with a FLISR (Fault Location Isolation and Service Restoration) to improve the continuity of supply. The authors used IEC 61850 GOOSE (Generic Object Oriented Substation Event) messages to allow exchange of overcurrent pick-up signals between relays. A GOOSE is a service using a mechanism of publisher/subscriber to allow a fast and reliable system wide distribution of input/output values from a publisher to receivers through a multicast/broadcast method [32]. More details on the IEC 61850 standard is given in the next chapter. The first drawback in the proposed solution is that the bi-directional power flow and short-circuit current flow require directional protection function. However, as discussed previously, the presence of distributed generator may create

an issue in the direction determination. Secondly, the pick-up overcurrent stage is not safe from blinding due to DG intermediate fault current injection, which may result in the non-operation of some protection thresholds. Thirdly, the network model is unknown to the controller which is monitoring the status of circuit breakers to determine the current configuration of the network. Therefore, the controller do not have the capability to automatically enroll the status of new upcoming circuit breakers in the protection scheme, which could be interesting especially during network model evolution.

II.5.5. Limitations of protection coordination techniques on active distribution networks

Although many techniques have already been proposed, they remain limited in scope. Their scope do not include the following aspects:

- Firstly, the protection scheme needs to be automatically adapted to changing network conditions (installation of a new circuit on an existing feeder, circuit reconfiguration, islanding operating mode, connection of new distributed generator, etc.), equipment parameters modification (replacement of an old power transformer, replacement of a line conductor), to cope with a meshed network including multiple infeed from DG;
- Secondly, the reduction of fault current at the main MV feeder level due to the infeed from DG may increase the fault clearance time of the main MV feeder. This fault clearance time is to be reduced for any fault, anywhere in the distribution network even in presence of intermediate infeed from DG.

II.5.6. Conclusion

In this chapter, we looked at the protection coordination techniques both on passive and active distribution networks with their advantages and drawbacks. To overcome all the limitations discussed previously, we propose a novel concept of protection scheme based on differential protection called “Zone Differential Protection” (ZDP). In fact, the differential protection has been used for long time on unit protection (generator, transformer, line, cable, motor, etc.). The basic principle is to check that the current entering the protected area is equal to the current leaving the protected

area. In the case of a distribution feeder, the Zone Differential Protection would be a wide area protection requiring data exchange between protection devices at remote locations. In the principle, a controller placed at the head of the feeder is first given the network model of the feeder. Then, from this knowledge, the feeder controller splits the feeder into zones and checks for each zone, the balance between entering, leaving and internal components (capacitor banks, storage, generators, loads) currents.

The modeling of the Zone Differential Protection will be developed in the chapter 4. To be able to achieve the Zone Differential Protection, the distribution feeder needs to have the model of the downstream network it is supplying. This knowledge is only available at the Control Center which uses the CIM (Common Information Model) data model while the feeder data model is based on IEC 61850. Therefore, due to the difference of data models, a harmonization on the relevant domains is necessary between the CIM and IEC 61850 data models to allow their interoperability. This will require a deep analysis of the two data models to understand their specificities, discrepancies, limits and how a model transformation can be designed to allow the transfer of the feeder network model.

Chapter III : Harmonization between IEC 61850 and CIM (Common Information Model)

- Chapter III : Harmonization between IEC 61850 and CIM (Common Information Model)..... 68
- III.1. Introduction..... 69
- III.2. IEC 61850 and IEC CIM 70
 - III.2.1. IEC 61850..... 71
 - III.2.1.1. Goal and definition 71
 - III.2.1.2. Scope 72
 - III.2.1.3. Data modeling approach 73
 - III.2.1.4. System Configuration Description Language (SCL) object model 74
 - III.2.2. Common Information Model (CIM)..... 75
 - III.2.2.1. Definition and scope..... 75
 - III.2.2.2. Data model 77
- III.3. Harmonization between IEC 61850 and IEC CIM 80
 - III.3.1. Methodology of harmonization 80
 - III.3.2. Specificities of unbalanced distribution networks 82
 - III.3.3. Data models constrains for achieving the transfer of network model 84
- III.4. Conclusion 84

III.1. Introduction

The previous chapter 2 highlighted the impacts of DG on the protection coordination on MV distribution feeders. These impacts call for new requirements on protection coordination. As discussed in chapter 1, the objective of this research work is to investigate a new concept for improving the protection coordination on distribution feeders. The concept (developed in chapter 4) consists in transferring to the feeder, its electrical network model from the Control Center, to allow it better ensure the protection coordination in presence of DG. The electrical network model contains electrical components on the feeder along with the connectivity between them. To reach this goal, a data exchange is required on one hand, between the Control Center and the distribution feeder located at the supplying substation, and on the other hand, a cooperation between protection devices at both feeder and field levels. One of the key levers for efficiently achieving these data exchange is by exchanging information on a syntactic and semantic levels between the Control Center and feeder but also between feeder devices. In other words, the data model used at the Control Center (IEC Common Information Model) and the one used on the Substation/feeder/field levels (IEC 61850) must be interoperable. Interoperability is the ability of two or more IEDs from the same vendor, or different vendors, to exchange information and use that information for correct execution of specified functions [33]. This interoperability is only possible through harmonization which is obtained within a standardization framework. At IEC (International Electrotechnical Commission) level, the technical committee TC57 is concerned with issues related to power system management and associated information exchange. Much of the work within TC57 is focused on creating standards facilitating interoperability of communication and control systems used for power system control and operation. The two core standards identified by IEC TC57 for implementing Smart Grid in the power utility automation are IEC 61850 and the Common Information Model [6].

In this thesis, two use cases are analyzed. The first use case dealing with the transfer of network model from the Control Center to the distribution feeder is discussed in this chapter as it requires the harmonization between IEC CIM and IEC 61850.

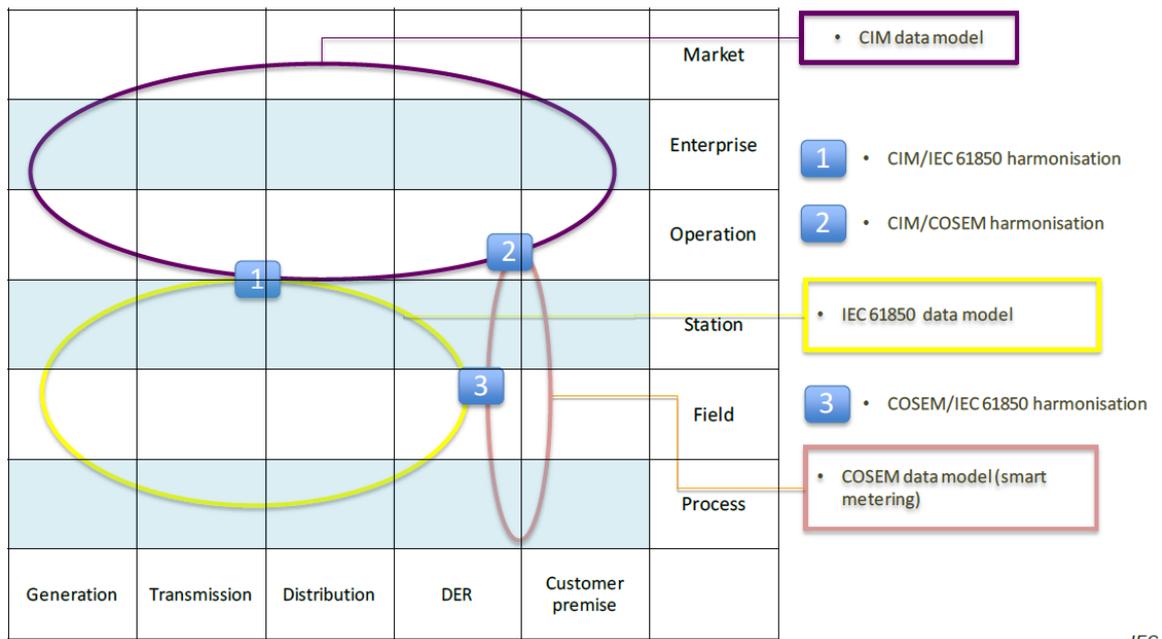
The second use case is concerned with a device to device data exchange to achieve a protection scheme. This part will be discussed in chapter 4 as it uses the IEC

61850 equivalent model of the incoming IEC CIM network model as the input to achieve the distribution feeder protection scheme. All the devices involved in the data exchange (IEC 61850 compliant) are already interoperable.

Before being able to achieve the first use case, it is necessary to understand both semantic and syntactic structures of each relevant data model. Therefore, in this chapter, we will first introduce the IEC 61850 and IEC CIM standards. The attempt is not to go into the details of the two standards but rather to give an overview on the data models. Secondly, the methodology for harmonizing the two data models will be covered. This will allow us to define the mapping rules between the two data models. Thirdly, the status of the current activities related to harmonization between IEC 61850 and IEC CIM at the IEC TC57 level will be discussed. However, the scope of the harmonization will be restricted to the domain of our first use case. Finally, the constraints of the current IEC CIM and IEC 61850 data models for achieving later our second use case (see details in chapter IV dedicated to modeling) will be described.

III.2. IEC 61850 and IEC CIM

IEC CIM and IEC 61850 are two sets of standards maintained by the Technical Committee TC57 of the International Electrotechnical Commission (IEC). TC57 consists of several working groups (WG), each responsible for developing a standard that addresses a specific issue on power system communication and control [6]. Amongst others, the Working Group 10 is dedicated to standardization activities related to IEC 61850 while Working Groups 13 (IEC 61970), 14 (IEC 61968), 16 (IEC 62325) are dedicated to IEC CIM. To ensure the long-term interoperability, including between IEC 61850 and IEC CIM, the WG19 is in charge of the harmonization of the activities of all the Working Groups within the TC57 [34]. Even though they both refer to the same power system, the IEC 61850 and IEC CIM have been initially developed separately resulting in different data models. However, as shown in Fig.III-1, while the scopes of IEC 61850 and IEC CIM are not the same, their harmonization could make them complementary.



IEC

Fig.III-1 – Harmonization work mapping in the Smart Grid Architecture Model (SGAM) [35]

III.2.1. IEC 61850

III.2.1.1. Goal and definition

IEC 61850 is concerned with automation systems that consist of one or more Intelligent Electronic Devices (IEDs) connected by a communication system [36]. The goal of this standard is to provide interoperability between the IEDs from different manufacturers or, more precisely, between application functions to be performed in the power system hosted in the IEDs from different manufacturers [37].

To this end, IEC 61850 has three components:

- A data model with standardized names and meaning of data (in IEC 61850-7-4, IEC 61850-7-3), abstract services (IEC 61850-7-2) mapped to specific protocols. The data model covers different domains including generation, transmission, distribution, DG.
- A communication model enabling the data model to be mapped on different communication protocols such as:
 - TCP-IP/MMS protocol (defined in IEC 61850-8-1) for client-server applications;

- Publisher/Subscriber protocol for peer-to-peer communication using GOOSE messages (IEC 61850-8-1);
 - Publisher/Subscriber protocol for exchanging analog sample values (IEC 61850-9-2) typically used to send current and voltage from sensors to the bay level IEDs;
 - Web-services (IEC 61850-8-2);
 - OPC-UA, IEC 60870-5-101/104, DNP3;
 - User Datagram Protocol (UDP) for the transmission of synchro phasor information (IEC 61850-90-5);
- A standardized XML-based configuration language called SCL (System Configuration Description Language) defined in IEC 61850-6 that allows an exchange of power system and device configurations in a multi-vendor context, a specification of requirements, a description of a real installation, a description of device capabilities.

III.2.1.2. Scope

The initial scope of IEC 61850 was the standardization of communication in substation automation systems. The first edition of the standard was primarily related to protection, control and monitoring. Then, the original parts of the IEC 61850 series, consisting of ten parts, were updated and extended to cover new areas amongst which:

- The communication between substations (IEC 61850-90-1);
- The communication between substation and control centers (IEC 61850-90-2);
- Condition monitoring (IEC 61850-90-3);
- The feeder automation (IEC 61850-90-6);
- The modeling of photovoltaic, storage and other DER inverters (IEC 61850-90-7);
- The modeling of hydropower plants (IEC 61850-7-410), distributed energy resources (IEC 61850-7-420);
- The modeling of wind turbines has been standardized according to IEC 61850, within the IEC 61400-25 series, Communications for monitoring and control of wind power plants;

- Wide area engineering guidelines (IEC 61850-90-12);
- Power quality (IEC 61850-90-17).

Before moving further, it is important to understand the modeling approach of IEC 61850 to see how the data to be exchanged is organized.

III.2.1.3. Data modeling approach

The approach of IEC 61850 as defined in [33] is to decompose the application functions into the smallest entities which are used to exchange information. The granularity is given by a reasonable distributed allocation of these entities to dedicated devices (IED). These entities are called Logical Nodes [4]. The logical nodes can be organized into one or more Logical Devices (LD). Each logical Node has properties called Data Objects (DO) and each Data Object has Data Attributes (DA) with their associated types. The IEC61850 data modeling shown on Fig.III-2 illustrates how a physical circuit breaker is virtualized into a Logical Node instance (XCBR1) with its data object **Pos** and related data attributes (Status **StVal** and quality **q**).

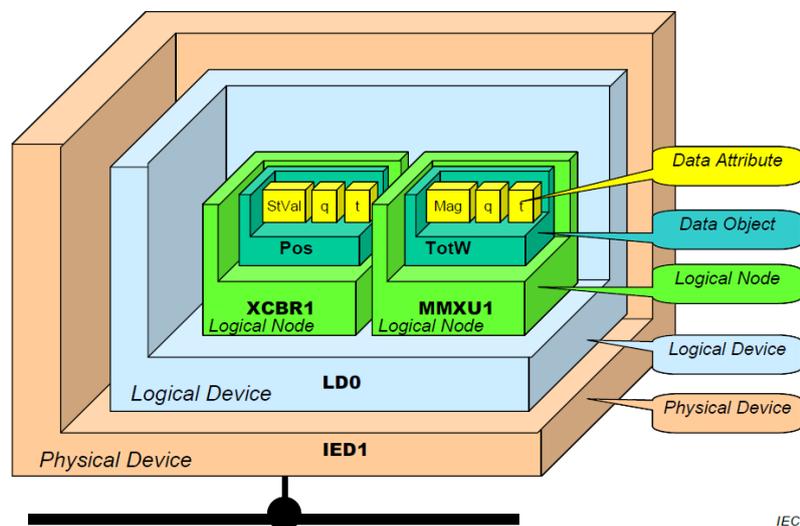


Fig.III-2 –IEC 61850 data modeling [4]

Knowing how the data is organized, the next step is to understand how to exchange the data. To this regard, the System Configuration Description Language (SCL) is used.

III.2.1.4. System Configuration Description Language (SCL) object model

IEC 61850 specifies a file format for describing communication related to IED (Intelligent Electronic Device) configuration and IED parameters, communication system configurations, switchyard (function) structures, and the relations between them. The main purpose of the format is to exchange IED capability descriptions, and at the system level, descriptions between engineering tools of different manufacturers in a compatible way. The defined language is called SCL [38]. To be able to translate the incoming IEC CIM network model, it is necessary to understand the SCL object model to know where the IEC CIM incoming network model should reside in the equivalent IEC 61850 file. As already explained in section III.2.1.1., SCL uses an XML based language to allow the exchange of configuration files. To this end, SCL has defined a standardized vocabulary and grammar along with a formalized structure of exchange files in which the IEC 61850 data model is encapsulated on XML syntax.

The SCL object model has five basic parts [20]:

- 1) Header: to identify the SCL configuration file and version;
- 2) Substation / Line / Process: to describe the functional structure of a primary process and identify the primary devices and their electrical connections inside substations and power networks. This part contains the electrical network model;
- 3) Product: this stands for all Substation Automation product-related objects such as IEDs and logical node implementations; it also includes distributed IEDs such as RTUs (Remote Terminal Units) typically installed on MV/LV substations along the distribution feeder;
- 4) Communication: this contains communication-related object types such as subnetworks and communication access points and describes the communication connections between IEDs as a base for communication paths between logical nodes as clients and servers;
- 5) Data type template section allowing the specification of which data and attributes really exist in an IED.

Fig.III-3 shows a simplified UML (Unified Modeling Language) model of IEC 61850 with primary equipment containership, allocation of functions to different containers and substation topology. In addition, the IED (product section of the SCL) is shown with its associated communication information.

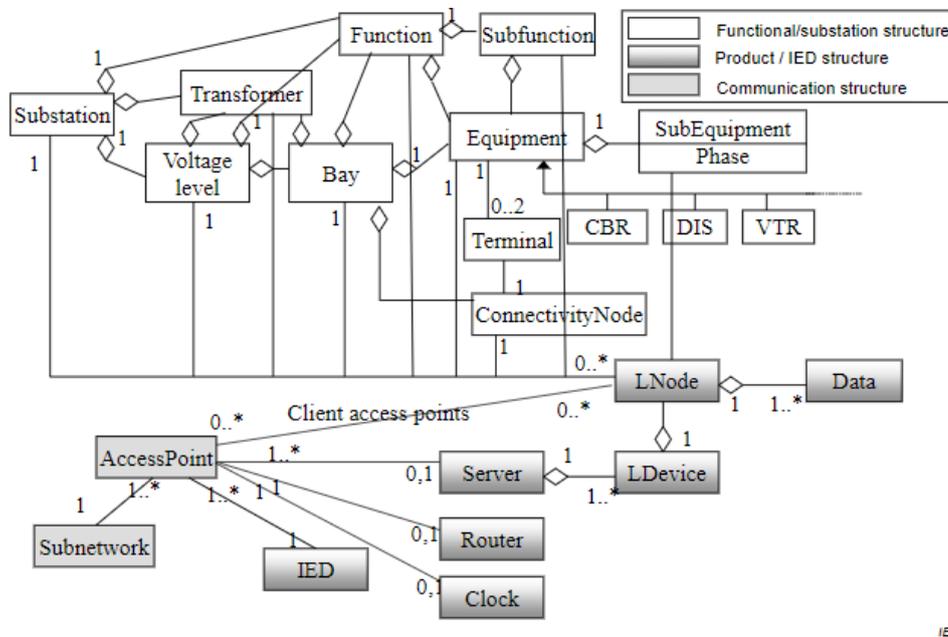


Fig.III-3 – IEC 61850 SCL object model [38]

Initially the IEC 61850 was dedicated to Substation Automation. Today, the advent of DER have changed the electrical network paradigm especially on distribution networks which were traditionally passive. Therefore, the scope of IEC 61850 has been extended on many areas as discussed on section III.2.1.2. amongst which the integration of DER in the IEC 61850 data model with the associated information exchange services.

III.2.2. Common Information Model (CIM)

III.2.2.1. Definition and scope

To control and operate the electrical network, utilities use several applications at the Control Centre level, which exchange data between them. Each application generally uses a data representation different to the representation in the other applications. As

a result, the data exchange between these applications is difficult and requires the development of adapters between each two applications.

In addition, an exchange of network models is required between utilities to model the equivalent network of the neighboring utilities for planning studies. For this network model exchange to happen seamlessly, a common semantic model is required.

The Common Information Model (CIM) is an information model that allows the integration of data in a multi-vendor environment on one hand, and the exchange of network model between utilities on the other hand. The CIM model uses the Unified Modeling Language (UML) to represent all power system components into classes with their attributes along with the relationships between them. By providing a standard way of representing power system resources as classes and attributes, along with their relationships, the CIM facilitates the integration and interoperability of network applications developed independently by different vendors, between entire systems running network applications developed independently, or between a system running network applications and other systems concerned with different aspects of power system operations, such as generation or distribution management [39]. As shown on Fig.III-4, the CIM consists in three main series of standards:

- IEC 61970 standard series for Energy Management System Application Program Interface (EMS-API). It is the CIM core model as it defines the power system components;
- IEC 61968 standard series for System Interfaces for distribution network management. IEC 61968 is an extension of IEC 61970 to distribution network. It shares its data types with IEC 61970 while adding new classes for asset management, work management, customer management, among others;
- IEC 62325 standard series (Energy Markets) dedicated to the data exchange between market participants.

Each of these standards are partitioned into different packages and the various parts of the standards may refer to classes from several packages.

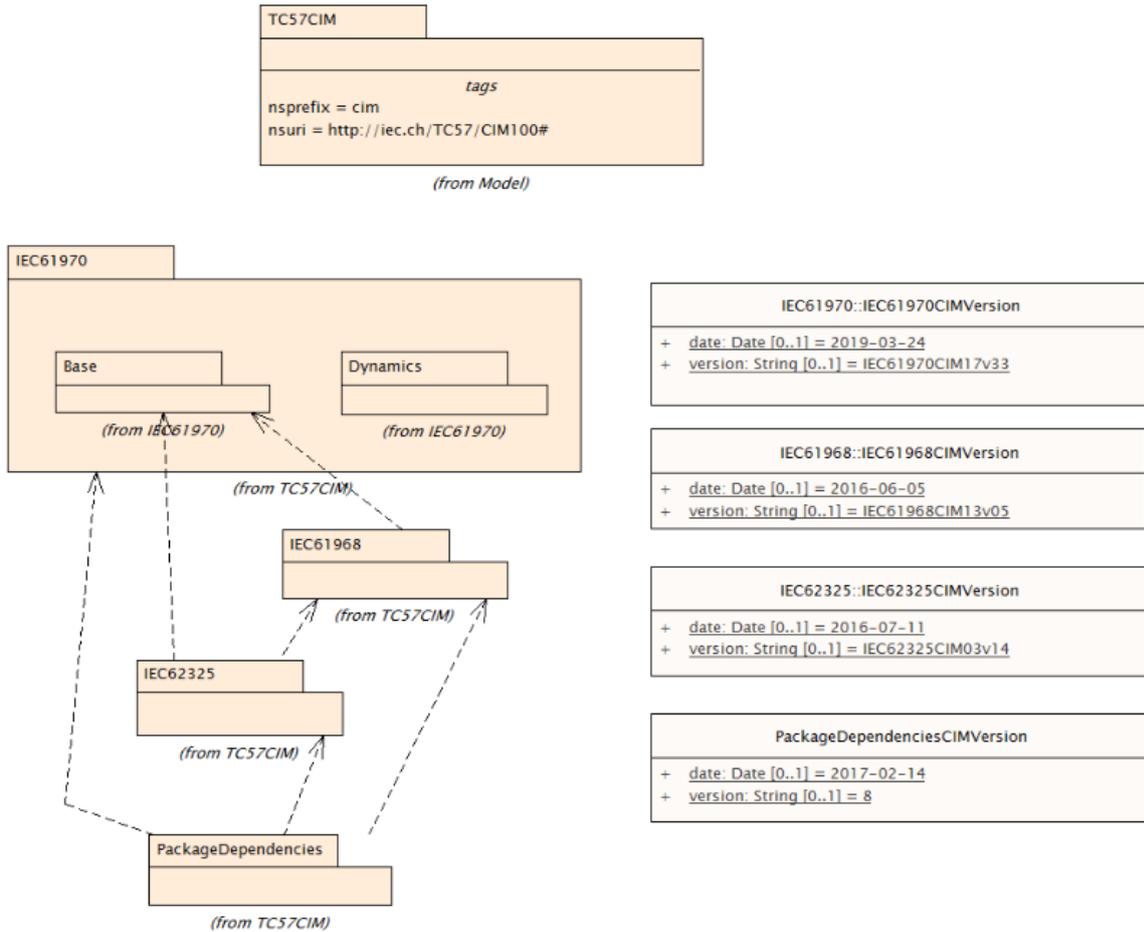


Fig.III-4 – Package dependencies in CIM [39]

The initial scope of the CIM was on balanced electrical networks (transmission and generation) according to the EMS (Energy Management System) perspective.

III.2.2.2. Data model

As discussed previously, the scope of the CIM is wide. However, we do not attempt to cover of the data model but only our domain of interest which is how to model an electrical network.

The CIM uses UML to describe the power system components through class diagrams. Fig.III-5 shows the class diagram for CIM equipment hierarchy with the **IdentifiedObject** class at the uppermost level. All the lower level equipment inherit from the **IdentifiedObject** class attributes for their identification. Furthermore, each power system component is a class with its associated attributes. The CIM data model allows the modeling of both three phase balanced and unbalanced networks as illustrated in Fig.III-8. But, because the data model is very detailed, it is necessary to derive a contextual model also referred to as **profile** from the base model. Then, the profile is serialized into XML for exchange.

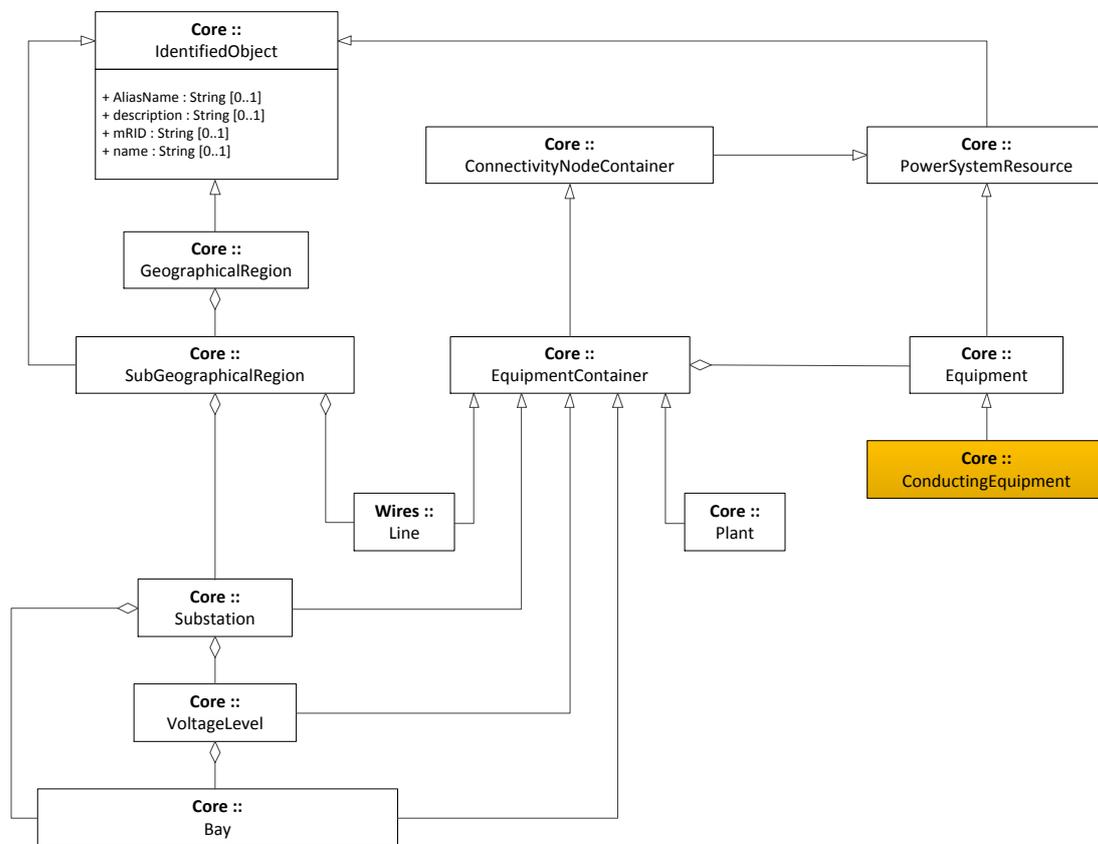


Fig.III-5 – Equipment class hierarchy in CIM – adapted from [39]

This process has been defined by IEC Technical Committee TC 57 in a three layers architecture shown in Fig.III-6.

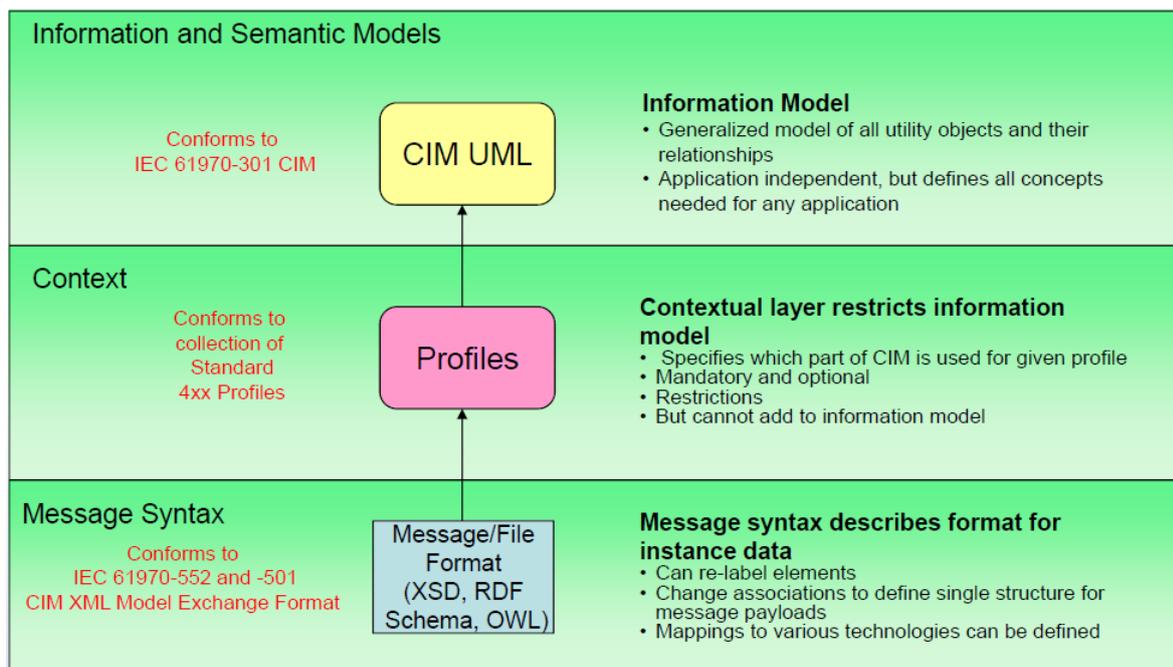


Fig.III-6 – Three layers architecture in CIM [40]

The understanding of the two data models allows us to proceed with the harmonization in the next section. However, generic differences between the two data models can be highlighted before proceeding into the harmonization. Firstly, the CIM focused on EMS (Energy Management Systems) while IEC 61850 was on substation before 2009 and has been later extended to the power system. Secondly, to build a network model, even though the network connectivity parameters (terminals, connectivity nodes, etc.) are very similar between CIM and IEC 61850, the power system components identification method is different because where CIM has a genuine and unique ID, IEC 61850 uses the 'name' attribute as ID. Thirdly, the mapping between CIM classes and equivalent IEC 61850 ones is not always a one-to-one mapping because for some classes, it is a one-to-many mapping. Lastly, the CIM model is poor concerning the communication (IP address, VLAN, and so on) and protection aspects.

III.3. Harmonization between IEC 61850 and IEC CIM

The objective of the harmonization is to create a model transformation allowing a bi-directional conversion from one data model to another. The distribution feeder being based on IEC 61850 and the incoming network model defined in IEC CIM, it is necessary to define rules for mapping the elements in one model to the corresponding one in the other model. Our attempt in this chapter is not to discuss the current harmonization status at IEC TC57 level between IEC 61850 and IEC CIM on its entirety but only in the domain of our first use case related to the transfer of network model.

III.3.1. Methodology of harmonization

An electric network model contains:

- Power system components (line/cable sections, switching equipment, current transformers, loads, generating sources, power transformers, capacitor banks, upstream utility equivalent network and so on) with their attributes;
- Connectivity elements including terminals and connectivity nodes;
- Geographic coordinates;
- Equipment containership hierarchy
- Naming convention

The mapping consists in establishing a correspondence between power system components in both models to allow the model transformation. Fig.III-7 specifies the equipment mapping between IEC 61850 and IEC CIM as per [5]. As illustrated in Fig.III-7, the type of equipment in IEC 61850 SCL is defined by a type code whilst in the CIM the equipment type is defined by its concrete class. Table III-1, in the appendix A1, shows the type codes described in [38]. More details of the mapping of those type codes to CIM classes, defined in [39], is given in [37]. In addition, Table III-2 to Table III-6, in the appendix A1, depict the mapping related to power system components, equipment names, geographic position, connectivity elements and equipment containers.

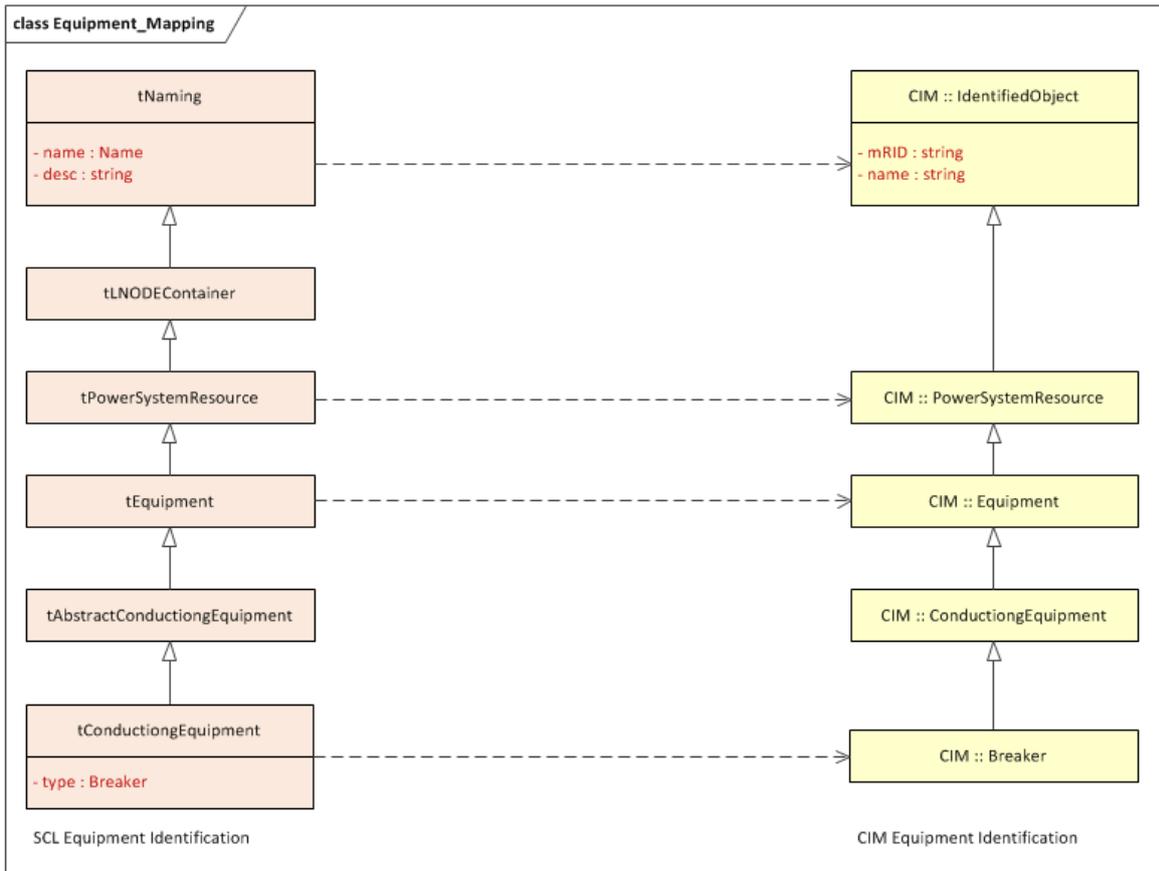


Fig.III-7 – Equipment mapping between IEC 61850 and CIM – adapted from [36]

It is important to put the emphasis on the identification of the power system resources. In fact, each power system resource can be identified using the **mRID** and **name** attributes associated to the CIM **IdentifiedObject** class. While in IEC 61850, the power system resources inherits the **name** and **desc** attributes from the **tNaming** class. The most common issue is to map the CIM global unique ID **mRID** attribute to IEC 61850 which do not have this attribute. In lieu and place, IEC 61850 has the **name** attribute playing the role of its ID; which may be confusing especially during the model re-export. However, in our thesis, we have considered that the network model is only changed from Control Center where it is globally maintained. Therefore, as will be discussed further, the power system IDs should be defined from the CIM model and propagated to all the applications consuming these data.

The equipment mapping previously presented is a generic mapping process. In fact, to map power system components on unbalanced networks, more insight is

necessary for knowing how the data models will be used to address the specificity of unbalanced distribution networks embedding DERs.

III.3.2. Specificities of unbalanced distribution networks

With unbalanced MV distribution networks, it is necessary to consider the representation of power system resources on a per phase basis as the mapping discussed previously mainly covered three phase balanced elements.

On the SCL object model shown on Fig.III-3, the **Equipment** object may have a **SubEquipment** object to cover non three phase scenarios. The CIM models provide a means to specify equivalent single-line representation of balanced three phase networks or to additionally and optionally specify individual phase detail. In single phase networks there is a direct correspondence between Terminal objects and physical wire connections. In the single-line representation of balanced three phase networks we use one **Terminal** to represent the group of coordinating phase connections. Thus, one **Terminal** can be used to specify one or more coordinated phase connections using the **Terminal.phases** attribute which is of enumeration type **PhaseCode**. **PhaseCode** has the possible phase connection combinations of ABC, ABCN, AB, BC, CA, A, B, C and so forth [39].

Therefore, we can summarize by considering the following scenarios:

Scenarios	IEC 61850	CIM
Three phase equipment	One instance of equipment. No instance of SubEquipment	One instance of equipment. Terminal.phases = 'ABC'
3 single phase equipment	One instance of equipment and three instances of SubEquipment	One instance of equipment. Terminal.phases = 'ABC'
2 phase equipment operated together	One instance of equipment and two instances of SubEquipment	One instance of equipment. Terminal.phases = 'AC' or 'BC' or 'AB'

The Fig.III-8 shows, for each CIM conducting equipment, the associated single-phase element which is an equivalent to the IEC 61850 SubEquipment.

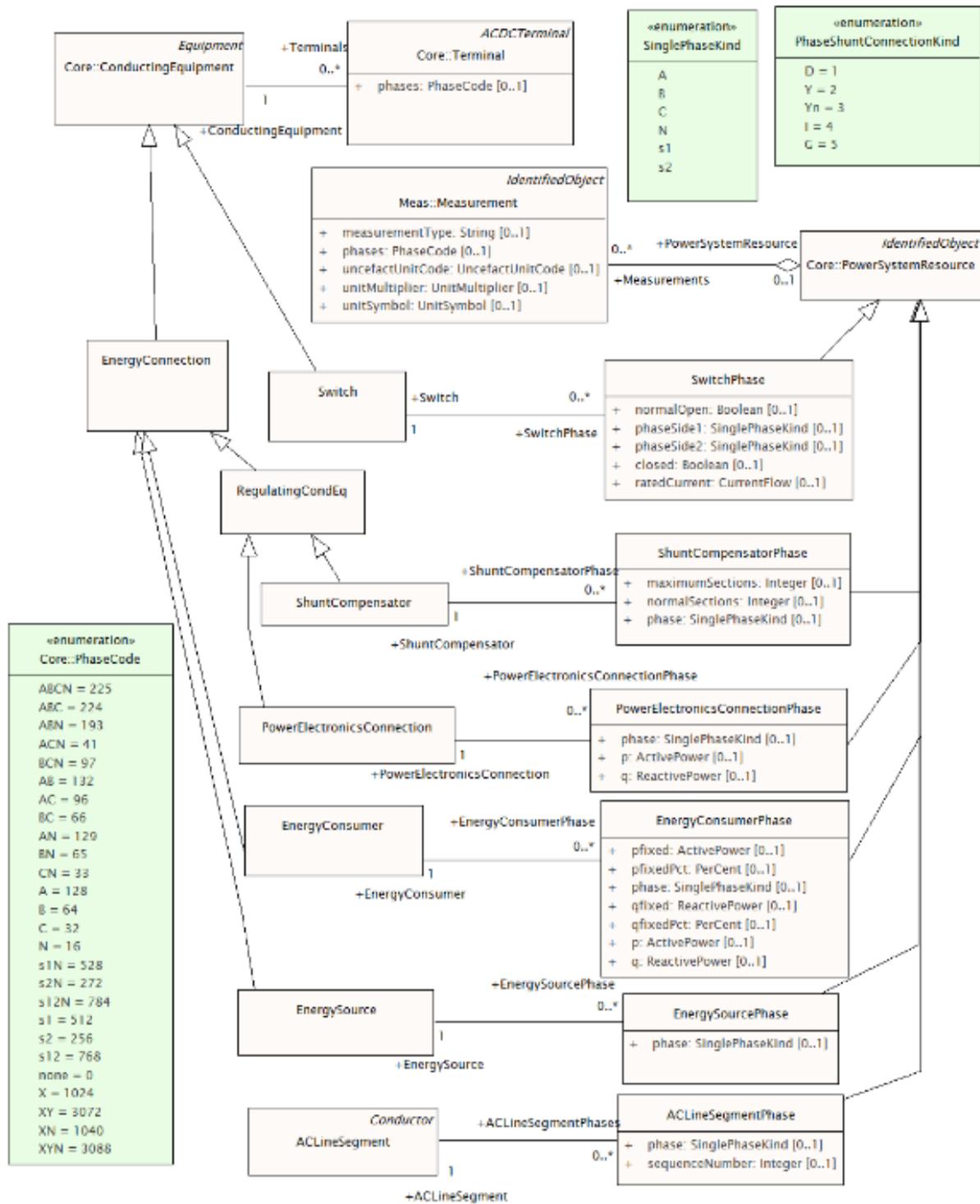


Fig.III-8 – Phase wire data model in CIM [39]

These dependencies are very important for describing unbalanced networks.

III.3.3. Data models constrains for achieving the transfer of network model

What was envisioned at the beginning of the thesis was to be able to generate an IEC 61850 SCL (Substation Configuration Language) file including all the needed protection functions from the CIM network model. Unfortunately, the protection model in CIM is incomplete. Furthermore, several important communication parameters such as IP address, VLAN, MAC address among others are not present in the CIM model. This makes impossible the generation of the SCL file from the CIM network model without the provision of additional information. Therefore, the output of our model transformation from CIM to IEC 61850 will only include the network connectivity. The protection functions along with the communication parameters are not considered.

III.4. Conclusion

CIM and IEC 61850 are two core standards to achieve the Smart Grid Objectives [34]. In this chapter, we discussed the necessary alignment between the two data models along with the current harmonization activities at the IEC TC 57 level. Also, the mapping between power system resources in both data models has been discussed. This will allow us to convert our incoming CIM network model into IEC 61850 even though some parts are missing (protection functions, communication parameters for example). During specification time, the transferred file may be used by an IEC 61850 System engineer in lieu and place of the current specification method which is in paper format. However, during run-time, an 'on the fly' configuration process is needed for updating our feeder protection system.

The next chapter deals with the Zone Differential Protection based on the incoming distribution feeder network model. An unbalanced three phase distribution feeder is given its own network model to create zones of protection to which the differential protection principles will be applied. In this regard, an adapted version of the IEEE 123 nodes test feeder is modelled in CIM, then translated in IEC 61850 and finally supplied to a feeder controller for performing the needed protection scheme. The real value of bringing the computations on the field is that the remote service for protection settings changes can be easily achieved if based on IEC 61850.

Chapter IV : Modeling

- Chapter IV : Modeling 86
 - IV.1. Introduction 88
 - IV.2. Basic principles of the differential protection..... 91
 - IV.3. Reference distribution feeder 91
 - IV.3.1. Definitions 91
 - IV.3.2. Specificities of distribution feeders..... 94
 - IV.3.3. Choice of our test distribution feeder..... 94
 - IV.3.4. Description of the test feeder network 95
 - IV.3.5. Modifications brought to the test feeder 95
 - IV.4. Modeling approach 98
 - IV.4.1. Description of the modeling environment..... 98
 - IV.4.2. Modeling tools 99
 - IV.4.3. Modeling principles..... 100
 - IV.4.4. Modeling assumptions 102
 - IV.4.5. Constraints 102
 - IV.4.5.1. False differential currents 102
 - IV.5. Modeling of the distribution feeder based on CIM model 103
 - IV.5.1. Introduction 103
 - IV.5.1.1. The three layers architecture of CIM 104
 - IV.5.1.2. Serialization of the network model in CIM 104
 - IV.5.2. Modeling of the distribution feeder 104
 - IV.5.3. Introduction to RDF (Resource Description Framework)..... 105
 - IV.6. Modeling of the distribution feeder IEC 61850 model 106
 - IV.7. Modeling of the distribution feeder based on graph theory..... 107
 - IV.7.1. Distribution feeder abstraction..... 107
 - IV.7.2. Architecture of zone differential protection 113
 - IV.8. Modeling of network components according to their behavior..... 114
 - IV.8.1. Upstream network 114
 - IV.8.2. Power transformer 115
 - IV.8.3. Line and cable segments 116

IV.8.4. Load	119
IV.8.5. Capacitor bank	119
IV.8.6. Synchronous machine	121
IV.9. Modeling of the test feeder into the power system simulation tool (OpenDSS)	121
IV.10. Conclusion	122

IV.1. Introduction

A good analysis of a distribution power system requires a correct understanding of the behavior of the components composing this power system. Therefore, an adequate representation of those components is essential in each type of power system study to capture the power system reality. The representation of power system components will depend on the types of network analysis to achieve.

In this section, we will be interested in the study of a new zone differential protection applied to an electricity distribution feeder. Basically, the distribution feeder is split into different invariant zones. On each zone, the principle of the differential protection is applied to check that the balance between loads (internal loads and external load towards neighboring zones) and the generation (internal generation and current injections at the zone borders). The validation of such protection scheme requires to perform steady state power flow and short-circuit simulations. In addition, dynamics simulations are necessary. Therefore, the power system components representation should be done to allow for these types of analysis.

Also, a prerequisite to any study of implementation of a protection scheme is to identify the technical constraints on the network that should be accounted for. To this end, the following technical aspects should be considered:

- The magnetizing inrush phenomenon appearing during power transformer energization must be considered. In fact, the magnetizing inrush is a transient current appearing on the primary side of a power transformer when it is being energized. As it drives a fault-like high current, this normal phenomenon must be accounted for;
- The harmonic pollution from power electronics interfacing some non-utility generating sources with the grid;
- The neutral configuration of the distribution network for managing the earth faults;
- The load pattern is not perfectly known;
- The unbalanced phasing and loading should also be considered as the distribution network may consist of several one, two and three phase loads;

- The topology changes due to circuit reconfiguration should also be accounted for since it potentially transfers part of the distribution feeder circuit onto another feeder acting as a back-up. Hence, the zone differential protection of the back-up feeder should integrate this new portion of network to the feeder centralized differential protection scheme;
- The presence of intermittent generation which introduce uncertainty on their available output power and create many technical challenges on protection amongst which sympathetic tripping, premature fuse blowing, potential relay blinding, increase of the fault elimination time, etc.;
- The presence of sources interfaced by inverters which short-circuit current contribution is limited to 120% of the inverter's rated current;
- Any addition of a new component, decommissioning of a component, modification of an electrical parameter on an existing component may have a significant impact on the zone differential protection, which might result in unnecessary tripping. As such, the integration of these changes into the protection scheme during run-time, is a real challenge.

Through the different technical aspects mentioned above, we can see the distribution system is a complex. To study this system, we will consider a multi-faceted approach with four different levels of modeling.

In the **first level** of modeling, the distribution feeder is described in CIM model. Recall that the Control Center uses an application called 'network model manager' which centralizes and maintains the distribution network model. This application is used by the Control Center to transfer the network model to the distribution feeder at the substation. Therefore, the Common Information Model (CIM) discussed in chapter 3 is used to describe each network component of the targeted distribution network in CIM by using CIM objects. Then, the description is contextualized and stored in a CIM XML file which is finally sent to the feeder to give it the knowledge of its downstream network. This approach has two main advantages: the first is to enable an easy integration of changes (addition of new equipment, deletion of an existing equipment, modification of electric parameters) on the network model into automation functions such as zone differential protection scheme by tying the network model to

these functions. The second advantage is to avoid being in an all-centralized control architecture by sharing part of the global knowledge with the feeder. This makes possible the so-called “**feeder automation**” which is the capacity of the feeder to perform automation functions (voltage control, wide area protection scheme, power balancing, circuit reconfiguration, etc.).

*In the **second level***, we are interested in the study of the behavior of the electrical system. In this level, each distribution network component (synchronous generation, solar PV, load, capacitor bank, line voltage regulator, power transformer, etc.) will be modeled to put in evidence its physical behavior during a specific power system study like power flow or short circuit study.

For the sake of computations simplification, a **third level** has been added. This level utilizes the graph theory which is very helpful in the analysis of complex systems such as electricity distribution networks. In fact, the differential protection is expected to trip rapidly and isolate the only faulty portion of the electric network by sending a trip command to one to several circuit breaker(s) or recloser(s). Indeed, isolating a part of an electric network is only possible if there is a circuit breaker or recloser to disconnect that part. To do so, it is important to view the distribution feeder within a network paradigm that enables us to get the connections between the different components (connectivity). So, the idea is to transform the distribution feeder circuit into a graph which is then split at its boundaries into several sub-circuits called subgraphs, each representing an invariant zone on which a differential protection scheme can be implemented. An invariant zone is a zone which is insensitive to topology changes.

The **fourth level** is dedicated to the modeling of the electrical network components in IEC 61850 model. Even though the Control Center is sending a network model in CIM XML file to the distribution feeder, this later does not use the CIM model but the IEC 61850 model. It turns out that the incoming network model needs to be transformed into IEC 61850 model which is possible thanks to the harmonization results between the two data models. See chapter 3 for more details. In fact, today, the integration of the changes on the network model into a protection scheme demands the manual intervention of an IEC 61850 system engineer to create the SCD (System Configuration Description) and further generate the CID (Configured

IED Description) files for protective devices. This approach is time-consuming, not error free and does not allow a direct integration of changes onto the automation functions during runtime. But, in the future, this network model update will be done 'on the fly' without any human intervention to update the feeder automation functions.

But, before proceeding, it is important to give some basic principles on the differential protection before presenting how it can be applied to a distribution feeder.

IV.2. Basic principles of the differential protection

Kirchhoff's current law states that the current flowing into a node must be equal to the current flowing out of it. This principle is used in the differential protection which compare the magnitude of the current entering a protected area to the magnitude of the current leaving that area. Should the differential current be not zero, a fault is assumed to occur in the protected zone. See appendix A2 for more details.

The basic principles described in appendix A2 focused on differential protection applied to a high voltage transmission line. However, a distribution feeder circuit has many specificities that need to be analyzed before implementing the differential protection principles on it. To facilitate the understanding of the rest of the discussion, a few definitions are given in the following subsections.

IV.3. Reference distribution feeder

IV.3.1. Definitions

Our objective is to apply the previous differential protection principles to a distribution feeder. However, to better understand the rest of the discussions, some definitions are necessary. Fig.IV-4 is used for illustration.

Definition IV-1 - Protected area:

A protected area is the area which is under protection. It is delimited by the current transformers located at the boundaries of the protected area. Fig.IV-4 shows a feeder consisting in several zones, each representing a protected area.

Definition IV-2 - Internal fault:

At any given time, when we refer to a fault at any bus within a specific zone, say zone 1, this fault is referred to as an “internal fault” relatively to zone 1.

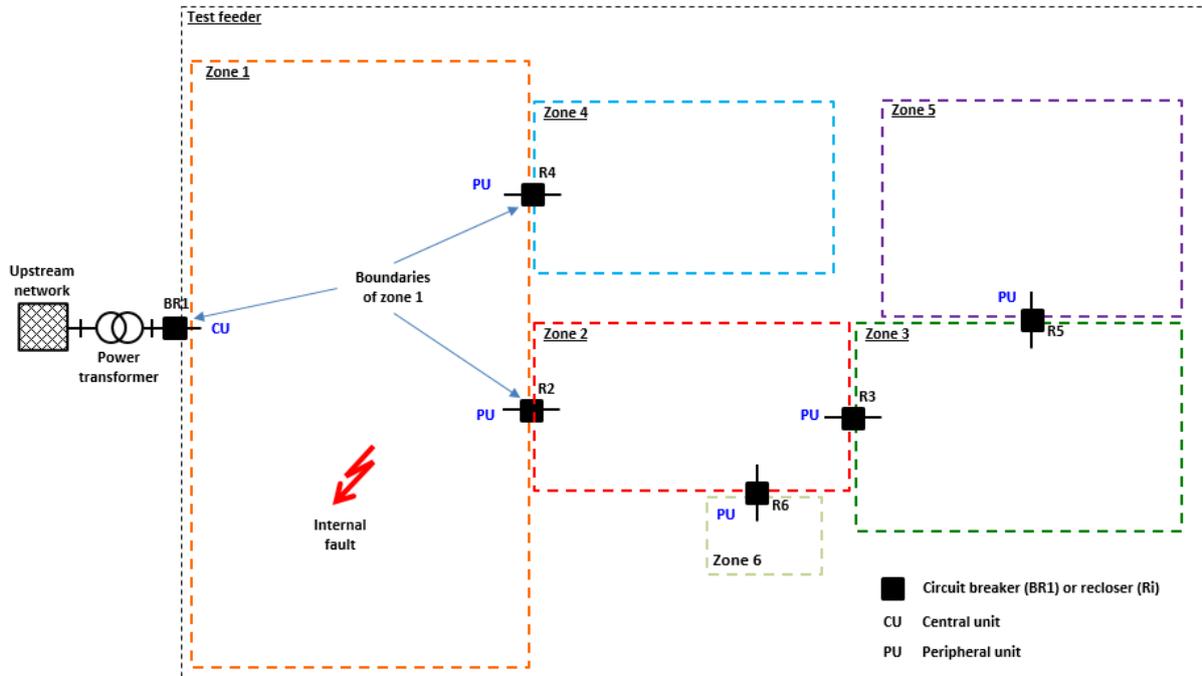


Fig.IV-4 – Example of a distribution feeder split in zones

Definition IV-3 - External fault:

For all the neighboring zones (other than the faulty one), the fault is regarded as an “external fault”.

Definition IV-4 - Zone boundary:

A zone boundary refers to the link between different zones. It is ensured by either a circuit breaker or a recloser. To isolate a faulty protected area, a trip command is sent to each of the zone boundaries to open them. Each zone boundary is equipped with a protective device connected to a current measurement.

Definition IV-5 - Zone differential protection:

The zone differential protection corresponds to a differential protection applied to a zone which, in this case, represents the “protected area”. Each zone includes at least one current infeed and one or several current outfeed (s), loads. Also, electrical equipment such as capacitor banks, generators, power transformer, storage system, amongst others may be present.

Definition IV-6 - Peripheral unit (PU):

The peripheral units have responsibility for collecting the required data, such as voltages and currents, circuit breaker/recloser status and processing it into digital form for onwards transmission to the central unit [26].

Definition IV-7 - Central unit (CU):

The central unit performs the calculations required for the protection functions [26]. In fact, at reception of the electric current samples and circuit breaker/recloser status from peripheral units, it calculates the differential current in the protected area after a time alignment of the samples to account for time latencies. Should the total injected current does not match with the total consumed current, a fault is assumed in the zone under consideration.

Definition IV-8 - Intertrip:

Tripping signal that is send to a remote protective device to open its circuit breaker or recloser. The intertrip signals are sent to the peripheral units by the central unit. In a zone differential protection context, the intertrip signals are sent to boundaries should a fault is detected within the zone.

Definition IV-9 – Zone of study:

We are basically interested in the protection of the distribution feeder which is the electric network extending from the circuit breaker at the supplying substation to one or more tie points downstream. For load flow and short-circuit studies, it is important to account for the supplying grid. Therefore, the zone of study includes the distribution feeder itself and the feeding source. However, our protection scheme will be only applied to the feeder.

IV.3.2. Specificities of distribution feeders

The distribution system consists generally in a set of radial feeders connected to one or several feeding substations. A circuit breaker placed at the head of the feeder (substation side) connects each distribution feeder to the feeding substation. In the rest of the discussion, we will focus on North American type distribution feeders. In the US, the distribution network is in four wires as the neutral point is directly earthed and distributed at several points. In addition, the electricity distribution can be done on two to four wires through several laterals and sub-laterals tapped off the main circuit. Hence, the loads may be balanced or unbalanced. A few decades ago, when the circuit were small with a few customers, it was acceptable to open the circuit breaker at the head of the feeder to isolate a fault. Nowadays, with feeder circuits spreading over a large geographic area and with increasing demand related to quality of supply, reclosers have been introduced in the distribution feeders, giving the possibility to isolate smaller parts of the feeder during a fault. Basically, a recloser is like a circuit breaker in that it has the capability to break a short-circuit and perform a reclosing sequence.

Compared to traditional passive distribution feeder where the power generally comes only from one substation at a time, the current distribution feeder is active due to the presence of distributed energy resources (generating sources, storage and controllable loads) which contribute to the power flows and short-circuit currents. The variability of the output power of the generating sources is stochastic for intermittent sources and deterministic for non-intermittent ones. In addition, the circuit reconfiguration modifies the topology of the feeder circuit to mitigate some overload constraints or to restore the service after an outage. Though, the electricity distribution system is a complex and dynamic system. As a matter of fact, the differential protection principle presented above needs to adapt to this context. For the rest of this thesis, we use a reference distribution feeder on which the differential protection will be implemented.

IV.3.3. Choice of our test distribution feeder

A set of test feeders has been developed by IEEE (Institute of Electrical and Electronics Engineers) with the intend of providing the software developers with

common data for validating some power system analysis functions such as power flow, optimal power flow, etc. To validate the differential protection, the selected test feeder should represent various distribution network specificities including the presence of reclosers to allow for the creation of protection zones for the simulation of both internal and external faults. In addition, the test feeder should include unbalanced loads and phasing to cover specificities of unbalanced distribution networks. This is typically the case of North American distribution networks. As a result, the IEEE 123 nodes test feeder has been selected as it consists of a large network with unbalanced phasing and loads, capacitors banks, line voltage regulators and many reclosers.

IV.3.4. Description of the test feeder network

The IEEE 123 nodes test feeder [14] is characterized by overhead lines and underground cables, unbalanced loading with constant current, constant impedance, or constant power model, line voltage regulators, shunt capacitor banks, and multiple switches. As illustrated in Fig.IV-5, this test feeder is a 4.16kV circuit supplied by a single point 90kV external grid through one 90/4.16kV-10MVA power transformer connected between nodes 150 and 150r. The network data of the IEEE 123 nodes test feeder is given on appendix A3. Fig.IV-5 shows the network structure.

IV.3.5. Modifications brought to the test feeder

Firstly, to allow multi-directional power flows and short circuit currents contributions especially for protection coordination purposes, some changes have been brought to the base IEEE 123 nodes test feeder. These changes consist in the connection of :

- one 400kW diesel generator (D1) at node 18 through a 0.48/4.16kV-1000kVA-7%-Dyn11 power transformer; the 4.16kV side of the transformer is coupled in delta (D), the 480V side is in wye (yn) and the vector group is 11;
- a second 400kW diesel generator (D2) at node 79 through a 0.48/4.16kV-1000kVA-7%-Dyn11 power transformer; the 4.16kV side of the transformer is coupled in delta (D), the 480V side is in wye (yn) and the vector group is 11.

Secondly, the normally opened reclosers have not been considered in our model.

The normally opened reclosers are used for service restoration which are not in our scope. Finally, the load models have all been changed to 'constant power' to be able to perform time-series power flow simulations in OpenDSS as discussed further. In the rest of the document, the modified IEEE 123 nodes test feeder, shown in Fig.IV-5, will be referred to as 'reference network'.

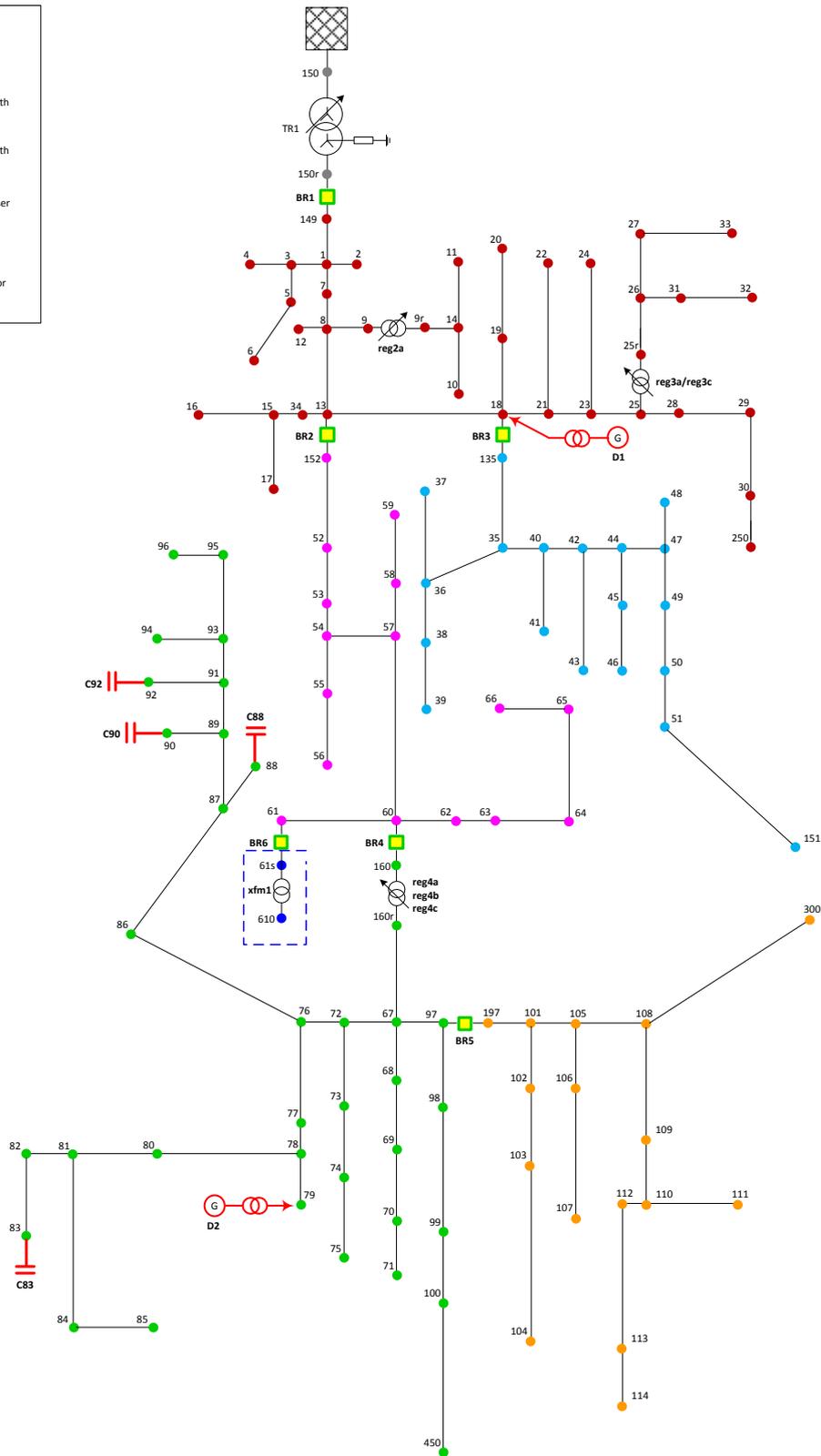
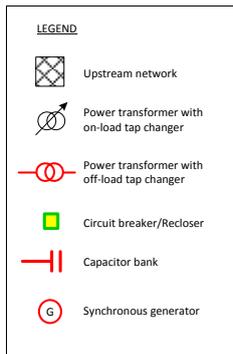


Fig.IV-5 – Reference network

After this brief presentation of the reference test feeder, our next section will first introduce the modeling environment, the modeling tools and principles. Then, the

modeling of feeder using the four levels of modeling previously described in the introduction of this chapter are discussed.

IV.4. Modeling approach

In this section, we will discuss the modeling environment, the modeling tools and the modeling principles. Then, the modeling of the different network components will be introduced.

IV.4.1. Description of the modeling environment

As already explained previously, the Control Center has a global knowledge on the connectivity model of the distribution network. Unlike the topology, which is a snapshot of the network, the network connectivity model defines the physical connection of the network i.e. how the different components of the network are connected to each other regardless of the status of reclosers or circuit breakers. The network model, described in CIM model, is transferred to the MV feeder controller to give it the knowledge of the downstream network it is supplying. In this thesis, this knowledge is used to perform a zone differential protection scheme on an active distribution test feeder. To this end, a simplified Distribution Management System (DMS) has been modeled using an object-oriented programming language called Python. The Fig.IV-6 shows our modeling environment.

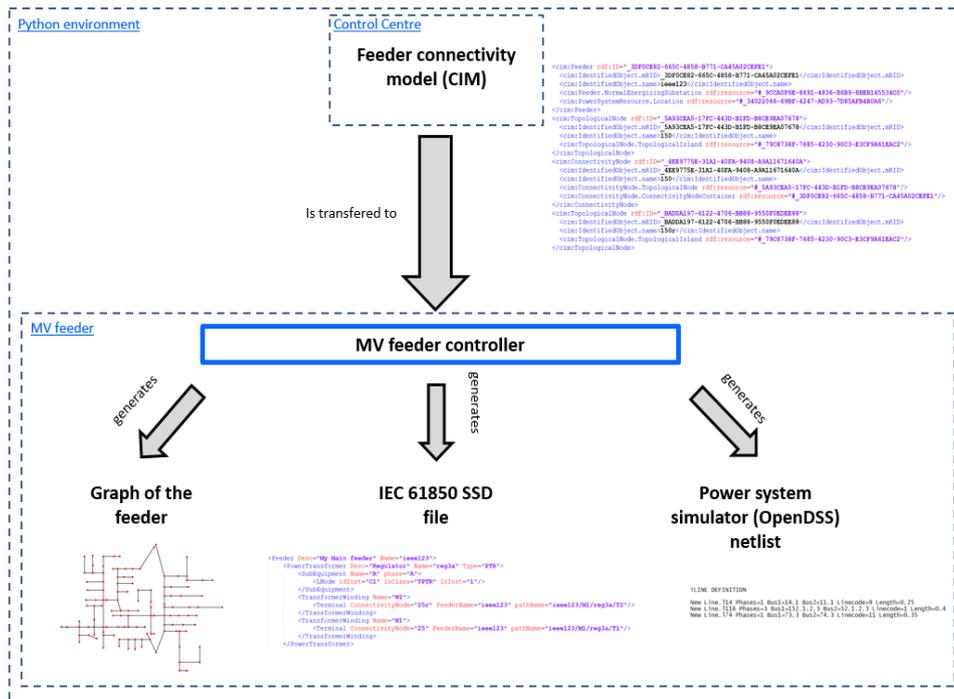


Fig.IV-6 – Modeling environment

IV.4.2. Modeling tools

To analyze the active and complex distribution network for a protection coordination purpose, it is important to understand the impact of the variability introduced by intermittent sources, the impact of storage systems and both balanced and unbalanced loads, the contribution of the different generating sources to the short circuit current, the effect of harmonics, among others. In traditional passive distribution networks, the load flow calculations methods were using one of the network specificity, which is a radial circuit connected to a single voltage controlled bus. The insertion of distributed energy resources into the previous passive network has introduced new difficulties in the distribution network modeling. One of these difficulties is the multi-directional power flows. Another difficulty is that the distributed energy resources come in many different technologies that need to be modeled in power system simulations tools. Furthermore, to understand the impact of the variability of the intermittent generating sources on distribution automation functions and characterize the time-dependent aspects of the system, the modeling tool should have a sequential time simulation capability also called time series, which is not easy

to obtain with a classic snapshot modeling technique. OpenDSS (Open Distribution System Simulator) meets these requirements.

The OpenDSS is a comprehensive electrical system simulation tool for electric utility distribution systems. OpenDSS refers to the open-source implementation of the DSS. It is implemented in three forms [41]:

- A stand-alone executable program (OpenDSS.exe)
- An in-process COM server DLL designed to be driven from a variety of existing software platforms (OpenDSSEngine.DLL)
- A Stdcall DLL that provides all the functions of the COM server, but can be used from languages that do not support COM or that require Thread safe execution as on a Cloud server (OpenDSSDirect.DLL)

The OpenDSS program has been use for many applications such as load flow, fault study, harmonics study, etc.

In this thesis, we will be using the second form of implementation consisting in driving the OpenDSS from Python through the COM interface. The main reason is that, in a smart grid context where many specific control functions may be required, advanced capabilities offered by object-oriented languages such as Python allow new features to be added to OpenDSS functionalities such as user-defined scripting, complex network analysis, plotting capabilities of Python.

IV.4.3. Modeling principles

Due to time constraints, the connectivity model of the reference network in CIM RDF XML format is created from a retro-engineering process by making a CIM export of the reference network from OpenDSS. The exported file is the base network connectivity model. Assuming the network connectivity model is at the Control Center, this CIM RDF XML file is passed to the MV feeder controller. At reception of this file, the controller does many operations (Fig.IV-7) amongst which:

- The parsing and extraction of the network components and connectivity;
- The creation of a graph for network analysis and zone creation;
- The creation of the IEC 61850 equivalent of the incoming network model as the feeder is using the IEC 61850 data model; in addition, what is envisioned is the

reduction of the engineering process by automatically achieving the model transformation in lieu and place of an IEC 61850 system engineer. This automatic translation can be very useful for feeder automation functions which could be in position to integrate 'on the fly' the changes on the incoming network model;

- The generation of the OpenDSS netlist from Python for providing the power system simulation software with the updated version of the network in case there are changes into it.

Once the OpenDSS netlist is built together with load and generation profiles, Python performs a time-series simulation by iterating over several time steps and commanding OpenDSS to execute a power flow for each time step. At each simulation step, the current at the zone boundaries are retrieved from OpenDSS and combined with load and internal generation currents to calculate the differential currents in each zone. Then, the relevant actions are taken accordingly. This approach is slower as Python stops OpenDSS at each time step to retrieve the solution of the simulation, process the data and take relevant decisions. However, for a protection scheme, it is necessary to monitor the current flow at each simulation step to check whether the operating point lies within the operating region of the zone differential protection.

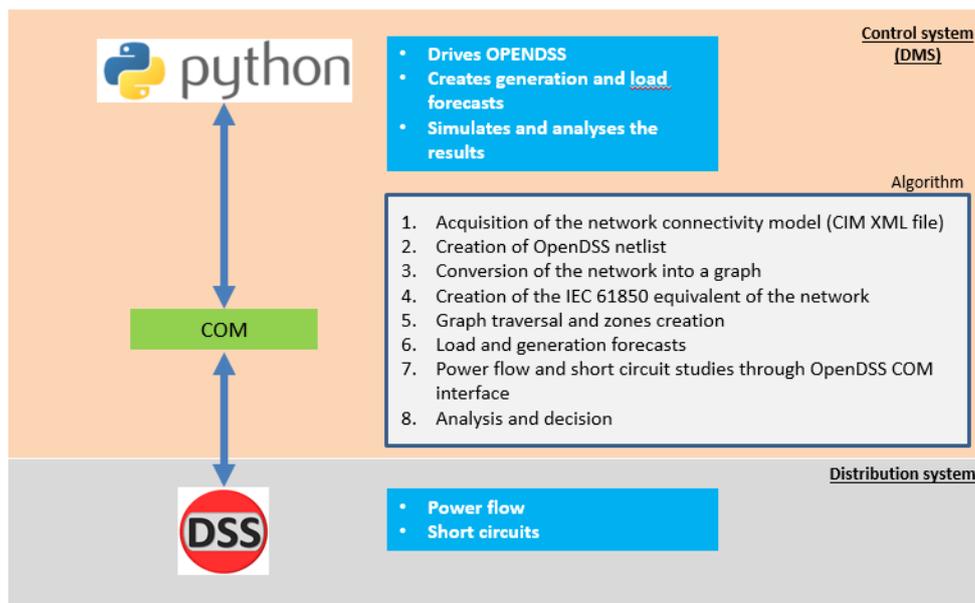


Fig.IV-7 – Simulation architecture

IV.4.4. Modeling assumptions

- The circuit breaker and five reclosers of our test feeder are modeled as three pole devices meaning that only three phase commands (open or close) will be possible;
- The power ramp-up on generating sources is not considered in this thesis;
- For time constraints reasons, the communication network has not been modeled. Therefore, the time latencies from the transmission of electric currents by peripheral units to their reception by the central unit (feeder controller) have not been considered; the electric currents are read by the controller for each simulation;
- For security reasons, it is assumed that no protected zone can be operated in islanded mode;

IV.4.5. Constraints

As discussed in the basic requirements of a protection system, one important quality of a protection system is the sensitivity, i.e. the ability to detect very small currents. To define the minimum setting value of the differential protection, it is crucial to make allowance for the false differential currents during normal operating conditions and during some transient normal situations.

IV.4.5.1. False differential currents

Fig.IV-8 shows the different causes of false differential currents. The false differential currents may be originating from :

CT (current transformer) errors: the conversion of the current flowing in the primary circuit to a secondary current that is safer for the protection device connected to the secondary winding of the CT creates both amplitude and phase errors called transformation errors.

Power transformer inrush current: the inrush current is a transient current appearing on the primary side of the power transformer when its primary winding is energized. However, even though the inrush current is very high (several times the power transformer rated current) in magnitude, it is not a fault and should not cause a trip.

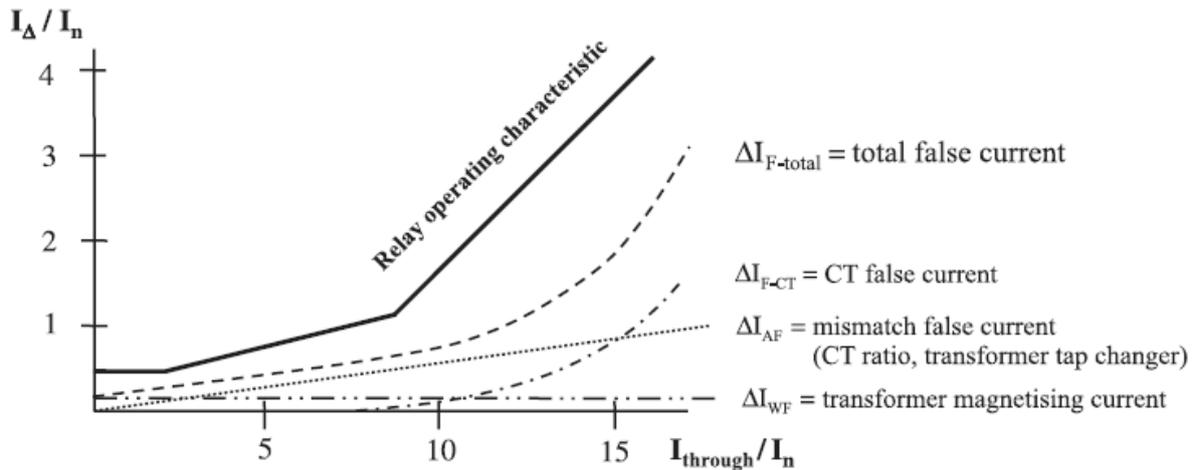


Fig.IV-8 – False differential currents during load and external faults [42]

IV.5. Modeling of the distribution feeder based on CIM model

IV.5.1. Introduction

The core of network modeling is to describe all the network components (conducting equipment in CIM) and how there are connected to each other also referred to as “connectivity”. The CIM modeling is a very challenging activity since it demands a good understanding of the network components data to map on relevant CIM classes.

In this section, our aim is to describe the network model of a distribution feeder in CIM. The created network model will be further transferred to the controller of the related MV feeder from the Control Center. To this end, one question must be answered: how to pass from the core CIM information model in UML to a file that can be exchanged, understood and used for some purposes? To answer this question, we will adopt the CIM three layers architecture based on UN/CEFACT CCTS (Core Component Technical Specification) and shown on previous Fig.III-6. This architecture is discussed below.

IV.5.1.1. The three layers architecture of CIM

The CIM three layers architecture defines a workflow to pass from the information and semantic models to a syntactic level that allows a file exchange. The **first layer** of the architecture corresponds to the core information model composed of hundreds of CIM classes and thousands of attributes expressed in UML diagrams. However, for the needs of a specific business, a contextual definition called “profile” is defined in the **second layer**. This profile is a restricted subset of the core information model. Finally, the **third layer**, which uses the previous profile, allows an information exchange through messages or files. This information exchange is enabled by a serialization process.

IV.5.1.2. Serialization of the network model in CIM

In fact, the profiles can be expressed syntactically in either XML (eXtensible Markup Language) or RDF (Resource Description Framework). However, since RDF allows the description of the link between different components of an electrical network, which is important in network model exchange, it will be used for the serialization of the network model for exchange purposes. In the rest of this section, the first two layers are used to model the conducting equipment of our test feeder by instantiating some classes of the base information model and contextualizing their attributes to the need of our application. The third layer is discussed further.

Before converting the conducting equipment of the distribution feeder circuit into CIM objects, let us first discuss how CIM uses a class diagram to abstract a distribution feeder with its conducting equipment and the connectivity between them.

IV.5.2. Modeling of the distribution feeder

At a very high level, a distribution feeder can be regarded as a container extending from a supplying source (typically a primary HV/MV substation) to one or several opened tie points. The feeder consists of interconnected network components called conducting equipment. In CIM, the **Line** class is used to model the feeder. See appendix A4 for more details.

IV.5.3. Introduction to RDF (Resource Description Framework)

As described in the introduction of this section, the CIM model has a three layers architecture: one for the information model, the second for the contextualization of the base information model and the last layer which focuses on the serialization or how to describe the CIM network model into a format that can be exchanged. The first two layers have been discussed previously. To exchange power system network model, CIM uses the RDF model which provides a means of mapping object-oriented design like CIM to XML. RDF allows us to describe a collection of data using a triplet statement also known as (**subject, predicate, object**) or (**resource, property, value**). In the RDF model, a resource is anything that can be identified. A Uniform Resource Identifier (URI) is used to designate a resource. A property is any characteristic of a resource that can be described with a value. The triplet (resource, property, value) is the atomic unit of information in RDF and is called a “statement” [43]. To illustrate this concept, an example of serialization of an **EnergySource** object using CIM RDF XML is given in Fig.IV-15. As we can see on Fig.IV-15, the description of the **EnergySource** resource uses both CIM and RDF vocabularies. The example below gives nine sets of statements amongst which only the three first are described are follows:

- The “**resource**” EnergySource with the unique ID "_63AFF42B-4970-4CDC-A5FB-C34D99AB1AA3" has a “**property**” called **name** which **value** is “source
- The “**resource**” EnergySource with the unique ID "_63AFF42B-4970-4CDC-A5FB-C34D99AB1AA3" has a “**property**” called **EquipmentContainer** which unique ID **value** is "#_E1E770AC-2698-498B-BA7F-90C3411C6FF0"
- The “**resource**” EnergySource with the unique ID "_63AFF42B-4970-4CDC-A5FB-C34D99AB1AA3" has a “**property**” called **voltageMagnitude** which **value** is 90

```

<cim:EnergySource rdf:ID="_63AFF42B-4970-4CDC-A5FB-C34D99AB1AA3">
  <cim:IdentifiedObject.name>source</cim:IdentifiedObject.name>
  <cim:Equipment.EquipmentContainer rdf:resource="#_E1E770AC-2698-498B-BA7F-90C3411C6FF0"/>
  <cim:EnergySource.voltageMagnitude>90</cim:EnergySource.voltageMagnitude>
  <cim:EnergySource.voltageAngle>0</cim:EnergySource.voltageAngle>
  <cim:EnergySource.r>0.19645385627943</cim:EnergySource.r>
  <cim:EnergySource.x>0.785815425117719</cim:EnergySource.x>
  <cim:EnergySource.r0>1.02558459032349</cim:EnergySource.r0>
  <cim:EnergySource.x0>3.07675377097046</cim:EnergySource.x0>
  <cim:PowerSystemResource.Location rdf:resource="#_3318572A-DE4F-4B69-BF1F-959392995F90"/>
</cim:EnergySource>

```

■ Subject
■ Predicate
■ Object

Fig.IV-15 – Example of serialization of the ‘EnergySource’ Object in CIM RDF XML

IV.6. Modeling of the distribution feeder IEC 61850 model

In previous chapter III, the mapping of CIM power system components into IEC 61850 was presented. To date, the IEC 61850 configuration related to both substations and feeders are done manually by an IEC 61850 system engineer from a network described in paper format. This scenario does not allow an update ‘on the fly’ of the envisioned feeder automation functions from incoming CIM model. As already discussed, what is proposed and simulated in this thesis is the automatic transformation of the CIM model into IEC 61850. Of course, several critical data required in the feeder/substation automation such as IP address, VLAN, full protection functions, are currently missing in the CIM model. Therefore, in the future, the CIM model should provide the capability to directly integrate the missing data to generate the full IEC 61850 configuration file of the feeder. Appendix B2 gives an extract of the equivalent of the CIM reference network model in IEC 61850. The model conversion is based on the mapping defined in chapter III.

IV.7. Modeling of the distribution feeder based on graph theory

IV.7.1. Distribution feeder abstraction

The analysis of a distribution feeder requires a correct understanding of the network under consideration. The network to be modeled consists of many buses connected by branches such as cables, lines, transformers, switching devices. To facilitate the modeling of this network, simplify the analysis and the queries on it, the graph theory is used. In fact, the distribution feeder electrical network can be regarded as a graph $G = (V, E)$ where $V = \{v_1, v_2, \dots, v_n\}$ is the set of nodes and $E = \{e_1, e_2, \dots, e_m\}$ is the set of edges linking different nodes. Each node can connect a load, a source.

Furthermore, due to the multi-directional power flow with the presence of distributed energy resources, the graph edges will be undirected. Hence, the network can be represented as an undirected graph G with n nodes and m edges. There are two possible models for representing the distribution feeder with a graph. The first model called “**bus-branch**” is a simplified model that describes the feeder network as buses and branches without any switching devices. However, when dealing with a zone differential protection, it is very important that the feeder network model includes switching devices such as circuit breakers or reclosers to be able to isolate the faulty zones. To overcome this limitation, a “**node-breaker**” model is used. The node-breaker is a breaker-oriented model allowing a detailed modeling of the network. Fortunately, as the incoming network model from the Control Center includes switching devices (circuit breaker and reclosers for example), this model will be used to represent the distribution feeder network in a graph.

Zone creation

The objective of the zone creation is to have invariants areas in the feeder, each representing the smallest possible zones in the circuit that can be isolated by a differential protection relay. As such, the differential protection principle can be applied on each of the zone acting then as a “**protected area**”. To create a zone, it is essential that the feeder circuit includes switching devices controllable by protection relays. Therefore, for protection reasons, a zone boundary is always equipped with a

recloser or a circuit breaker. A feeder circuit may consist of several zones interconnected through circuit breakers or reclosers acting as “**boundaries**”.

In view of the circuit on Fig.IV-16 below, the reference network has five reclosers and one circuit breaker which can be regarded as “boundaries” between the different zones. Therefore, the reference network can be split into six interconnected zones as shown on Fig.IV-16. The creation of zone is implemented in Python by considering the global reference network as a graph that may be split off to form a set of subgraphs (equivalent to sub-circuits), each representing a zone. More specifically, a graph traversal is performed to find the location of boundaries. Once a boundary is found, it is opened, and the process continues until all the boundaries are visited. This creates several islands representing subgraphs of the initial graph. Then, the subgraphs are extracted to finally form the zones.

Zone abstraction

To further implement the differential protection on the distribution feeder, additional details are necessary. Zone incoming and outgoing currents are not enough to determine the differential current in the zone. The different electric components in the zone need to be identified.

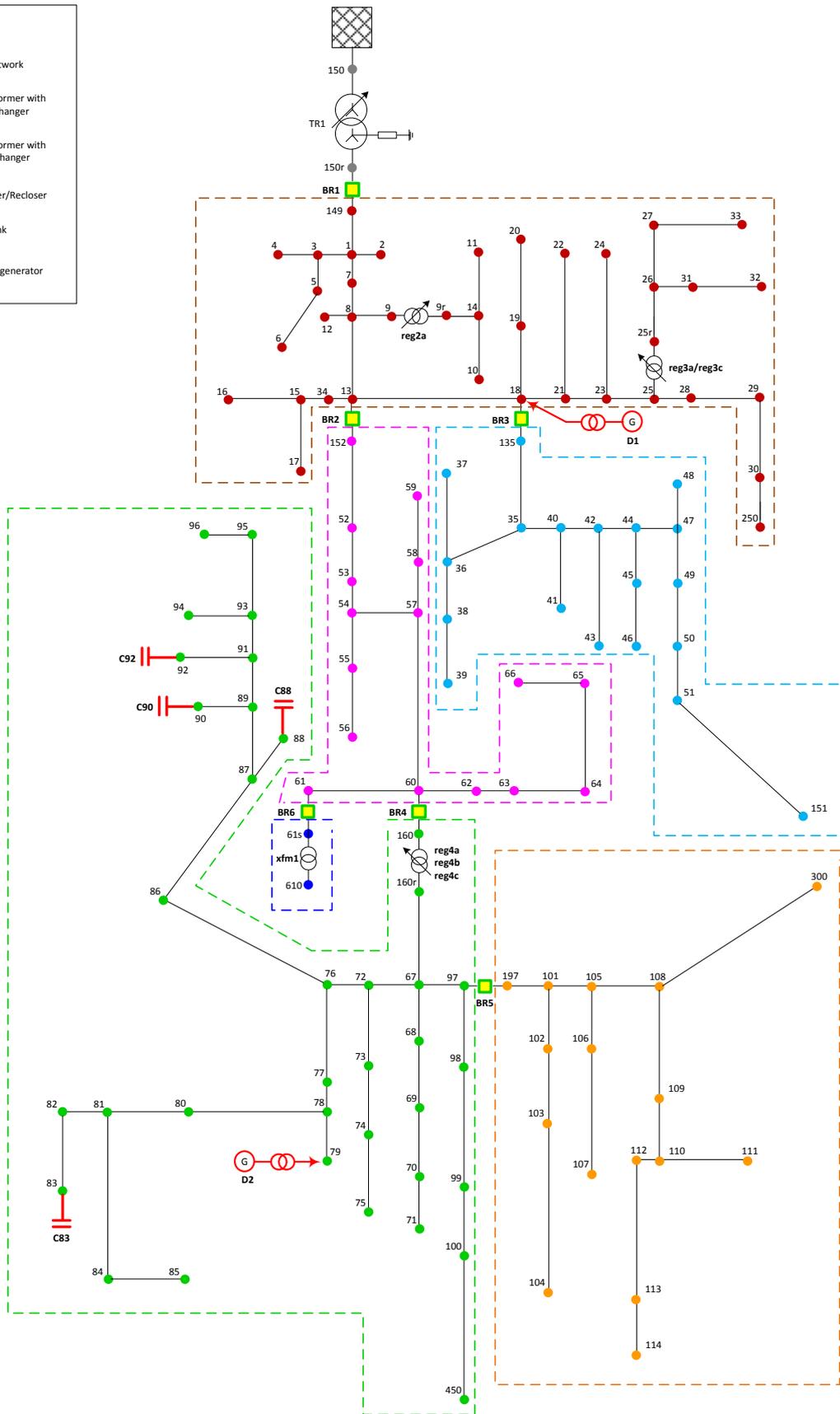
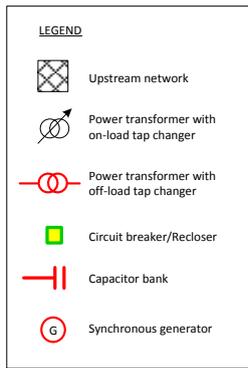


Fig.IV-16 – Reference network split in zones

Thinking a zone as an electrical network, it can be abstracted as in Fig.IV-17.

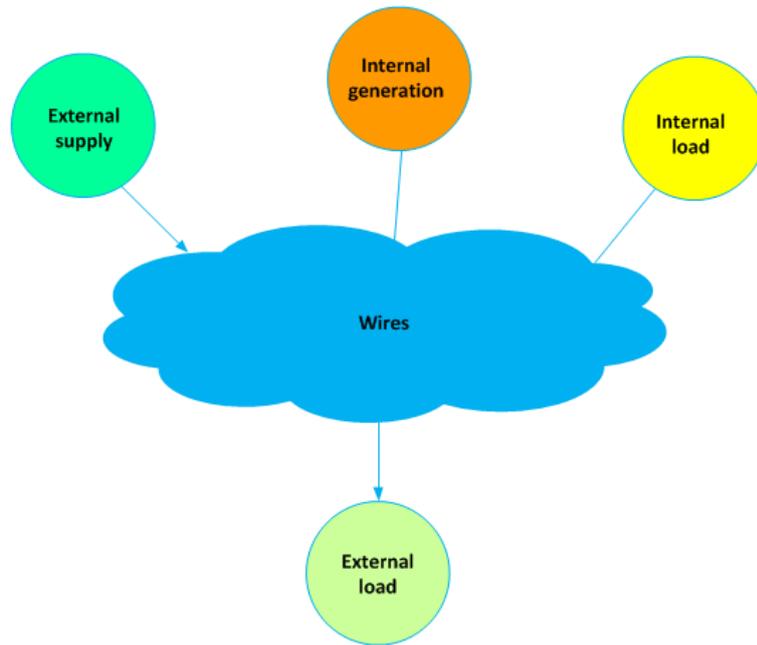


Fig. IV-17 – Zone abstraction – adopted from [44]

In fact, one external supply injects a current into a zone, call it I_{inj} to supply both total internal load (I_{load_int}) and total external load (I_{load_ext}). The total external load is the load exported towards neighboring zone(s). In addition, active and reactive currents may be produced by internal generating sources (I_{gen_int}) and storage systems.

However, a specificity of the storage system is that, depending on its operating status (charging, discharging, idling), the storage system can be a load (I_{stor+}), or a generating source (I_{stor-}), or none of them. Reactive currents (I_{cap_bank}) are also injected from capacitor banks which are considered as negative loads.

Considering that the sum of generated current equals the sum of consumed current,

$$\underline{I}_{inj} + \underline{I}_{gen_int} + \underline{I}_{stor-} = \underline{I}_{load_int} + \underline{I}_{load_ext} + \underline{I}_{cap_bank} + \underline{I}_{stor+} \quad \text{Eq. IV.9}$$

$$\underline{I}_{inj} - \underline{I}_{load_ext} = \underline{I}_{load_int} + \underline{I}_{cap_bank} + \underline{I}_{stor+} - (\underline{I}_{gen_int} + \underline{I}_{stor-}) \quad \text{Eq. IV.10}$$

However, because the proposed differential protection is phase segregative, Eq. IV.10 will be define for each phase as below:

$$\underline{I}_{inj_A} - \underline{I}_{load_ext_A} = \underline{I}_{load_int_A} + \underline{I}_{cap_bank_A} + \underline{I}_{stor+_A} - (\underline{I}_{gen_int_A} + \underline{I}_{stor-_A}) \quad \text{Eq. IV.11.a}$$

$$\underline{I}_{inj_B} - \underline{I}_{load_ext_B} = \underline{I}_{load_int_B} + \underline{I}_{cap_bank_B} + \underline{I}_{stor+_B} - (\underline{I}_{gen_int_B} + \underline{I}_{stor-_B}) \quad \text{Eq. IV.11.b}$$

$$\underline{I}_{inj_C} - \underline{I}_{load_ext_C} = \underline{I}_{load_int_C} + \underline{I}_{cap_bank_C} + \underline{I}_{stor+_C} - (\underline{I}_{gen_int_C} + \underline{I}_{stor-_C}) \quad \text{Eq. IV.11.c}$$

Therefore, as with the formulation of differential current in Eq.IV.5, it is possible to rewrite Eq.IV.11.a, Eq.IV.11.b and Eq.IV.11.c as below:

$$I_{diff_A} = \left| \left(\underline{I}_{inj_A} - \underline{I}_{load_ext_A} \right) - \left(\underline{I}_{load_int_A} + \underline{I}_{cap_bank_A} + \underline{I}_{stor+_A} - (\underline{I}_{gen_int_A} + \underline{I}_{stor-_A}) \right) \right| \quad \text{Eq. IV.12.a}$$

$$I_{diff_B} = \left| \left(\underline{I}_{inj_B} - \underline{I}_{load_ext_B} \right) - \left(\underline{I}_{load_int_B} + \underline{I}_{cap_bank_B} + \underline{I}_{stor+_B} - (\underline{I}_{gen_int_B} + \underline{I}_{stor-_B}) \right) \right| \quad \text{Eq. IV.12.b}$$

$$I_{diff_C} = \left| \left(\underline{I}_{inj_C} - \underline{I}_{load_ext_C} \right) - \left(\underline{I}_{load_int_C} + \underline{I}_{cap_bank_C} + \underline{I}_{stor+_C} - (\underline{I}_{gen_int_C} + \underline{I}_{stor-_C}) \right) \right| \quad \text{Eq. IV.12.c}$$

The operation of the zone differential protection occurs should the current I_{diff} be greater than or equal to the differential pick-up value as follows:

$$I_{diff_A} \geq \text{differential pick - up value on phase A} \quad \text{Eq. IV.13.a}$$

$$I_{diff_B} \geq \text{differential pick - up value on phase B} \quad \text{Eq. IV.13.b}$$

$$I_{diff_C} \geq \text{differential pick - up value on phase C} \quad \text{Eq. IV.13.c}$$

In theory, I_{diff_A} , I_{diff_B} and I_{diff_C} are equal to 0 under normal operating conditions. and during external faults. However, in practice, some false differential current should be accounted for as discussed in section IV.4.5.1.

Similarly to the differential current, the restraining current defined in Eq.IV.7 can be applied to reformulate. We get:

$$I_{restr} = \frac{|I_{inj}| + |I_{load_ext}| + |I_{load_int} + I_{cap_bank} + I_{stor+} - (I_{gen_int} + I_{stor-})|}{2} \quad \text{Eq. IV.14}$$

On a per phase basis, the restraining current can be rewritten as follows:

$$I_{restr_A} = \frac{|I_{inj_A}| + |I_{load_ext_A}| + |I_{load_int_A} + I_{cap_bank_A} + I_{stor+_A} - (I_{gen_int_A} + I_{stor-_A})|}{2} \quad \text{Eq. IV.15.a}$$

$$I_{restr_B} = \frac{|I_{inj_B}| + |I_{load_ext_B}| + |I_{load_int_B} + I_{cap_bank_B} + I_{stor+_B} - (I_{gen_int_B} + I_{stor-_B})|}{2} \quad \text{Eq. IV.15.b}$$

$$I_{restr_C} = \frac{|I_{inj_C}| + |I_{load_ext_C}| + |I_{load_int_C} + I_{cap_bank_C} + I_{stor+_C} - (I_{gen_int_C} + I_{stor-_C})|}{2} \quad \text{Eq. IV.15.c}$$

Finally, the differential protection trips should one of the two conditions below be met:

For phase A:

$$I_{restr_A} < I_{s2_A} \quad \text{and} \quad I_{diff_A} > k_1 \times I_{restr_A} + I_{s1_A} \quad \text{Eq. IV.16.a}$$

$$I_{restr_A} > I_{s2_A} \quad \text{and} \quad I_{diff_A} > k_2 \times (I_{restr_A} - I_{s2_A}) + k_1 \times I_{s2_A} + I_{s1_A} \quad \text{Eq. IV.16.b}$$

For phase B:

$$I_{restr_B} < I_{s2_B} \quad \text{and} \quad I_{diff_B} > k_1 \times I_{restr_B} + I_{s1_B} \quad \text{Eq. IV.17.a}$$

$$I_{restr_B} > I_{s2_B} \quad \text{and} \quad I_{diff_B} > k_2 \times (I_{restr_B} - I_{s2_B}) + k_1 \times I_{s2_B} + I_{s1_B} \quad \text{Eq. IV.17.b}$$

For phase C:

$$I_{restr_C} < I_{s2_C} \quad \text{and} \quad I_{diff_C} > k_1 \times I_{restr_C} + I_{s1_C} \quad \text{Eq. IV.18.a}$$

$$I_{restr_C} > I_{s2_C} \text{ and } I_{diff_C} > k_2 \times (I_{restr_C} - I_{s2_C}) + k_1 \times I_{s2_C} + I_{s1_C} \quad \text{Eq. IV.18.b}$$

At this stage, the parameters of the operating characteristic are defined (differential and restraining pick-up current, slopes) along with trip conditions, the zone differential protection can be applied to each zone. In the next section, the behavior of the zone differential protection is analyzed.

IV.7.2. Architecture of zone differential protection

Now that the zones are formed and abstracted, the zone differential protection will utilize the architecture given on Fig.IV-18.

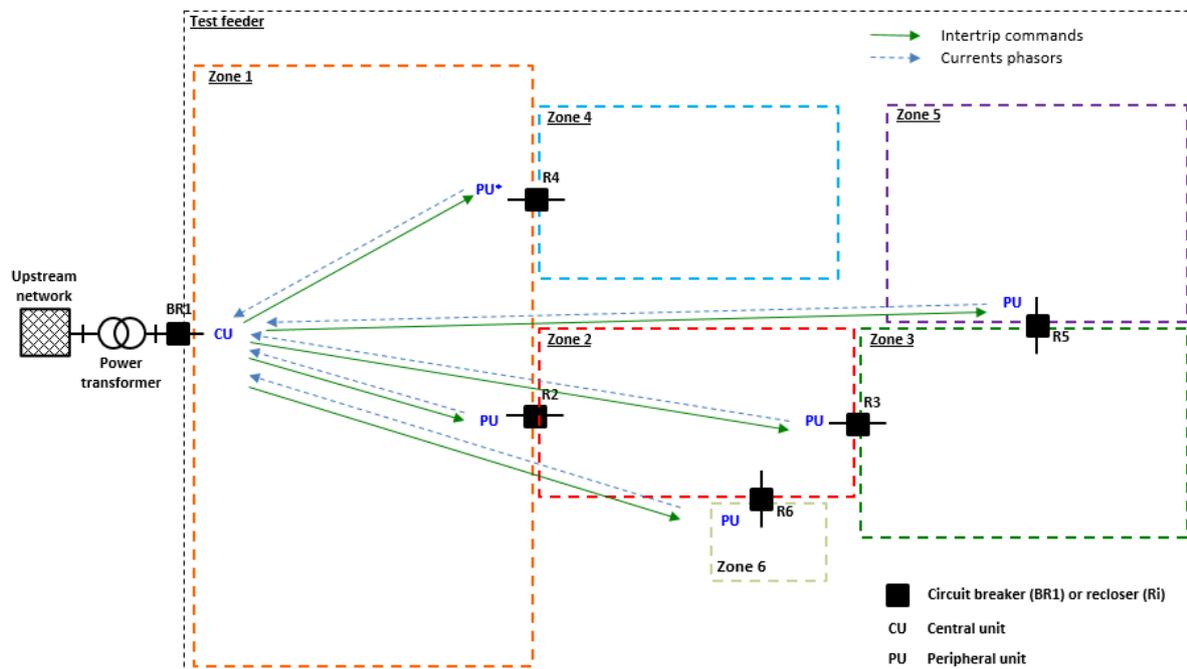


Fig. IV-18 – Data exchange between central and peripheral units

At the boundaries of each zone, a peripheral unit (PU) is placed to transmit the recloser status and the local electric current measurements in form of samples to the central unit (CU) located at the head of the test feeder. This central unit embeds an algorithm that sequentially computes the differential current in each zone in the jurisdiction of the feeder and takes the decision to trip or not based on the calculated differential current.

IV.8. Modeling of network components according to their behavior

Each of the network components is modeled individually by its equivalent circuit to reflect its behavior during steady state conditions. Their behavior during transient conditions have not been modeled.

IV.8.1. Upstream network

The upstream network (Fig. IV-16), is the grid source which supplies our reference distribution feeder through a step-down 90/4.16kV power transformer. For load flow study, it is modeled as the slack bus, i.e. with a constant voltage source and a reference angle of zero. To account for short circuit calculation, the upstream source is characterized by its equivalent impedance which determines the current contribution of the source to short circuits on the feeder. According to the IEC60909 standard, the equivalent impedance of the upstream network is related to the system nominal voltage and the short circuit current by the following equations:

$$I_{k3}'' = \frac{1.1 \times U_n}{\sqrt{3} \times |Z_1|} \quad \text{Eq. IV.19}$$

$$I_{k1}'' = \frac{\sqrt{3} \times 1.1 \times U_n}{|Z_1 + Z_2 + Z_0|} \quad \text{Eq. IV.20}$$

Where:

I_{k3}'' = three-phase short-circuit current contribution of the upstream source;

I_{k1}'' = single-phase short-circuit current contribution of the upstream source;

$Z_1 = R_1 + j \times X_1$ is the positive sequence equivalent impedance of the upstream source at the connection point;

$Z_2 = R_2 + j \times X_2$ is the negative sequence equivalent impedance of the upstream source at the connection point; it is assumed that the negative sequence impedance is equal to the positive sequence impedance;

In our thesis, we will model the three-phase, single-phase short circuit currents and the time constants X_1/R_1 and X_0/R_0 of the upstream source in lieu and place of the equivalent impedances.

IV.8.2. Power transformer

The reference network includes one 90/4.16kV power transformer with on-load tap changer, two 4.16/LV power transformer with off-load tap changer and six line voltage regulators. Any power transformer can be modeled as shown in Fig.IV-19.

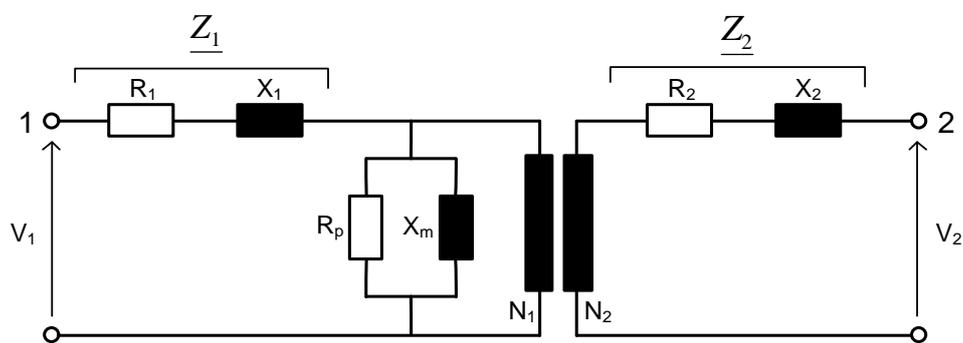


Fig. IV-19 – Power transformer electrical model

Where:

V_1, V_2 : Primary and secondary voltage

N_1, N_2 : Primary and secondary winding turns

R_1, R_2 : Primary and secondary ohmic resistance

X_1, X_2 : Primary and secondary ohmic reactance

R_p : Equivalent resistance of the core losses

X_m : Magnetizing reactance

The equivalent resistance of the core losses is not modeled as it does not impact our use case. The magnetizing inrush should be accounted for due to the potential

unnecessary tripping it might cause. However, the effect of this parameter is not effective on steady state.

IV.8.3. Line and cable segments

The reference network consists of many single-phase and three-phases AC lines segments with relatively short lengths, between one hundred to one thousand meters. The presence of short line segments enables to model them as a series impedance (composed by a resistance in series with an inductance) while neglecting the shunt capacitance. However, with this simple representation, the capacitive current generated from each line segment is ignored during earth faults. For unbalanced three-phase systems, there is a requirement to accurately define the individual conductor parameters for each phase and their spacing. This is to allow unbalanced power-flow engines to create the impedance matrices for the unbalanced lines [45]. Actually, line segment impedances can be represented at the base frequency either by its symmetrical component impedances ($\underline{Z}_1 = R_1 + j \times X_1 =$ positive sequence impedance and $\underline{Z}_0 = R_0 + j \times X_0 =$ zero sequence impedance) or by the impedance matrices. Whatever representation, any line segment can be defined by referring to a “*linecode*” that contains the impedances per unit length. But, as the representation by symmetrical components does not account for line asymmetries, we will use the impedance matrices for each single and multi-phase line segments as below.

For single-phase line segment:

A single-phase line segment may be modeled by a ‘pi’ model as shown in Fig.IV-20.

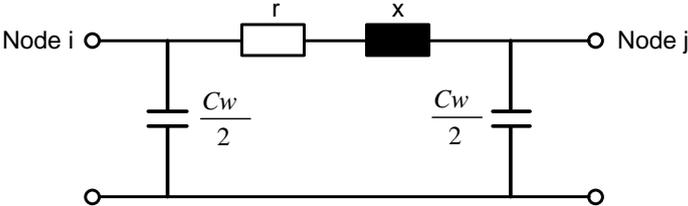


Fig.IV-20 – Pi model of a line segment

This 'pi' model can be transformed into a set of three matrices representing respectively the resistance (r_{matrix}), reactance (x_{matrix}) and shunt capacitance (c_{matrix}) matrices, where:

$$r_{matrix} = [r] \quad \text{Eq. IV.21}$$

$$x_{matrix} = [x] \quad \text{Eq. IV.22}$$

$$c_{matrix} = [c] \quad \text{Eq. IV.23}$$

r : Single-phase line segment resistance per unit length (Ω/km)

x : Single-phase line segment reactance per unit length (Ω/km)

c : Single-phase line segment shunt capacitance per unit length (nF)

For two-phase line segment:

As formulated on Eq. IV-21, Eq. IV-22 and Eq. IV-23, a two-phase line segment is modeled by the following impedance matrices:

$$r_{matrix} = \begin{pmatrix} r_{11} & r_{12} \\ r_{21} & r_{22} \end{pmatrix} \quad \text{Eq. IV.24}$$

$$x_{matrix} = \begin{pmatrix} x_{11} & x_{12} \\ x_{21} & x_{22} \end{pmatrix} \quad \text{Eq. IV.25}$$

$$c_{matrix} = \begin{pmatrix} c_{11} & c_{12} \\ c_{21} & c_{22} \end{pmatrix} \quad \text{Eq. IV.26}$$

For three-phase line segment:

Similarly, a three-phase line segment is modeled by the following impedance matrices:

$$r_{matrix} = \begin{pmatrix} r_{11} & r_{12} & r_{13} \\ r_{21} & r_{22} & r_{23} \\ r_{31} & r_{32} & r_{33} \end{pmatrix} \quad \text{Eq. IV.27}$$

$$x_{matrix} = \begin{pmatrix} x_{11} & x_{12} & x_{13} \\ x_{21} & x_{22} & x_{23} \\ x_{31} & x_{32} & x_{33} \end{pmatrix} \quad \text{Eq. IV.28}$$

$$c_{matrix} = \begin{pmatrix} c_{11} & c_{12} & c_{13} \\ c_{21} & c_{22} & c_{23} \\ c_{31} & c_{32} & c_{33} \end{pmatrix} \quad \text{Eq. IV.29}$$

where:

- r_{11}, r_{22}, r_{33} : resistance per unit length (Ω/km) on respectively phase 1, 2 and 3
- r_{12}, r_{21} : resistance per unit length (Ω/km) between phase 1 and 2
- r_{13}, r_{31} : resistance per unit length (Ω/km) between phase 1 and 3
- r_{23}, r_{32} : resistance per unit length (Ω/km) between phase 2 and 3
- x_{11}, x_{22}, x_{33} : reactance per unit length (Ω/km) on phase 1, 2 and 3
- x_{12}, x_{21} : reactance per unit length (Ω/km) between phase 1 and 2
- x_{13}, x_{31} : reactance per unit length (Ω/km) between phase 1 and 3
- x_{23}, x_{32} : reactance per unit length (Ω/km) between phase 2 and 3
- c_{11}, c_{22}, c_{33} : capacitance (nF) on phase 1, 2 and 3
- c_{12}, c_{21} : capacitance (nF) between phase 1 and 2
- c_{13}, c_{31} : capacitance (nF) between phase 1 and 3
- c_{23}, c_{32} : capacitance (nF) between phase 2 and 3

Thus, the only properties required for completely defining a line segment are the “linecode” name and the length of the segment.

IV.8.4. Load

Loads are power delivery points which can be, according to their nature and use, residential, industrial, commercial load or a combination of them. In this thesis, all the loads of our reference distribution feeder are connected to the medium voltage side (4.16kV) of the network. In addition, load types can be constant power, or constant current or constant impedance.

In the network simulation software (OpenDSS), the load can be modeled by providing amongst others the rated powers and the load type. However, this only allow for a snapshot power flow simulation. To check the behavior of the Zone Differential Protection under different load conditions, time series simulation is used. However, the time series simulation is only possible for constant power load type in OpenDSS. Therefore, the different loads types are reverted to constant and a load profile is associated to each load. A load profile is a predefined curve that sets the behavior of a piece of load. The instantaneous customer and system loads are often considered to have Gaussian distributions [25]. To create the load profiles, we generate random values following a normal distribution with a mean $\mu=0.5$ (50% of the rated load) and a standard deviation $\sigma=0.05$ (5% of the rated load).

See details in the appendix B5;

IV.8.5. Capacitor bank

A capacitor bank is used for reactive power compensation with the objective to improve a voltage profile. As expressed in Eq.IV.30, the reactive power Q of the capacitor bank is determined by its capacitance C , the operating voltage U and the frequency f with $f = \frac{\omega}{2 \times \pi}$, ω being the angular frequency

$$Q = C\omega U^2$$

Eq. IV.30

As with load, capacitor bank will be given profiles. To define the profile, let us consider that a capacitor bank may be in one of the situations below :

- Available and ready to start but put out of service. Let us call this status AVOS;
- Available in service meaning that the capacitor bank is switched on. Let us call it AVIS;
- In maintenance denoted by UNAV for unavailable.

To illustrate these situations, time-dependent curves are given on Fig.IV-21. In the principle, these curves are generated from Python as follows :

- UNAV (unavailable): a one-hour duration is randomly generated between 1 and 24h to simulate the unavailability of the capacitor bank;
- AVOS (available out of service): between 0 to 9 hours AM;
- AVIS (available in service): switched on between 9AM and 10PM unless there is a contingency in between for maintenance reasons (simulated by UNAV parameter).

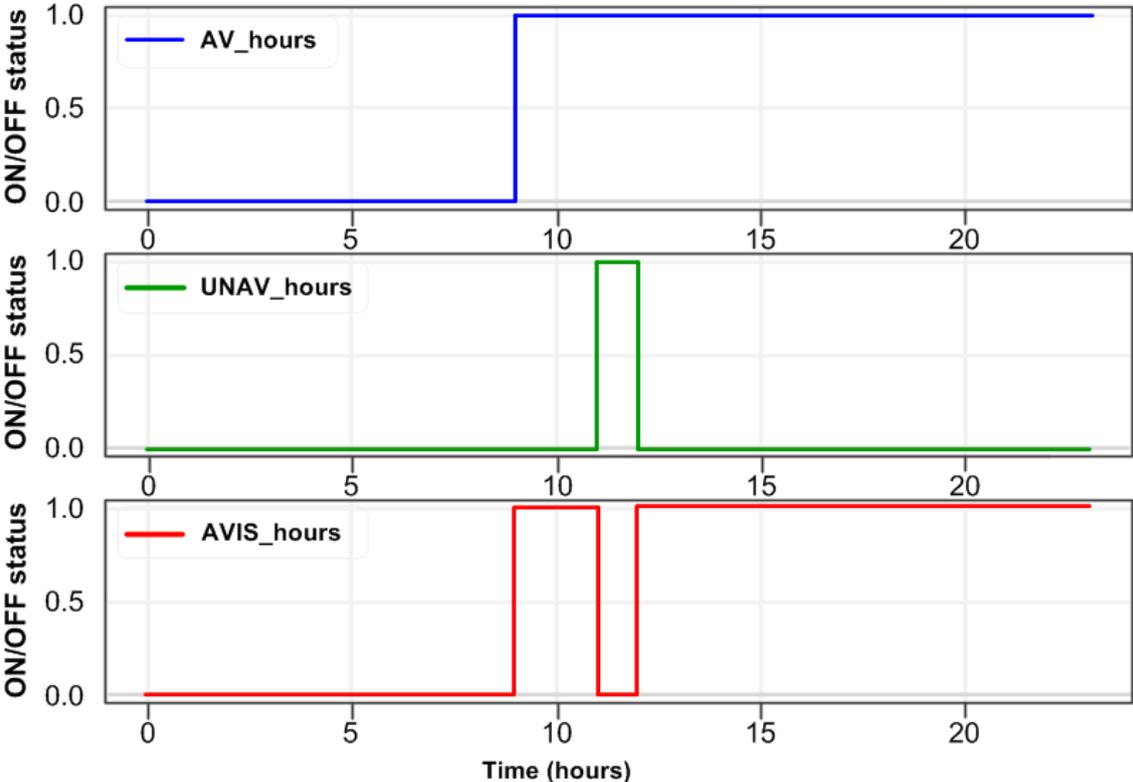


Fig.IV-21 – Example of operating profile of a capacitor bank

IV.8.6. Synchronous machine

Each diesel generator of the reference network is modeled as a synchronous machine. The parameters of the generators (voltage, reactances, power factor, active and reactive powers) are given in the appendix B5. Also, as with the loads, a generation profile is associated to each diesel.

Similarly to the load, a generation profile is used to define the behavior of a piece of generating source. To create the profiles for diesel machines, we generate a constant injection curve where generators produce constantly their rated active and reactive powers.

IV.9. Modeling of the test feeder into the power system simulation tool (OpenDSS)

As already discussed, OpenDSS has been chosen for our network simulations. In appendix B5, the OpenDSS version of the reference network generated from Python is given. In appendix C5, the OpenDSS version of the modified reference network (to check the incremental management aspect) including addition of new power system components is shown.

It is very important to mention that the direction of the electric current flow is very impactful in a differential protection. As any flow, this electric current flows in a direction which may be forward or backward. Therefore, because the flow is oriented, it can be given a positive or negative sign. This current sign can be defined thanks to the CT (current transformer) polarity. A CT is an equipment that changes the magnitude of a primary electric current from a high value to a lower value withstandable by to a protection device connected to its secondary winding. However, the CT model in OpenDSS does not provide the current flow direction. Therefore, the current direction will be computed within our scripts.

IV.10. Conclusion

Before conducting the steady state simulations, it was necessary to adequately model the reference network. Four modeling levels have been discussed. Firstly, the reference network has been modeled in CIM to mirror the physical reference network originating from the Control Center. This is called the incoming network model. Secondly, the reference network has been modeled in IEC 61850 (feeder data model) thanks to the harmonization between CIM and IEC 61850. Thirdly, a graph has been created from the reference network for ZDP zones creation. Finally, the behavioral modeling of the reference network components have been presented to get ready the network simulator (OpenDSS) for running the steady state simulations in the next chapter.

Chapter V : Simulations

Chapter V : Simulations	124
V.1. Introduction.....	126
V.2. Simulation methodology	126
V.2.1. Preliminary checks	127
V.2.2. Network simulations	127
V.2.3. Simulation tools	128
V.2.4. Format of simulation results	129
V.3. Setting of differential protection parameters.....	129
V.3.1. Differential protection parameters.....	129
V.3.1.1. Setting criteria of I_{s1}	129
V.3.1.2. Setting of slope k_1	130
V.3.1.3. Setting of I_{s2} and slope k_2	130
V.3.2. Current sign convention.....	130
V.3.3. Tripping decisions	130
V.4. Interpretation of simulation results	131
V.4.1. Simulations in simulation package SP1.....	131
V.4.1.1. Reference network model	131
V.4.1.2. IEC 61850 equivalent of reference model	132
V.4.1.3. Graph of the reference network.....	133
V.4.1.4. Zones creation.....	133
V.4.1.5. OpenDSS netlist of the reference network in SP1	133
V.4.1.6. Normal sequential power flow simulations in SP1	133
V.4.1.7. Short-circuit simulations in SP1	140
V.4.2. Simulations in simulation package SP2.....	143
V.4.2.1. Modified reference network model.....	143
V.4.2.2. Graph of the modified network	143
V.4.2.3. Zones creation in SP2.....	143
V.4.2.4. OpenDSS netlist of the modified reference network in SP2.....	144
V.4.2.5. Normal sequential power flow simulations in SP2	144

V.4.2.7. Short-circuit simulations in SP2	146
V.5. Conclusions on simulation results	151

V.1. Introduction

For recall, in chapter II, the protection coordination issues due to the presence of DERs (Distributed Energy Resources) on the distribution feeders were presented. Then, we went through the necessary alignment of CIM and IEC 61850 data models in chapter III to make transfer of the network model to the feeder possible. Finally, the modeling of the proposed new Zone Differential Protection (ZDP) has been described in chapter IV.

In the current chapter, the implementation and behavior of the zone differential protection are analyzed through simulations. It is important to mention that dynamic simulations have not been performed in this thesis to fully validate the ZDP.

V.2. Simulation methodology

Basically, steady state network simulations are run based on the modeling process described on Fig.IV-6 and Fig.IV-7. For each simulation, a controller, located at the head of the distribution feeder, gets the currents from all relevant power system components and sequentially computes, for each phase of the different zones of the feeder, the bias and differential currents. The bias and differential currents represent the operating point of the zone differential protection, with bias current on the abscissa and differential current on the ordinate. Finally, the differential protection operating point is placed on the operating characteristic to check if it falls within the operating (TRIP AREA) or restraining region (NO TRIP AREA). See tripping characteristic on Fig.IV.3 in appendix A2.

The network simulations are divided into two Simulations Packages (SP) :

- The first package (SP1) consists in assessing the behavior of the zone differential protection using the adapted IEEE 123 nodes network model (call it reference network model);
- In the second package (SP2), some changes (addition of new power system components) are introduced into the reference network model to check the

incremental management aspect or how these changes are enrolled in the zone differential protection.

For each simulation package, there are some preliminary checks before network simulations begin.

V.2.1. Preliminary checks

Before assessing the behavior of the ZDP, the preliminary verifications below are done to ensure that all the power system components in the incoming network model are enrolled in the feeder controller protection scheme and more globally in the feeder automation functions.

- IEC 61850 equivalent of the incoming CIM network model: consisting in checking that all the power system components in the CIM model are present in the IEC 61850 XML file. The CIM network model corresponding to the reference network model and the equivalent IEC 61850 XML file are shown respectively on appendices B1 and B2 for SP1. To illustrate the incremental management or how the changes are integrated in the ZDP, an update of the initial CIM network model with new power system components is given along with its IEC 61850 equivalent in appendices C1 and C2 dedicated to SP2;
- The graph of the global network including all the nodes and edges: consisting in checking that the graph reflects the given network model. See appendices B3 and C3 respectively for SP1 and SP2;
- The zones creation: the split of the incoming network model into zones is checked, along with the composition and borders of each zone. See graph of each zone in appendices B4 and C4 respectively for SP1 and SP2.

Now that the feeder controller has all the data per zone, network simulations can be performed.

V.2.2. Network simulations

To make possible the network simulations for ZDP validation, it is necessary to model the incoming network model (from CIM) under the selected power system simulation software. As already discussed in section IV.4.2, OpenDSS has been

chosen. Therefore, the automatic generation of the OpenDSS netlist from Python will be checked for alignment with the incoming network model before starting the simulations. However, OpenDSS allows a profile to be associated to a load only if the load model is “constant power”. Therefore, the load models have been changed accordingly. See modified OpenDSS netlist in appendices B5 and C5 respectively for SP1 and SP2.

Once the network is modeled in OpenDSS, two types of simulations are conducted as below:

- A normal 24 steps sequential power flow simulation mirroring the normal operating conditions (based on load and generation profiles) in which the ZDP is not supposed to operate. The results of the power flow simulations are shown in appendices B6 and C6 respectively for SP1 and SP2;
- Short-circuit simulations where different types of faults will be applied on the network while varying their location and their resistance. The ZDP is supposed to operate only if the fault appears within the zone. It should be stable for external faults. The results are shown in appendices B7 and C7 respectively for SP1 and SP2;

The ZDP is evaluated on a per phase base. For each zone, what is monitored is the balance between, on one hand, the currents flowing in/out of the zone and the total internal (load + generation) currents on the other hand in line with equation Eq.IV.10. Should this equation be not satisfied, and the operating point falls in the operation region of the differential characteristic, the ZDP operates. See settings criteria related to the differential operating value in section IV.3.1.1.

V.2.3. Simulation tools

As discussed previously, the network simulation tool used to conduct our simulations is OpenDSS. However, OpenDSS is controlled through the COM interface by Python to take profit of the capabilities of Python. The python version and computer characteristics used for the simulation are given below :

- Python version = 3.6.1
- Python compiler = MSC v.1900 64 bit (AMD64)

- System = Windows 7
- processor = Intel64 Family 6 Model 60 Stepping 3, Genuine Intel, 3.4GHz, Intel i5
- CPU count = 8
- Interpreter = 64bit

V.2.4. Format of simulation results

For both power flow and short-circuit simulations, the results will be presented in tabular format indicating, for each zone, the total internal load + generation current along with the currents flowing in/out of the zone. In addition, the current operating point (I_{restr} , I_{diff}) will be shown on the differential characteristic as shown on Fig.IV-3 to check the behavior of the zone differential protection.

V.3. Setting of differential protection parameters

V.3.1. Differential protection parameters

The proposed ZDP is a biased differential protection with four basic parameters as described in section IV.2. The setting values are defined as below:

V.3.1.1. Setting criteria of I_{s1}

I_{s1} is the differential current pick-up setting. Its setting should fulfil the following criteria:

- Greater or equal to 130% of the maximum phase load current of the zone (criterion 1);
- Below the minimum short-circuit current (criterion 2);
- Above the maximum differential current under normal operating conditions due to current transformer errors, IED measuring errors (criterion 3);

For the IEEE 123 nodes feeder, which includes both overhead lines segments along with cables, high resistive faults may appear generally on overhead parts, causing the short-circuit currents to potentially fall below the maximum phase load

current. Hence, criteria 1 and 2 may be conflicting if the short-circuit current is not sufficiently high compared to the maximum phase load current. On the contrary, if the faults are direct with high short-circuit currents, then, criterion 1 and 2 can be easily satisfied.

Finally, to account for criterion 3, a setting of 10% of the phase rated current of the zone has been considered to ensure sensitivity for resistive faults especially on overhead lines. This setting has been validated upon the short-circuit simulations.

V.3.1.2. Setting of slope k_1

Under normal operation, a differential current may appear due to CT errors. The slope k_1 is fitted to avoid any undesired tripping. It is typically set to 30%.

V.3.1.3. Setting of I_{s2} and slope k_2

I_{s2} is the restraining current pick-up setting. For each zone, I_{s2} is a knee point for discriminating the maximum possible operating current on a phase with the through fault current on the same phase. At the occurrence of a fault in a zone, a through fault current flows in neighboring zones which may create CT saturation on zone borders. This could result in an unnecessary tripping of the sound zone. Hence, the knee-point current I_{s2} is set to 120% of the rated phase current of the zone. Furthermore, a second slope k_2 is used to ensure the stability of sound neighboring zones during external faults. The slope k_2 is typically set to 80%.

V.3.2. Current sign convention

The current entering one zone is considered as positive while the leaving one is counted negative. In addition, all the current measurements are taken from the terminal 1 on each conducting equipment.

V.3.3. Tripping decisions

The ZDP operating point is the point of coordinate (I_{restr} , I_{diff}) resulting in the calculation of I_{diff} and I_{restr} as per Eq. IV.12.a, Eq. IV.12.b, Eq. IV.12.c, Eq. IV.15.a, Eq. IV.15.b, Eq. IV.15.c. The ZDP trips should previous Eq. IV.16.a or Eq.

IV.16.b are met for phase A, Eq. IV.17.a or Eq. IV.17.b for phase B, Eq. IV.18.a or Eq. IV.18.b for phase C.

V.4. Interpretation of simulation results

V.4.1. Simulations in simulation package SP1

In this section, the preliminary checks discussed previously, and the steady state network simulation conducted on reference network model are presented.

V.4.1.1. Reference network model

In the appendix B1, our reference network model is given in a CIM RDF XML file mirroring the real network in CIM model. This initial CIM RDF XML model is obtained through a retro engineering process during which the reference network was firstly model in OpenDSS. Then, an export to CIM has been done from OpenDSS. The advantage of doing this is to get all the network components IDs (coded into 128 bits) pre-assigned. However, the basic export was not adequate to our ZDP for some reasons. Recall that each power system component has one or more terminals connecting the component to phases of the network. Also, the ZDP is phase segregative and needs to clearly identify the phase(s) to which each power system component is connected to especially for unbalanced distribution networks. But, as illustrated on the extract below, this information is not present in the initial CIM export.

```
<cim:Terminal rdf:ID="_7BE43355-58F4-430F-8E13-F68F52503899">
  <cim:IdentifiedObject.mRID>_7BE43355-58F4-430F-8E13-F68F52503899</cim:IdentifiedObject.mRID>
  <cim:IdentifiedObject.name>source_T1</cim:IdentifiedObject.name>
  <cim:Terminal.ConductingEquipment rdf:resource="#_C6177614-AB14-4C05-AE4F-12F23C3FCE7A"/>
  <cim:ACDCTerminal.sequenceNumber>1</cim:ACDCTerminal.sequenceNumber>
  <cim:Terminal.ConnectivityNode rdf:resource="#_4EE9775E-31A1-40FA-9408-A9A11671640A"/>
</cim:Terminal>
```

However, the base CIM 'Terminal' class has a 'phase' attribute which can take one of the following values : A, B, C, AB, BC, AC, ABC, ABCN. Therefore, the 'phase' attribute has been added to each terminal as per its connection to the network. The modification of the previous extract is shown below.

```

<cim:Terminal rdf:ID="_7BE43355-58F4-430F-8E13-F68F52503899">
  <cim:IdentifiedObject.mRID>_7BE43355-58F4-430F-8E13-F68F52503899</cim:IdentifiedObject.mRID>
  <cim:IdentifiedObject.name>source_T1</cim:IdentifiedObject.name>
  <cim:Terminal.ConductingEquipment rdf:resource="#_C6177614-AB14-4C05-AE4F-12F23C3FCE7A"/>
  <cim:Terminal.phases>ABC</cim:Terminal.phases>
  <cim:ACDCTerminal.sequenceNumber>1</cim:ACDCTerminal.sequenceNumber>
  <cim:Terminal.ConnectivityNode rdf:resource="#_4EE9775E-31A1-40FA-9408-A9A11671640A"/>
</cim:Terminal>

```

V.4.1.2. IEC 61850 equivalent of reference model

To date, the IEC 61850 configuration of substations, feeders are done manually by a System engineer from an incoming network described in paper format. This process does not allow an update ‘on the fly’ of the envisioned feeder automation functions from incoming CIM model. As already discussed, we proposed and simulated an automatic transformation of the CIM model into IEC 61850. Of course, several critical data required in the feeder/substation automation such as IP address, VLAN, full protection functions, are currently missing in the CIM model. Therefore, in the future, the CIM model should provide the capability to directly integrate the missing data to allow for the generation of the full IEC 61850 configuration file of the feeder/substation.

In addition, as highlighted in section III.3.1, the current IEC 61850 model uses a ‘name’ attribute to identify the power system components, meaning that if for example the name of a component is changed at IEC 61850 level, nobody knows if this component represents a new component or the same one but with a new name. Therefore, if a Control Center application asks for data from the component via the previous name, the connection to the component will be refused. See appendix B2a for details on the current identification approach. As a result, we proposed to have the same identification method on both models. In the simulations conducted, an ‘ID’ attribute is added to each IEC 61850 power system component as the counterpart of the CIM *mRID* (master ID) attribute. Appendix B2b illustrates the proposed identification method for the IEC 61850 file.

V.4.1.3. Graph of the reference network

As discussed in section IV.6, the incoming reference network model is converted into a graph representing the connectivity of the network. The graph is used here especially for zone creations. See appendix B3 for the simulation package SP1.

V.4.1.4. Zones creation

Following the global graph construction, Python generates the different zones composing the global graph. A snapshot of each created zone in SP1 is given in Appendix B4 along with the borders. For each zone, the breakers/reclosers at borders are shown based on the connectivity data into the graph. The knowledge of the borders is used by the ZDP to isolate the faulty zone. After the zones creation, all the power system components (load, generating sources, capacitor banks, etc.) belonging to a specific zone are checked by the Python script before starting the ZDP computations.

V.4.1.5. OpenDSS netlist of the reference network in SP1

The OpenDSS netlist has been automatically created from the reference network model to allow network simulations. For recall, OpenDSS is controlled by Python through its COM interface. The netlist is given in appendix B5 for SP1.

V.4.1.6. Normal sequential power flow simulations in SP1

The normal sequential power flow simulation consists in 24 simulation steps. For each simulation step, the balance between the total internal (load - generation) and the arithmetic sum of currents on zone border(s) is checked for each phase of different zones. For the sake of clarity, the first simulation step is detailed below with computations done over zone 1. Also, the graph representation of the complete reference network connectivity and the zone 1 are given respectively on Fig.V-1 and Fig.V-2 for illustration. See zone borders in appendix B4.

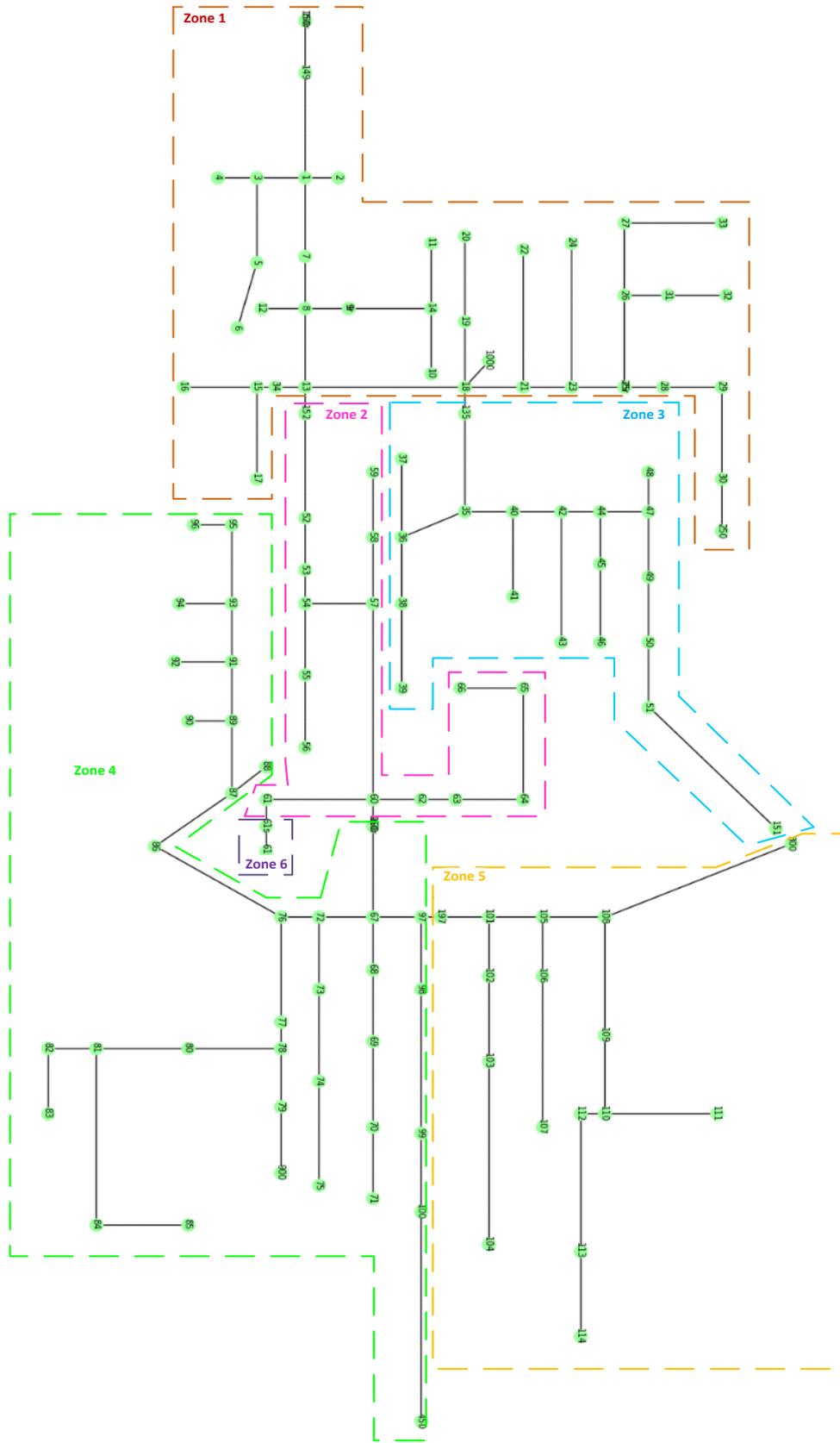


Fig.V-1 – Graph representation of the reference network connectivity

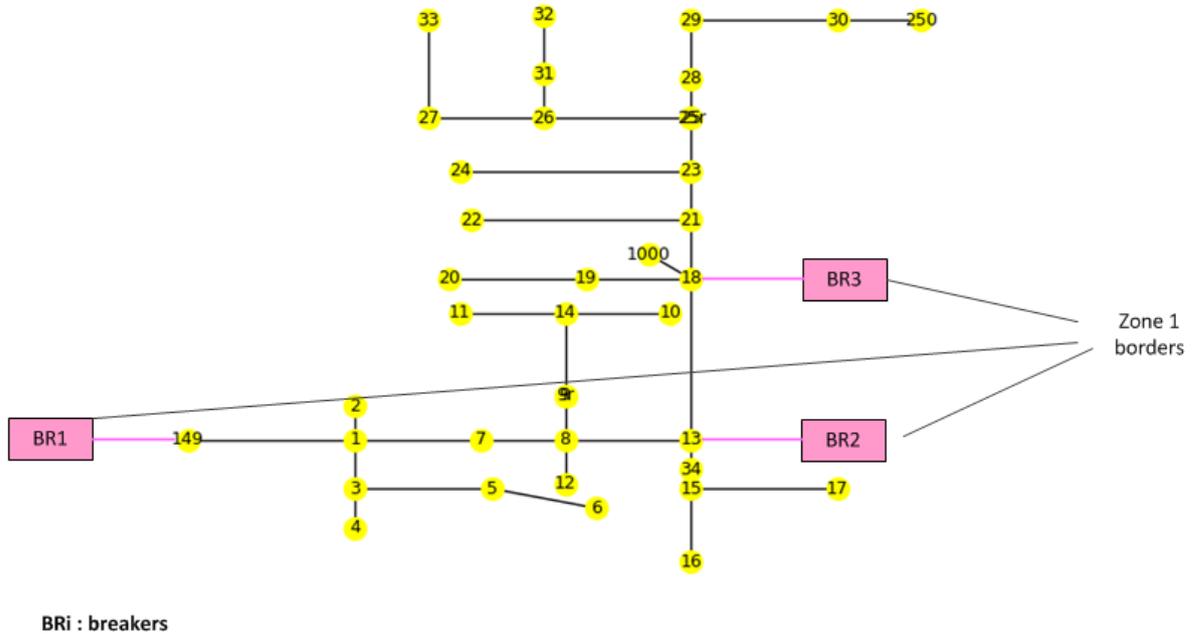


Fig.V-2 – Graph representation of zone 1 connectivity

To evaluate the conditions of operation of the zone differential protection, the process is, firstly, to compute for each zone, the actual phase differential and restraining currents. Secondly, the zone differential and restraining pick-up currents are computed. This second step allows the drawing of the operating characteristic of the ZDP. Thirdly, the previously computed differential and restraining currents are placed on the zone differential operating characteristic to check if there is a trip or not. Finally, the border(s) are tripped should a fault occurs inside a zone.

Computation of actual phase differential and restraining currents:

The actual differential (I_{diff_A} , I_{diff_B} and I_{diff_C}) and restraining (I_{restr_A} , I_{restr_B} and I_{restr_C}) currents are computed based on the equations Eq.IV.12a, Eq.IV.12b, Eq.IV.12c, Eq.IV.15a, Eq.IV.15b, Eq.IV.15c. To achieve these computations the result of the power flow simulation performed on the reference network model is used. The Python script commands OpenDSS to run a power

flow for every simulation step. For each step, the power flow solution is read by the Python script to compute, for each zone, the total internal (load - generation) current along with the currents flowing on zone borders.

The results are given below (see appendix B6 for more results on simulation package SP1) :

Current flow

	Zone 1 - Phase A	Zone 1 - Phase B	Zone 1 - Phase C
Total internal (load – gen) (A)	21.59-61.62j	19.91+14.71j	35.66+63.99j
Breaker BR1 (A)	144.68-338.94j	-255.77+48.63j	173.28+264.82j
Breaker BR2 (A)	-69.29+180.16j	159.82-21.18j	-95.30-137.84j
Breaker BR3 (A)	-53.77+97.15j	115.83-12.77j	-42.34-63.00j

From the values given on the table above, we can compute the differential currents on zone 1.

Actual differential current on phase A (Idiff_A)

On Eq.IV.12.a, the expression $(\underline{I_{inj_A}} - \underline{I_{load_ext_A}})$ represents the difference between the total current injected on phase A of one zone and the total current retrieved from the zone while the expression

$(\underline{I_{load_int_A}} + \underline{I_{cap_bank_A}} + \underline{I_{stor+_A}} - (\underline{I_{gen_int_A}} + \underline{I_{stor-_A}}))$ is the total internal (load - generation) on phase A of the same zone.

$(\underline{I_{inj_A}} - \underline{I_{load_ext_A}})$ is obtained by adding the currents given at the zone borders.

The current summation at zone 1 borders gives :

$$(\underline{I_{inj_A}} - \underline{I_{load_ext_A}}) = 21.62-61.63j \text{ for phase A}$$

$$(\underline{I_{inj_B}} - \underline{I_{load_ext_B}}) = 19.88+14.68j \text{ for phase B}$$

$$(\underline{I_{inj_C}} - \underline{I_{load_ext_C}}) = 35.64+63.98j \text{ for phase C}$$

Therefore, the differential current I_{diff_A} is close to zero as $(I_{inj_A} - I_{load_ext_A})$ is equal to $(I_{load_int_A} + I_{cap_bank_A} + I_{stor+_A} - (I_{gen_int_A} + I_{stor-_A}))$. Same for phases B and C.

Actual restraining current on phase A (I_{restr_A})

Similarly, the value of the restraining currents can be computed based on Eq.IV.15.a, Eq.IV.15.b and Eq.IV.15.c.

	Zone 1 - Phase A	Zone 1 - Phase B	Zone 1 - Phase C
Computed Restraining current (A)	368.94	281.42	316.60

The rated currents computed by the Python script are given below:

	Zone 1 - Phase A	Zone 1 - Phase B	Zone 1 - Phase C
Computed rated current (A)	(74.9+37.4j)	(16.65+8.32j)	(66.61+33.30j)
Module of the Computed rated current (A)	83.71	18.55	74.46

Therefore, expressing the previously computed restraining currents on phases A, B and C related to phase rated currents, we obtain:

	Zone 1 - Phase A	Zone 1 - Phase B	Zone 1 - Phase C
Computed restraining current in relation of rated current	$\frac{368.94}{83.71} = 4.4 \times I_{n_A}$	$\frac{281.42}{18.55} = 15.17 \times I_{n_B}$	$\frac{316.6}{74.46} = 4.25 \times I_{n_C}$

Secondly, the differential and restraining pick-up settings defined on sections V.3.1.1 (for differential threshold I_{s1}), and V.3.1.3 (for restraining threshold I_{s2}) must be evaluated.

I_{s1_A} = differential current pick-up setting on phase A. It is set to 10% of the phase A rated current = (7.49+3.74j). We get $|I_{s1_A}| = 8.37A = 0.1 \cdot I_{n_A}$

I_{s2_A} = restraining current pick-up setting on phase A. It is set to 120% of the phase A rated current = (89.88+44.88j). We get $|I_{s2_A}| = 100.46\text{A} = 1.2 \cdot I_{n_A}$

To complete the drawing of the differential protection operating characteristic, the slopes k_1 and k_2 are added as defined in V.3.1.2 ($k_1=30\%$, $k_2=80\%$). Same principles apply to phases B and C.

For remind, the zone differential protection trips should the conditions described on Eq.IV.16a, Eq.IV.16b be met for phase A, Eq.IV.17a, Eq.IV.17b be met for phase B, Eq.IV.18a and Eq.IV.18b be met for phase C.

Finally, Fig V.3 gives the ZDP operating point (represented by a black cross) on each phase of zone 1, at the first simulation step.

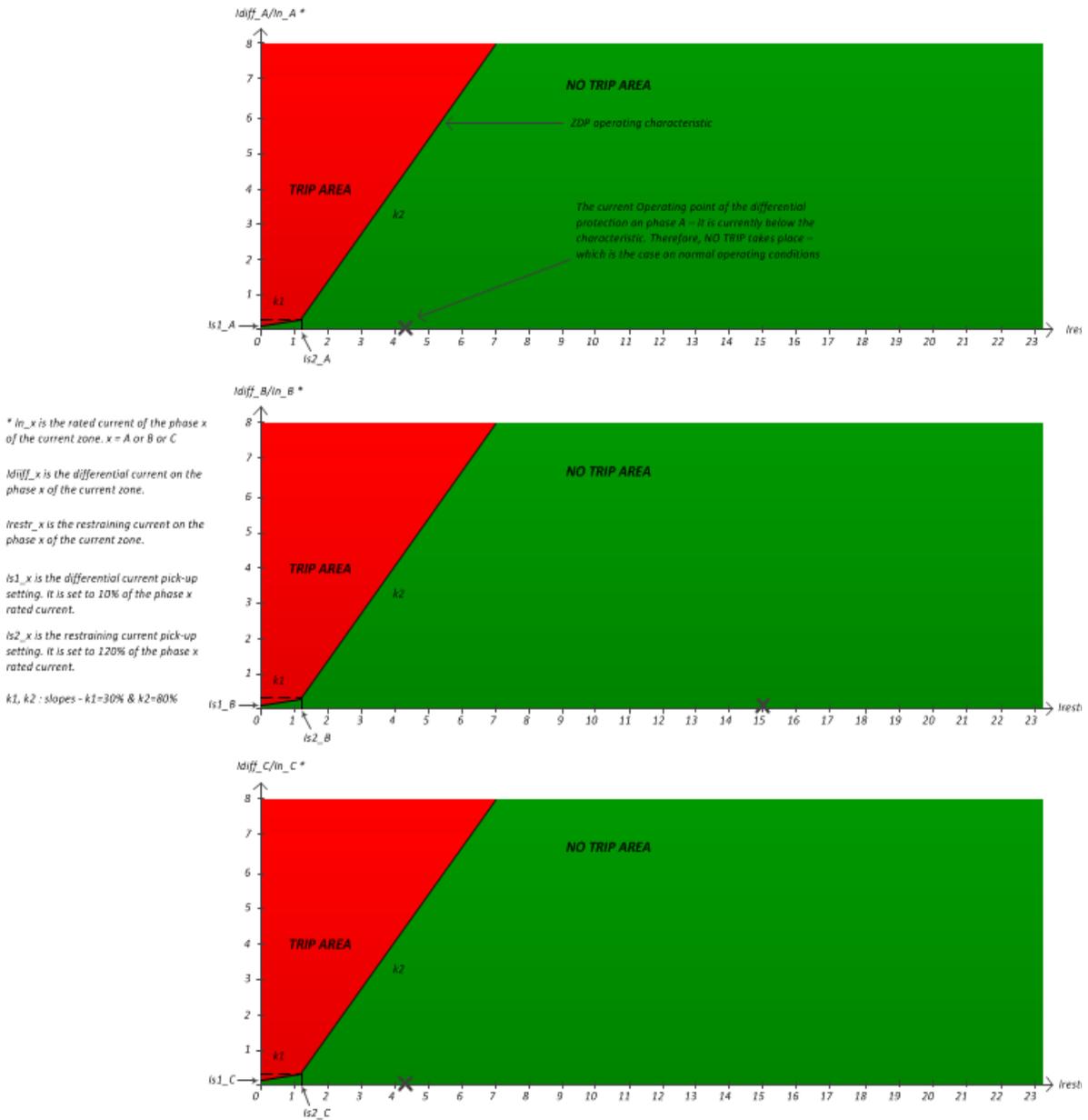


Fig V.3 – ZDP operating points of zone 1 – Normal power flow – Simulation step 1

The zone differential protection (ZDP) will only trip if Eq.16.b or Eq.17.b or Eq.18.b are satisfied. In other words, if the operating point falls within the “trip area”. However, as shown on Fig V.1, the operation point on each phase is always in the “NO TRIP AREA”. Therefore, the ZDP does not trip in this case. This behaviour is normal as the ZDP is expected to be stable on normal operating conditions. See more results on appendix B6 for SP1.

V.4.1.7. Short-circuit simulations in SP1

Following the same process as previously, short-circuit simulations are conducted to check the behaviour of the ZDP during abnormal conditions. The simulations include several direct and resistive faults at different buses of the reference network. The following faults have been simulated :

Fault number	Fault location		Phases involved	Fault resistance (Ω)
	Bus	Zone		
1	35	3	AB	0
2	35	3	AB	50
3	61s	6	ABC	0
4	78	4	BC	100
5	450	4	ABC	0

The simulation results of the fault number 1 are given below with a focus on zone 1. (see appendix B7 for more results on simulation package SP1) :

	Zone 1 - Phase A	Zone 1 - Phase B	Zone 1 - Phase C
Total internal (load – gen) (A)	457.38+311.3j	659.55-130.17j	563.22+60.92j
Breaker BR1 (A)	150.9-4512.31j	-2611.91+3622.32j	744.44+301.55j
Breaker BR2 (A)	-161.74-273.21j	-238.25+241.28j	-127.23-157.73j
Breaker BR3 (A)	468.23+5096.83j	3509.71-3993.77j	-54-82.91j

From the values given on the table above, we can compute the differential currents on zone 1.

Actual differential current (I_{diff_A}) on phase A

$$\left(\underline{I}_{inj_A} - \underline{I}_{load_ext_A} \right) = 457.39+311.31j \text{ for phase A}$$

$$\left(\underline{I}_{inj_B} - \underline{I}_{load_ext_B} \right) = 659.55-130.17j \text{ for phase B}$$

$$\left(\underline{I}_{inj_C} - \underline{I}_{load_ext_C} \right) = 563.21+60.91j \text{ for phase C}$$

Therefore, compared to the (load-gen) currents on the corresponding phases given on the previous table, the actual differential current is nearly zero.

Actual restraining current (I_{restr_A}) on phase A

The restraining current is given below:

	Zone 1 - Phase A	Zone 1 - Phase B	Zone 1 - Phase C
Computed Restraining current (A)	5251.94	5396.97	835.65

Therefore, expressing the previously computed restraining currents on phases A, B and C related to phase rated currents, we obtain:

	Zone 1 - Phase A	Zone 1 - Phase B	Zone 1 - Phase C
Computed restraining current in relation of rated current	$\frac{5251.94}{83.71} = 62.7 \times I_{n_A}$	$\frac{5396.97}{18.55} = 290.8 \times I_{n_B}$	$\frac{835.65}{74.46} = 11.2 \times I_{n_C}$

The results show that the ZDP does not issue a trip command for isolating zone 1. Fig.V.4 shows that the operating point is in the “no trip area” of the operating characteristic.

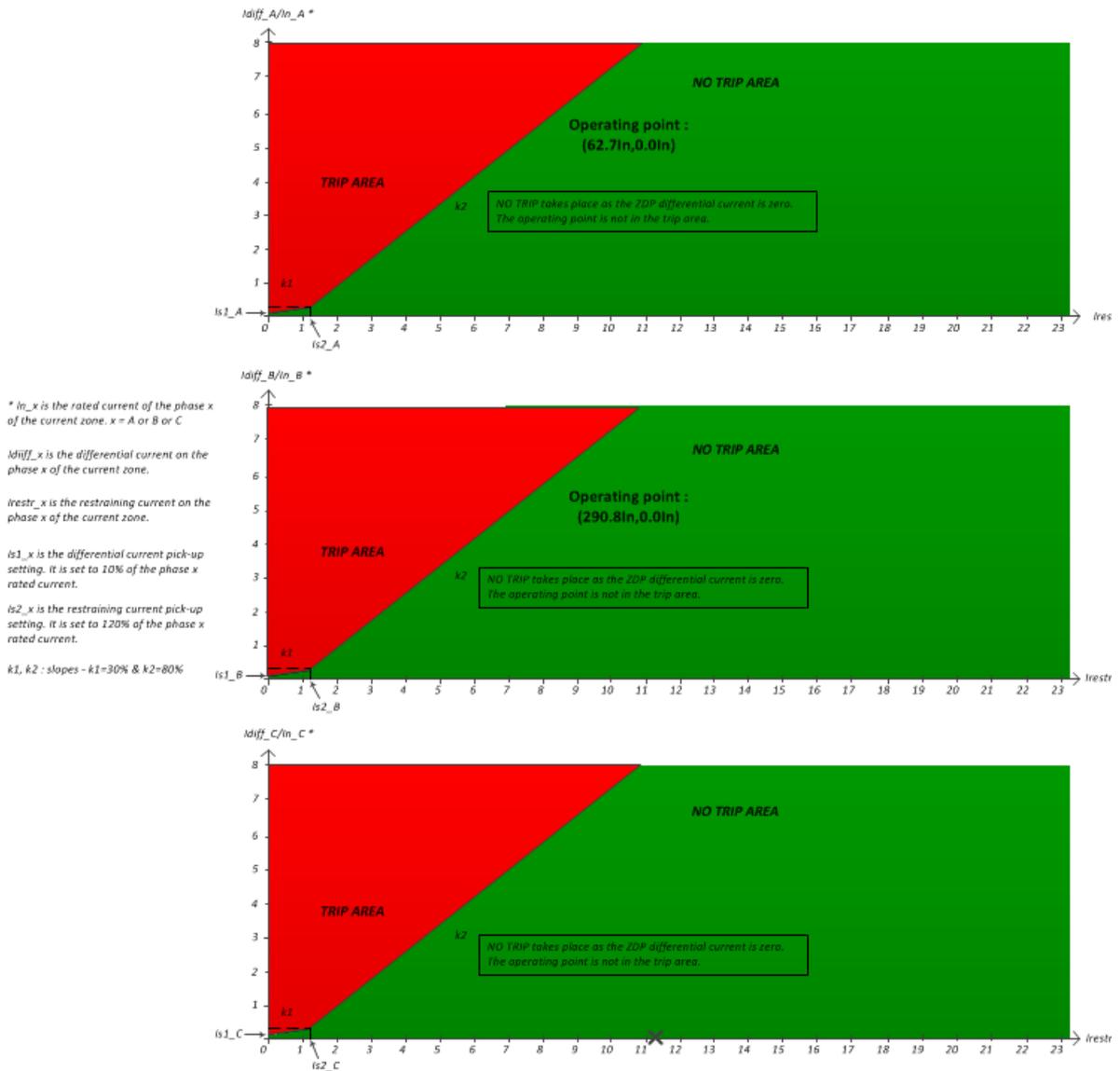


Fig V.4 – ZDP operating points of zone 1 – Short-circuit simulations – AB fault on bus 35 in zone 3 – Fault resistance = 0

ZDP operating time:

The ZDP is executed sequentially, meaning that the differential function is applied to each zone, one at a time. Table V.1 gives the ZDP operation time for each faulty zone. The operating time we are referring to in table V.1 is the time between the fault detection and the ZDP decision.

Fault number	Fault location		Phases involved	Fault resistance (Ω)	ZDP operating time in faulty zone (ms)
	Bus	Zone			
1	35	3	AB	0	136.39
2	35	3	AB	50	158.79
3	61s	6	ABC	0	116.23
4	78	4	BC	100	200.77
5	450	4	ABC	0	216.60

Table V.1 – ZDP operating time obtained for faults on zones 3, 6 and 4

V.4.2. Simulations in simulation package SP2

Similarly to SP1, the same preliminary checks are conducted in SP2. See appendices C1 to C5.

V.4.2.1. Modified reference network model

In the appendix C1, an extract of the newly added parts is given. New power system components have been added to the initial reference network as follows:

- Addition of a single phase load connected to phase B at bus 251 in zone 3
- Addition of a single phase load connected to phase B at bus 185 in in zone 4
- Addition of a three phase line segment between buses 151 and 251 in zone 3
- Addition of a three phase line segment between buses 85 and 185 in zone 4

V.4.2.2. Graph of the modified network

The modified network is then translated into its equivalent graph as in simulation package (SP1) for future zones creation. See the illustration in appendix C3 for the simulation package SP2.

V.4.2.3. Zones creation in SP2

Following the construction of the new graph, Python generates the different zones composing the graph. A snapshot of each created zone in SP2 is given in

Appendix C4 along with the borders. For each zone, the breakers/reclosers at borders are shown based on the connectivity data into the previous graph.

V.4.2.4. OpenDSS netlist of the modified reference network in SP2

The OpenDSS netlist has been automatically created from the modified reference network to allow network simulations. An extract of the netlist containing the added elements is given in appendix C5 for SP2.

V.4.2.5. Normal sequential power flow simulations in SP2

The results are given below where only zone 1 is illustrated (see appendix C6 for more results on simulation package SP2) :

Current flow :

	Zone 1 - Phase A	Zone 1 - Phase B	Zone 1 - Phase C
Total internal (load – gen) (A)	25.18-72.13j	14.83+15.24j	40.55+77.35j
Breaker BR1 (A)	174.40-381.96j	-282.58+46.30j	186.55+310.24j
Breaker BR2 (A)	-96.76+211.99j	188.47-18.92j	-98.79-162.76j
Breaker BR3 (A)	-52.42+97.83j	108.92-12.17j	-47.21-70.14j

Actual differential current on phase A (I_{diff_A})

Applying the same process as in the simulation package 1 (SP1), we get:

$$\left(\underline{I_{inj_A}} - \underline{I_{load_ext_A}} \right) = 25.22-72.14j \text{ for phase A}$$

$$\left(\underline{I_{inj_B}} - \underline{I_{load_ext_B}} \right) = 14.81+15.21j \text{ for phase B}$$

$$\left(\underline{I_{inj_C}} - \underline{I_{load_ext_C}} \right) = 40.55+77.34j \text{ for phase C}$$

Therefore, the differential current I_{diff_A} is close to zero as $\left(\underline{I_{inj_A}} - \underline{I_{load_ext_A}} \right)$ is

equal to $\left(\underline{I_{load_int_A}} + \underline{I_{cap_bank_A}} + \underline{I_{stor+_A}} - \left(\underline{I_{gen_int_A}} + \underline{I_{stor-_A}} \right) \right)$. Same for phases B and

C.

Actual restraining current on phase A (I_{restr_A})

Similarly, the value of the restraining currents are given below :

	Zone 1 - Phase A	Zone 1 - Phase B	Zone 1 - Phase C
Computed Restraining current (A)	420.15	303.31	362.14

The rated currents computed by the Python script in zone 1 are given below:

	Zone 1 - Phase A	Zone 1 - Phase B	Zone 1 - Phase C
Computed rated current (A)	(74.9+37.4j)	(16.65+8.32j)	(66.61+33.30j)
Module of the Computed rated current (A)	83.71	18.55	74.46

Therefore, expressing the previously computed restraining currents on phases A, B and C related to phase rated currents, we obtain:

	Zone 1 - Phase A	Zone 1 - Phase B	Zone 1 - Phase C
Computed restraining current in relation of rated current	$\frac{420.15}{83.71} = 5 \times I_{n_A}$	$\frac{303.31}{18.55} = 16.3 \times I_{n_B}$	$\frac{362.14}{74.46} = 4.8 \times I_{n_C}$

Fig.V.5 gives the ZDP operating point (represented by a black cross) on each phase of zone 1, at the first simulation step. As illustrated on Fig.V.5, the operating point is within the “NO TRIP AREA” of the ZDP for all three phases A, B and C. Therefore, no trip takes place which is normal during normal operating conditions. See more results on appendix C6 for SP2.

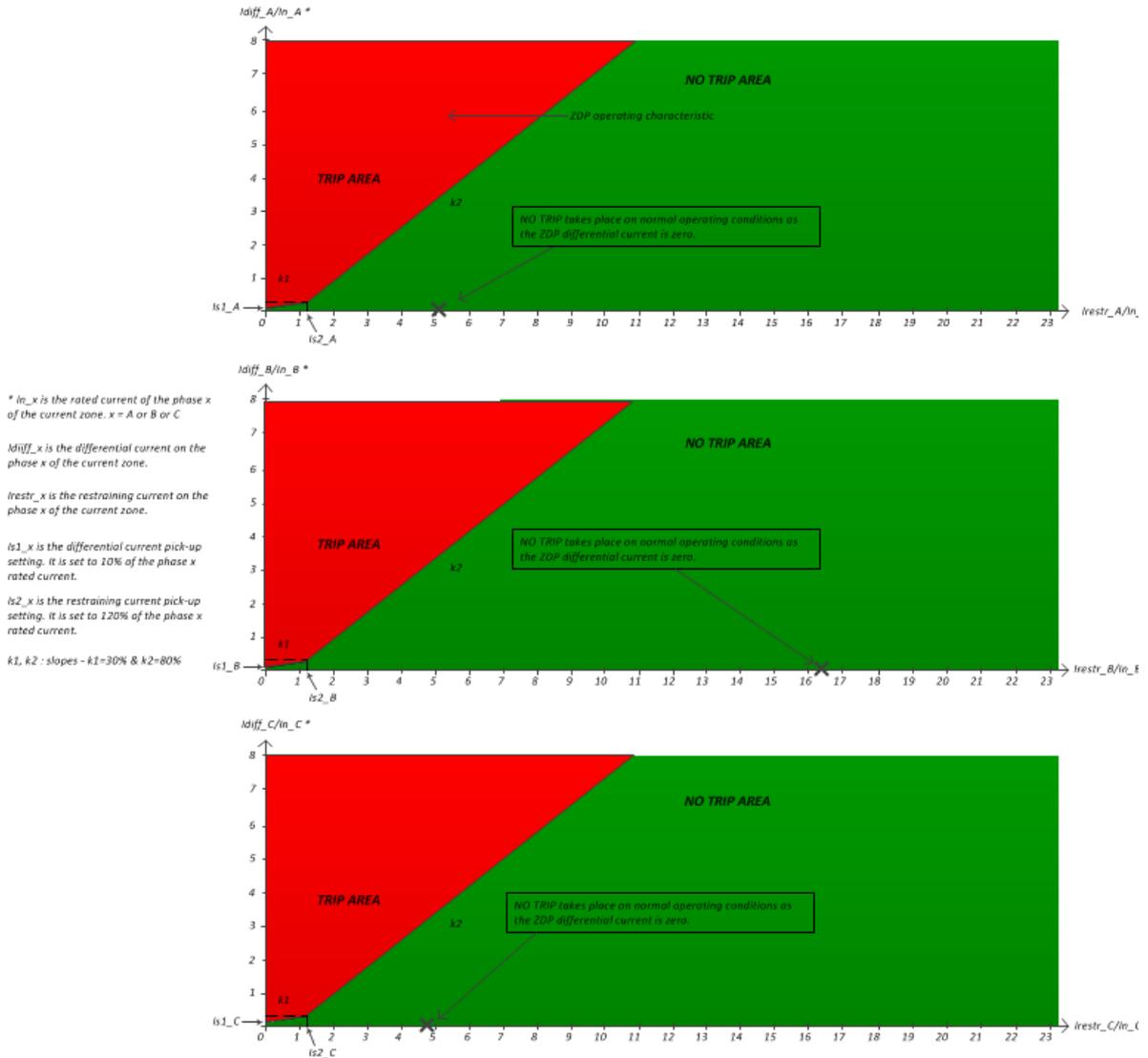


Fig V.5 – ZDP operating points of zone 1 – Normal power flow –
Simulation step 1 – SP2

V.4.2.7. Short-circuit simulations in SP2

The results of the first fault simulation are given below. A fault is simulated on the newly added bus 251 in zone 3. However, for all the other zones 1, 2, 4, 5 and 6, the ZDP is supposed to be stable. Zone 1 will be used to illustrate the stability for external faults while zone 3 will be used to illustrate the trip within the faulty zone. Fig.V.6 gives the graph representation of zone 3 in SP2.

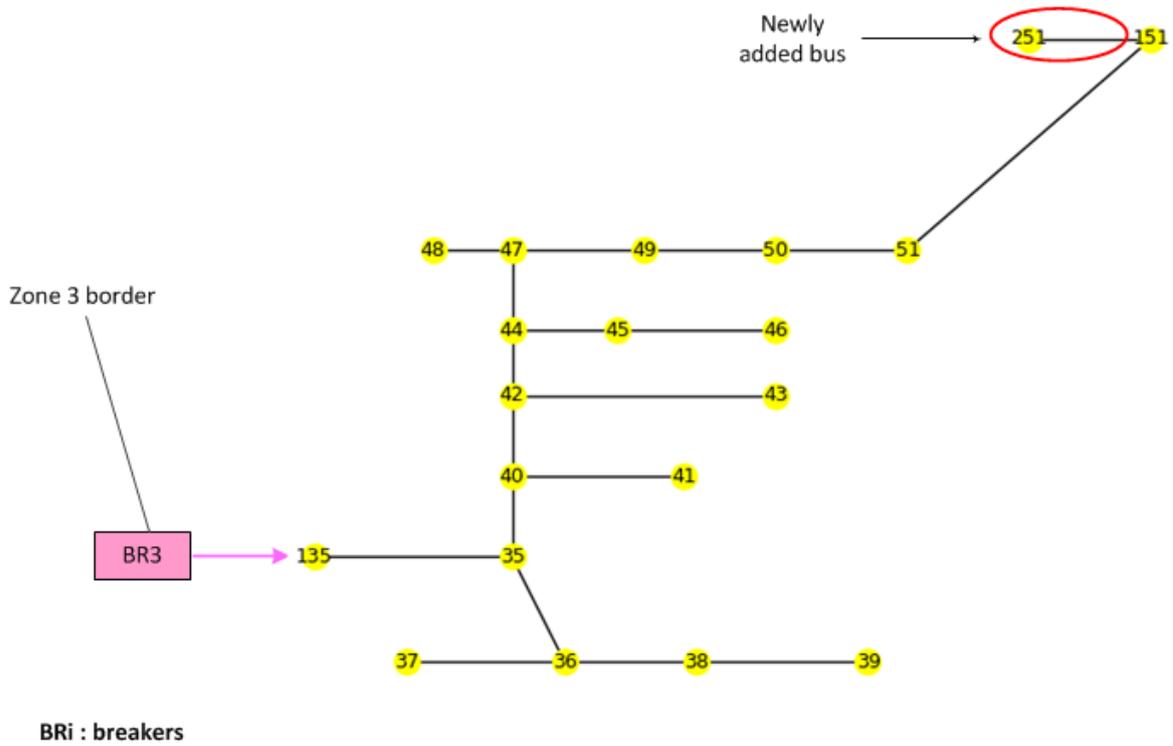


Fig.V-6 – Graph representation of zone 3

The fault characteristics are shown in the table below.

Fault number	Fault location		Phases involved	Fault resistance (Ω)
	Bus	Zone		
1	251	3	B	50

Current flow during short-circuit:

	Zone 1 - Phase A	Zone 1 - Phase B	Zone 1 - Phase C
Total internal (load – gen) (A)	42.35-83.53j	13.47+22.25j	50.95+88.94j
Breaker BR1 (A)	295.82-384.75j	-358.88-47.01j	130.23+387.96j
Breaker BR2 (A)	-190.58+181.35j	195.8+67.33j	-22.98-218.20j
Breaker BR3 (A)	-62.89+119.84j	176.54+1.88j	-56.31-80.85j

From the values given on the table above, we can compute the differential and restraining currents on zone 1.

Actual differential current on phase A (Idiff_A)

Applying the same process as in the simulation package 1 (SP1), we get:

$$\left(I_{inj_A} - I_{load_ext_A} \right) = 42.35-83.56j \text{ for phase A}$$

$$\left(I_{inj_B} - I_{load_ext_B} \right) = 13.46+22.2j \text{ for phase B}$$

$$\left(I_{inj_C} - I_{load_ext_C} \right) = 50.94+88.91j \text{ for phase C}$$

Therefore, the differential current Idiff_A is close to zero as $\left(I_{inj_A} - I_{load_ext_A} \right)$ is equal to $\left(I_{load_int_A} + I_{cap_bank_A} + I_{stor+_A} - \left(I_{gen_int_A} + I_{stor-_A} \right) \right)$. Same for phases B and C.

Actual restraining current on phase A (Irestr_A)

Similarly, the value of the restraining currents are given below :

	Zone 1 - Phase A	Zone 1 - Phase B	Zone 1 - Phase C
Computed Restraining current (A)	488.7	385.78	414.83

Therefore, expressing the computed restraining currents on phases A, B and C related to phase rated currents, which is the same as in SP1 for zone 1 , we obtain:

	Zone 1 - Phase A	Zone 1 - Phase B	Zone 1 - Phase C
Computed restraining current in relation of rated current	$\frac{488.7}{83.71} = 5.8 \times In_A$	$\frac{385.78}{18.55} = 20.8 \times In_B$	$\frac{414.83}{74.46} = 5.6 \times In_C$

Fig.V.7-a and Fig.V.7.b gives the ZDP operating point (represented by a black cross) on each phase for respectively zone 1 and zone 3. As shown on Fig.V.7-a, the operating point is zone 1 is within the “NO TRIP AREA” for phases A, B and C. See more results on appendix C7 for SP2.

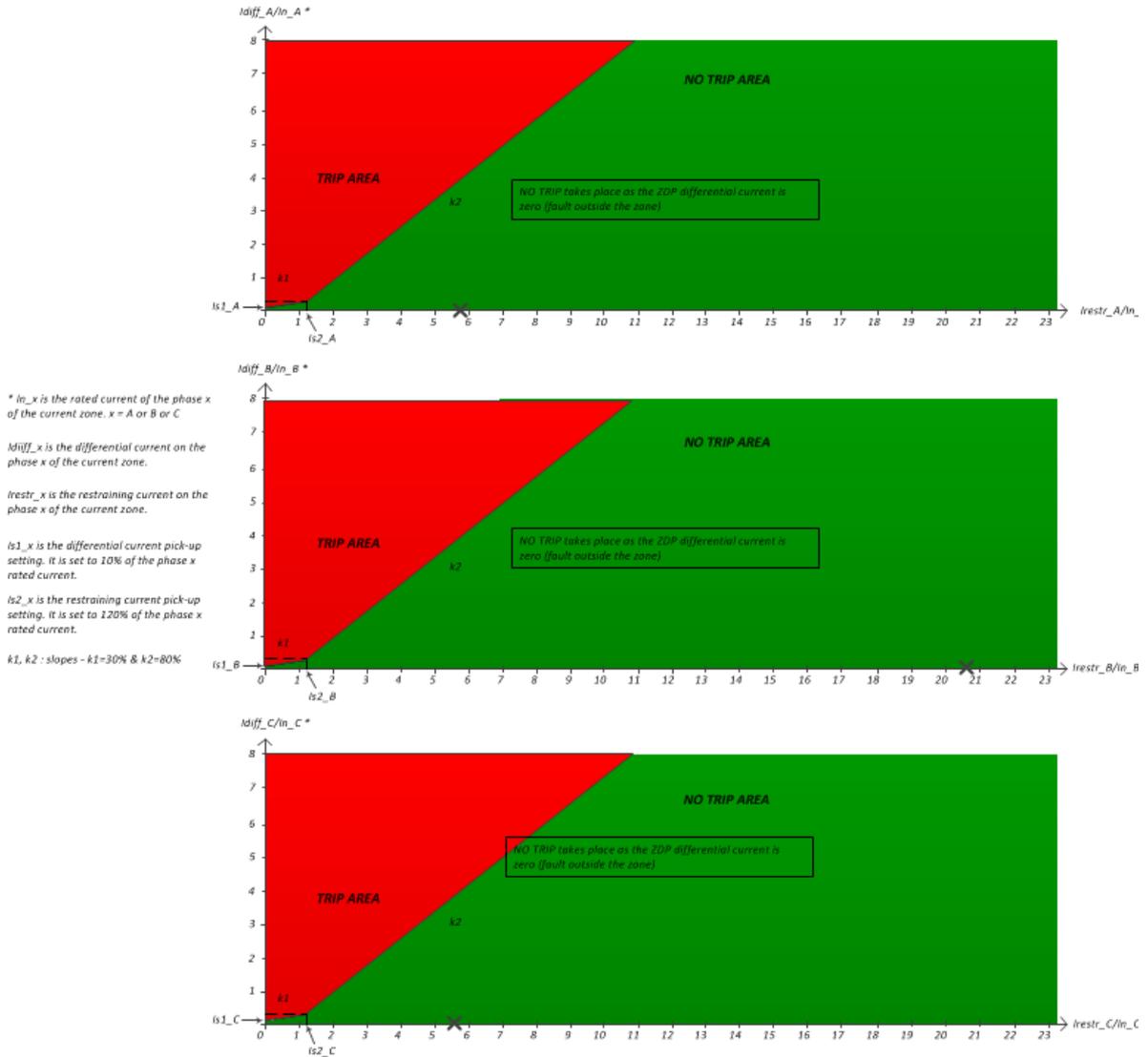


Fig V.7-a – ZDP operating points of zone 1 for a BN fault, bus 251 in zone 3

However, the trip occurs on the faulty zone 3. See Fig.V.7-b.

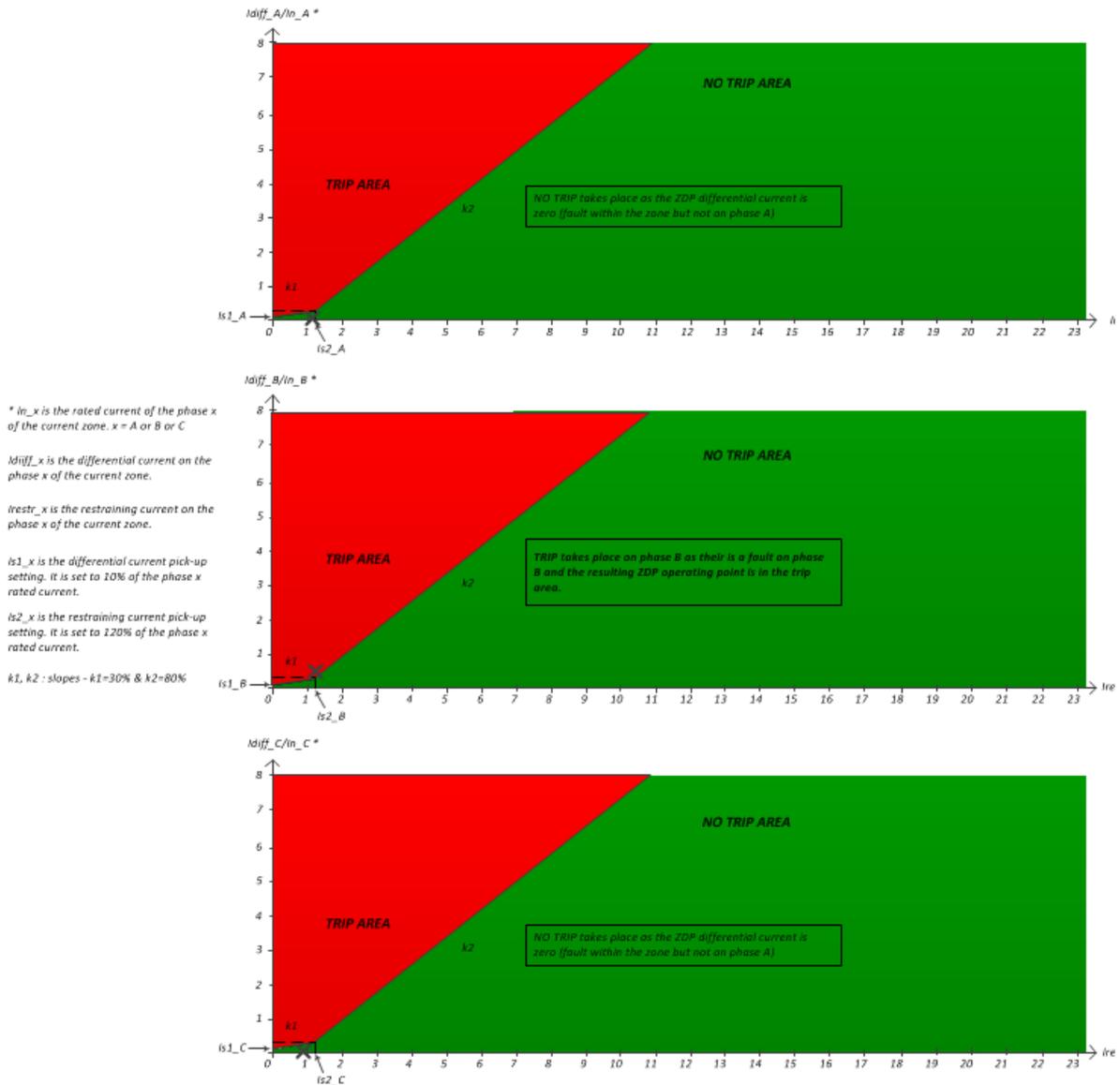


Fig V.7-b – ZDP operating points of zone 3 for an in-zone BN fault, bus 251

Fig.V.7-b shows that the ZDP trips on phase B as the operating point is within the “TRIP AREA”. However, the ZDP remains stable on sound phases A and C.

ZDP operating time:

The operating time of the ZDP for the fault on bus 251 in zone 3 is 176.8ms. See appendix C7 for results on the other zones.

V.5. Conclusions on simulation results

The simulations conducted in this chapter show that the new concept of Zone Differential Protection (ZDP) proposed could ensure a good protection coordination in distribution feeders with embedded distributed generation. The behavior of the ZDP have been reported under steady state sequential power flow and short-circuit based on the reference network model. In addition, the same simulations have been performed on the modified version of the reference network model in order to check the incremental aspect or how the modifications are enrolled into the ZDP. The ZDP operation times range between 110 and 220ms over different zones. However, this operating time is high, partly due to the script that has been added for the determination of the electric current direction (see section IV.9), before the computations of differential currents. Consequently, even though the unfaulty zones do not trip their border(s) for external faults, the generating sources within those sound zones will trip.

The implementation of the Zone Differential Protection was complex as several difficulties had to be overcome amongst which:

- The reformulation of the basic principle of differential protection based on Kirchhoff's current law stating that the current flowing into a node must be equal to the current flowing out of it. However, a zone has internal loads and distributed generation along with external current injection(s) and loads. Therefore, an adaptation of the basic principle was required;
- The zone creation was also a challenge. The graph representation of the distribution feeder was a great help to the zone creation;
- The unbalance of loads had to be accounted for as our reference network consisted of single phase, two phase and three phase equipment connected in delta or star;
- The management of changes in the incoming network model is a 'must' especially when the feeder automation functions is expected to integrate modifications 'on the fly' during operation;

Chapter VI : General Conclusions and Perspectives

VI.1. Conclusions

The presence of DERs (Distributed Energy Resources) on traditionally passive distribution networks has not only brought changes on the energy supply paradigm but also on automation functions such as protection coordination, Volt/Var/Watt control to name a few. Adverse effects of distributed on the protection coordination on the distribution feeder has been highlighted, leading to the need for a new protection coordination paradigm. This research work has brought the following key contributions:

- Proposition of a new mindset consisting in providing the distribution feeder with knowledge on the electric circuit it is supplying. This knowledge is centralized at the Control Center which uses the CIM (Common Information Model) data model. The scenario was to transfer, to the distribution feeder, its network model from the Control Center to help it perform some automation functions (protection coordination, Volt/Var/Watt control, etc.). However, because the distribution feeder data model is based on IEC 61850, the harmonization between CIM and IEC 61850 was required. The proposed mindset have been applied to protection coordination to show its applicability. However, it could also be applied to other feeder automation functions amongst which the Volt/Var/Watt control;
- Analysis of CIM and IEC 61850 data models and design of a model transformation engine allowing the network model transfer to the feeder;
- Based on the transferred knowledge, a new protection scheme called Zone Differential Protection (ZDP), located at the head of the feeder, have been investigated and applied to a modified version of the IEEE 123 nodes test feeder to assess its behavior during steady state power flow and disturbances. The chapters IV et V discussed the main developments in terms of modeling and simulations on the proposed ZDP. The simulations have shown the stability of the ZDP under normal power flow. During faulty conditions, the ZDP does not trip sound zones borders for external faults. However, the high operating time of the ZDP (between 116 and 216ms) will

create an unavailability of distributed generation within sound zones. As already discussed, the high operation time can be reduced if the power system simulator used, gives the current flow direction;

- The proposed network model transfer enables a network model continuity between the Control Center and the feeder automation functions, then allowing, an update 'on the fly' of the envisioned feeder automation functions. Needless to say that IEC 61850 and CIM data model are not currently aligned on aspects related to the protection and communication. However, harmonization between the IEC 61850 and CIM are still ongoing at IEC level.
- Proposition to have the same method of identifying power system components on CIM and IEC 61850. In fact, the current IEC 61850 model uses a 'name' attribute to identify the power system components, meaning that if for example the name of a component is changed by the IEC 61850 System engineer, The Control Center does not know if this component represents a new component or the same one but with a new name. In the simulations conducted, an 'ID' attribute has been added to each IEC 61850 power system component as the counterpart of the CIM *mRID* (master ID) attribute.

In addition, some recommendations related to IEC 61850 and CIM data models are given below to facilitate the implementation of the concept.

Recommendations related to IEC 61850:

- IEC SCL does not allow for a distribution feeder (line container) to contain substations which are containers themselves; several MV/LV distribution substations can be connected to a distribution feeder. Therefore, it should be possible to represent a distribution substation as a container, then connect it to a feeder;

- In IEC61850, the fact that the name of an object plays the role of its ID may be confusing during the conversion of the CIM incoming network model to IEC61850 SCL. As a result, we recommend adding an 'ID' attribute to each IEC 61850 object and align its reference to the **mRID** from the CIM incoming network model.

Recommendations related to IEC CIM:

- Also, to be able to fully tie the feeder automation functions to the incoming network model, some enhancements must be brought to the CIM model particularly the communication aspects. Communication parameters such as IP address, VLAN (Virtual Local Area Network), MAC address do not currently exist in the CIM model. Therefore, their addition could be a real enhancement for the feeder automation.
- In addition, the protection and control model is incomplete in CIM. In fact, the proposed protection functions are very limited, making difficult if not impossible the specification of protection functions on a feeder. The extension of the protection and control model could facilitate the generation of the IEC 61850 SCL files.

VI.2. Perspectives

The zone differential protection brings a solution to the protection coordination on active distribution feeders. However, due to time constraints, many aspects have not been covered. Therefore, further simulations are required to prove the reliability of the zone differential protection. There are many perspectives to this research work. The following directions could be dug:

- The integration of the advanced metering infrastructure (AMI) into the distribution feeder automation could increase the observability level on the distribution network and improve the accuracy of the calculations performed by the differential protection scheme. AMI is the infrastructure by which timestamped meter data are remotely collected periodically. For the purpose of the zone differential protection, the collected meter data will be transferred to the feeder controller. Two main constraints need to be considered. Firstly, the metering system should be able to transfer the load current measurements at a periodicity adequate for time critical applications such as the zone differential protection. Secondly, a harmonization between the data model used on the feeder (IEC 61850) and the data model used for metering (COSEM) is needed. Accurate load models could be used in lieu and place of harmonization. However, the lack of standardization could be a drawback to its wide adoption;
- The Phasor Monitoring Unit into a Wide Area Monitoring System to allow the transmission of electric current values and breakers status from peripheral units to the feeder controller (central unit) would be a large enhancement. The time latencies considerations during the currents transmission through routers would be of major support for the ZDP.
- The zone invariance may be reformulated by considering the presence of sectionalizers on some laterals or sub-laterals of each zone; this could significantly improve the reliability indicators;
- The dynamic updating of the differential protection following a change of jurisdiction on one zone, more specifically when one zone is transferred to a back-up distribution feeder. In fact, the electric currents from the zone

peripheral unit(s) need to be redirected to the central unit of the back-up distribution feeder;

- The management of the evolution in the incoming network model needs to be improved. Whenever the network model is received from the Control Center, the feeder controller rebuilds the graph of the whole network which is time consuming. It could be interesting to investigate a new approach to only update the modified part of the network model;
- The system management aspects for the automatic updating of the protection devices to account for firmware updates;
- The online maintenance of the protection devices involved in the protection coordination without sacrificing the reliability of the protection coordination;
- The use of parallel computing for a distribution feeder with several interconnected zones. Our simulations have been done based on a sequential algorithm, meaning that the differential protection computations are applied to each zone instead of applying it simultaneously to all zones;
- The cost benefit analysis (CBA) needs to be covered. In fact, the benefits of a zone differential protection must not only be examined from the technical point of view, an economic assessment is also necessary.
- Dynamic simulations including the transient models of generators in order to consider the grid code constraints on generators.

Bibliography

- [1] N. Hadjsaid, J. Canard and F. Dumas, "Dispersed generation impact on distribution networks," in *IEEE Computer Application in Power*, April 1999.
- [2] M. Uslar, M. Specht, S. Rohjans, J. Trefke and J.M. Gonzalez, *The Common Information Model CIM: IEC 61970, 61968 and 62325*, Springer Heidelberg, 2012.
- [3] EURELECTRIC, "DSO priorities for Smart Grid standardization, An EURELECTRIC position paper," 2013.
- [4] IEC TR 62357-1-, "Power systems management and associated information exchange – Part 1: Reference architecture, Edition 2.0," IEC, 2016.
- [5] IEC TS 62361-102 Edition 2 – DC, "Power system management and associated information exchange – Interoperability in the long term – Part 2: CIM-IEC 61850 harmonization - Edition 2 – DC," IEC, 2020.
- [6] CEN-CENELEC-ETSI, Smart Grid Coordination Group, "Smart Grid Reference Architecture", 2012.
- [7] J.C.Sabonnadière and N. Hadjsaid, "SmartGrids – Les reseaux électriques intelligents", Hermes Science Publications, 2012.
- [8] IPCC, "Climate change 2021 – The Physical Science basis – Summary for policy makers - Assessment report AR6," IPCC, 2021.
- [9] AFNOR, "NFC 18510 - Opérations sur les ouvrages et installations électriques et dans un environnement électrique - Prévention du risque électrique," AFNOR Editions, 2012.
- [10] P. Fonti, "Transformateurs de courant, Erreurs de spécification et solutions, CT 195," 2001.
- [11] IEEE, "P1547/ D6.0 - Draft Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power System Interfaces," IEEE, 2016.
- [12] P. Kundur, *Power System Stability and Control*, McGraw-Hill Education, 2006.
- [13] J. Keller and B. Kroposki, "Understanding Fault Characteristics of Inverter-Based Distributed Energy Resources, National Renewable Energy Laboratory (NREL), Technical Report NREL/ TP-550-46698," 2010.
- [14] IEEE PES (Power & Energy Society), "IEEE PES AMPS DSAS Test Feeder Working Group, IEEE 123 nodes test feeder, version 03 Feb 2014", [Online]. Available: <http://sites.ieee.org/pes-testfeeders/resources/>. [Accessed 16 January 2020].

- [15] A. Croguennoc, "Protection des réseaux à moyenne tension de distribution publique, D4810," in *Techniques de l'ingénieur*, 1991.
- [16] P. P. Barker and R. W. De Mello, "Determining the Impact of Distributed Generation on Power Systems, I. Radial Distribution Systems, pp. 1645-1656," in *Proceedings of IEEE Power Engineering Society Summer Meeting, Seattle, Vol. 3*, 16-20 July 2000.
- [17] ENTSO-E, "Implementation guideline for network code, Requirements for grid connection applicable to all generators," 2013. [Online]. Available: https://www.entsoe.eu/network_codes/rfg/. [Accessed 15 12 2019].
- [18] L. Guise, "Grid codes, Evolution and potential impacts," Schneider Electric, March 2016.
- [19] A. Sinclair, D. Finney, D. Martin and P. Sharma, "Distance Protection in Distribution Systems: How It Assists With Integrating Distributed Resources," in *IEEE Transactions on Industry Applications*, 2013.
- [20] R. Sirsi and S. Dasarathan, "Application of Fault Current Limiter to limit Distributed Generation effect on Distance Relay Coordination," in *Annual IEEE India Conference INDICON*, 2014.
- [21] B. Li, C. Li, F. Guo, and Y. Xin, "Overcurrent protection coordination in a power distribution network with the active superconductive fault current limiter," in *IEEE Transactions on Applied Superconductivity*, vol. 24, no.5, 2014.
- [22] D.D. Giustina, A. Dedè, A.A. de Sotomayor, and F. Ramos, "Toward an Adaptive Protection System for the distribution grid by using the IEC 61850," in *IEEE International Conference on Industrial Technology (ICIT)*, 2015.
- [23] D. Ishchenko, A. Oudalov, H. Laaksonen, A. Kostianen, S. Sundfors, S. Vahakuopus and H. M. Pekkala, "Practical Implementation of Adaptive Protection and Control in a Medium Voltage Microgrid," in *PAC WORLD*, 2015.
- [24] B.P. Bhattarai, B. Bak-Jensen, S. Chaudhary, and J.R. Pillai, "An Adaptive Overcurrent Protection in Smart Distribution Grid," in *IEEE Eindhoven PowerTech*, 2015.
- [25] E. Lakervi and E. J. Holmes, "Electricity Distribution Network Design", 2nd Edition, IET, 2003.
- [26] AREVA, "Network Protection & Automation Guide", First edition, 2002.
- [27] A. Phadke and S. Horowitz, "Power system relaying", Third edition, John Wiley & Sons, Ltd, 2008.
- [28] F. Sautriau, "Protection des réseaux par le système de Sélectivité Logique, Cahier technique 2," Merlin Gerin, 1990.
- [29] A. Phadke and J. Thorpe, Computer relaying for power systems, 2nd edition, John Wiley & Sons Inc, 2009.

- [30] N. Schaefer, "Impacts of DER on Distribution System Protection, EES-UETP Course, "Protection of Future Networks with Distributed Generation", in *EES-UETP Manchester-UK, 8-10 March, 2011*.
- [31] A. D. A. d. S. F. R. D.D. Giustina, "Toward an Adaptive Protection System for the distribution grid by using the IEC 61850," in *IEEE International Conference on Industrial Technology (ICIT), 2015*.
- [32] IEC, TC57, WG10, "IEC 61850-7-2 IS/ Amendment 1, Power systems management and associated information exchange – Part 7-2: Basic Information and communication structure – Abstract Communication Service Interface (ACSI), Edition 2.0," IEC, February 2020.
- [33] IEC, TC57, WG10,, "IEC 61850 - Communication networks and system in power utility automation – Part 1 – Introduction and overview – Edition 2.0," IEC, March 2013.
- [34] IEC, TC57, "Power system management and associated information exchange, Current and future smart grid standardization activities," [Online]. Available: https://www.iec.ch/resources/tcdash/Poster_IEC_TC57.pdf. [Accessed 12 March 2021].
- [35] IEC, TC57, "IEC TR 62357-1- Power systems management and associated information exchange – Part 1: Reference architecture, Edition 2.0," IEC, November 2016.
- [36] IEC, TC57, "IEC 62361-102 TS: « Power system management and associated information exchange – Interoperability in the long term - Part 2: CIM-IEC 61850 harmonization», " IEC, 2015.
- [37] IEC, TC57, WG10, "IEC 61850-5: 2013 – Amendment 1: 2020 – Power systems management and associated information exchange – Part 5: Communication requirements for functions and device models, Edition 2.0," IEC, May 2020.
- [38] IEC, TC57, WG10, "IEC 61850-6- Power systems management and associated information exchange – Part 6: Configuration description language for communication in power utility automation systems related to IEDs, Edition 2.1," IEC, June 2018.
- [39] IEC, TC57, WG13, "IEC CDV-61970-301- Energy management system application program interface (EMS-API) – Part 301: Common information model (CIM) base, Edition 7, CIM17," IEC, 2019.
- [40] T. Saxton, "CIM Standards overview and its role in the Utility Enterprise," in *CIM Users Group, Amsterdam, Netherlands, 2016*.
- [41] R. C. Dugan, D. Montenegro and A. Ballenti, "EPRI Distribution System Simulator," [Online]. Available: <https://sourceforge.net/p/electricdss/code/HEAD/tree/trunk/Distrib/Doc/OpenDSSManual.pdf>. [Accessed 12 December 2020].
- [42] G. Ziegler, "download.e-bookshelf.de," [Online]. Available: <https://download.e-bookshelf.de/download/0000/6042/27/L-G-0000604227-0002364945.pdf>. [Accessed 3 November 2020].

- [43] S.E. Widergren, A. Devos, J. Zhu, "XML for CIM model exchange," in *22nd IEEE Power Engineering conference*, 2001.
- [44] S. Grijalva, "Co-simulation of decentralized grid control algorithms, Georgia Institute of Technology," in *NIST Transactive Energy Challenge Preparatory Workshop*, March 2015.
- [45] EPRI, "Common Information Model Primer – Fourth Edition - Technical report," EPRI (Electric Power Research Institute), 2018.
- [46] W. Vicente, "Modélisation des réseaux de distribution sous incertitudes, PhD thesis, Institut National Polytechnique de Grenoble," 2012.

APPENDIX A1

Mapping between IEC 61850 and CIM

Appendix A1 – Mapping between IEC 61850 and CIM

Table III-1 – Equipment type codes [37]

Type code	Meaning	Number of terminals (connections to different connectivity nodes)
CBR	Circuit Breaker	2
DIS	Disconnect or earthing switch	2
VTR	Voltage Transformer	1
CTR	Current Transformer	2
PTW	Power Transformer Winding	1/2
PTR	Power Transformer	Implicit via windings
LTC	Load Tap Changer	Part of winding
GEN	Generator	1
CAP	Capacitor Bank	1/2
REA	Reactor	1/2
CON	Converter	1/2
MOT	Motor	1
FAN	Fan	1
PMP	Pump	1
EFN	Earth Fault Neutralizer (Petersen coil)	1
PSH	Power Shunt	2
BAT	Battery	1
BSH	Bushing	2
CAB	Power Cable	2
GIL	Gas Insulated Line	2
LIN	Power overhead line or line segment: line segments connected by connectivity nodes from a line. A line segment within a substation could be used to attach for example special LNs, or physical line properties. For a GIS line segment, GIL could be used instead.	2
RES	Neutral resistor	2
RRC	Rotating Reactive Component	1
SAR	Surge Arrester	1
SCR	Semiconductor Controlled Rectifier	2
SMC	Synchronous Machine	1
TCF	Thyristor Controlled Reactive component	2
IFL	Infeeding Line, substation limiting object; models a possibly infeeding power network line outside the substation at the single line border	1

Appendix A1 – Mapping between IEC 61850 and CIM - continued

Table III-2 – Correspondence between IEC 61850 Logical Nodes and CIM classes adapted from [36], [37]

The table below gives the mapping between IEC 61850 equipment type/Logical nodes to the related CIM classes. The table is not exhaustive as it presents only the equipment involved further in our test feeder.

Equipment Type code	Equivalent Logical Node (LN) in IEC 61850	Logical Node short description	Related CIM classes
CBR	Circuit Breaker	XCBR	Breaker
CTR	Current Transformer	TCTR	CurrentTransformer
PTW	Power Transformer Winding		PowerTransformerEnd
PTR	Power Transformer	YPTR	PowerTransformer
LTC	Load Tap Changer	YLTC	RatioTapChanger (amongst others)
GEN	Generator	ZGEN	GeneratingUnit
CAP	Capacitor Bank	ZCAP	ShuntCompensator
LIN	Power overhead line or line segment: line segments connected by connectivity nodes from a line. A line segment within a substation could be used to attach for example special LNs, or physical line properties. For a GIS line segment, GIL could be used instead.	ZLIN	ACLineSegment
RES	Neutral resistor	ZRES	Resistor
SMC	Synchronous Machine	ZSMC	SynchronousMachine
IFL	Infeeding Line, substation limiting object; models a possibly infeeding power network line outside the substation at the single line border		EnergySource
LOD	Load	DLOD	EnergyConsumer
STO	Storage	DSTO	PowerElectronicUnit
PVA/PVM	Photovoltaic array characteristics/ Photovoltaic module ratings	DPVA/DPVM	PhotoVoltaicUnit
ECP	Electrical Connection Point	DECP	Equipment→Terminal
PCC	Point of Common Coupling	DPCC	Equipment→Terminal
BAT	Battery	DBAT	BatteryUnit
PROT	Protection equipment	Not applicable as the protection equipment is a container of functions (LNs)	ProtectionEquipment

Table III-3 – Equipment name mapping between IEC 61850 and CIM [36]

Attribute	SCL description	CIM mapping
Name	Identification of each object within its container. Must be unique within the container. Must be unique within the file for top level objects.	IdentifiedObject.name Name.name where Name is associated with a NameType "SCL.name"
Desc	User oriented textual designation	IdentifiedObject.description
mRID (Master Resource ID)	Missing.	Globally unique ID

Table III-4 – Geographic position mapping between IEC 61850 and CIM [36]

Attribute	SCL description	CIM mapping
Latitude	Geographic position of device in WGS84 coordinates - latitude	Asset → Location → PositionPoint.xPosition
Longitude	Geographic position of device in WGS84 coordinates - longitude	Asset → Location → PositionPoint.yPosition
Altitude	Geographic position of device in WGS84 coordinates - Altitude	Asset → Location → PositionPoint.zPosition

Table III-5 – Connectivity elements mapping between IEC 61850 and CIM [36]

IEC 61850 connectivity element	CIM mapping
Terminal	Terminal
ConnectivityNode	ConnectivityNode

Appendix A1 – Mapping between IEC 61850 and CIM - continued

Table III-6 – Equipment container mapping between IEC 61850 and CIM [36]

IEC 61850 equipment container	CIM equipment container	Designation
Substation	Substation	Substation container
Line	Line	Line container
VoltageLevel	VoltageLevel	Voltage level container

APPENDIX A2

Basic principle of differential protection

Appendix A2 – Basic principles of differential protection

The basic principle of a differential protection is to compare the magnitude of the current entering a protected area to the magnitude of the current leaving that area. Should the differential current be not zero, a fault is deemed to occur in the protected zone. The differential protection is a direct application of the Kirchhoff's first Law stating that the vector sum of the currents entering the protected area is equal to the vector sum of the currents leaving the protected area. Traditionally, the differential protection is used for the protection of a line, a generator, a motor, a transformer, a reactor, a cable or busbar.

In the Fig.IV-1, the differential protection is applied on a high voltage overhead line just for the sake of illustration. Before analyzing the current flows during normal and abnormal situations, it is important to mention that for a line, there is one differential protection relay at each terminal of the line. Each protection relay calculates the differential current by comparing the current measured locally to the current receives from the protection relay at the other terminal of the line and vice versa. According to this figure, the currents flowing in the line L1 can be expressed as follows

$$\underline{I}_1 = I_{1m} \times \cos(\theta_{11}) + j \times I_{1m} \times \sin(\theta_{11}) \quad \text{Eq. IV.1}$$

$$\underline{I}_2 = I_{2m} \times \cos(\theta_{12}) + j \times I_{2m} \times \sin(\theta_{12}) \quad \text{Eq. IV.2}$$

Where:

- I_{1m} and I_{2m} represent the magnitudes of currents I_1 and I_2
- θ_{11} and θ_{12} represent the phases of currents I_1 and I_2

On normal operating conditions, the current flows from sources to loads as in Fig.IV-1. Alternatively, when a fault appears on line L1, the short-circuit currents flow from the upstream sources to the fault point as indicated on Fig.IV-2. As we can see, the current flow direction is different in the two situations and this will, of course, directly impacts the calculation of the differential current. Therefore, it is useful to establish a convention of direction of current flow. To this end, the direction measured from the busbar onwards along a feeder is taken as positive. However, it is important to mention that the differential protection relay gets the flowing current from a current transformer connected to it which, as its name suggests, transforms the primary current flowing in the line into a secondary current that the relay can withstand. So, the current flow direction will be depending on how the current transformer is connected. On Fig.IV-1, a black dot is represented close to each of the current transformers CT11, CT12, CT21 and CT22 to represent their positive entry point (hot point).

Finally, when the current flows from one busbar to the line and the CT hot point is located at the busbar side, the protection relay considers the flowing current is in the forward direction. Therefore, the polarity is positive, and the current is given a positive sign. Alternatively, when the current flows from the line to the busbar while the CT hot point is still located at the busbar side, the protection relay considers the flowing current is in the backward direction. The polarity is negative, and the current is given a negative sign.

Appendix A2 – Basic principles of differential protection - continued

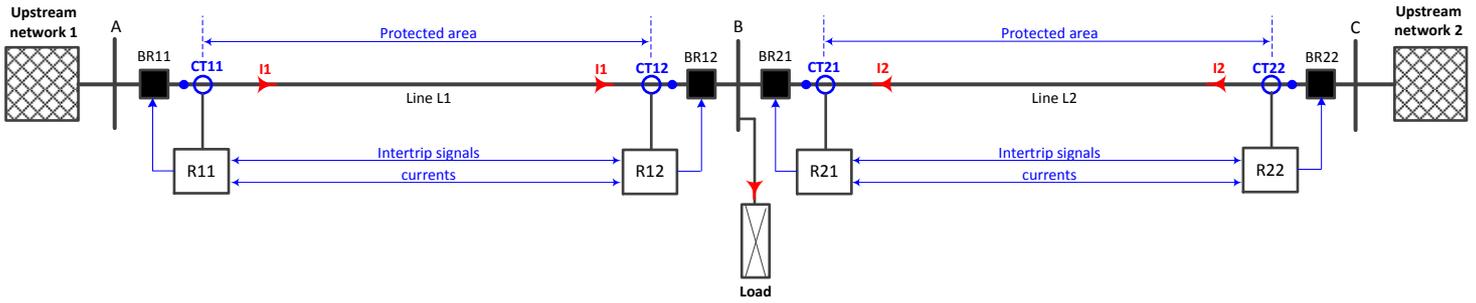


Fig.IV-1 – Current flow direction during normal operating conditions

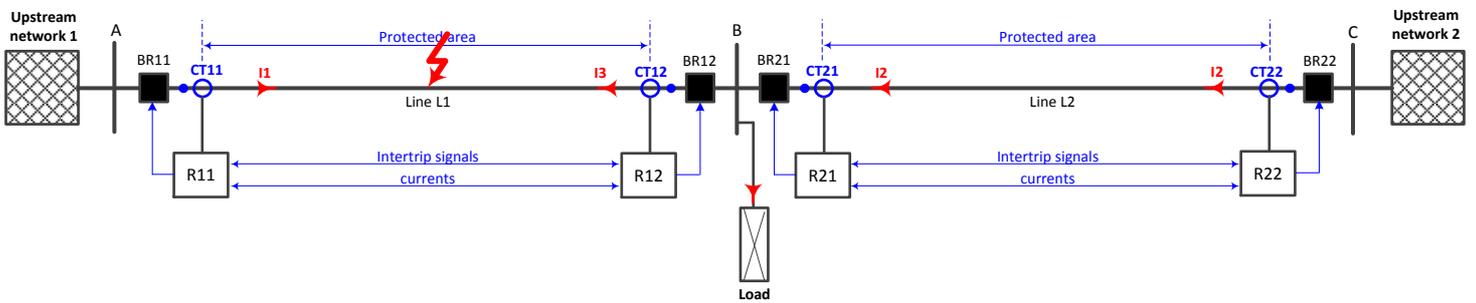
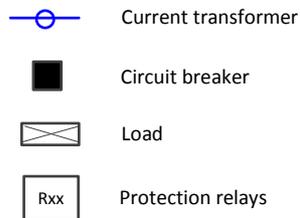


Fig.IV-2 – Current flow direction during fault



Let us assume that I_{diff} is the differential current. Applying Kirchhoff's first law on the circuit on Fig.IV-2 gives, for each phase:

$$I_{diff} = |I_1 + I_2| \quad \text{Eq. IV.3}$$

$$I_{diff} = \sqrt{[\text{Re}(I_1) + \text{Re}(I_2)]^2 + [\text{Im}(I_1) + \text{Im}(I_2)]^2} \quad \text{Eq. IV.4}$$

Appendix A2 – Basic principles of differential protection - continued

Now, let us consider a fault on line L1 (abnormal situations), both protection relays R11 and R12 see a forward direction current flow as the measured currents flow from their busbars (respectively A and B) to the line. Hence, the differential protection on each side of the line measures the summation of the currents at both sides of the line. Should the differential current be not zero, a fault is deemed to exist on the line. During normal operating conditions, as the current flow direction changes compared to the abnormal situation, the differential protection measures the difference of the currents at both sides of the line under consideration. Then, the differential current is written as follows:

$$I_{diff} = |I_1 - I_2| \quad \text{Eq. IV.5}$$

$$I_{diff} = \sqrt{[\text{Re}(I_1) - \text{Re}(I_2)]^2 + [\text{Im}(I_1) - \text{Im}(I_2)]^2} \quad \text{Eq. IV.6}$$

In practice, however, a considerable differential current can sometimes occur under normal load conditions or during a “through fault” even though there is no fault in the protected area. This is especially the case when a through fault is accompanied by a current transformer (CT) saturation. In addition, the inaccuracies in the measurement and the inaccuracies introduced by the difference of magnetizing curves of the current transformers forming the protected area (CT11/CT12 for line L1 and CT21/CT22 for line L2 in Fig.IV-1) bring a differential current during normal operating conditions. As a result, the lowest threshold of the differential protection (also called differential protection operating value) should fulfill at least the following criteria:

- Be greater than the inaccuracies appearing on normal operating conditions (criterion 1)
- Be below the minimum short-circuit current for a fault on the protected area (criterion 2)
- Be stable during a through fault. This is the case, for example, of the differential protection on line L2 which should be stable when a fault appears on line L1 (see Fig.IV-2) (criterion 3)

To ensure the stability of the differential protection for external faults, a restraining condition (Eq.IV.7) is added. Finally, the condition in Eq.IV.3 is supplemented by a second condition representing the scalar mean of the magnitude of currents at the line terminals:

$$I_{restr} = \frac{|I_1| + |I_2|}{2} \quad \text{Eq. IV.7}$$

I_{restr} is the restraining current

Appendix A2 – Basic principles of differential protection - continued

The trip decision of the differential protection relay is issued as soon as the operating point is above the operating characteristic shown on Fig.IV-3. The operating point is the point of coordinate (I_{diff} , I_{restr}) resulting in the calculation of I_{diff} and I_{restr} as per Eq.IV.5 and Eq.IV.7. As illustrated on the figure, the operating characteristic of the differential protection is typically a dual slope characteristic with four parameters:

- The differential current lowest threshold, let us call it I_{s1}
- The restraining current I_{s2} (knee point)
- The first slope $k1$
- The second slope $k2$

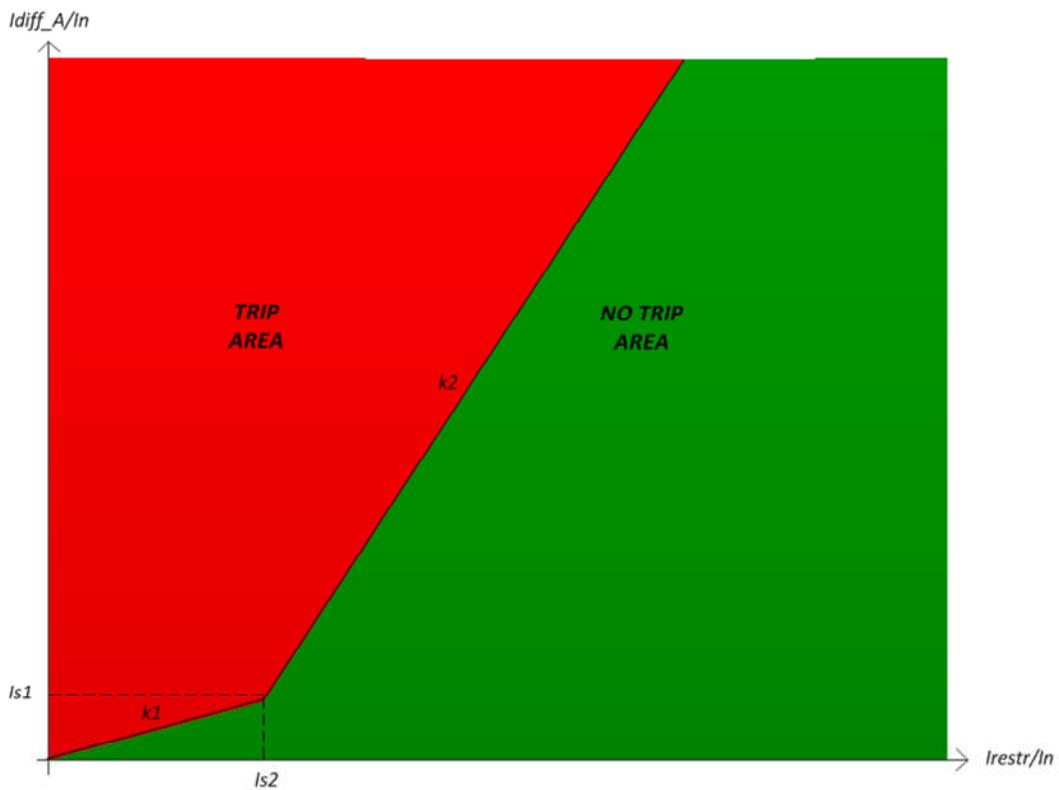


Fig.IV-3 – Operating characteristic of a biased differential protection

The trip decision is based on the following conditions:

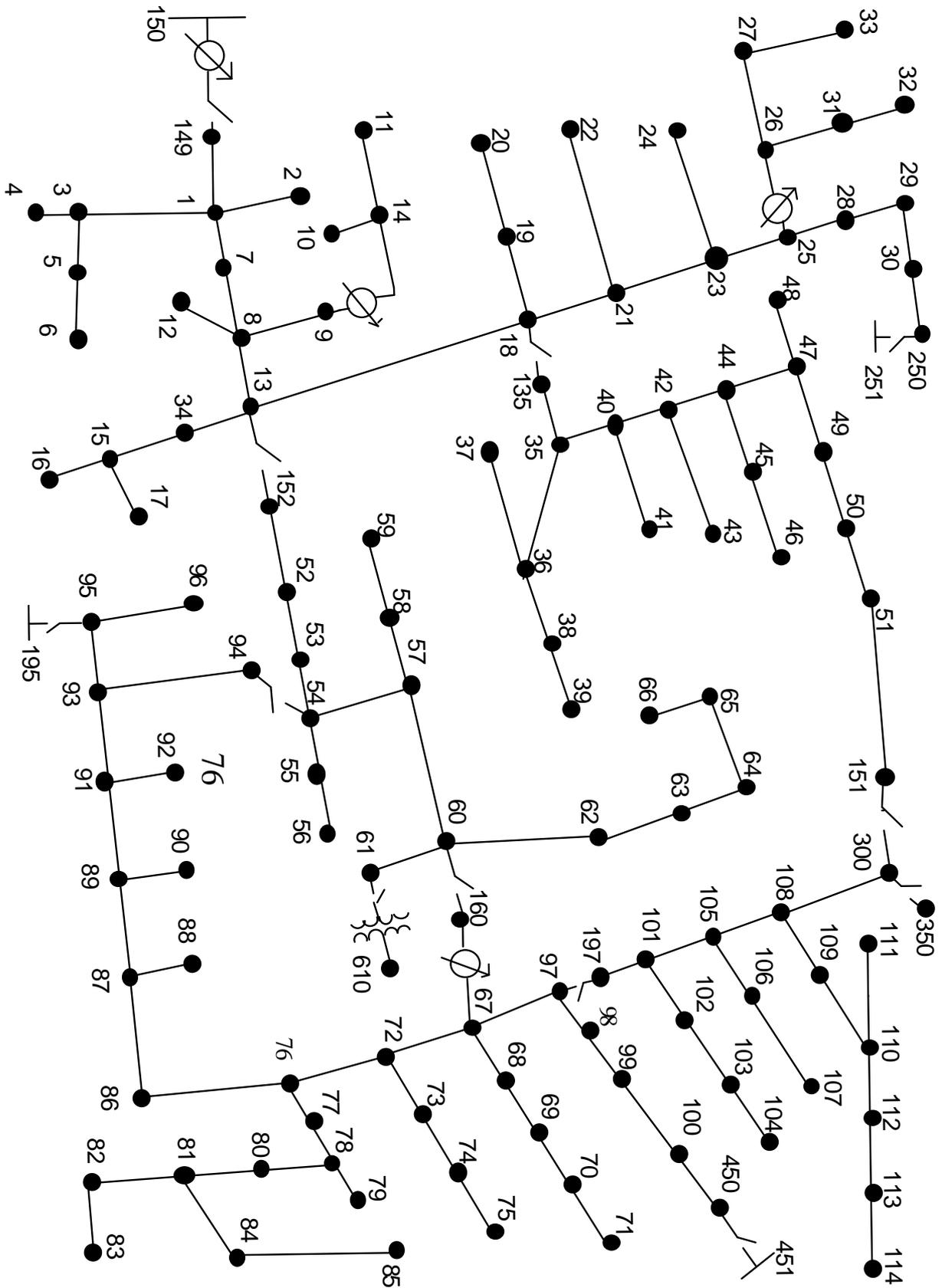
$$I_{restr} < I_{s2} \text{ then } I_{diff} > k_1 \times I_{restr} + I_{s1} \quad \text{Eq. IV.8.a}$$

$$I_{restr} > I_{s2} \text{ then } I_{diff} > k_2 \times (I_{restr} - I_{s2}) + k_1 \times I_{s2} + I_{s1} \quad \text{Eq. IV.8.b}$$

APPENDIX A3

IEEE 123 nodes network data

Network diagram



Appendix A3 – IEEE 123 nodes network data

Line/cable data

Node A	Node B	Length (ft.)	Config.
1	2	175	10
1	3	250	11
1	7	300	1
3	4	200	11
3	5	325	11
5	6	250	11
7	8	200	1
8	12	225	10
8	9	225	9
8	13	300	1
9	14	425	9
13	34	150	11
13	18	825	2
14	11	250	9
14	10	250	9
15	16	375	11
15	17	350	11
18	19	250	9
18	21	300	2
19	20	325	9
21	22	525	10
21	23	250	2
23	24	550	11
23	25	275	2
25	26	350	7
25	28	200	2
26	27	275	7
26	31	225	11
27	33	500	9
28	29	300	2

Node A	Node B	Length (ft.)	Config.
40	41	325	11
40	42	250	1
42	43	500	10
42	44	200	1
44	45	200	9
44	47	250	1
45	46	300	9
47	48	150	4
47	49	250	4
49	50	250	4
50	51	250	4
51	151	500	4
52	53	200	1
53	54	125	1
54	55	275	1
54	57	350	3
55	56	275	1
57	58	250	10
57	60	750	3
58	59	250	10
60	61	550	5
60	62	250	12
62	63	175	12
63	64	350	12
64	65	425	12
65	66	325	12
67	68	200	9
67	72	275	3
67	97	250	3
68	69	275	9

Appendix A3 – IEEE 123 nodes network data

Line/cable data

Node A	Node B	Length (ft.)	Config.
29	30	350	2
30	250	200	2
31	32	300	11
34	15	100	11
35	36	650	8
35	40	250	1
36	37	300	9
36	38	250	10
38	39	325	10
78	79	225	6
78	80	475	6
80	81	475	6
81	82	250	6
81	84	675	11
82	83	250	6
84	85	475	11
86	87	450	6
87	88	175	9
87	89	275	6
89	90	225	10
89	91	225	6
91	92	300	11
91	93	225	6
93	94	275	9
93	95	300	6
95	96	200	10
97	98	275	3
98	99	550	3
99	100	300	3

Node A	Node B	Length (ft.)	Config.
69	70	325	9
70	71	275	9
72	73	275	11
72	76	200	3
73	74	350	11
74	75	400	11
76	77	400	6
76	86	700	3
77	78	100	6
100	450	800	3
101	102	225	11
101	105	275	3
102	103	325	11
103	104	700	11
105	106	225	10
105	108	325	3
106	107	575	10
108	109	450	9
108	300	1000	3
109	110	300	9
110	111	575	9
110	112	125	9
112	113	525	9
113	114	325	9
135	35	375	4
149	1	400	1
152	52	400	1
160	67	350	6
197	101	250	3

Appendix A3 – IEEE 123 nodes network data

Overhead line configuration data

Config.	Phasing	Phase Cond.	Neutral Cond.	Spacing
		ACSR	ACSR	ID
1	A B C N	336,400 26/7	4/0 6/1	500
2	C A B N	336,400 26/7	4/0 6/1	500
3	B C A N	336,400 26/7	4/0 6/1	500
4	C B A N	336,400 26/7	4/0 6/1	500
5	B A C N	336,400 26/7	4/0 6/1	500
6	A C B N	336,400 26/7	4/0 6/1	500
7	A C N	336,400 26/7	4/0 6/1	505
8	A B N	336,400 26/7	4/0 6/1	505
9	A N	1/0	1/0	510
Config.	Phasing	Phase Cond.	Neutral Cond.	Spacing
10	B N	1/0	1/0	510
11	C N	1/0	1/0	510

Underground cable configuration data

Config.	Phasing	Cable	Spacing
12	A B C	1/0 AA CN	515

Shunt capacitors data

Node	Ph-A	Ph-B	Ph-C
	kVAr	kVAr	kVAr
83	200	200	200
88	50		
90		50	
92			50
Total	250	250	250

Appendix A3 – IEEE 123 nodes network data

Regulators data

Regulator ID	1		
Line Segment	150 - 149		
Location	150		
Phases	A-B-C		
Connection	3-Ph, Wye		
Monitoring Phase	A		
Bandwidth	2.0 volts		
PT Ratio	20		
Primary CT Rating	700		
Compensator settings	Ph-A		
R - Setting	3		
X - Setting	7.5		
Voltage Level	120		

Regulator ID	2		
Line Segment	9 - 14		
Location	9		
Phases	A		
Connection	1-Ph, L-G		
Monitoring Phase	A		
Bandwidth	2.0 volts		
PT Ratio	20		
Primary CT Rating	50		
Compensator settings	Ph-A		
R - Setting	0.4		
X - Setting	0.4		
Voltage Level	120		

Regulator ID	3		
Line Segment	25 - 26		
Location	25		
Phases	A-C		
Connection	2-Ph, L-G		
Monitoring Phase	A & C		
Bandwidth	1		
PT Ratio	20		
Primary CT Rating	50		
Compensator settings	Ph-A	Ph-C	
R - Setting	0,4	0,4	
X - Setting	0,4	0,4	
Voltage Level	120	120	

Appendix A3 – IEEE 123 nodes network data

Regulators data - continued

Regulator ID	4		
Line Segment	160 - 67		
Location	160		
Phases	A-B-C		
Connection	3-Ph, LG		
Monitoring Phase	A-B-C		
Bandwidth	2		
PT Ratio	20		
Primary CT Rating	300		
Compensator settings	Ph-A	Ph-B	Ph-C
R - Setting	0,6	1,4	0,2
X - Setting	1,3	2,6	1,4
Voltage Level	124	124	124

Transformers data

	kVA	kV-high	kV-low	R - %	X - %
Substation	5 000	115 - D	4.16 Gr-W	1	8
XFM - 1	150	4.16 - D	.480 - D	1,27	2,72

Three phase switches data

Node A	Node B	Normal
13	152	closed
18	135	closed
60	160	closed
61	610	closed
97	197	closed
150	149	closed
250	251	open
450	451	open
54	94	open
151	300	open
300	350	open

Appendix A3 – IEEE 123 nodes network data

Spot loads data

Node	Load	Ph-1	Ph-1	Ph-2	Ph-2	Ph-3	Ph-4
	Model	kW	kVAr	kW	kVAr	kW	kVAr
1	Y-PQ	40	20	0	0	0	0
2	Y-PQ	0	0	20	10	0	0
4	Y-PR	0	0	0	0	40	20
5	Y-I	0	0	0	0	20	10
6	Y-Z	0	0	0	0	40	20
7	Y-PQ	20	10	0	0	0	0
9	Y-PQ	40	20	0	0	0	0
10	Y-I	20	10	0	0	0	0
11	Y-Z	40	20	0	0	0	0
12	Y-PQ	0	0	20	10	0	0
16	Y-PQ	0	0	0	0	40	20
17	Y-PQ	0	0	0	0	20	10
19	Y-PQ	40	20	0	0	0	0
20	Y-I	40	20	0	0	0	0
22	Y-Z	0	0	40	20	0	0
24	Y-PQ	0	0	0	0	40	20
28	Y-I	40	20	0	0	0	0
29	Y-Z	40	20	0	0	0	0
30	Y-PQ	0	0	0	0	40	20
31	Y-PQ	0	0	0	0	20	10
32	Y-PQ	0	0	0	0	20	10
33	Y-I	40	20	0	0	0	0
34	Y-Z	0	0	0	0	40	20
35	D-PQ	40	20	0	0	0	0
37	Y-Z	40	20	0	0	0	0
38	Y-I	0	0	20	10	0	0
39	Y-PQ	0	0	20	10	0	0
41	Y-PQ	0	0	0	0	20	10
42	Y-PQ	20	10	0	0	0	0
43	Y-Z	0	0	40	20	0	0
45	Y-I	20	10	0	0	0	0
46	Y-PQ	20	10	0	0	0	0
47	Y-I	35	25	35	25	35	25
48	Y-Z	70	50	70	50	70	50
49	Y-PQ	35	25	70	50	35	20
50	Y-PQ	0	0	0	0	40	20

Appendix A3 – IEEE 123 nodes network data

Spot loads data - continued

Node	Load	Ph-1	Ph-1	Ph-2	Ph-2	Ph-3	Ph-4
	Model	kW	kVAr	kW	kVAr	kW	kVAr
51	Y-PQ	20	10	0	0	0	0
52	Y-PQ	40	20	0	0	0	0
53	Y-PQ	40	20	0	0	0	0
55	Y-Z	20	10	0	0	0	0
56	Y-PQ	0	0	20	10	0	0
58	Y-I	0	0	20	10	0	0
59	Y-PQ	0	0	20	10	0	0
60	Y-PQ	20	10	0	0	0	0
62	Y-Z	0	0	0	0	40	20
63	Y-PQ	40	20	0	0	0	0
64	Y-I	0	0	75	35	0	0
65	D-Z	35	25	35	25	70	50
66	Y-PQ	0	0	0	0	75	35
68	Y-PQ	20	10	0	0	0	0
69	Y-PQ	40	20	0	0	0	0
70	Y-PQ	20	10	0	0	0	0
71	Y-PQ	40	20	0	0	0	0
73	Y-PQ	0	0	0	0	40	20
74	Y-Z	0	0	0	0	40	20
75	Y-PQ	0	0	0	0	40	20
76	D-I	105	80	70	50	70	50
77	Y-PQ	0	0	40	20	0	0
79	Y-Z	40	20	0	0	0	0
80	Y-PQ	0	0	40	20	0	0
82	Y-PQ	40	20	0	0	0	0
83	Y-PQ	0	0	0	0	20	10
84	Y-PQ	0	0	0	0	20	10
85	Y-PQ	0	0	0	0	40	20
86	Y-PQ	0	0	20	10	0	0
87	Y-PQ	0	0	40	20	0	0
88	Y-PQ	40	20	0	0	0	0
90	Y-I	0	0	40	20	0	0
92	Y-PQ	0	0	0	0	40	20
94	Y-PQ	40	20	0	0	0	0
95	Y-PQ	0	0	20	10	0	0
96	Y-PQ	0	0	20	10	0	0

Appendix A3 – IEEE 123 nodes network data

Spot loads data - continued

Node	Load	Ph-1	Ph-1	Ph-2	Ph-2	Ph-3	Ph-4
	Model	kW	kVAr	kW	kVAr	kW	kVAr
98	Y-PQ	40	20	0	0	0	0
99	Y-PQ	0	0	40	20	0	0
100	Y-Z	0	0	0	0	40	20
102	Y-PQ	0	0	0	0	20	10
103	Y-PQ	0	0	0	0	40	20
104	Y-PQ	0	0	0	0	40	20
106	Y-PQ	0	0	40	20	0	0
107	Y-PQ	0	0	40	20	0	0
109	Y-PQ	40	20	0	0	0	0
111	Y-PQ	20	10	0	0	0	0
112	Y-I	20	10	0	0	0	0
113	Y-Z	40	20	0	0	0	0
114	Y-PQ	20	10	0	0	0	0

Impedance matrices

Configuration 1:

Z (R +jX) in ohms per mile

```
0.4576  1.0780  0.1560  0.5017  0.1535  0.3849
        0.4666  1.0482  0.1580  0.4236
                0.4615  1.0651
```

B in micro Siemens per mile

```
5.6765  -1.8319  -0.6982
        5.9809  -1.1645
                5.3971
```

Appendix A3 – IEEE 123 nodes network data

Impedance matrices - continued

Configuration 2:

Z (R +jX) in ohms per mile

0.4666	1.0482	0.1580	0.4236	0.1560	0.5017
		0.4615	1.0651	0.1535	0.3849
				0.4576	1.0780

B in micro Siemens per mile

5.9809	-1.1645	-1.8319
	5.3971	-0.6982
		5.6765

Configuration 3:

Z (R +jX) in ohms per mile

0.4615	1.0651	0.1535	0.3849	0.1580	0.4236
		0.4576	1.0780	0.1560	0.5017
				0.4666	1.0482

B in micro Siemens per mile

5.3971	-0.6982	-1.1645
	5.6765	-1.8319
		5.9809

Appendix A3 – IEEE 123 nodes network data

Impedance matrices - continued

Configuration 4:

Z (R +jX) in ohms per mile

0.4615	1.0651	0.1580	0.4236	0.1535	0.3849
		0.4666	1.0482	0.1560	0.5017
				0.4576	1.0780

B in micro Siemens per mile

5.3971	-1.1645	-0.6982
	5.9809	-1.8319
		5.6765

Configuration 5:

Z (R +jX) in ohms per mile

0.4666	1.0482	0.1560	0.5017	0.1580	0.4236
		0.4576	1.0780	0.1535	0.3849
				0.4615	1.0651

B in micro Siemens per mile

5.9809	-1.8319	-1.1645
	5.6765	-0.6982
		5.3971

Appendix A3 – IEEE 123 nodes network data

Impedance matrices - continued

Configuration 6:

Z (R +jX) in ohms per mile

0.4576	1.0780	0.1535	0.3849	0.1560	0.5017
		0.4615	1.0651	0.1580	0.4236
				0.4666	1.0482

B in micro Siemens per mile

5.6765	-0.6982	-1.8319
	5.3971	-1.1645
		5.9809

Configuration 7:

Z (R +jX) in ohms per mile

0.4576	1.0780	0.0000	0.0000	0.1535	0.3849
		0.0000	0.0000	0.0000	0.0000
				0.4615	1.0651

B in micro Siemens per mile

5.1154	0.0000	-1.0549
	0.0000	0.0000
		5.1704

Appendix A3 – IEEE 123 nodes network data

Impedance matrices - continued

Configuration 8:

Z (R +jX) in ohms per mile

0.4576	1.0780	0.1535	0.3849	0.0000	0.0000
		0.4615	1.0651	0.0000	0.0000
				0.0000	0.0000

B in micro Siemens per mile

5.1154	-1.0549	0.0000
	5.1704	0.0000
		0.0000

Configuration 9:

Z (R +jX) in ohms per mile

1.3292	1.3475	0.0000	0.0000	0.0000	0.0000
		0.0000	0.0000	0.0000	0.0000
				0.0000	0.0000

B in micro Siemens per mile

4.5193	0.0000	0.0000
	0.0000	0.0000
		0.0000

Appendix A3 – IEEE 123 nodes network data

Impedance matrices - continued

Configuration 10:

Z (R +jX) in ohms per mile

0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		1.3292	1.3475	0.0000	0.0000
				0.0000	0.0000

B in micro Siemens per mile

0.0000	0.0000	0.0000
	4.5193	0.0000
		0.0000

Configuration 11:

Z (R +jX) in ohms per mile

0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		0.0000	0.0000	0.0000	0.0000
				1.3292	1.3475

B in micro Siemens per mile

0.0000	0.0000	0.0000
	0.0000	0.0000
		4.5193

Appendix A3 – IEEE 123 nodes network data

Impedance matrices - continued

Configuration 12:

Z (R +jX) in ohms per mile

1.5209	0.7521	0.5198	0.2775	0.4924	0.2157
		1.5329	0.7162	0.5198	0.2775
				1.5209	0.7521

B in micro Siemens per mile

67.2242	0.0000	0.0000
	67.2242	0.0000
		67.2242

APPENDIX A4

Translation of the reference network components
into CIM classes

A4-1- Modeling of the feeder container

At a very high level, a feeder can be regarded as a container starting from a supplying source (a primary substation for example) and ending at a selected tie point. The feeder consists of several network components called conducting equipment. In CIM, the **Line** class is used to model the feeder. The class diagram on Fig.IV-9 shows the concept of equipment containers to describe the hierarchies in CIM. As we can see, there is an inheritance relation between the **Line** class and the **EquipmentContainer** class meaning that the feeder, modeled as a **Line**, is an Equipment container. Furthermore, the line is contained within a **SubGeographicalRegion** and a **GeographicalRegion**. In each rectangle, the text in bold is the CIM package containing the class and the normal text is the name of the class. For example, the **Line** class is contained in the **Wires** package.

This concept of container may be very interesting when performing feeder automation in that the container can be considered as a dynamic “jurisdiction” containing a set of conducting equipment participating to an automation function at the instant t. The automation function might be a voltage control scheme, a protection coordination scheme, etc. Should the feeder topology changes following a circuit reconfiguration, the extension of the feeder “jurisdiction” is going to change, either to exclude or include conducting equipment from/to the current feeder container. Typically, in the case of a differential protection, a zone may be excluded to the feeder jurisdiction at the instant t after a fault or circuit reconfiguration. As a result, the electric currents information of this zone will be automatically excluded from the differential protection current calculations performed by the feeder central unit.

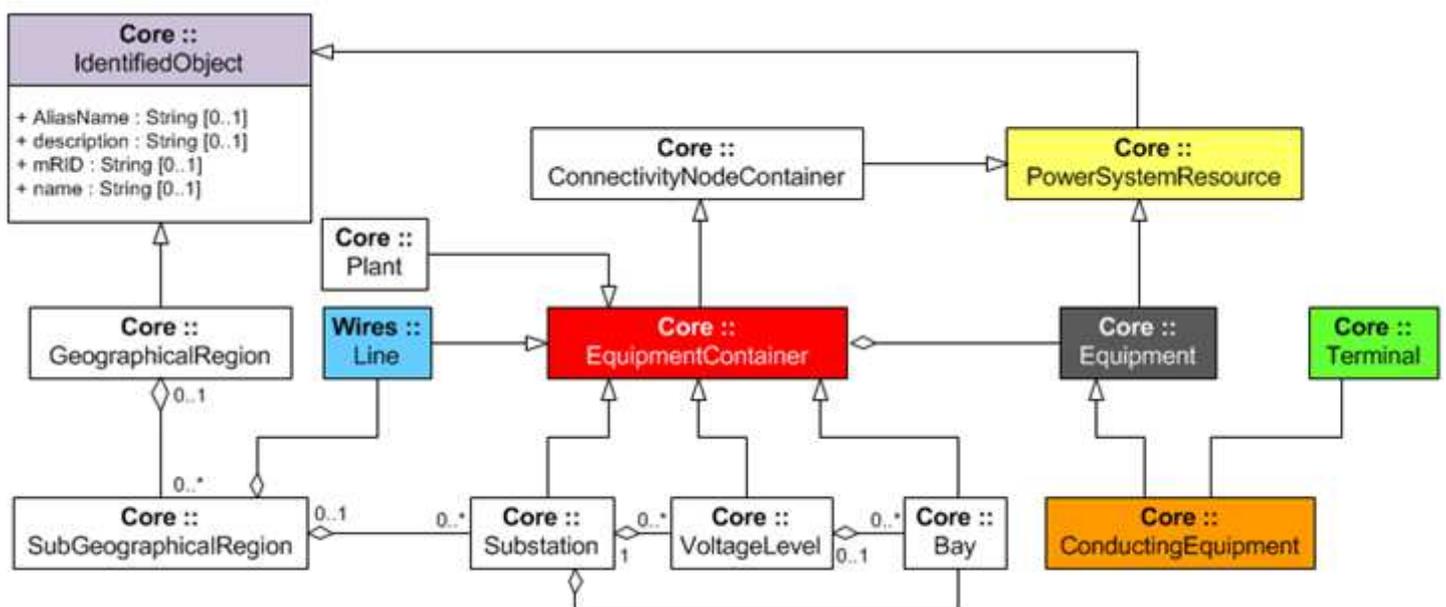


Fig.IV-9 – Equipment container class diagram – adapted from [38]

A4-2- Modeling of the connectivity

To model the **connectivity**, **Terminal** and **connectivity node** are defined [38]. Basically, each conducting equipment has one or more terminal(s). A terminal may be connected to one and only one connectivity node. A connectivity node may connect one or more terminals of different conducting equipment. So, the connectivity is achieved by associating the terminal(s) of conducting equipment to the right connectivity nodes. Each terminal, connectivity node has a name and a unique identifier (ID).

A4-3- Modeling of the conducting equipment

A conducting equipment is a network component that carries electric current. CIM uses UML to define a class hierarchy for each conducting equipment by stating that any conducting equipment is basically an equipment which is itself a power system resource. In addition, each power system resource must be identified by a unique identifier called MRID (Master Resource ID) and a name. Translating this in UML, the **ConductingEquipment** class inherits from its parent, the **Equipment** class, which in turn inherits from the **PowerSystemResource** class. Also, to allow for its identification, the **PowerSystemResource** class inherits from the **IdentifiedObject** class as shown on Fig.IV-9.

Furthermore, the **ConductingEquipment** class has sub-classes which inherit from their parent attributes and association to other classes such as the **Terminal**. In our reference distribution feeder, the following network components will be covered and modeled in CIM: the circuit breaker/recloser, cable and line sections, capacitor bank, power transformer, line voltage regulator, wind and CHP generating source, storage system, PV, load, upstream source and buses. These components can be categorized into two groups: two-terminals conducting equipment, one-terminal conducting equipment. Whatever the number of terminals, each conducting equipment has a name, a unique ID, a base voltage and an equipment container.

A4-3-1 – Modeling of two terminal conducting equipment

The Fig.IV-10 gives a UML description of a two-terminals conducting equipment and how it connects to both upstream and downstream nodes. However, even though a power transformer is a two-terminals conducting equipment, this UML description does not include the power transformer which has some specificities that are discussed further.

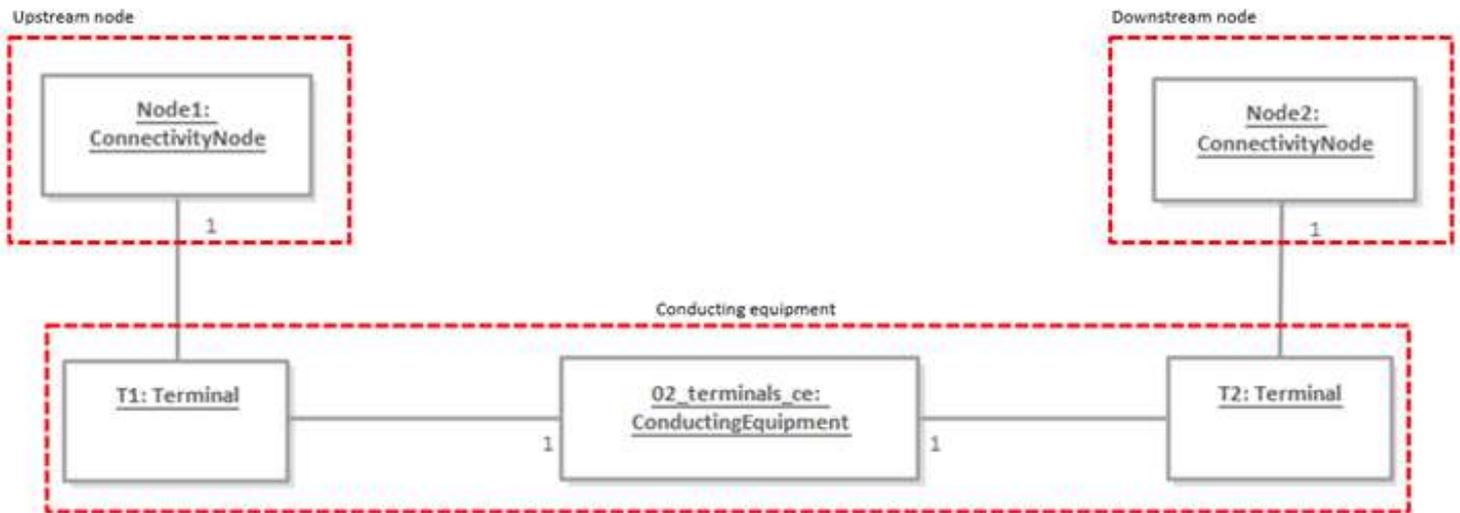


Fig.IV-10 – Two-terminals conducting equipment and its connectivity

A4-3-1-1 – Modeling of the circuit breaker

The circuit breaker is a mechanical switching device capable of making, carrying, and breaking currents under normal circuit conditions and, making, carrying for a specified time, and breaking currents under specified abnormal circuit conditions e.g. those of short circuit [23].

As for the recloser, it is a pole-mounted fault interrupter with built-in phase and ground relays, current transformer (CT), and supplemental controls [38]. After a fault, it can execute a preset reclosing sequence a preset number of times before going to a lock-out condition. However, since it is designed to operate like the circuit breaker, the recloser will be modeled as a circuit breaker even though the dedicated class in CIM is the **recloser** class.

In CIM, the circuit breaker is a piece of conducting equipment represented by the **Breaker** class. As indicated on the Fig.IV-11, the Breaker is a type of switch, which inherits from its parent class, the ProtectedSwitch class, which in its turn inherits from the Switch class. As a conducting Equipment, the Breaker inherits also to all the parent classes defined on the class inheritance hierarchy (**Equipment, PowerSystemResource, IdentifiedObject classes**). One of the main attribute of a circuit breaker object model is its status. The status is represented by the property "normalOpen" associated to the **Switch** class from which the **Breaker** class inherits.

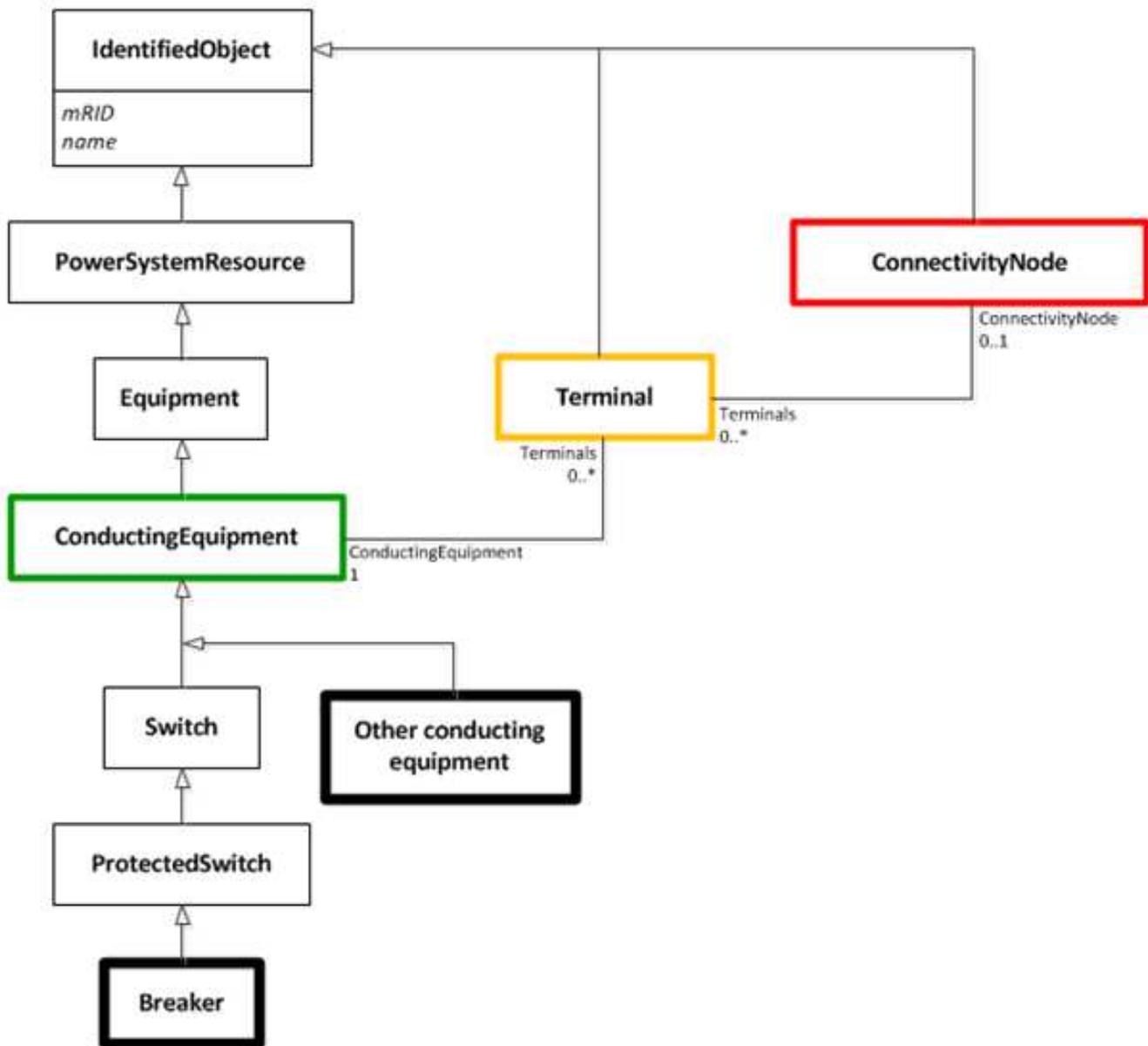


Fig.IV-11 – Class diagram of a circuit breaker – adapted from [38]

The same approach used for modeling the circuit breaker is applied to the other conducting equipment.

A4-3-1-2 – Modeling of cable and overhead line

The test feeder consists of several single, two and three phase cable and line sections. Therefore, we will adopt the same modeling principles as on the load. In CIM, a three-phase balanced line segment is basically represented by the **ACLineSegment** class with the length of the line section as attribute. However, for a three-phase unbalanced line segment, the **ACLineSegmentPhase** class, representing each phase of the line segment, is associated to the **ACLineSegment** class. To define the impedance per unit length of each line segment, we use the concept of “linecode”. To this end, the **PerLengthPhaseImpedance** class defines the impedance and admittance parameters per unit length of n-wire unbalanced lines, in matrix form [38]. But, since the linecode is in matrix format as detailed further in section 5.7, it is necessary to associate the **PhaseImpedanceData** class to the **PerLengthPhaseImpedance** class. In fact, the **PhaseImpedanceData** class has a triplet of resistance r, reactance x and susceptance b to define the values of the matrix entries. The **PhaseImpedanceData** class also has a “sequence number” attribute defining the column position of each entry within the symmetric matrix.

For the sake of illustration, let us consider the modeling of the three-phase line L76 connected between nodes 76 and 77 of the IEEE 123 nodes test feeder. The line L76 is 400 feet long and uses the linecode 6 which is as follows at 50Hz:

$$r_{matrix} = \begin{pmatrix} 0.0866 & 0.0290 & 0.0295 \\ 0.0290 & 0.087 & 0.0299 \\ 0.0295 & 0.0299 & 0.0883 \end{pmatrix} \quad \text{in } \Omega/\text{feet}$$

$$x_{matrix} = \begin{pmatrix} 0.2041 & 0.0728 & 0.0950 \\ 0.0728 & 0.2017 & 0.0802 \\ 0.0950 & 0.0802 & 0.1985 \end{pmatrix} \quad \text{in } \Omega/\text{feet}$$

$$c_{matrix} = \begin{pmatrix} 2.8517 & -0.3507 & -0.9202 \\ -0.3507 & 2.7113 & -0.5850 \\ -0.9202 & -0.5850 & 3.0046 \end{pmatrix} \quad \text{in nF}$$

However, since the matrices above are symmetric, only the six entries in the lower triangle of the matrix are retained to define the matrix. Therefore, we will use six instances of the **PhaseImpedanceData** class to represent these six entries as shown on the Fig.IV-12.

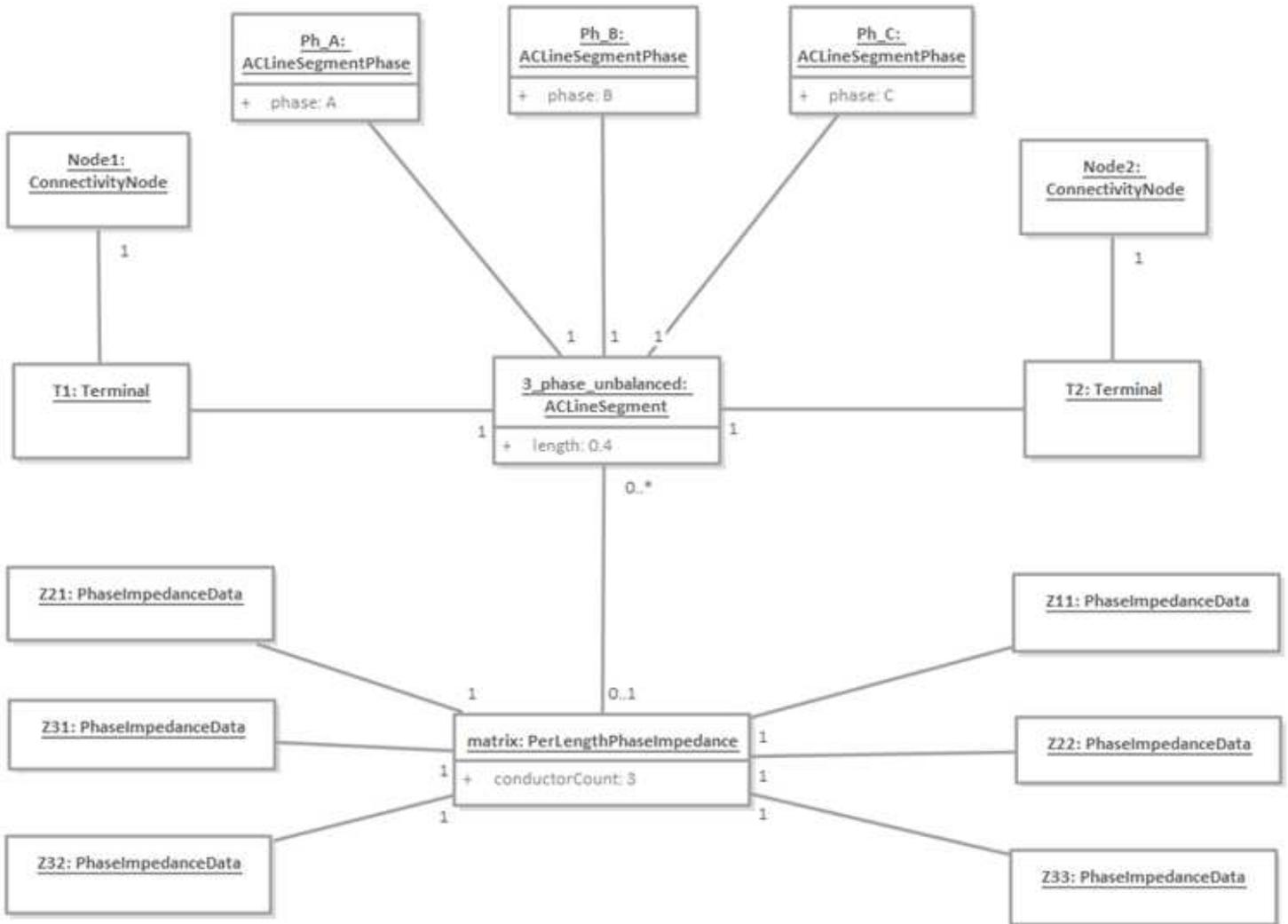


Fig.IV-12 - Modeling of a three-phase unbalanced line segment using a linecode defined in matrix format

A4-3-1-3 – Modeling of power transformer

The power transformer is one of the most complex network components to map in CIM. Our test feeder is composed of one two-winding balanced transmission power transformer (case of the 90/4.16kV substation transformer supplying the test feeder) and distribution transformers (case of line voltage regulators and step-up transformers connected to DERs). Since CIM version 15, a power transformer is modeled as shown on Fig.IV-13.

A balanced three-phase transmission power transformer can be modeled as shown on Fig.IV-13 using the classes marked with red rectangles. It is a conducting equipment modeled as follows:

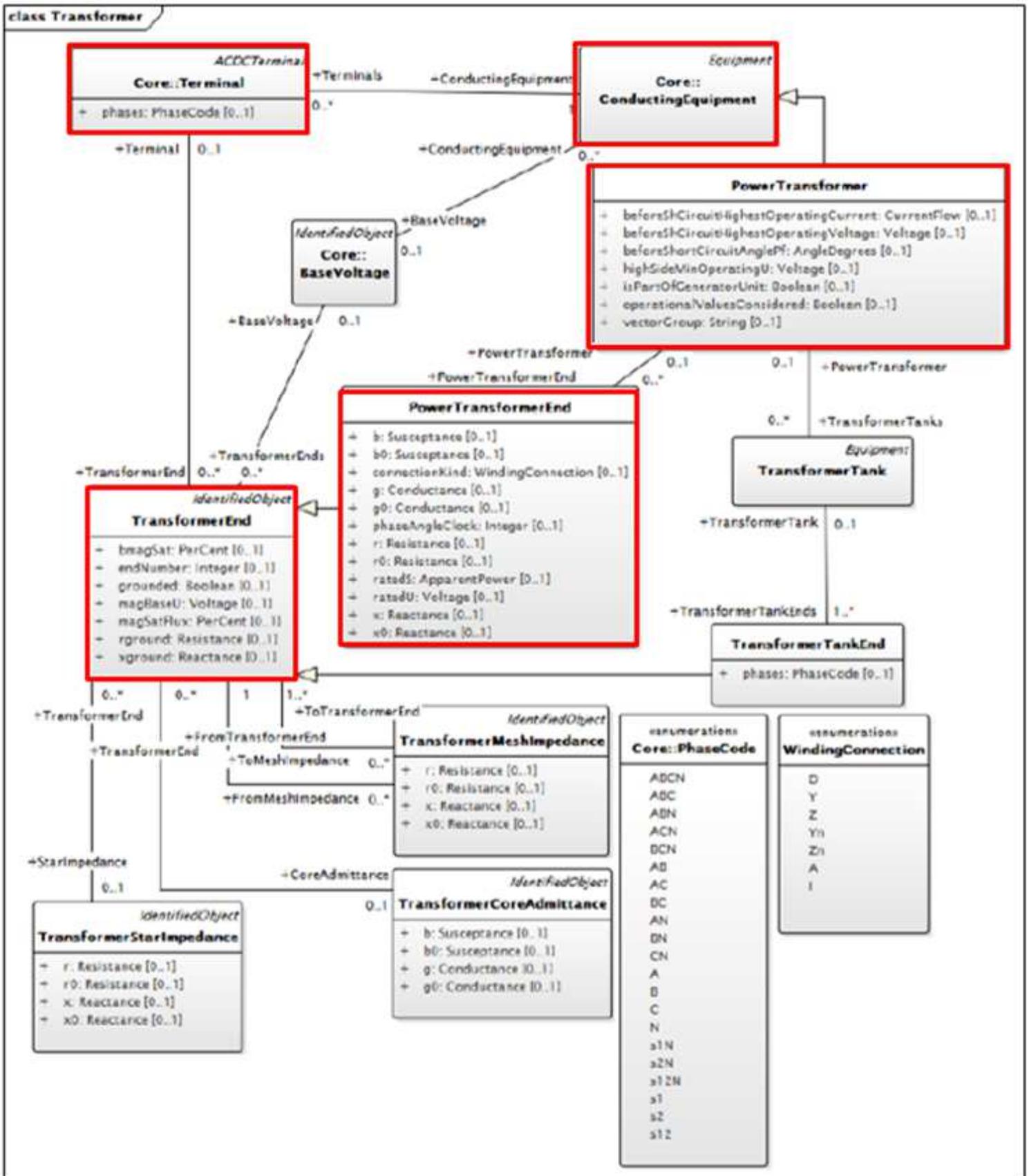


Fig.IV-13 – Balanced power transformer model class diagram [38]

- The power transformer is represented by the ***PowerTransformer*** class;
- A ***PowerTransformerEnd*** class is associated to this ***PowerTransformer*** class to represent the internal configuration of each of the two windings of the transformer; the ***PowerTransformerEnd*** class inherits from the ***TransformerEnd*** class;
- The ***TransformerEnd*** class is added to represent the terminal of each of the two windings; also, as the primary winding is equipped with a tap changer, the ***RatioTapChanger*** class is added to this winding;
- The impedance of each winding and the admittance of the transformer core are modeled respectively by the ***TransformerMeshImpedance*** class and the ***TransformerCoreAdmittance*** class.

The coupling is determined by the “connectionKind” attribute on the ***PowerTransformerEnd*** class. In our test feeder, the primary winding (90kV side) is connected in wye with the neutral point to the ground (YN). The secondary winding (4.16kV side) is also connected in wye with the neutral point to the ground (yn) through an impedance which limits the earth fault current to 300A. Therefore, on the 4.16kV side of this substation power transformer, the “grounded” attribute of the ***TransformerEnd*** class instance will be set to “True” while the “rground” and “xground” are set to the related impedance of limitation. Likewise, on the 90kV side of the transformer, the “grounded” attribute will be set to “True” while the “rground” and “xground” are set to zero as there is no earth current limitation.

A4-3-2 – Modeling of one terminal conducting equipment

The Fig.IV-14 gives a UML description of each one-terminal conducting equipment and its connectivity.

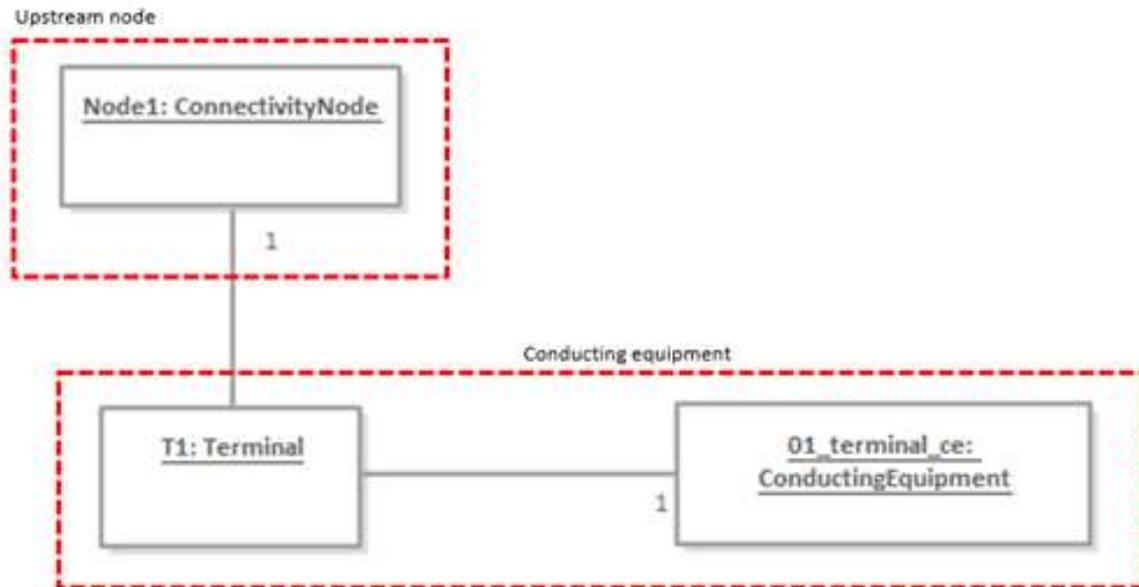


Fig.IV-14– One-terminal conducting equipment and its connectivity

A4-3-2-1 – Modeling of the upstream source

The upstream source is the Thevenin equivalent of the grid at the supplying point. In CIM, the upstream source maps to the **EnergySource** class. Among all the **EnergySource** class attributes, the following attributes are sufficient to characterize the upstream source:

- The Voltage magnitude and angle
- The equivalent positive sequence resistance (r) and reactance (x) at the grid connection point
- The equivalent zero sequence resistance (r0) and reactance (x0) at the grid connection point

A4-3-2-2 – Modeling of load

Load may be connected between one phase to ground, two phases or three phases. In addition, when it is a three-phase load, it may be balanced or unbalanced. In CIM, a load maps to the **EnergyConsumer** class with the following attributes:

- The load model (constant power, constant current or constant impedance) which maps to **LoadResponseCharacteristic** class
- The rated active and reactive powers
- The phase connection (Delta or Wye)

Appendix A4 – Translation of the reference network components into CIM model - continued

In addition, an unbalanced load introduces a complexity in the modeling. In fact, to the **EnergyConsumer** class, it is necessary to associate a sub class called **EnergyConsumerPhase** for each phase of the unbalanced load that introduces an extra attribute related to the phase the load is connected to (A, B or C).

A4-3-2-3 – Modeling of capacitor bank

Our test feeder includes both single and tri phase capacitor banks. Therefore, we will adopt the same modeling principles as on the load. In CIM, a capacitor bank is mapped using the **LinearShuntCompensator** class with the following attributes:

- The rated active and reactive powers
- The phase connection (Delta or Wye)
- The nominal voltage
- The positive sequence shunt susceptance (b) per section

With:

$$b = C \times \omega = \frac{Q}{V^2} \quad \text{for single phase capacitor banks (C88a, C90b and C92c)}$$

$$b = C \times \omega = \frac{Q}{U^2} \quad \text{for three phase capacitor banks (C83)}$$

U is the phase to phase voltage, V is the phase to ground voltage and Q is the rated reactive power of the capacitor bank.

Furthermore, it is necessary to associate to the **LinearShuntCompensator** class, a sub class called **LinearShuntCompensatorPhase**, for each phase of the single-phase capacitor banks C88a, C90b and C92c. This introduces an extra attribute related to the phase the capacitor bank is connected to (A, B or C).

A4-3-2-4 – Modeling of synchronous machine

In CIM, a synchronous machine is mapped using the **SynchronousMachine** class with the following attributes:

- The rated active and reactive powers
- The rated voltage
- The power factor
- The synchronous, transient, subtransient positive sequence reactances
- The production mode : PQ, PV

APPENDIX B1

Extract of the reference
network model (for SP1) in CIM RDF XML

Appendix B1 – Extract of reference network model in CIM RDF XML

```
<?xml version="1.0" encoding="utf-8"?>
<!-- un-comment this line to enable validation
-->
<rdf:RDF xmlns:cim="http://iec.ch/TC57/2012/CIM-schema-cim17#" xmlns:rdf="http://www.w3.org/1999/02/22-rdf-syntax-ns#">
<!--
-->
<cim:IEC61970CIMVersion rdf:ID="_BD8112C9-C464-46A6-8E1F-BD352D6A1E62">
  <cim:IEC61970CIMVersion.version>IEC61970CIM17v22</cim:IEC61970CIMVersion.version>
  <cim:IEC61970CIMVersion.date>2018-01-30</cim:IEC61970CIMVersion.date>
</cim:IEC61970CIMVersion>
<cim:CoordinateSystem rdf:ID="_BD8112C9-C464-46A6-8E1F-BD352D6A1E62">
  <cim:IdentifiedObject.mRID>_BD8112C9-C464-46A6-8E1F-BD352D6A1E62</cim:IdentifiedObject.mRID>
  <cim:IdentifiedObject.name>ieee123_CrsUrn</cim:IdentifiedObject.name>
  <cim:CoordinateSystem.crsUrn>OpenDSSLocalBusCoordinates</cim:CoordinateSystem.crsUrn>
</cim:CoordinateSystem>
<cim:GeographicalRegion rdf:ID="_5FE3E298-FBB3-4FA2-9883-04B77FCB43FB">
  <cim:IdentifiedObject.mRID>_5FE3E298-FBB3-4FA2-9883-04B77FCB43FB</cim:IdentifiedObject.mRID>
  <cim:IdentifiedObject.name>ieee123_Region</cim:IdentifiedObject.name>
</cim:GeographicalRegion>
<cim:SubGeographicalRegion rdf:ID="_9A26035F-5BDE-4CD4-9629-17206899773E">
  <cim:IdentifiedObject.mRID>_9A26035F-5BDE-4CD4-9629-17206899773E</cim:IdentifiedObject.mRID>
  <cim:IdentifiedObject.name>ieee123_SubRegion</cim:IdentifiedObject.name>
  <cim:SubGeographicalRegion.Region rdf:resource="#_5FE3E298-FBB3-4FA2-9883-04B77FCB43FB"/>
</cim:SubGeographicalRegion>
<cim:Substation rdf:ID="_9CCA0F6E-8691-4836-B6B9-8BEB145534C0">
  <cim:IdentifiedObject.mRID>_9CCA0F6E-8691-4836-B6B9-8BEB145534C0</cim:IdentifiedObject.mRID>
  <cim:IdentifiedObject.name>ieee123_Substation</cim:IdentifiedObject.name>
  <cim:Substation.Region rdf:resource="#_9A26035F-5BDE-4CD4-9629-17206899773E"/>
</cim:Substation>
<cim:Location rdf:ID="_34022066-69BF-4247-AD93-7D85AFB4B0A6">
  <cim:IdentifiedObject.mRID>_34022066-69BF-4247-AD93-7D85AFB4B0A6</cim:IdentifiedObject.mRID>
  <cim:IdentifiedObject.name>ieee123_Location</cim:IdentifiedObject.name>
  <cim:Location.CoordinateSystem rdf:resource="#_BD8112C9-C464-46A6-8E1F-BD352D6A1E62"/>
</cim:Location>
<cim:Feeder rdf:ID="_3DF0CE82-665C-4858-B771-CA45A02CEFE1">
  <cim:IdentifiedObject.mRID>_3DF0CE82-665C-4858-B771-CA45A02CEFE1</cim:IdentifiedObject.mRID>
  <cim:IdentifiedObject.name>ieee123</cim:IdentifiedObject.name>
  <cim:Feeder.NormalEnergizingSubstation rdf:resource="#_9CCA0F6E-8691-4836-B6B9-8BEB145534C0"/>
  <cim:PowerSystemResource.Location rdf:resource="#_34022066-69BF-4247-AD93-7D85AFB4B0A6"/>
</cim:Feeder>
.
.
.
.
.
<cim:ConnectivityNode rdf:ID="_278091EC-8E96-4726-8F04-E9EF3A367C23">
  <cim:IdentifiedObject.mRID>_278091EC-8E96-4726-8F04-E9EF3A367C23</cim:IdentifiedObject.mRID>
  <cim:IdentifiedObject.name>610</cim:IdentifiedObject.name>
  <cim:ConnectivityNode.TopologicalNode rdf:resource="#_7CB5FAB8-99D9-401F-ACA1-A45A1BC7A9D8"/>
  <cim:ConnectivityNode.ConnectivityNodeContainer rdf:resource="#_3DF0CE82-665C-4858-B771-CA45A02CEFE1"/>
</cim:ConnectivityNode>
<cim:TopologicalIsland rdf:ID="_79C8738F-7685-4230-90C3-E3CF9A61EAC2">
  <cim:IdentifiedObject.mRID>_79C8738F-7685-4230-90C3-E3CF9A61EAC2</cim:IdentifiedObject.mRID>
  <cim:IdentifiedObject.name>ieee123_Island</cim:IdentifiedObject.name>
  <cim:TopologicalIsland.AngleRefTopologicalNode rdf:resource="#_5A93CEA5-17FC-443D-B1FD-B8CE9EA07678"/>
</cim:TopologicalIsland>
<cim:BaseVoltage rdf:ID="_1A8F3C1B-5EA7-4989-95F8-BF0C0DA7EF52">
  <cim:IdentifiedObject.mRID>_1A8F3C1B-5EA7-4989-95F8-BF0C0DA7EF52</cim:IdentifiedObject.mRID>
  <cim:IdentifiedObject.name>BaseV_90.0000</cim:IdentifiedObject.name>
  <cim:BaseVoltage.nominalVoltage>90000</cim:BaseVoltage.nominalVoltage>
</cim:BaseVoltage>
```

Appendix B1 – Extract of reference network model in CIM RDF XML - continued

```
.
.
<cim:BaseVoltage rdf:ID="_F96DD9D3-AD7B-4947-8387-E6F851C54296">
  <cim:IdentifiedObject.mRID>_F96DD9D3-AD7B-4947-8387-E6F851C54296</cim:IdentifiedObject.mRID>
  <cim:IdentifiedObject.name>BaseV_4.1600</cim:IdentifiedObject.name>
  <cim:BaseVoltage.nominalVoltage>4160</cim:BaseVoltage.nominalVoltage>
</cim:BaseVoltage>
<cim:BaseVoltage rdf:ID="_BFFD575E-F1CE-4B02-AB92-4982916C677C">
  <cim:IdentifiedObject.mRID>_BFFD575E-F1CE-4B02-AB92-4982916C677C</cim:IdentifiedObject.mRID>
  <cim:IdentifiedObject.name>BaseV_0.4800</cim:IdentifiedObject.name>
  <cim:BaseVoltage.nominalVoltage>480</cim:BaseVoltage.nominalVoltage>
</cim:BaseVoltage>
<cim:EnergySource rdf:ID="_C6177614-AB14-4C05-AE4F-12F23C3FCE7A">
  <cim:IdentifiedObject.mRID>_C6177614-AB14-4C05-AE4F-12F23C3FCE7A</cim:IdentifiedObject.mRID>
  <cim:IdentifiedObject.name>source</cim:IdentifiedObject.name>
  <cim:Equipment.EquipmentContainer rdf:resource="#_3DF0CE82-665C-4858-B771-CA45A02CEFE1"/>
  <cim:ConductingEquipment.BaseVoltage rdf:resource="#_1A8F3C1B-5EA7-4989-95F8-BF0C0DA7EF52"/>
  <cim:EnergySource.nominalVoltage>90000</cim:EnergySource.nominalVoltage>
  <cim:EnergySource.voltageMagnitude>90000</cim:EnergySource.voltageMagnitude>
  <cim:EnergySource.voltageAngle>0</cim:EnergySource.voltageAngle>
  <cim:EnergySource.r>0.19645385627943</cim:EnergySource.r>
  <cim:EnergySource.x>0.785815425117719</cim:EnergySource.x>
  <cim:EnergySource.r0>1.02558459032349</cim:EnergySource.r0>
  <cim:EnergySource.x0>3.07675377097046</cim:EnergySource.x0>
  <cim:PowerSystemResource.Location rdf:resource="#_2469FEB1-8644-4230-8C87-ABE491FFFB9A"/>
</cim:EnergySource>
<cim:Terminal rdf:ID="_7BE43355-58F4-430F-8E13-F68F52503899">
  <cim:IdentifiedObject.mRID>_7BE43355-58F4-430F-8E13-F68F52503899</cim:IdentifiedObject.mRID>
  <cim:IdentifiedObject.name>source_T1</cim:IdentifiedObject.name>
  <cim:Terminal.ConductingEquipment rdf:resource="#_C6177614-AB14-4C05-AE4F-12F23C3FCE7A"/>
  <cim:Terminal.phases>ABC</cim:Terminal.phases>
  <cim:ACDCTerminal.sequenceNumber>1</cim:ACDCTerminal.sequenceNumber>
  <cim:Terminal.ConnectivityNode rdf:resource="#_4EE9775E-31A1-40FA-9408-A9A11671640A"/>
</cim:Terminal>
<cim:Location rdf:ID="_2469FEB1-8644-4230-8C87-ABE491FFFB9A">
  <cim:IdentifiedObject.mRID>_2469FEB1-8644-4230-8C87-ABE491FFFB9A</cim:IdentifiedObject.mRID>
  <cim:IdentifiedObject.name>source_Loc</cim:IdentifiedObject.name>
  <cim:Location.CoordinateSystem rdf:resource="#_BD8112C9-C464-46A6-8E1F-BD352D6A1E62"/>
</cim:Location>
<cim:PositionPoint rdf:ID="_7078A379-8AB2-42A8-8C91-F80A6C7B2D74">
  <cim:PositionPoint.Location rdf:resource="#_2469FEB1-8644-4230-8C87-ABE491FFFB9A"/>
  <cim:PositionPoint.sequenceNumber>1</cim:PositionPoint.sequenceNumber>
  <cim:PositionPoint.xPosition>100</cim:PositionPoint.xPosition>
  <cim:PositionPoint.yPosition>1500</cim:PositionPoint.yPosition>
</cim:PositionPoint>
```

```
.
.
.
.
```

Appendix B1 – Extract of reference network model in CIM RDF XML - continued

```
.  
.  
<cim:LinearShuntCompensator rdf:ID="_18961F0F-D570-408C-80C1-1551788B5B20">  
  <cim:IdentifiedObject.mRID>_18961F0F-D570-408C-80C1-1551788B5B20</cim:IdentifiedObject.mRID>  
  <cim:IdentifiedObject.name>c88a</cim:IdentifiedObject.name>  
  <cim:Equipment.EquipmentContainer rdf:resource="#_3DF0CE82-665C-4858-B771-CA45A02CEFE1"/>  
  <cim:ConductingEquipment.BaseVoltage rdf:resource="#_F96DD9D3-AD7B-4947-8387-E6F851C54296"/>  
  <cim:ShuntCompensator.nomU>2402</cim:ShuntCompensator.nomU>  
  <cim:LinearShuntCompensator.bPerSection>0.00866610602738073</cim:LinearShuntCompensator.bPerSection>  
  <cim:LinearShuntCompensator.gPerSection>0</cim:LinearShuntCompensator.gPerSection>  
  <cim:ShuntCompensator.aVRDelay>0</cim:ShuntCompensator.aVRDelay>  
  <cim:ShuntCompensator.phaseConnection rdf:resource="http://iec.ch/TC57/2012/CIM-schema-cim17#PhaseShuntConnectionKind.Y"/>  
  <cim:ShuntCompensator.grounded>true</cim:ShuntCompensator.grounded>  
  <cim:LinearShuntCompensator.b0PerSection>0</cim:LinearShuntCompensator.b0PerSection>  
  <cim:LinearShuntCompensator.g0PerSection>0</cim:LinearShuntCompensator.g0PerSection>  
  <cim:ShuntCompensator.normalSections>1</cim:ShuntCompensator.normalSections>  
  <cim:ShuntCompensator.maximumSections>1</cim:ShuntCompensator.maximumSections>  
  <cim:PowerSystemResource.Location rdf:resource="#_5A7893E3-6837-44E4-B0B0-E833B21FED93"/>  
</cim:LinearShuntCompensator>  
<cim:LinearShuntCompensatorPhase rdf:ID="_7392057D-3F09-4C49-B56E-2E9D88123B88">  
  <cim:IdentifiedObject.mRID>_7392057D-3F09-4C49-B56E-2E9D88123B88</cim:IdentifiedObject.mRID>  
  <cim:IdentifiedObject.name>c88a_A</cim:IdentifiedObject.name>  
  <cim:ShuntCompensatorPhase.phase rdf:resource="http://iec.ch/TC57/2012/CIM-schema-cim17#SinglePhaseKind.A"/>  
  <cim:LinearShuntCompensatorPhase.bPerSection>0.00866610602738073</cim:LinearShuntCompensatorPhase.bPerSection>  
  <cim:LinearShuntCompensatorPhase.gPerSection>0</cim:LinearShuntCompensatorPhase.gPerSection>  
  <cim:ShuntCompensatorPhase.normalSections>1</cim:ShuntCompensatorPhase.normalSections>  
  <cim:ShuntCompensatorPhase.maximumSections>1</cim:ShuntCompensatorPhase.maximumSections>  
  <cim:ShuntCompensatorPhase.ShuntCompensator rdf:resource="#_18961F0F-D570-408C-80C1-1551788B5B20"/>  
  <cim:PowerSystemResource.Location rdf:resource="#_5A7893E3-6837-44E4-B0B0-E833B21FED93"/>  
</cim:LinearShuntCompensatorPhase>  
<cim:Terminal rdf:ID="_B0569CAE-15FF-4007-ABDA-C64BC2065F1A">  
  <cim:IdentifiedObject.mRID>_B0569CAE-15FF-4007-ABDA-C64BC2065F1A</cim:IdentifiedObject.mRID>  
  <cim:IdentifiedObject.name>c88a_T1</cim:IdentifiedObject.name>  
  <cim:Terminal.ConductingEquipment rdf:resource="#_18961F0F-D570-408C-80C1-1551788B5B20"/>  
  <cim:Terminal.phases>A</cim:Terminal.phases>  
  <cim:ACDCTerminal.sequenceNumber>1</cim:ACDCTerminal.sequenceNumber>  
  <cim:Terminal.ConnectivityNode rdf:resource="#_ACAB7F66-28E4-48C9-B0F0-8DE116147839"/>  
</cim:Terminal>  
cim:Location rdf:ID="_5A7893E3-6837-44E4-B0B0-E833B21FED93">  
  <cim:IdentifiedObject.mRID>_5A7893E3-6837-44E4-B0B0-E833B21FED93</cim:IdentifiedObject.mRID>  
  <cim:IdentifiedObject.name>c88a_Loc</cim:IdentifiedObject.name>  
  <cim:Location.CoordinateSystem rdf:resource="#_BD8112C9-C464-46A6-8E1F-BD352D6A1E62"/>  
</cim:Location>  
<cim:PositionPoint rdf:ID="_9FF6E287-4C8D-45A0-A682-6C3AB6A7B5C5">  
  <cim:PositionPoint.Location rdf:resource="#_5A7893E3-6837-44E4-B0B0-E833B21FED93"/>  
  <cim:PositionPoint.sequenceNumber>1</cim:PositionPoint.sequenceNumber>  
  <cim:PositionPoint.xPosition>2950</cim:PositionPoint.xPosition>  
  <cim:PositionPoint.yPosition>1300</cim:PositionPoint.yPosition>  
<  
.  
.  
.  
.
```

Appendix B1 – Extract of reference network model in CIM RDF XML - continued

```
.  
. <cim:PowerTransformer rdf:ID="_96FE98C4-1488-45CC-AB2F-BE5A4B0E9FB7">  
  <cim:IdentifiedObject.mRID>_96FE98C4-1488-45CC-AB2F-BE5A4B0E9FB7</cim:IdentifiedObject.mRID>  
  <cim:IdentifiedObject.name>tr_d1</cim:IdentifiedObject.name>  
  <cim:Equipment.EquipmentContainer rdf:resource="#_3DF0CE82-665C-4858-B771-CA45A02CEFE1"/>  
  <cim:PowerTransformer.vectorGroup>Dy1</cim:PowerTransformer.vectorGroup>  
  <cim:PowerSystemResource.Location rdf:resource="#_B41CE326-2A4D-4B47-A4AD-664FF286525A"/>  
</cim:PowerTransformer>  
<cim:Location rdf:ID="_B41CE326-2A4D-4B47-A4AD-664FF286525A">  
  <cim:IdentifiedObject.mRID>_B41CE326-2A4D-4B47-A4AD-664FF286525A</cim:IdentifiedObject.mRID>  
  <cim:IdentifiedObject.name>tr_d1_Loc</cim:IdentifiedObject.name>  
  <cim:Location.CoordinateSystem rdf:resource="#_BD8112C9-C464-46A6-8E1F-BD352D6A1E62"/>  
</cim:Location>  
<cim:PositionPoint rdf:ID="_270C1012-2CFC-45AA-AF8B-F0DC8888B959">  
  <cim:PositionPoint.Location rdf:resource="#_B41CE326-2A4D-4B47-A4AD-664FF286525A"/>  
  <cim:PositionPoint.sequenceNumber>1</cim:PositionPoint.sequenceNumber>  
  <cim:PositionPoint.xPosition>1400</cim:PositionPoint.xPosition>  
  <cim:PositionPoint.yPosition>2450</cim:PositionPoint.yPosition>  
</cim:PositionPoint>  
<cim:PositionPoint rdf:ID="_0FDDAB01-DD33-4E01-AEE5-B3885B5ECA51">  
  <cim:PositionPoint.Location rdf:resource="#_B41CE326-2A4D-4B47-A4AD-664FF286525A"/>  
  <cim:PositionPoint.sequenceNumber>2</cim:PositionPoint.sequenceNumber>  
  <cim:PositionPoint.xPosition>1500</cim:PositionPoint.xPosition>  
  <cim:PositionPoint.yPosition>2325</cim:PositionPoint.yPosition>  
</cim:PositionPoint>  
<cim:TransformerCoreAdmittance rdf:ID="_82D871BF-3D49-44B0-94C4-DD22C5037DDA">  
  <cim:IdentifiedObject.mRID>_82D871BF-3D49-44B0-94C4-DD22C5037DDA</cim:IdentifiedObject.mRID>  
  <cim:IdentifiedObject.name>tr_d1_Yc</cim:IdentifiedObject.name>  
  <cim:TransformerCoreAdmittance.g>0</cim:TransformerCoreAdmittance.g>  
  <cim:TransformerCoreAdmittance.g0>0</cim:TransformerCoreAdmittance.g0>  
  <cim:TransformerCoreAdmittance.b>0</cim:TransformerCoreAdmittance.b>  
  <cim:TransformerCoreAdmittance.b0>0</cim:TransformerCoreAdmittance.b0>  
  <cim:TransformerCoreAdmittance.TransformerEnd rdf:resource="#_86B9E48C-9D73-46E7-859B-FF8CF21D32C0"/>  
</cim:TransformerCoreAdmittance>  
<cim:TransformerMeshImpedance rdf:ID="_F34182FB-45BC-4597-B94E-2422AF4D3876">  
  <cim:IdentifiedObject.mRID>_F34182FB-45BC-4597-B94E-2422AF4D3876</cim:IdentifiedObject.mRID>  
  <cim:IdentifiedObject.name>tr_d1_Zsc_1</cim:IdentifiedObject.name>  
  <cim:TransformerMeshImpedance.r>0.00292608</cim:TransformerMeshImpedance.r>  
  <cim:TransformerMeshImpedance.r0>0.00292608</cim:TransformerMeshImpedance.r0>  
  <cim:TransformerMeshImpedance.x>0.016128</cim:TransformerMeshImpedance.x>  
  <cim:TransformerMeshImpedance.x0>0.016128</cim:TransformerMeshImpedance.x0>  
  <cim:TransformerMeshImpedance.FromTransformerEnd rdf:resource="#_86B9E48C-9D73-46E7-859B-FF8CF21D32C0"/>  
  <cim:TransformerMeshImpedance.ToTransformerEnd rdf:resource="#_794458D3-8841-4040-B73C-B275B268AB4D"/>  
</cim:TransformerMeshImpedance>  
<cim:PowerTransformerEnd rdf:ID="_86B9E48C-9D73-46E7-859B-FF8CF21D32C0">  
  <cim:IdentifiedObject.mRID>_86B9E48C-9D73-46E7-859B-FF8CF21D32C0</cim:IdentifiedObject.mRID>  
  <cim:IdentifiedObject.name>tr_d1_End_1</cim:IdentifiedObject.name>  
  <cim:PowerTransformerEnd.PowerTransformer rdf:resource="#_96FE98C4-1488-45CC-AB2F-BE5A4B0E9FB7"/>  
  <cim:PowerTransformerEnd.ratedS>1000000</cim:PowerTransformerEnd.ratedS>  
  <cim:PowerTransformerEnd.ratedU>480</cim:PowerTransformerEnd.ratedU>  
  <cim:PowerTransformerEnd.r>0.00146304</cim:PowerTransformerEnd.r>  
  <cim:PowerTransformerEnd.connectionKind rdf:resource="http://iec.ch/TC57/2012/CIM-schema-cim17#WindingConnection.D"/>  
  <cim:PowerTransformerEnd.phaseAngleClock>0</cim:PowerTransformerEnd.phaseAngleClock>  
  <cim:TransformerEnd.endNumber>1</cim:TransformerEnd.endNumber>  
  <cim:TransformerEnd.grounded>false</cim:TransformerEnd.grounded>  
  <cim:TransformerEnd.Terminal rdf:resource="#_907F6F53-9E85-47BF-B755-07F660291CD3"/>  
  <cim:TransformerEnd.BaseVoltage rdf:resource="#_BFFD575E-F1CE-4B02-AB92-4982916C677C"/>  
</cim:PowerTransformerEnd>
```

Appendix B1 – Extract of reference network model in CIM RDF XML - continued

```
.
.
<cim:Terminal rdf:ID="_907F6F53-9E85-47BF-B755-07F660291CD3">
  <cim:IdentifiedObject.mRID>_907F6F53-9E85-47BF-B755-07F660291CD3</cim:IdentifiedObject.mRID>
  <cim:IdentifiedObject.name>tr_d1_T1</cim:IdentifiedObject.name>
  <cim:Terminal.ConductingEquipment rdf:resource="#_96FE98C4-1488-45CC-AB2F-BE5A4B0E9FB7"/>
  <cim:Terminal.phases>ABC</cim:Terminal.phases>
  <cim:ACDCTerminal.sequenceNumber>1</cim:ACDCTerminal.sequenceNumber>
<cim:Terminal.ConnectivityNode rdf:resource="#_DE31806B-46AB-485B-9C41-7BABE98A9C4A"/>
</cim:Terminal>
<cim:PowerTransformerEnd rdf:ID="_794458D3-8841-4040-B73C-B275B268AB4D">
  <cim:IdentifiedObject.mRID>_794458D3-8841-4040-B73C-B275B268AB4D</cim:IdentifiedObject.mRID>
  <cim:IdentifiedObject.name>tr_d1_End_2</cim:IdentifiedObject.name>
  <cim:PowerTransformerEnd.PowerTransformer rdf:resource="#_96FE98C4-1488-45CC-AB2F-BE5A4B0E9FB7"/>
  <cim:PowerTransformerEnd.ratedS>1000000</cim:PowerTransformerEnd.ratedS>
  <cim:PowerTransformerEnd.ratedU>4160</cim:PowerTransformerEnd.ratedU>
  <cim:PowerTransformerEnd.r>0.10989056</cim:PowerTransformerEnd.r>
  <cim:PowerTransformerEnd.connectionKind rdf:resource="http://iec.ch/TC57/2012/CIM-schema-cim17#WindingConnection.Y"/>
  <cim:PowerTransformerEnd.phaseAngleClock>1</cim:PowerTransformerEnd.phaseAngleClock>
  <cim:TransformerEnd.endNumber>2</cim:TransformerEnd.endNumber>
  <cim:TransformerEnd.grounded>true</cim:TransformerEnd.grounded>
  <cim:TransformerEnd.rground>0</cim:TransformerEnd.rground>
  <cim:TransformerEnd.xground>0</cim:TransformerEnd.xground>
  <cim:TransformerEnd.Terminal rdf:resource="#_89E0B811-71B2-4F68-BCDE-7927DAB610BA"/>
  <cim:TransformerEnd.BaseVoltage rdf:resource="#_F96DD9D3-AD7B-4947-8387-E6F851C54296"/>
</cim:PowerTransformerEnd>
<cim:Terminal rdf:ID="_89E0B811-71B2-4F68-BCDE-7927DAB610BA">
  <cim:IdentifiedObject.mRID>_89E0B811-71B2-4F68-BCDE-7927DAB610BA</cim:IdentifiedObject.mRID>
  <cim:IdentifiedObject.name>tr_d1_T2</cim:IdentifiedObject.name>
  <cim:Terminal.ConductingEquipment rdf:resource="#_96FE98C4-1488-45CC-AB2F-BE5A4B0E9FB7"/>
  <cim:Terminal.phases>ABC</cim:Terminal.phases>
  <cim:ACDCTerminal.sequenceNumber>2</cim:ACDCTerminal.sequenceNumber>
<cim:Terminal.ConnectivityNode rdf:resource="#_C7478DDF-FB14-4964-AC3B-A07E6903838F"/>
</cim:Terminal>
```

```
.
.
.
.
```

Appendix B1 – Extract of reference network model in CIM RDF XML - continued

```
.  
.  
<cim:ACLineSegment rdf:ID="_987B1FD8-45B6-4F25-8D1F-26F589904C26">  
<cim:IdentifiedObject.mRID>_987B1FD8-45B6-4F25-8D1F-26F589904C26</cim:IdentifiedObject.mRID>  
<cim:IdentifiedObject.name>l115</cim:IdentifiedObject.name>  
<cim:Equipment.EquipmentContainer rdf:resource="#_3DF0CE82-665C-4858-B771-CA45A02CEFE1"/>  
<cim:ConductingEquipment.BaseVoltage rdf:resource="#_F96DD9D3-AD7B-4947-8387-E6F851C54296"/>  
<cim:Conductor.length>0.4</cim:Conductor.length>  
<cim:ACLineSegment.PerLengthImpedance rdf:resource="#_1BE75351-23F5-440A-85A8-C267D0B80F27"/>  
<cim:PowerSystemResource.Location rdf:resource="#_EB6118D5-D9E9-4DCC-B7F9-D326C1514DCE"/>  
</cim:ACLineSegment>  
<cim:Terminal rdf:ID="_7D57189C-F4C6-47FB-8545-76B73EAD5A28">  
<cim:IdentifiedObject.mRID>_7D57189C-F4C6-47FB-8545-76B73EAD5A28</cim:IdentifiedObject.mRID>  
<cim:IdentifiedObject.name>l115_T1</cim:IdentifiedObject.name>  
<cim:Terminal.ConductingEquipment rdf:resource="#_987B1FD8-45B6-4F25-8D1F-26F589904C26"/>  
<cim:Terminal.phases>ABC</cim:Terminal.phases>  
<cim:ACDCTerminal.sequenceNumber>1</cim:ACDCTerminal.sequenceNumber>  
<cim:Terminal.ConnectivityNode rdf:resource="#_E3095E22-6F2C-47F8-9829-6FC4CA56ADFE"/>  
</cim:Terminal>  
<cim:Terminal rdf:ID="_B069C354-E9CF-48A3-BB16-35E42E601143">  
<cim:IdentifiedObject.mRID>_B069C354-E9CF-48A3-BB16-35E42E601143</cim:IdentifiedObject.mRID>  
<cim:IdentifiedObject.name>l115_T2</cim:IdentifiedObject.name>  
<cim:Terminal.ConductingEquipment rdf:resource="#_987B1FD8-45B6-4F25-8D1F-26F589904C26"/>  
<cim:Terminal.phases>ABC</cim:Terminal.phases>  
<cim:ACDCTerminal.sequenceNumber>2</cim:ACDCTerminal.sequenceNumber>  
<cim:Terminal.ConnectivityNode rdf:resource="#_F2CAAF0B-6E41-4EC6-8BD7-4D875A9FAD8F"/>  
</cim:Terminal>  
<cim:Location rdf:ID="_EB6118D5-D9E9-4DCC-B7F9-D326C1514DCE">  
<cim:IdentifiedObject.mRID>_EB6118D5-D9E9-4DCC-B7F9-D326C1514DCE</cim:IdentifiedObject.mRID>  
<cim:IdentifiedObject.name>l115_Loc</cim:IdentifiedObject.name>  
<cim:Location.CoordinateSystem rdf:resource="#_BD8112C9-C464-46A6-8E1F-BD352D6A1E62"/>  
</cim:Location>  
<cim:PositionPoint rdf:ID="_E2B56EB6-1240-424A-BD87-EA5007738449">  
<cim:PositionPoint.Location rdf:resource="#_EB6118D5-D9E9-4DCC-B7F9-D326C1514DCE"/>  
<cim:PositionPoint.sequenceNumber>1</cim:PositionPoint.sequenceNumber>  
<cim:PositionPoint.xPosition>300</cim:PositionPoint.xPosition>  
<cim:PositionPoint.yPosition>1500</cim:PositionPoint.yPosition>  
</cim:PositionPoint>  
<cim:PositionPoint rdf:ID="_E2AAAB11-44BE-4291-AB8B-A9C7A2822040">  
<cim:PositionPoint.Location rdf:resource="#_EB6118D5-D9E9-4DCC-B7F9-D326C1514DCE"/>  
<cim:PositionPoint.sequenceNumber>2</cim:PositionPoint.sequenceNumber>  
<cim:PositionPoint.xPosition>700</cim:PositionPoint.xPosition>  
<cim:PositionPoint.yPosition>1500</cim:PositionPoint.yPosition>  
</cim:PositionPoint>
```

```
.  
.  
.  
.
```

Appendix B1 – Extract of reference network model in CIM RDF XML - continued

```
.  
.  
<cim:Breaker rdf:ID="_1D244F54-A550-49A2-80CE-126C35EA8E54">  
<cim:IdentifiedObject.name>BR2</cim:IdentifiedObject.name>  
<cim:Equipment.EquipmentContainer rdf:resource="#_3DF0CE82-665C-4858-B771-CA45A02CEFE1"/>  
<cim:ConductingEquipment.BaseVoltage rdf:resource="#_F96DD9D3-AD7B-4947-8387-E6F851C54296"/>  
<cim:Switch.normalOpen>false</cim:Switch.normalOpen>  
<cim:PowerSystemResource.Location rdf:resource="#_C1E5CF73-63A1-4786-995C-4E47D2C78296"/>  
</cim:Breaker>  
<cim:Terminal rdf:ID="_8D1CAA7A-F621-4A5B-8E27-933885D45E55">  
<cim:IdentifiedObject.mRID>_8D1CAA7A-F621-4A5B-8E27-933885D45E55</cim:IdentifiedObject.mRID>  
<cim:IdentifiedObject.name>BR2_T1</cim:IdentifiedObject.name>  
<cim:Terminal.ConductingEquipment rdf:resource="#_1D244F54-A550-49A2-80CE-126C35EA8E54"/>  
<cim:Terminal.phases>ABC</cim:Terminal.phases>  
<cim:ACDCTerminal.sequenceNumber>1</cim:ACDCTerminal.sequenceNumber>  
<cim:Terminal.ConnectivityNode rdf:resource="#_023C19D1-FFF2-4DC2-9E28-85A28BED56C1"/>  
</cim:Terminal>  
<cim:Terminal rdf:ID="_3F044E5E-CFFB-4D8F-8105-30B7A553F751">  
<cim:IdentifiedObject.mRID>_3F044E5E-CFFB-4D8F-8105-30B7A553F751</cim:IdentifiedObject.mRID>  
<cim:IdentifiedObject.name>BR2_T2</cim:IdentifiedObject.name>  
<cim:Terminal.ConductingEquipment rdf:resource="#_1D244F54-A550-49A2-80CE-126C35EA8E54"/>  
<cim:Terminal.phases>ABC</cim:Terminal.phases>  
<cim:ACDCTerminal.sequenceNumber>2</cim:ACDCTerminal.sequenceNumber>  
<cim:Terminal.ConnectivityNode rdf:resource="#_C1AEEBD9-B4C7-40E4-B72F-4914A881222E"/>  
</cim:Terminal>  
<cim:Location rdf:ID="_C1E5CF73-63A1-4786-995C-4E47D2C78296">  
<cim:IdentifiedObject.mRID>_C1E5CF73-63A1-4786-995C-4E47D2C78296</cim:IdentifiedObject.mRID>  
<cim:IdentifiedObject.name>sw2_Loc</cim:IdentifiedObject.name>  
<cim:Location.CoordinateSystem rdf:resource="#_BD8112C9-C464-46A6-8E1F-BD352D6A1E62"/>  
</cim:Location>  
<cim:PositionPoint rdf:ID="_7EC82C2F-305A-42D9-91B2-66290052210D">  
<cim:PositionPoint.Location rdf:resource="#_C1E5CF73-63A1-4786-995C-4E47D2C78296"/>  
<cim:PositionPoint.sequenceNumber>1</cim:PositionPoint.sequenceNumber>  
<cim:PositionPoint.xPosition>1500</cim:PositionPoint.xPosition>  
<cim:PositionPoint.yPosition>1500</cim:PositionPoint.yPosition>  
</cim:PositionPoint>  
<cim:PositionPoint rdf:ID="_83BF831A-7F5C-4F8F-8242-749783320C2B">  
<cim:PositionPoint.Location rdf:resource="#_C1E5CF73-63A1-4786-995C-4E47D2C78296"/>  
<cim:PositionPoint.sequenceNumber>2</cim:PositionPoint.sequenceNumber>  
<cim:PositionPoint.xPosition>1600</cim:PositionPoint.xPosition>  
<cim:PositionPoint.yPosition>1500</cim:PositionPoint.yPosition>  
</cim:PositionPoint>  
.  
.  
.  
.
```

Appendix B1 – Extract of reference network model in CIM RDF XML - continued

```
.  
.  
<cim:EnergyConsumer rdf:ID="_521F4438-4E98-47FE-8709-6D88A5338B8B">  
<cim:IdentifiedObject.mRID>_521F4438-4E98-47FE-8709-6D88A5338B8B</cim:IdentifiedObject.mRID>  
<cim:IdentifiedObject.name>s1a</cim:IdentifiedObject.name>  
<cim:Equipment.EquipmentContainer rdf:resource="#_3DF0CE82-665C-4858-B771-CA45A02CEFE1"/>  
<cim:ConductingEquipment.BaseVoltage rdf:resource="#_F96DD9D3-AD7B-4947-8387-E6F851C54296"/>  
<cim:EnergyConsumer.LoadResponse rdf:resource="#_74551824-C994-44C0-91B6-67B3033E0CDE"/>  
<cim:EnergyConsumer.pfixed>40000</cim:EnergyConsumer.pfixed>  
<cim:EnergyConsumer.qfixed>20000</cim:EnergyConsumer.qfixed>  
<cim:EnergyConsumer.customerCount>1</cim:EnergyConsumer.customerCount>  
<cim:EnergyConsumer.phaseConnection rdf:resource="http://iec.ch/TC57/2012/CIM-schema-cim17#PhaseShuntConnectionKind.Y"/>  
<cim:EnergyConsumer.grounded>true</cim:EnergyConsumer.grounded>  
<cim:PowerSystemResource.Location rdf:resource="#_CAEFA31E-7169-47A0-9249-8A3FD96F597F"/>  
</cim:EnergyConsumer>  
<cim:EnergyConsumerPhase rdf:ID="_DBF46BBC-5F6D-4CED-8D6D-1048A31A0136">  
<cim:IdentifiedObject.mRID>_DBF46BBC-5F6D-4CED-8D6D-1048A31A0136</cim:IdentifiedObject.mRID>  
<cim:IdentifiedObject.name>s1a_A</cim:IdentifiedObject.name>  
<cim:EnergyConsumerPhase.phase rdf:resource="http://iec.ch/TC57/2012/CIM-schema-cim17#SinglePhaseKind.A"/>  
<cim:EnergyConsumerPhase.pfixed>40000</cim:EnergyConsumerPhase.pfixed>  
<cim:EnergyConsumerPhase.qfixed>20000</cim:EnergyConsumerPhase.qfixed>  
<cim:EnergyConsumerPhase.EnergyConsumer rdf:resource="#_521F4438-4E98-47FE-8709-6D88A5338B8B"/>  
<cim:PowerSystemResource.Location rdf:resource="#_CAEFA31E-7169-47A0-9249-8A3FD96F597F"/>  
</cim:EnergyConsumerPhase>  
<cim:Terminal rdf:ID="_F85F8D95-13F9-4343-8CAD-865B42F2CEFC">  
<cim:IdentifiedObject.mRID>_F85F8D95-13F9-4343-8CAD-865B42F2CEFC</cim:IdentifiedObject.mRID>  
<cim:IdentifiedObject.name>s1a_T1</cim:IdentifiedObject.name>  
<cim:Terminal.ConductingEquipment rdf:resource="#_521F4438-4E98-47FE-8709-6D88A5338B8B"/>  
<cim:Terminal.phases>A</cim:Terminal.phases>  
<cim:ACDCTerminal.sequenceNumber>1</cim:ACDCTerminal.sequenceNumber>  
<cim:Terminal.ConnectivityNode rdf:resource="#_F2CAAF0B-6E41-4EC6-8BD7-4D875A9FAD8F"/>  
</cim:Terminal>  
<cim:Location rdf:ID="_CAEFA31E-7169-47A0-9249-8A3FD96F597F">  
<cim:IdentifiedObject.mRID>_CAEFA31E-7169-47A0-9249-8A3FD96F597F</cim:IdentifiedObject.mRID>  
<cim:IdentifiedObject.name>s1a_Loc</cim:IdentifiedObject.name>  
<cim:Location.CoordinateSystem rdf:resource="#_BD8112C9-C464-46A6-8E1F-BD352D6A1E62"/>  
</cim:Location>  
<cim:PositionPoint rdf:ID="_C64EFA88-CF0C-4800-B8F9-1AB6126B5BFA">  
<cim:PositionPoint.Location rdf:resource="#_CAEFA31E-7169-47A0-9249-8A3FD96F597F"/>  
<cim:PositionPoint.sequenceNumber>1</cim:PositionPoint.sequenceNumber>  
<cim:PositionPoint.xPosition>700</cim:PositionPoint.xPosition>  
<cim:PositionPoint.yPosition>1500</cim:PositionPoint.yPosition>  
</cim:PositionPoint>  
.  
.  
.  
.
```

Appendix B1 – Extract of reference network model in CIM RDF XML - continued

```
.
.
<cim:PerLengthPhaseImpedance rdf:ID="_236C9E22-D9E7-4869-8B2B-D17EFF0B4539">
  <cim:IdentifiedObject.mRID>_236C9E22-D9E7-4869-8B2B-D17EFF0B4539</cim:IdentifiedObject.mRID>
  <cim:IdentifiedObject.name>6</cim:IdentifiedObject.name>
  <cim:PerLengthPhaseImpedance.conductorCount>3</cim:PerLengthPhaseImpedance.conductorCount>
</cim:PerLengthPhaseImpedance>
<cim:PhaseImpedanceData rdf:ID="_C883530F-B10A-4AB8-9BB5-03BA6C6BE072">
  <cim:PhaseImpedanceData.PhaseImpedance rdf:resource="#_236C9E22-D9E7-4869-8B2B-D17EFF0B4539"/>
  <cim:PhaseImpedanceData.sequenceNumber>1</cim:PhaseImpedanceData.sequenceNumber>
  <cim:PhaseImpedanceData.r>0.086666667</cim:PhaseImpedanceData.r>
  <cim:PhaseImpedanceData.x>0.204166667</cim:PhaseImpedanceData.x>
  <cim:PhaseImpedanceData.b>8.95891141236381E-007</cim:PhaseImpedanceData.b>
</cim:PhaseImpedanceData>
<cim:PhaseImpedanceData rdf:ID="_1B616E35-04C0-4352-89F1-4BC9357DD57D">
  <cim:PhaseImpedanceData.PhaseImpedance rdf:resource="#_236C9E22-D9E7-4869-8B2B-D17EFF0B4539"/>
  <cim:PhaseImpedanceData.sequenceNumber>2</cim:PhaseImpedanceData.sequenceNumber>
  <cim:PhaseImpedanceData.r>0.02907197</cim:PhaseImpedanceData.r>
  <cim:PhaseImpedanceData.x>0.072897727</cim:PhaseImpedanceData.x>
  <cim:PhaseImpedanceData.b>-1.1019311093514E-007</cim:PhaseImpedanceData.b>
</cim:PhaseImpedanceData>
<cim:PhaseImpedanceData rdf:ID="_E525ADC8-82F4-4537-9122-75054822DAAA">
  <cim:PhaseImpedanceData.PhaseImpedance rdf:resource="#_236C9E22-D9E7-4869-8B2B-D17EFF0B4539"/>
  <cim:PhaseImpedanceData.sequenceNumber>3</cim:PhaseImpedanceData.sequenceNumber>
  <cim:PhaseImpedanceData.r>0.029545455</cim:PhaseImpedanceData.r>
  <cim:PhaseImpedanceData.x>0.095018939</cim:PhaseImpedanceData.x>
  <cim:PhaseImpedanceData.b>-2.89118820038372E-007</cim:PhaseImpedanceData.b>
</cim:PhaseImpedanceData>
<cim:PhaseImpedanceData rdf:ID="_023F53F6-D654-4B9B-BA0D-F1C84574D8D0">
  <cim:PhaseImpedanceData.PhaseImpedance rdf:resource="#_236C9E22-D9E7-4869-8B2B-D17EFF0B4539"/>
  <cim:PhaseImpedanceData.sequenceNumber>4</cim:PhaseImpedanceData.sequenceNumber>
  <cim:PhaseImpedanceData.r>0.087405303</cim:PhaseImpedanceData.r>
  <cim:PhaseImpedanceData.x>0.201723485</cim:PhaseImpedanceData.x>
  <cim:PhaseImpedanceData.b>8.51794957582517E-007</cim:PhaseImpedanceData.b>
</cim:PhaseImpedanceData>
<cim:PhaseImpedanceData rdf:ID="_FBAED954-184F-4C9D-B8BF-DE6ACF11E500">
  <cim:PhaseImpedanceData.PhaseImpedance rdf:resource="#_236C9E22-D9E7-4869-8B2B-D17EFF0B4539"/>
  <cim:PhaseImpedanceData.sequenceNumber>5</cim:PhaseImpedanceData.sequenceNumber>
  <cim:PhaseImpedanceData.r>0.029924242</cim:PhaseImpedanceData.r>
  <cim:PhaseImpedanceData.x>0.080227273</cim:PhaseImpedanceData.x>
  <cim:PhaseImpedanceData.b>-1.83786705469228E-007</cim:PhaseImpedanceData.b>
</cim:PhaseImpedanceData>
<cim:PhaseImpedanceData rdf:ID="_46A78215-EBD9-41AE-8677-291AC4569A1F">
  <cim:PhaseImpedanceData.PhaseImpedance rdf:resource="#_236C9E22-D9E7-4869-8B2B-D17EFF0B4539"/>
  <cim:PhaseImpedanceData.sequenceNumber>6</cim:PhaseImpedanceData.sequenceNumber>
  <cim:PhaseImpedanceData.r>0.088371212</cim:PhaseImpedanceData.r>
  <cim:PhaseImpedanceData.x>0.198522727</cim:PhaseImpedanceData.x>
  <cim:PhaseImpedanceData.b>9.43932938440164E-007</cim:PhaseImpedanceData.b>
</cim:PhaseImpedanceData>
.
.
.
.
</rdf:RDF>
```

APPENDIX B2

Extract of IEC 61850 equivalent of the reference
network model In SP1

Appendix B2a – Extract of IEC 61850 equivalent of the reference network model

The extract given hereafter is an extract of IEC 61850 equivalent of the reference network model where each power system component is identified by its 'name' attribute.

Appendix B2a – Extract of IEC 61850 equivalent of the reference network model

```
<?xml version="1.0" ?>
<SCL xmlns:xsi="http://www.w3.org/2001/XMLSchema-instance" xsi:noNamespaceSchemaLocation="test_validity_of_xml_file.xsd">
  <Header>
    <History id="TEST_THESIS_02012021.py" toolID="Python 3.6"/>
  </Header>
  <Line Desc="My Main feeder" Name="ieee123">
    <PowerTransformer Desc="Regulator" Name="reg4c" Type="PTR">
      <SubEquipment Name="T" phase="C">
        <LNNode IdInst="C1" InClass="YPTR" InInst="1"/>
      </SubEquipment>
      <TransformerWinding Name="W1" Type="PTW">
        <Terminal cNodeName="160" connectivityNode="ieee123/M1/160" lineName="ieee123" pathName="ieee123/M1/reg4c/T1"/>
      </TransformerWinding>
      <TransformerWinding Name="W2" Type="PTW">
        <Terminal cNodeName="160r" connectivityNode="ieee123/M1/160r" lineName="ieee123" pathName="ieee123/M1/reg4c/T2"/>
      </TransformerWinding>
    </PowerTransformer>
    <PowerTransformer Desc="Power Transformer" Name="xfm1" Type="PTR">
      <TransformerWinding Name="W1" Type="PTW">
        <Terminal cNodeName="61s" connectivityNode="ieee123/M1/61s" lineName="ieee123" pathName="ieee123/M1/xfm1/T1"/>
      </TransformerWinding>
      <TransformerWinding Name="W2" Type="PTW">
        <Terminal cNodeName="610" connectivityNode="ieee123/N1/610" lineName="ieee123" pathName="ieee123/N1/xfm1/T2"/>
      </TransformerWinding>
    </PowerTransformer>
    <PowerTransformer Desc="Power Transformer" Name="tr_d2" Type="PTR">
      <TransformerWinding Name="W2" Type="PTW">
        <Terminal cNodeName="79" connectivityNode="ieee123/M1/79" lineName="ieee123" pathName="ieee123/M1/tr_d2/T2"/>
      </TransformerWinding>
      <TransformerWinding Name="W1" Type="PTW">
        <Terminal cNodeName="900" connectivityNode="ieee123/N1/900" lineName="ieee123" pathName="ieee123/N1/tr_d2/T1"/>
      </TransformerWinding>
    </PowerTransformer>
    <PowerTransformer Desc="Regulator" Name="reg4b" Type="PTR">
      <SubEquipment Name="S" phase="B">
        <LNNode IdInst="C1" InClass="YPTR" InInst="1"/>
      </SubEquipment>
      <TransformerWinding Name="W1" Type="PTW">
        <Terminal cNodeName="160" connectivityNode="ieee123/M1/160" lineName="ieee123" pathName="ieee123/M1/reg4b/T1"/>
      </TransformerWinding>
      <TransformerWinding Name="W2" Type="PTW">
        <Terminal cNodeName="160r" connectivityNode="ieee123/M1/160r" lineName="ieee123" pathName="ieee123/M1/reg4b/T2"/>
      </TransformerWinding>
    </PowerTransformer>
    .
    .
    .
  </Line>
</SCL>
```

Appendix B2a – Extract of IEC 61850 equivalent of the reference network model - continued

```
.
.
<VoltageLevel Name="M1">
  <Voltage multiplier="k" unit="V" value="4.16"/>
  <ConductingEquipment Desc="Line/Cable segment" Name="I50" Type="LIN" pathName="iee123/M1/I50">
    <Terminal cNodeName="50" connectivityNode="iee123/M1/50" lineName="iee123" pathName="iee123/M1/I50/T1"/>
    <Terminal cNodeName="51" connectivityNode="iee123/M1/51" lineName="iee123" pathName="iee123/M1/I50/T2"/>
  </ConductingEquipment>
  .
  <ConductingEquipment Desc="Circuit Breaker" Name="BR2" Type="CBR" pathName="iee123/M1/BR2">
    <Terminal cNodeName="152" connectivityNode="iee123/M1/152" lineName="iee123" pathName="iee123/M1/BR2/T2"/>
    <Terminal cNodeName="13" connectivityNode="iee123/M1/13" lineName="iee123" pathName="iee123/M1/BR2/T1"/>
  </ConductingEquipment>
  .
  <ConductingEquipment Desc="Load" ID="_7EB6DFDC-7551-473B-86F8-4D164AF5F272" Name="s76c" Type="LOD" pathName="iee123/M1/s76c">
    <SubEquipment Name="R" phase="A">
      <LNode IdInst="C1" InClass="DLOD" InInst="1"/>
    </SubEquipment>
    <SubEquipment Name="T" phase="C">
      <LNode IdInst="C1" InClass="DLOD" InInst="2"/>
    </SubEquipment>
    <Terminal cNodeName="76" connectivityNode="iee123/M1/76" lineName="iee123" pathName="iee123/M1/s76c/T1"/>
  </ConductingEquipment>
  .
  <ConductingEquipment Desc="Shunt reactance" Name="c83" Type="CAP" pathName="iee123/M1/c83">
    <Terminal cNodeName="83" connectivityNode="iee123/M1/83" lineName="iee123" pathName="iee123/M1/c83/T1"/>
  </ConductingEquipment>
</VoltageLevel>
<ConnectivityNode Name="160" pathName="iee123/M1/160" x="3175" y="1850"/>
<ConnectivityNode Name="160r" pathName="iee123/M1/160r" x="3175" y="1850"/>
.
.
<ConnectivityNode Name="149" pathName="iee123/M1/149" x="300" y="1500"/>
<ConnectivityNode Name="105" pathName="iee123/M1/105" x="3525" y="2725"/>
<ConnectivityNode Name="135" pathName="iee123/M1/135" x="1600" y="2325"/>
<ConnectivityNode Name="36" pathName="iee123/M1/36" x="2075" y="2000"/>
</Line>
```

```
</SCL>
```

Appendix B2b – Extract of IEC 61850 equivalent file with a new ID attribute

The extract given hereafter is an extract of the IEC 61850 equivalent of the reference network model where a new ID attribute is proposed. In fact, each power system components is identified not by its 'name' attribute but by the same ID attribute as in the previous CIM reference model.

Appendix B2b – Extract of IEC 61850 equivalent file with a new ID attribute

```
<?xml version="1.0" ?>
<SCL xmlns:xsi="http://www.w3.org/2001/XMLSchema-instance" xsi:noNamespaceSchemaLocation="test_validity_of_xml_file.xsd">
  <Header>
    <History id="TEST_THESIS_02012021.py" toolID="Python 3.6"/>
  </Header>
  <Line Desc="My Main feeder" Name="ieee123">
    <PowerTransformer Desc="Regulator" ID="_C1322FC5-5B22-4749-93A6-EA61C62B70F9" Name="reg4c" Type="PTR">
      <SubEquipment Name="T" phase="C">
        <LNode IdInst="C1" InClass="YPTR" InInst="1"/>
      </SubEquipment>
      <TransformerWinding Name="W2" Type="PTW">
        <Terminal ID="_E1CBF52D-4EE0-47B6-AA43-496DD3542B66" cNodeName="160r" cnID="_4081276C-7B87-4933-B054-8EB8A5885330"
connectivityNode="ieee123/M1/160r" lineName="ieee123" pathName="ieee123/M1/reg4c/T2"/>
      </TransformerWinding>
      <TransformerWinding Name="W1" Type="PTW">
        <Terminal ID="_60F1F0DF-4B16-4EE1-8BE0-E23CFF550E47" cNodeName="160" cnID="_D4C8BDE7-E247-4EE8-8793-A2EA58AE0EF3"
connectivityNode="ieee123/M1/160" lineName="ieee123" pathName="ieee123/M1/reg4c/T1"/>
      </TransformerWinding>
    </PowerTransformer>
    <PowerTransformer Desc="Power Transformer" ID="_F6149DF5-4148-44B0-B3C3-71B5D65A23DF" Name="xfm1" Type="PTR">
      <TransformerWinding Name="W2" Type="PTW">
        <Terminal ID="_1512D37C-E6EB-4C66-8227-DE61904931FC" cNodeName="610" cnID="_278091EC-8E96-4726-8F04-E9EF3A367C23"
connectivityNode="ieee123/N1/610" lineName="ieee123" pathName="ieee123/N1/xfm1/T2"/>
      </TransformerWinding>
      <TransformerWinding Name="W1" Type="PTW">
        <Terminal ID="_7DED97E9-C1B5-47AA-A990-EDF4B906EBCF" cNodeName="61s" cnID="_54AE8769-8E8A-447F-BA9B-40234889A138"
connectivityNode="ieee123/M1/61s" lineName="ieee123" pathName="ieee123/M1/xfm1/T1"/>
      </TransformerWinding>
    </PowerTransformer>
    <PowerTransformer Desc="Power Transformer" ID="_BC6757C7-4E37-4E4E-8E85-3A1B3EB7828C" Name="tr_d2" Type="PTR">
      <TransformerWinding Name="W1" Type="PTW">
        <Terminal ID="_956696F2-8C6D-4201-9FEA-6DAA154072A0" cNodeName="900" cnID="_AB9514F7-40B8-4BA6-9276-30F948A305DB"
connectivityNode="ieee123/N1/900" lineName="ieee123" pathName="ieee123/N1/tr_d2/T1"/>
      </TransformerWinding>
      <TransformerWinding Name="W2" Type="PTW">
        <Terminal ID="_9DC27B71-69B3-4720-A9C6-67A05387E816" cNodeName="79" cnID="_C9A52B48-9DE8-4900-B53B-64262D4B8989"
connectivityNode="ieee123/M1/79" lineName="ieee123" pathName="ieee123/M1/tr_d2/T2"/>
      </TransformerWinding>
    </PowerTransformer>
  </Line>
</SCL>
```

Appendix B2b – Extract of IEC 61850 equivalent file with a new ID attribute

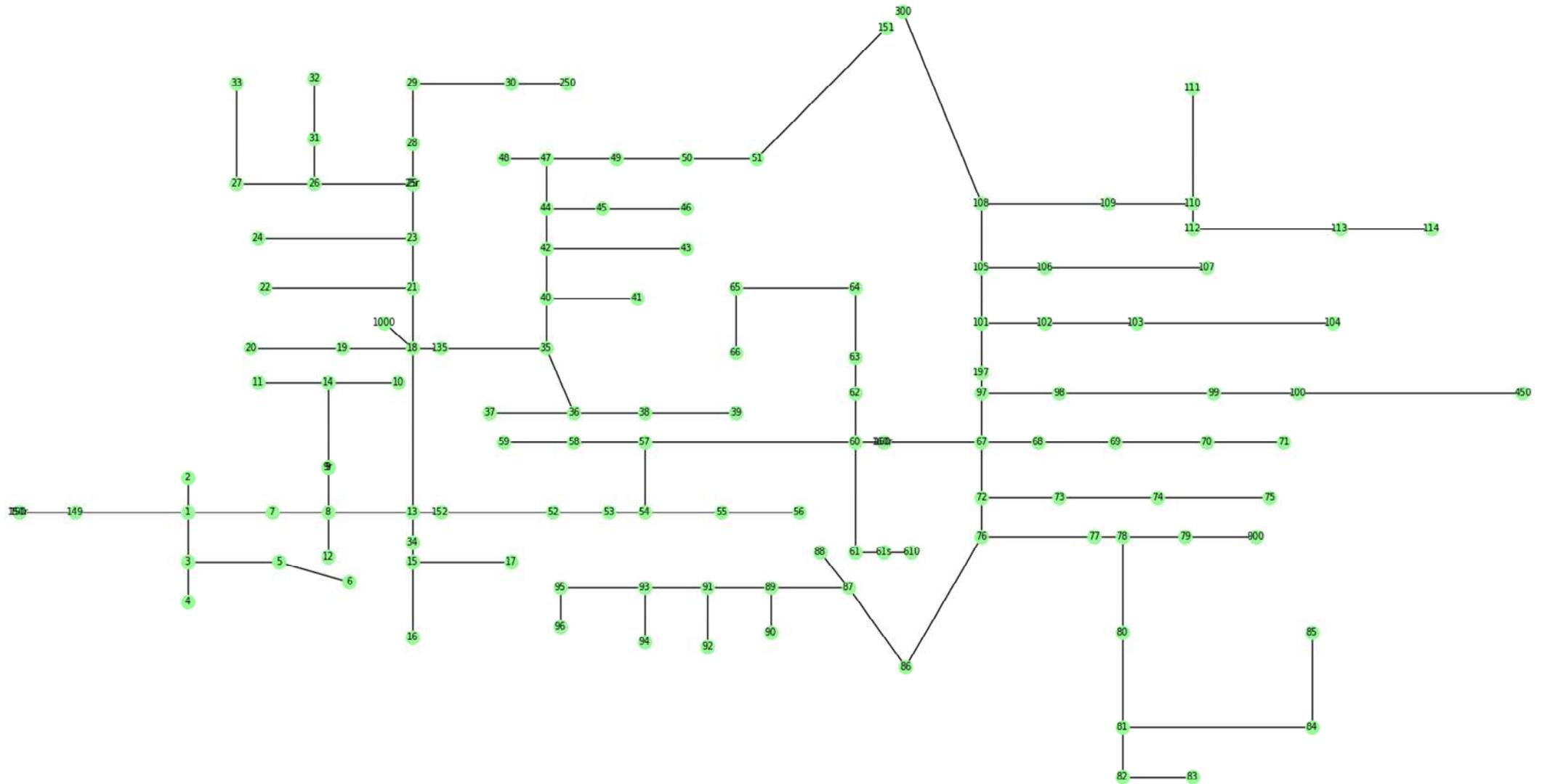
```
<VoltageLevel Name="M1">
  <Voltage multiplier="k" unit="V" value="4.16"/>
  <ConductingEquipment Desc="Line/Cable segment" ID="_8B5D38A8-3993-4FA5-899B-624F6A7DD88F" Name="I50" Type="LIN" pathName="ieee123/M1/I50">
    <Terminal ID="_80E66F61-86B4-4861-AF54-A50C7CDAE33C" cNodeName="51" cnID="_B1A89E68-5C0B-4D19-A445-270541356243"
connectivityNode="ieee123/M1/51" lineName="ieee123" pathName="ieee123/M1/I50/T2"/>
    <Terminal ID="_112F745E-32F1-4F64-898E-0C0C1846C5C5" cNodeName="50" cnID="_969CD7EF-E12E-4135-85CB-F527D400B525"
connectivityNode="ieee123/M1/50" lineName="ieee123" pathName="ieee123/M1/I50/T1"/>
  </ConductingEquipment>
  .
  .
  <ConductingEquipment Desc="Circuit Breaker" ID="_1D244F54-A550-49A2-80CE-126C35EA8E54" Name="BR2" Type="CBR" pathName="ieee123/M1/BR2">
    <Terminal ID="_3F044E5E-CFFB-4D8F-8105-30B7A553F751" cNodeName="152" cnID="_C1AEEDB9-B4C7-40E4-B72F-4914A881222E"
connectivityNode="ieee123/M1/152" lineName="ieee123" pathName="ieee123/M1/BR2/T2"/>
    <Terminal ID="_8D1CAA7A-F621-4A5B-8E27-933885D45E55" cNodeName="13" cnID="_023C19D1-FFF2-4DC2-9E28-85A28BED56C1"
connectivityNode="ieee123/M1/13" lineName="ieee123" pathName="ieee123/M1/BR2/T1"/>
  </ConductingEquipment>
  .
  .
  <ConductingEquipment Desc="Load" ID="_4A179794-9F66-4AE3-9821-97BD29E159CC" Name="s76b" Type="LOD" pathName="ieee123/M1/s76b">
    <SubEquipment Name="S" phase="B">
      <LNode IdInst="C1" InClass="DLOD" InInst="1"/>
    </SubEquipment>
    <SubEquipment Name="T" phase="C">
      <LNode IdInst="C1" InClass="DLOD" InInst="2"/>
    </SubEquipment>
    <Terminal ID="_6751E76A-9DD7-4714-9A63-87B3E491BEE9" cNodeName="76" cnID="_574AC391-32EF-451F-BAB6-5E2B72F9189E"
connectivityNode="ieee123/M1/76" lineName="ieee123" pathName="ieee123/M1/s76b/T1"/>
  </ConductingEquipment>
  .
  .
  <ConductingEquipment Desc="Shunt reactance" ID="_E41ADC05-89CA-47D8-9684-861DCCCB3B86" Name="c83" Type="CAP" pathName="ieee123/M1/c83">
    <Terminal ID="_23E29E9E-AECC-48D9-8AC4-EC65BF424845" cNodeName="83" cnID="_A81E9B6E-2B12-4FAA-8F66-DCAFC391F83A"
connectivityNode="ieee123/M1/83" lineName="ieee123" pathName="ieee123/M1/c83/T1"/>
  </ConductingEquipment>
  .
  .
</VoltageLevel>
<ConnectivityNode ID="_4081276C-7B87-4933-B054-8EB8A5885330" Name="160r" pathName="ieee123/M1/160r" x="3175" y="1850"/>
<ConnectivityNode ID="_D4C8BDE7-E247-4EE8-8793-A2EA58AE0EF3" Name="160" pathName="ieee123/M1/160" x="3175" y="1850"/>
.
.
<ConnectivityNode ID="_E3095E22-6F2C-47F8-9829-6FC4CA56ADFE" Name="149" pathName="ieee123/M1/149" x="300" y="1500"/>
<ConnectivityNode ID="_9934C41E-F800-4F01-BF82-8A11A6A4234F" Name="105" pathName="ieee123/M1/105" x="3525" y="2725"/>
<ConnectivityNode ID="_02C2A344-B877-4592-8827-599024A72C08" Name="135" pathName="ieee123/M1/135" x="1600" y="2325"/>
<ConnectivityNode ID="_13EF69CD-4EA8-46EC-8B49-09E0BBE45039" Name="36" pathName="ieee123/M1/36" x="2075" y="2000"/>
</Line>
.
</SCL>
```

APPENDIX B3

Graph of the reference network
for simulations in SP1

Appendix B3 – Graph of the reference network

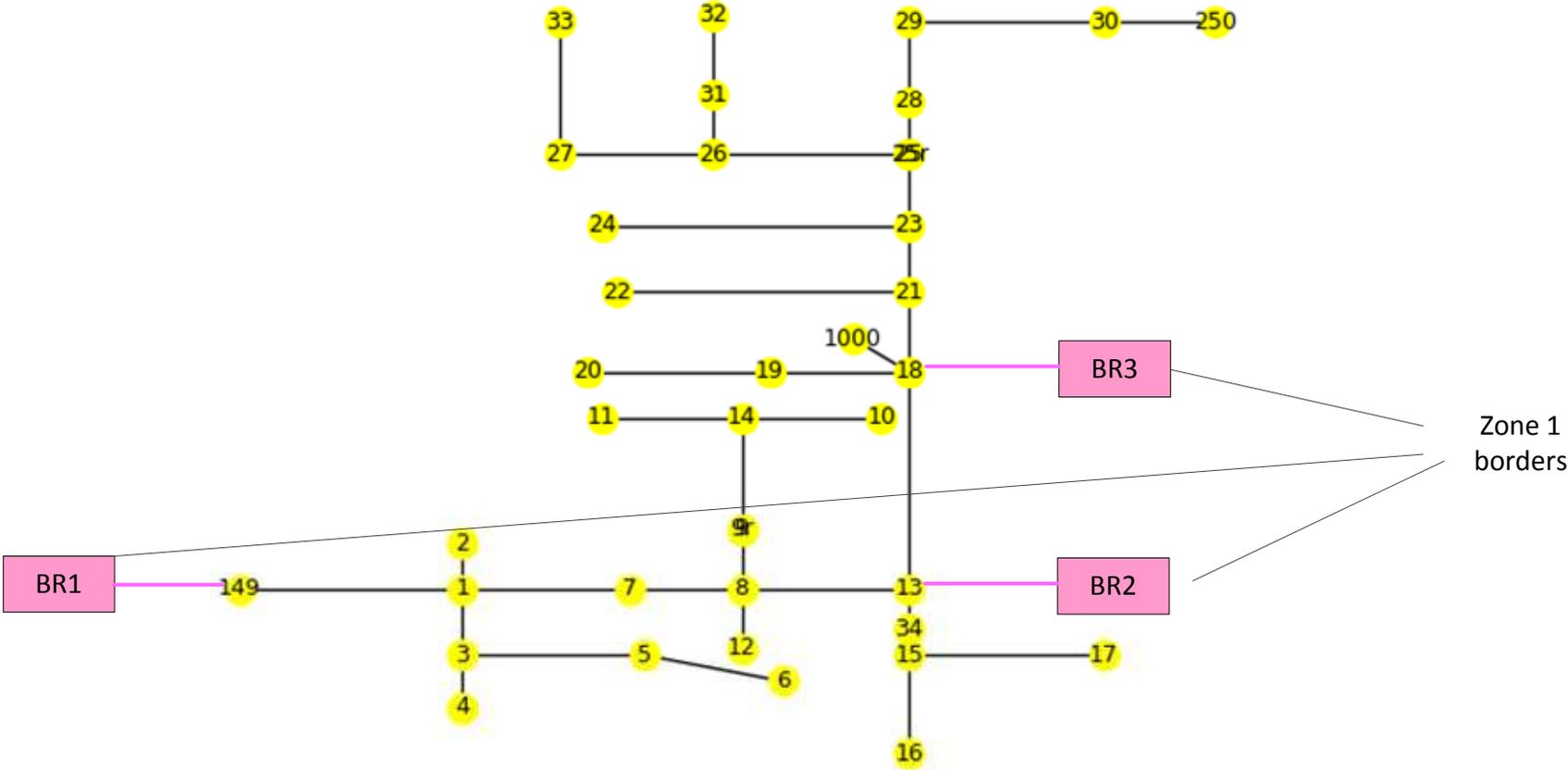
The graph below represents the connectivity of the reference network.



APPENDIX B4

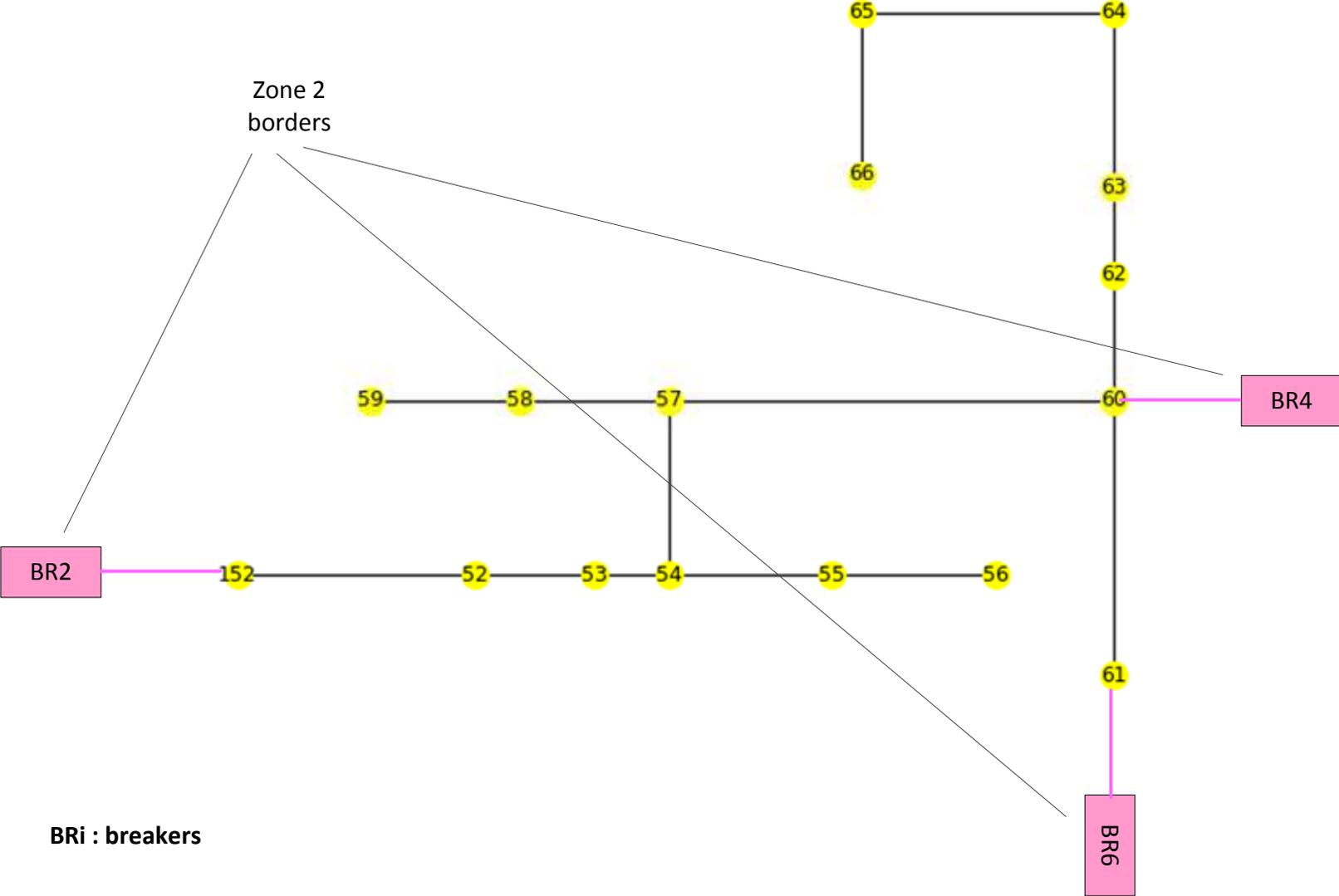
Zones creation in SP1

Appendix B4 – Zones creation – SP1

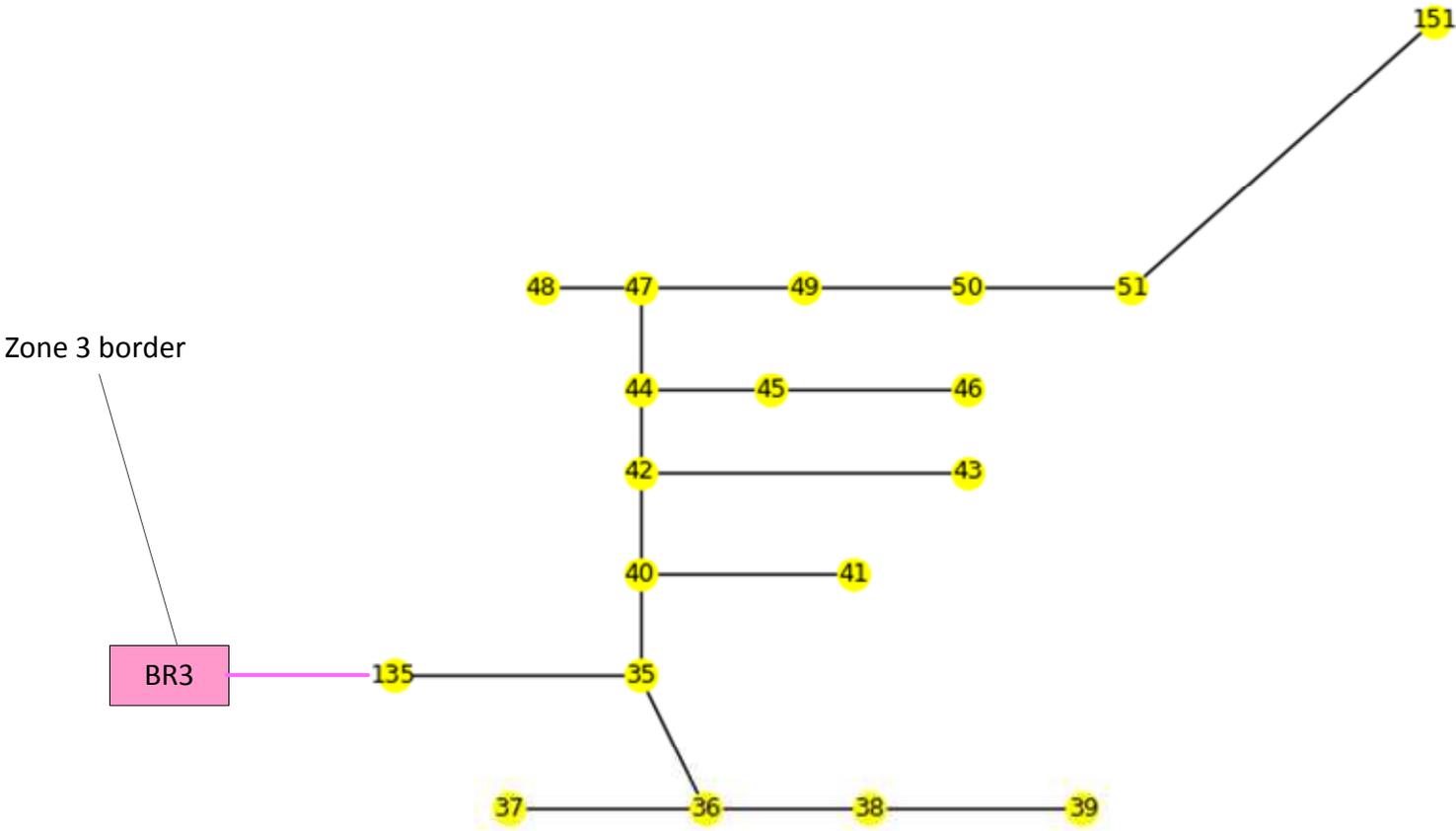


BRi : breakers

Appendix B4 – Zones creation – SP1 - continued



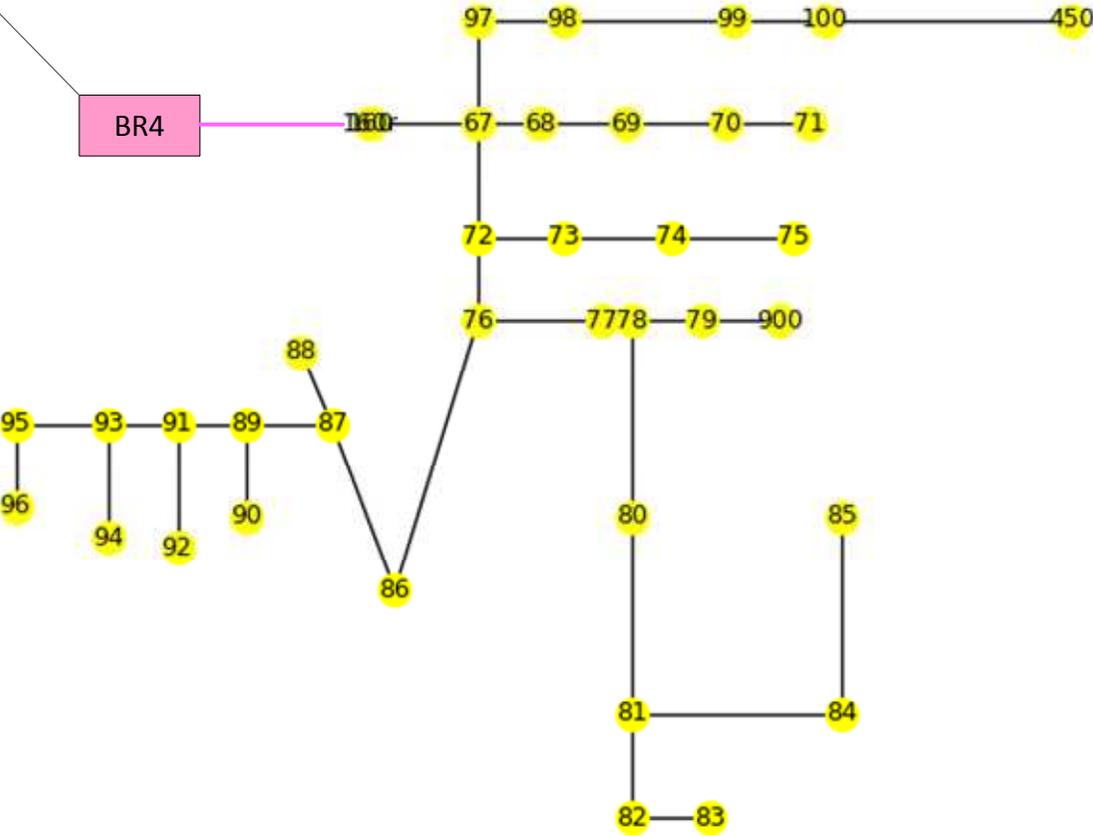
Appendix B4 – Zones creation – SP1 - continued



BRi : breakers

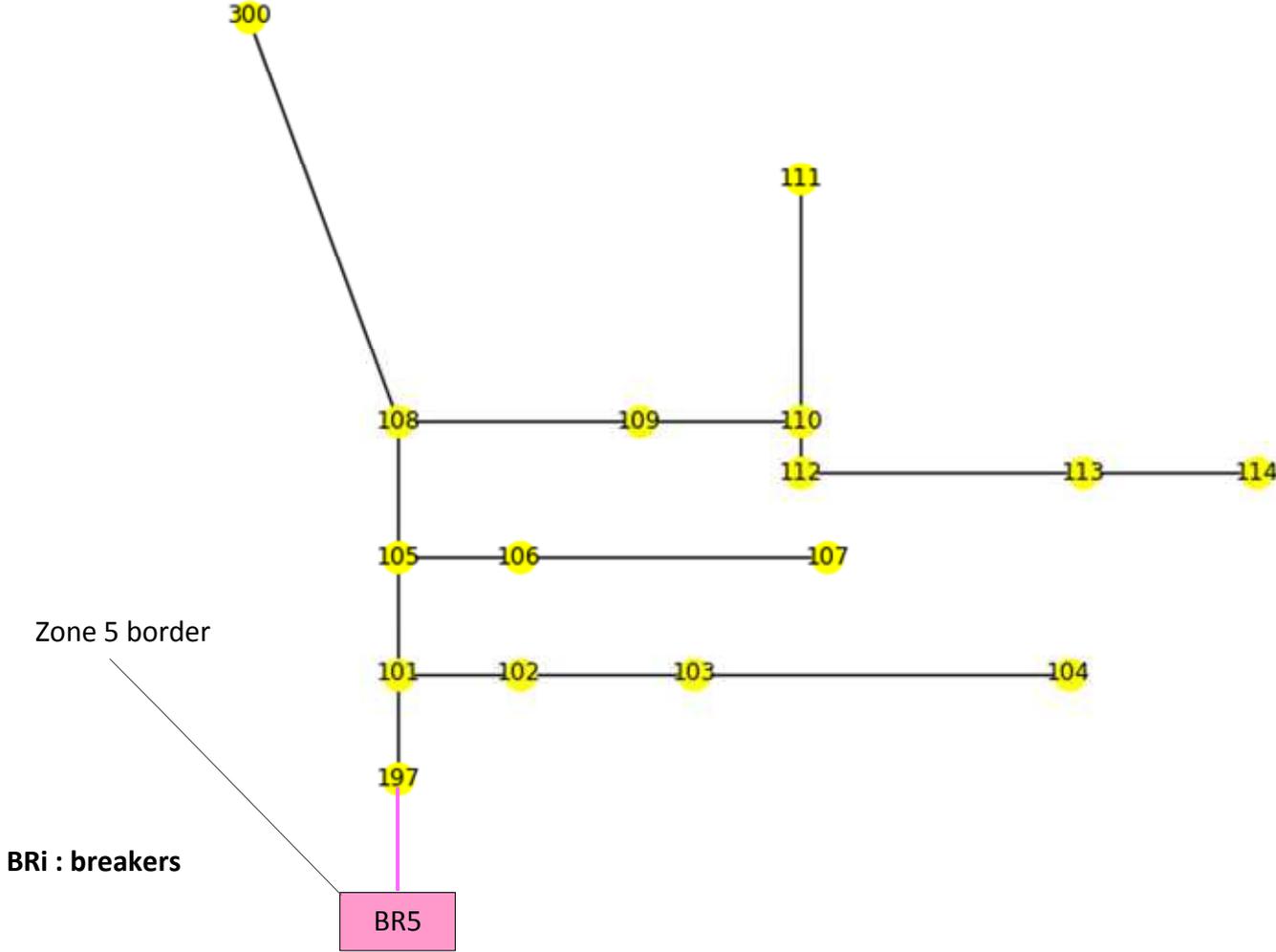
Appendix B4 – Zones creation – SP1 - continued

Zone 4 border



BRi : breakers

Appendix B4 – Zones creation – SP1 - continued



Appendix B4 – Zones creation – SP1 - continued

Zone 6 border



BRi : breakers

APPENDIX B5

OpenDSS netlist of the reference
network in SP1

Appendix B5 – OpenDSS netlist of the reference network – SP1

The OpenDSS netlist has been automatically generated from Python based on the incoming reference network. The netlist or circuit definition is controlled by a 'master' file we have called 'Test_Master.DSS', which invokes other files as below:

```
!-----REDIRECT ALL THE NETLIST FILES-----
```

```
Clear
```

```
CD C:/Users/SESA160732/Documents/test
```

```
Redirect Test_Upstream_net.DSS
```

```
Redirect Test_PowerTransformers.DSS
```

```
Redirect Test_Linecodes.DSS
```

```
Redirect Test_Lines.DSS
```

```
Redirect Test_Breakers.DSS
```

```
Redirect Test_Loads.DSS
```

```
Redirect Test_Capacitors.DSS
```

```
Redirect Test_Regulators.DSS
```

```
Redirect Test_Generators.DSS
```

```
Redirect Test_Monitors.DSS
```

```
!-----DEFINE THE BASE VOLTAGES-----
```

```
Set VoltageBases = [0.69, 0.48, 90.0, 4.16] ! ARRAY OF  
VOLTAGES IN KV
```

```
CalcVoltageBases ! PERFORMS ZERO LOAD POWER  
FLOW TO ESTIMATE VOLTAGE BASES
```

The 'master' file is run from another file we have called 'Test_Run.DSS' shown below:

```
CD C:/Users/SESA160732/Documents/test
```

```
Compile Test_Master.DSS
```

Appendix B5 – OpenDSS netlist of the reference network – SP1 - continued

B5-1- Upstream network

The upstream network is defined in a file called : Test_Upstream_net.DSS. The content is given below:

!SLACK BUS DEFINITION

New object=circuit.ieee123

~ BasekV=90.0 Bus1=150 MVASC3=10000.0 MVASC1=5000.0 angle=0 frequency=50 phases=3
x1r1=4.0 x0r0=3.0

Appendix B5 – OpenDSS netlist of the reference network – SP1 - continued

B5-2- Power transformers

The power transformers are defined in a file called : Test_PowerTransformers.DSS. The content is given below:

!POWER TRANSFORMER DEFINITION

New Transformer.xfm1 phases=3 windings=2 Xhl=5.0

~ wdg=1 bus=61s conn=Delta kv=4.16 kva=150.0

~ wdg=2 bus=610 conn=delta kv=0.48 kva=150.0

New Transformer.tr_d1 phases=3 windings=2 Xhl=7.0

~ wdg=1 bus=1000 conn=Delta kv=0.48 kva=1000.0

~ wdg=2 bus=18 conn=wye kv=4.16 kva=1000.0

New Transformer.tr1 phases=3 windings=2 Xhl=10.0

~ wdg=1 bus=150 conn=Delta kv=90.0 kva=10000.0

~ wdg=2 bus=150r conn=wye kv=4.16 kva=10000.0

New Transformer.tr_d2 phases=3 windings=2 Xhl=7.0

~ wdg=1 bus=900 conn=Delta kv=0.48 kva=1000.0

~ wdg=2 bus=79 conn=wye kv=4.16 kva=1000.0

Appendix B5 – OpenDSS netlist of the reference network – SP1 - continued

B5-3- Linecodes

The line configuration types are defined in a file called : Test_Lincodes.DSS. The content is given below:

!LINECODE DEFINITION

New Linecode.10 nphases=1 BaseFreq=50

~ rmatrix = [0.251742424]

~ xmatrix = [0.255208333]

~ cmatrix = [2.2703661280001484]

New Linecode.6 nphases=3 BaseFreq=50

~ rmatrix = [0.086666667 | 0.02907197 0.087405303 | 0.029545455 0.029924242 0.088371212]

~ xmatrix = [0.204166667 | 0.072897727 0.201723485 | 0.095018939 0.080227273 0.198522727]

~ cmatrix = [2.851710072000188 | -0.3507555660000224 2.7113475600001777 | -0.9202937870000605 -0.5850112530000382
3.004631862000197]

New Linecode.3 nphases=3 BaseFreq=50

~ rmatrix = [0.087405303 | 0.02907197 0.086666667 | 0.029924242 0.029545455 0.088371212]

~ xmatrix = [0.201723485 | 0.072897727 0.204166667 | 0.080227273 0.095018939 0.198522727]

~ cmatrix = [2.7113475600001777 | -0.3507555660000224 2.851710072000188 | -0.5850112530000382 -0.9202937870000605
3.004631862000197]

New Linecode.11 nphases=1 BaseFreq=50

~ rmatrix = [0.251742424]

~ xmatrix = [0.255208333]

~ cmatrix = [2.2703661280001484]

New Linecode.2 nphases=3 BaseFreq=50

~ rmatrix = [0.088371212 | 0.02992424 0.087405303 | 0.029545455 0.02907197 0.086666667]

~ xmatrix = [0.198522727 | 0.080227273 0.201723485 | 0.095018939 0.072897727 0.204166667]

~ cmatrix = [3.004631862000197 | -0.5850112530000382 2.7113475600001777 | -0.9202937870000605 -0.3507555660000224
2.851710072000188]

Appendix B5 – OpenDSS netlist of the reference network – SP1 - continued

B5-3- Linecodes - continued

New Linecode.12 nphases=3 BaseFreq=50

~ rmatrix = [0.288049242 | 0.09844697 0.29032197 | 0.093257576 0.09844697 0.288049242]
~ xmatrix = [0.142443182 | 0.052556818 0.135643939 | 0.040852273 0.052556818 0.142443182]
~ cmatrix = [33.77150149000231 | 0.0 33.77150149000231 | 0.0 0.0 33.77150149000231]

New Linecode.1 nphases=3 BaseFreq=50

~ rmatrix = [0.086666667 | 0.029545455 0.088371212 | 0.02907197 0.029924242 0.087405303]
~ xmatrix = [0.204166667 | 0.095018939 0.198522727 | 0.072897727 0.080227273 0.201723485]
~ cmatrix = [2.851710072000188 | -0.9202937870000605 3.004631862000197 | -0.3507555660000224 -0.5850112530000382
2.7113475600001777]

New Linecode.9 nphases=1 BaseFreq=50

~ rmatrix = [0.251742424]
~ xmatrix = [0.255208333]
~ cmatrix = [2.2703661280001484]

New Linecode.4 nphases=3 BaseFreq=50

~ rmatrix = [0.087405303 | 0.029924242 0.088371212 | 0.02907197 0.029545455 0.086666667]
~ xmatrix = [0.201723485 | 0.080227273 0.198522727 | 0.072897727 0.095018939 0.204166667]
~ cmatrix = [2.7113475600001777 | 0.5850112530000382 3.004631862000197 | -0.3507555660000224 -0.9202937870000605
2.851710072000188]

New Linecode.7 nphases=2 BaseFreq=50

~ rmatrix = [0.086666667 | 0.02907197 0.087405303]
~ xmatrix = [0.204166667 | 0.072897727 0.201723485]
~ cmatrix = [2.56982959600017 | -0.5299513700000361 2.597460011000171]

New Linecode.5 nphases=3 BaseFreq=50

~ rmatrix = [0.088371212 | 0.029545455 0.086666667 | 0.029924242 0.02907197 0.087405303]
~ xmatrix = [0.198522727 | 0.095018939 0.204166667 | 0.080227273 0.072897727 0.201723485]
~ cmatrix = [3.004631862000197 | -0.9202937870000605 2.851710072000188 | -0.5850112530000382 -0.3507555660000224
2.7113475600001777]

Appendix B5 – OpenDSS netlist of the reference network – SP1 - continued

B5-3- Linecodes - continued

New Linecode.8 nphases=2 BaseFreq=50

~ rmatrix = [0.086666667 | 0.02907197 0.087405303]

~ xmatrix = [0.204166667 | 0.072897727 0.201723485]

~ cmatrix = [2.56982959600017 | -0.5299513700000361 2.597460011000171]

Appendix B5 – OpenDSS netlist of the reference network – SP1 - continued

B5-4- Lines

!LINE DEFINITION

New Line.I95 Phases=1 Bus1=95.2 Bus2=96.2 Linecode=10 Length=0.2
New Line.I30 Phases=3 Bus1=28.1.2.3 Bus2=29.1.2.3 Linecode=2 Length=0.3
New Line.I9 Phases=1 Bus1=8.1 Bus2=9.1 Linecode=9 Length=0.225
New Line.I21 Phases=1 Bus1=21.2 Bus2=22.2 Linecode=10 Length=0.525
New Line.I1 Phases=1 Bus1=1.2 Bus2=2.2 Linecode=10 Length=0.175
New Line.I25 Phases=2 Bus1=25r.3.1 Bus2=26.3.1 Linecode=7 Length=0.35
New Line.I57 Phases=1 Bus1=57.2 Bus2=58.2 Linecode=10 Length=0.25
New Line.I74 Phases=1 Bus1=73.3 Bus2=74.3 Linecode=11 Length=0.35
New Line.I62 Phases=3 Bus1=62.1.2.3 Bus2=63.1.2.3 Linecode=12 Length=0.175
New Line.I49 Phases=3 Bus1=49.1.2.3 Bus2=50.1.2.3 Linecode=4 Length=0.25
New Line.I11 Phases=1 Bus1=9r.1 Bus2=14.1 Linecode=9 Length=0.425
New Line.I84 Phases=3 Bus1=82.1.2.3 Bus2=83.1.2.3 Linecode=6 Length=0.25
New Line.I89 Phases=1 Bus1=89.2 Bus2=90.2 Linecode=10 Length=0.25
New Line.I63 Phases=3 Bus1=63.1.2.3 Bus2=64.1.2.3 Linecode=12 Length=0.35
New Line.I6 Phases=1 Bus1=5.3 Bus2=6.3 Linecode=11 Length=0.25
New Line.I110 Phases=1 Bus1=110.1 Bus2=111.1 Linecode=9 Length=0.575
New Line.I99 Phases=3 Bus1=100.1.2.3 Bus2=450.1.2.3 Linecode=3 Length=0.8
New Line.I112 Phases=1 Bus1=112.1 Bus2=113.1 Linecode=9 Length=0.525
New Line.I54 Phases=3 Bus1=54.1.2.3 Bus2=55.1.2.3 Linecode=1 Length=0.275
New Line.I33 Phases=1 Bus1=31.3 Bus2=32.3 Linecode=11 Length=0.3
New Line.I46 Phases=1 Bus1=45.1 Bus2=46.1 Linecode=9 Length=0.3
New Line.I34 Phases=1 Bus1=34.3 Bus2=15.3 Linecode=11 Length=0.1
New Line.I51 Phases=3 Bus1=51.1.2.3 Bus2=151.1.2.3 Linecode=4 Length=0.5
New Line.I115 Phases=3 Bus1=149.1.2.3 Bus2=1.1.2.3 Linecode=1 Length=0.4
New Line.I24 Phases=3 Bus1=23.1.2.3 Bus2=25.1.2.3 Linecode=2 Length=0.275
New Line.I113 Phases=1 Bus1=113.1 Bus2=114.1 Linecode=9 Length=0.325
New Line.I85 Phases=1 Bus1=84.3 Bus2=85.3 Linecode=11 Length=0.475
New Line.I88 Phases=3 Bus1=87.1.2.3 Bus2=89.1.2.3 Linecode=6 Length=0.275
New Line.I81 Phases=3 Bus1=80.1.2.3 Bus2=81.1.2.3 Linecode=6 Length=0.175
New Line.I8 Phases=1 Bus1=8.2 Bus2=12.2 Linecode=10 Length=0.225
New Line.I16 Phases=1 Bus1=15.3 Bus2=16.3 Linecode=11 Length=0.375

Appendix B5 – OpenDSS netlist of the reference network – SP1 - continued

B5-4- Lines - continued

New Line.l64 Phases=3 Bus1=64.1.2.3 Bus2=65.1.2.3 Linecode=12 Length=0.425
New Line.l59 Phases=1 Bus1=58.2 Bus2=59.2 Linecode=10 Length=0.25
New Line.l2 Phases=1 Bus1=1.3 Bus2=3.3 Linecode=11 Length=0.25
New Line.l67 Phases=3 Bus1=67.1.2.3 Bus2=72.1.2.3 Linecode=3 Length=0.275
New Line.l97 Phases=3 Bus1=98.1.2.3 Bus2=99.1.2.3 Linecode=3 Length=0.55
New Line.l102 Phases=1 Bus1=102.3 Bus2=103.3 Linecode=11 Length=0.325
New Line.l106 Phases=1 Bus1=106.2 Bus2=107.2 Linecode=10 Length=0.575
New Line.l114 Phases=3 Bus1=135.1.2.3 Bus2=35.1.2.3 Linecode=4 Length=0.375
New Line.l12 Phases=1 Bus1=13.3 Bus2=34.3 Linecode=11 Length=0.15
New Line.l111 Phases=1 Bus1=110.1 Bus2=112.1 Linecode=9 Length=0.125
New Line.l65 Phases=3 Bus1=65.1.2.3 Bus2=66.1.2.3 Linecode=12 Length=0.325
New Line.l83 Phases=1 Bus1=81.3 Bus2=84.3 Linecode=11 Length=0.675
New Line.l96 Phases=3 Bus1=97.1.2.3 Bus2=98.1.2.3 Linecode=3 Length=0.275
New Line.l82 Phases=3 Bus1=81.1.2.3 Bus2=82.1.2.3 Linecode=6 Length=0.25
New Line.l58 Phases=3 Bus1=57.1.2.3 Bus2=60.1.2.3 Linecode=3 Length=0.75
New Line.l40 Phases=1 Bus1=40.3 Bus2=41.3 Linecode=11 Length=0.325
New Line.l50 Phases=3 Bus1=50.1.2.3 Bus2=51.1.2.3 Linecode=4 Length=0.25
New Line.l86 Phases=3 Bus1=86.1.2.3 Bus2=87.1.2.3 Linecode=6 Length=0.45
New Line.l5 Phases=1 Bus1=3.3 Bus2=5.3 Linecode=11 Length=0.325
New Line.l101 Phases=3 Bus1=101.1.2.3 Bus2=105.1.2.3 Linecode=3 Length=0.275
New Line.l4 Phases=1 Bus1=3.3 Bus2=4.3 Linecode=11 Length=0.2
New Line.l68 Phases=3 Bus1=67.1.2.3 Bus2=97.1.2.3 Linecode=3 Length=0.25
New Line.l39 Phases=1 Bus1=38.2 Bus2=39.2 Linecode=10 Length=0.325
New Line.l56 Phases=3 Bus1=55.1.2.3 Bus2=56.1.2.3 Linecode=1 Length=0.275
New Line.l47 Phases=3 Bus1=47.1.2.3 Bus2=48.1.2.3 Linecode=4 Length=0.15
New Line.l98 Phases=3 Bus1=99.1.2.3 Bus2=100.1.2.3 Linecode=3 Length=0.3
New Line.l13 Phases=3 Bus1=13.1.2.3 Bus2=18.1.2.3 Linecode=2 Length=0.825
New Line.l90 Phases=3 Bus1=89.1.2.3 Bus2=91.1.2.3 Linecode=6 Length=0.225
New Line.l70 Phases=1 Bus1=69.1 Bus2=70.1 Linecode=9 Length=0.325
New Line.l10 Phases=3 Bus1=8.1.2.3 Bus2=13.1.2.3 Linecode=1 Length=0.3
New Line.l3 Phases=3 Bus1=1.1.2.3 Bus2=7.1.2.3 Linecode=1 Length=0.3
New Line.l73 Phases=3 Bus1=72.1.2.3 Bus2=76.1.2.3 Linecode=3 Length=0.2

Appendix B5 – OpenDSS netlist of the reference network – SP1 - continued

B5-4- Lines - continued

New Line.l29 Phases=1 Bus1=27.1 Bus2=33.1 Linecode=9 Length=0.5
New Line.l15 Phases=1 Bus1=14.1 Bus2=10.1 Linecode=9 Length=0.25
New Line.l80 Phases=3 Bus1=78.1.2.3 Bus2=80.1.2.3 Linecode=6 Length=0.475
New Line.l61 Phases=3 Bus1=60.1.2.3 Bus2=62.1.2.3 Linecode=12 Length=0.25
New Line.l44 Phases=1 Bus1=44.1 Bus2=45.1 Linecode=9 Length=0.2
New Line.l26 Phases=3 Bus1=25.1.2.3 Bus2=28.1.2.3 Linecode=2 Length=0.2
New Line.l43 Phases=3 Bus1=42.1.2.3 Bus2=44.1.2.3 Linecode=1 Length=0.2
New Line.l19 Phases=3 Bus1=18.1.2.3 Bus2=21.1.2.3 Linecode=2 Length=0.3
New Line.l55 Phases=3 Bus1=54.1.2.3 Bus2=57.1.2.3 Linecode=3 Length=0.35
New Line.l45 Phases=3 Bus1=44.1.2.3 Bus2=47.1.2.3 Linecode=1 Length=0.25
New Line.l118 Phases=3 Bus1=197.1.2.3 Bus2=101.1.2.3 Linecode=3 Length=0.25
New Line.l14 Phases=1 Bus1=14.1 Bus2=11.1 Linecode=9 Length=0.25
New Line.l76 Phases=3 Bus1=76.1.2.3 Bus2=77.1.2.3 Linecode=6 Length=0.4
New Line.l32 Phases=3 Bus1=30.1.2.3 Bus2=250.1.2.3 Linecode=2 Length=0.2
New Line.l23 Phases=1 Bus1=23.3 Bus2=24.3 Linecode=11 Length=0.55
New Line.l100 Phases=1 Bus1=101.3 Bus2=102.3 Linecode=11 Length=0.225
New Line.l94 Phases=3 Bus1=93.1.2.3 Bus2=95.1.2.3 Linecode=6 Length=0.3
New Line.l93 Phases=1 Bus1=93.1 Bus2=94.1 Linecode=9 Length=0.275
New Line.l72 Phases=1 Bus1=72.3 Bus2=73.3 Linecode=11 Length=0.275
New Line.l22 Phases=3 Bus1=21.1.2.3 Bus2=23.1.2.3 Linecode=2 Length=0.25
New Line.l18 Phases=1 Bus1=18.1 Bus2=19.1 Linecode=9 Length=0.25
New Line.l38 Phases=1 Bus1=36.2 Bus2=38.2 Linecode=10 Length=0.25
New Line.l31 Phases=3 Bus1=29.1.2.3 Bus2=30.1.2.3 Linecode=2 Length=0.35
New Line.l53 Phases=3 Bus1=53.1.2.3 Bus2=54.1.2.3 Linecode=1 Length=0.125
New Line.l7 Phases=3 Bus1=7.1.2.3 Bus2=8.1.2.3 Linecode=1 Length=0.2
New Line.l78 Phases=3 Bus1=77.1.2.3 Bus2=78.1.2.3 Linecode=6 Length=0.1
New Line.l35 Phases=2 Bus1=35.1.2 Bus2=36.1.2 Linecode=8 Length=0.65
New Line.l104 Phases=1 Bus1=105.2 Bus2=106.2 Linecode=10 Length=0.225
New Line.l42 Phases=1 Bus1=42.2 Bus2=43.2 Linecode=10 Length=0.5
New Line.l36 Phases=3 Bus1=35.1.2.3 Bus2=40.1.2.3 Linecode=1 Length=0.25

Appendix B5 – OpenDSS netlist of the reference network – SP1 - continued

B5-4- Lines - continued

New Line.l71 Phases=1 Bus1=70.1 Bus2=71.1 Linecode=9 Length=0.275
New Line.l60 Phases=3 Bus1=60.1.2.3 Bus2=61.1.2.3 Linecode=5 Length=0.55
New Line.l107 Phases=1 Bus1=108.1 Bus2=109.1 Linecode=9 Length=0.45
New Line.l116 Phases=3 Bus1=152.1.2.3 Bus2=52.1.2.3 Linecode=1 Length=0.4
New Line.l105 Phases=3 Bus1=105.1.2.3 Bus2=108.1.2.3 Linecode=3 Length=0.325
New Line.l52 Phases=3 Bus1=52.1.2.3 Bus2=53.1.2.3 Linecode=1 Length=0.2
New Line.l69 Phases=1 Bus1=68.1 Bus2=69.1 Linecode=9 Length=0.275
New Line.l17 Phases=1 Bus1=15.3 Bus2=17.3 Linecode=11 Length=0.35
New Line.l20 Phases=1 Bus1=19.1 Bus2=20.1 Linecode=9 Length=0.325
New Line.l103 Phases=1 Bus1=103.3 Bus2=104.3 Linecode=11 Length=0.7
New Line.l77 Phases=3 Bus1=76.1.2.3 Bus2=86.1.2.3 Linecode=3 Length=0.7
New Line.l66 Phases=1 Bus1=67.1 Bus2=68.1 Linecode=9 Length=0.2
New Line.l48 Phases=3 Bus1=47.1.2.3 Bus2=49.1.2.3 Linecode=4 Length=0.25
New Line.l28 Phases=1 Bus1=26.3 Bus2=31.3 Linecode=11 Length=0.225
New Line.l117 Phases=3 Bus1=160r.1.2.3 Bus2=67.1.2.3 Linecode=6 Length=0.35
New Line.l91 Phases=1 Bus1=91.3 Bus2=92.3 Linecode=11 Length=0.3
New Line.l27 Phases=2 Bus1=26.3.1 Bus2=27.3.1 Linecode=7 Length=0.275
New Line.l37 Phases=1 Bus1=36.1 Bus2=37.1 Linecode=9 Length=0.3
New Line.l79 Phases=3 Bus1=78.1.2.3 Bus2=79.1.2.3 Linecode=6 Length=0.225
New Line.l92 Phases=3 Bus1=91.1.2.3 Bus2=93.1.2.3 Linecode=6 Length=0.225
New Line.l41 Phases=3 Bus1=40.1.2.3 Bus2=42.1.2.3 Linecode=1 Length=0.25
New Line.l75 Phases=1 Bus1=74.3 Bus2=75.3 Linecode=11 Length=0.4
New Line.l87 Phases=1 Bus1=87.1 Bus2=88.1 Linecode=9 Length=0.175
New Line.l109 Phases=1 Bus1=109.1 Bus2=110.1 Linecode=9 Length=0.3
New Line.l108 Phases=3 Bus1=108.1.2.3 Bus2=300.1.2.3 Linecode=3 Length=1.0

Appendix B5 – OpenDSS netlist of the reference network – SP1 - continued

B5-5- Breakers/Reclosers

The breakers/reclosers are defined in a file called : Test_Breakers.DSS. The content is given below:

!BREAKER DEFINITION

!NORMALLY CLOSED SWITCHES ARE DEFINED AS SHORT LINES

New Line.BR4 phases=3 Bus1=60.1.2.3 Bus2=160.1.2.3 r1=0.001 r0=0.001 x1=0.0 x0=0.0 c1=0.0 c0=0.0 Length=0.001 Switch=yes
New Line.BR2 phases=3 Bus1=13.1.2.3 Bus2=152.1.2.3 r1=0.001 r0=0.001 x1=0.0 x0=0.0 c1=0.0 c0=0.0 Length=0.001 Switch=yes
New Line.BR6 phases=3 Bus1=61.1.2.3 Bus2=61s.1.2.3 r1=0.001 r0=0.001 x1=0.0 x0=0.0 c1=0.0 c0=0.0 Length=0.001 Switch=yes
New Line.BR3 phases=3 Bus1=18.1.2.3 Bus2=135.1.2.3 r1=0.001 r0=0.001 x1=0.0 x0=0.0 c1=0.0 c0=0.0 Length=0.001 Switch=yes
New Line.BR5 phases=3 Bus1=97.1.2.3 Bus2=197.1.2.3 r1=0.001 r0=0.001 x1=0.0 x0=0.0 c1=0.0 c0=0.0 Length=0.001 Switch=yes
New Line.BR1 phases=3 Bus1=150r.1.2.3 Bus2=149.1.2.3 r1=0.001 r0=0.001 x1=0.0 x0=0.0 c1=0.0 c0=0.0 Length=0.001 Switch=yes

Appendix B5 – OpenDSS netlist of the reference network – SP1 - continued

B5-6- Loads

The loads are defined in a file called : Test_Loads.DSS. As already explained, the load models have been changed to ‘Constant power’ to be able to run a time series power flow. The content is given below:

!LOADSHAPES DEFINITION

```
New LoadShape.loadcurve_s99b npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s99b.txt action=normalize
New LoadShape.loadcurve_s20a npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s20a.txt action=normalize
New LoadShape.loadcurve_s5c npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s5c.txt action=normalize
New LoadShape.loadcurve_s24c npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s24c.txt action=normalize
New LoadShape.loadcurve_s37a npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s37a.txt action=normalize
New LoadShape.loadcurve_s102c npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s102c.txt action=normalize
New LoadShape.loadcurve_s83c npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s83c.txt action=normalize
New LoadShape.loadcurve_s85c npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s85c.txt action=normalize
New LoadShape.loadcurve_s62c npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s62c.txt action=normalize
New LoadShape.loadcurve_s88a npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s88a.txt action=normalize
New LoadShape.loadcurve_s52a npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s52a.txt action=normalize
New LoadShape.loadcurve_s84c npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s84c.txt action=normalize
New LoadShape.loadcurve_s65b npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s65b.txt action=normalize
New LoadShape.loadcurve_s79a npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s79a.txt action=normalize
New LoadShape.loadcurve_s7a npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s7a.txt action=normalize
New LoadShape.loadcurve_s12b npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s12b.txt action=normalize
New LoadShape.loadcurve_s76a npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s76a.txt action=normalize
New LoadShape.loadcurve_s63a npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s63a.txt action=normalize
New LoadShape.loadcurve_s29a npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s29a.txt action=normalize
New LoadShape.loadcurve_s74c npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s74c.txt action=normalize
New LoadShape.loadcurve_s92c npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s92c.txt action=normalize
New LoadShape.loadcurve_s49b npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s49b.txt action=normalize
New LoadShape.loadcurve_s112a npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s112a.txt action=normalize
New LoadShape.loadcurve_s46a npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s46a.txt action=normalize
New LoadShape.loadcurve_s50c npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s50c.txt action=normalize
New LoadShape.loadcurve_s1a npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s1a.txt action=normalize
New LoadShape.loadcurve_s6c npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s6c.txt action=normalize
New LoadShape.loadcurve_s75c npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s75c.txt action=normalize
```

Appendix B5 – OpenDSS netlist of the reference network – SP1 - continued

B5-6- Loads - continued

New LoadShape.loadcurve_s104c npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s104c.txt action=normalize
New LoadShape.loadcurve_s76b npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s76b.txt action=normalize
New LoadShape.loadcurve_s22b npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s22b.txt action=normalize
New LoadShape.loadcurve_s96b npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s96b.txt action=normalize
New LoadShape.loadcurve_s103c npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s103c.txt action=normalize
New LoadShape.loadcurve_s113a npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s113a.txt action=normalize
New LoadShape.loadcurve_s43b npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s43b.txt action=normalize
New LoadShape.loadcurve_s82a npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s82a.txt action=normalize
New LoadShape.loadcurve_s90b npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s90b.txt action=normalize
New LoadShape.loadcurve_s80b npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s80b.txt action=normalize
New LoadShape.loadcurve_s11a npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s11a.txt action=normalize
New LoadShape.loadcurve_s55a npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s55a.txt action=normalize
New LoadShape.loadcurve_s111a npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s111a.txt action=normalize
New LoadShape.loadcurve_s49c npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s49c.txt action=normalize
New LoadShape.loadcurve_s109a npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s109a.txt action=normalize
New LoadShape.loadcurve_s65c npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s65c.txt action=normalize
New LoadShape.loadcurve_s70a npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s70a.txt action=normalize
New LoadShape.loadcurve_s87b npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s87b.txt action=normalize
New LoadShape.loadcurve_s59b npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s59b.txt action=normalize
New LoadShape.loadcurve_s98a npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s98a.txt action=normalize
New LoadShape.loadcurve_s86b npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s86b.txt action=normalize
New LoadShape.loadcurve_s66c npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s66c.txt action=normalize
New LoadShape.loadcurve_s38b npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s38b.txt action=normalize
New LoadShape.loadcurve_s48 npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s48.txt action=normalize
New LoadShape.loadcurve_s51a npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s51a.txt action=normalize
New LoadShape.loadcurve_s19a npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s19a.txt action=normalize
New LoadShape.loadcurve_s53a npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s53a.txt action=normalize
New LoadShape.loadcurve_s64b npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s64b.txt action=normalize
New LoadShape.loadcurve_s9a npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s9a.txt action=normalize
New LoadShape.loadcurve_s73c npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s73c.txt action=normalize
New LoadShape.loadcurve_s77b npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s77b.txt action=normalize
New LoadShape.loadcurve_s4c npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s4c.txt action=normalize

Appendix B5 – OpenDSS netlist of the reference network – SP1 - continued

B5-6- Loads - continued

New LoadShape.loadcurve_s35a npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s35a.txt action=normalize
New LoadShape.loadcurve_s100c npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s100c.txt action=normalize
New LoadShape.loadcurve_s33a npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s33a.txt action=normalize
New LoadShape.loadcurve_s69a npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s69a.txt action=normalize
New LoadShape.loadcurve_s28a npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s28a.txt action=normalize
New LoadShape.loadcurve_s71a npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s71a.txt action=normalize
New LoadShape.loadcurve_s30c npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s30c.txt action=normalize
New LoadShape.loadcurve_s10a npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s10a.txt action=normalize
New LoadShape.loadcurve_s31c npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s31c.txt action=normalize
New LoadShape.loadcurve_s65a npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s65a.txt action=normalize
New LoadShape.loadcurve_s49a npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s49a.txt action=normalize
New LoadShape.loadcurve_s58b npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s58b.txt action=normalize
New LoadShape.loadcurve_s45a npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s45a.txt action=normalize
New LoadShape.loadcurve_s56b npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s56b.txt action=normalize
New LoadShape.loadcurve_s47 npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s47.txt action=normalize
New LoadShape.loadcurve_s114a npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s114a.txt action=normalize
New LoadShape.loadcurve_s32c npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s32c.txt action=normalize
New LoadShape.loadcurve_s42a npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s42a.txt action=normalize
New LoadShape.loadcurve_s76c npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s76c.txt action=normalize
New LoadShape.loadcurve_s41c npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s41c.txt action=normalize
New LoadShape.loadcurve_s16c npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s16c.txt action=normalize
New LoadShape.loadcurve_s2b npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s2b.txt action=normalize
New LoadShape.loadcurve_s107b npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s107b.txt action=normalize
New LoadShape.loadcurve_s60a npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s60a.txt action=normalize
New LoadShape.loadcurve_s106b npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s106b.txt action=normalize
New LoadShape.loadcurve_s39b npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s39b.txt action=normalize
New LoadShape.loadcurve_s95b npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s95b.txt action=normalize
New LoadShape.loadcurve_s34c npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s34c.txt action=normalize
New LoadShape.loadcurve_s68a npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s68a.txt action=normalize
New LoadShape.loadcurve_s17c npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s17c.txt action=normalize
New LoadShape.loadcurve_s94a npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s94a.txt action=normalize

Appendix B5 – OpenDSS netlist of the reference network – SP1 - continued

B5-6- Loads - continued

!LOAD DEFINITION

New Load.s99b Bus1=99.2 Phases=1 Conn=Wye Model=1 kV=2.4 kW=40.0 kvar=20.0 daily=loadcurve_s99b status=variable
New Load.s20a Bus1=20.1 Phases=1 Conn=Wye Model=5 kV=2.4 kW=40.0 kvar=20.0 daily=loadcurve_s20a status=variable
New Load.s5c Bus1=5.3 Phases=1 Conn=Wye Model=5 kV=2.4 kW=20.0 kvar=10.0 daily=loadcurve_s5c status=variable
New Load.s24c Bus1=24.3 Phases=1 Conn=Wye Model=1 kV=2.4 kW=40.0 kvar=20.0 daily=loadcurve_s24c status=variable
New Load.s37a Bus1=37.1 Phases=1 Conn=Wye Model=2 kV=2.4 kW=40.0 kvar=20.0 daily=loadcurve_s37a status=variable
New Load.s102c Bus1=102.3 Phases=1 Conn=Wye Model=1 kV=2.4 kW=20.0 kvar=10.0 daily=loadcurve_s102c status=variable
New Load.s83c Bus1=83.3 Phases=1 Conn=Wye Model=1 kV=2.4 kW=20.0 kvar=10.0 daily=loadcurve_s83c status=variable
New Load.s85c Bus1=85.3 Phases=1 Conn=Wye Model=1 kV=2.4 kW=40.0 kvar=20.0 daily=loadcurve_s85c status=variable
New Load.s62c Bus1=62.3 Phases=1 Conn=Wye Model=2 kV=2.4 kW=40.0 kvar=20.0 daily=loadcurve_s62c status=variable
New Load.s88a Bus1=88.1 Phases=1 Conn=Wye Model=1 kV=2.4 kW=40.0 kvar=20.0 daily=loadcurve_s88a status=variable
New Load.s52a Bus1=52.1 Phases=1 Conn=Wye Model=1 kV=2.4 kW=40.0 kvar=20.0 daily=loadcurve_s52a status=variable
New Load.s84c Bus1=84.3 Phases=1 Conn=Wye Model=1 kV=2.4 kW=20.0 kvar=10.0 daily=loadcurve_s84c status=variable
New Load.s65b Bus1=65.2.3 Phases=1 Conn=Delta Model=2 kV=4.16 kW=35.0 kvar=25.0 daily=loadcurve_s65b status=variable
New Load.s79a Bus1=79.1 Phases=1 Conn=Wye Model=2 kV=2.4 kW=40.0 kvar=20.0 daily=loadcurve_s79a status=variable
New Load.s7a Bus1=7.1 Phases=1 Conn=Wye Model=1 kV=2.4 kW=20.0 kvar=10.0 daily=loadcurve_s7a status=variable
New Load.s12b Bus1=12.2 Phases=1 Conn=Wye Model=1 kV=2.4 kW=20.0 kvar=10.0 daily=loadcurve_s12b status=variable
New Load.s76a Bus1=76.1.2 Phases=1 Conn=Delta Model=5 kV=4.16 kW=105.0 kvar=80.0 daily=loadcurve_s76a status=variable
New Load.s63a Bus1=63.1 Phases=1 Conn=Wye Model=1 kV=2.4 kW=40.0 kvar=20.0 daily=loadcurve_s63a status=variable
New Load.s29a Bus1=29.1 Phases=1 Conn=Wye Model=2 kV=2.4 kW=40.0 kvar=20.0 daily=loadcurve_s29a status=variable
New Load.s74c Bus1=74.3 Phases=1 Conn=Wye Model=2 kV=2.4 kW=40.0 kvar=20.0 daily=loadcurve_s74c status=variable
New Load.s92c Bus1=92.3 Phases=1 Conn=Wye Model=1 kV=2.4 kW=40.0 kvar=20.0 daily=loadcurve_s92c status=variable
New Load.s49b Bus1=49.2 Phases=1 Conn=Wye Model=1 kV=2.4 kW=70.0 kvar=50.0 daily=loadcurve_s49b status=variable
New Load.s112a Bus1=112.1 Phases=1 Conn=Wye Model=5 kV=2.4 kW=20.0 kvar=10.0 daily=loadcurve_s112a status=variable
New Load.s46a Bus1=46.1 Phases=1 Conn=Wye Model=1 kV=2.4 kW=20.0 kvar=10.0 daily=loadcurve_s46a status=variable
New Load.s50c Bus1=50.3 Phases=1 Conn=Wye Model=1 kV=2.4 kW=40.0 kvar=20.0 daily=loadcurve_s50c status=variable
New Load.s1a Bus1=1.1 Phases=1 Conn=Wye Model=1 kV=2.4 kW=40.0 kvar=20.0 daily=loadcurve_s1a status=variable
New Load.s6c Bus1=6.3 Phases=1 Conn=Wye Model=2 kV=2.4 kW=40.0 kvar=20.0 daily=loadcurve_s6c status=variable
New Load.s75c Bus1=75.3 Phases=1 Conn=Wye Model=1 kV=2.4 kW=40.0 kvar=20.0 daily=loadcurve_s75c status=variable
New Load.s104c Bus1=104.3 Phases=1 Conn=Wye Model=1 kV=2.4 kW=40.0 kvar=20.0 daily=loadcurve_s104c status=variable

Appendix B5 – OpenDSS netlist of the reference network – SP1 - continued

B5-6- Loads - continued

New Load.s76b Bus1=76.2.3 Phases=1 Conn=Delta Model=5 kV=4.16 kW=70.0 kvar=50.0 daily=loadcurve_s76b status=variable
New Load.s22b Bus1=22.2 Phases=1 Conn=Wye Model=2 kV=2.4 kW=40.0 kvar=20.0 daily=loadcurve_s22b status=variable
New Load.s96b Bus1=96.2 Phases=1 Conn=Wye Model=1 kV=2.4 kW=20.0 kvar=10.0 daily=loadcurve_s96b status=variable
New Load.s103c Bus1=103.3 Phases=1 Conn=Wye Model=1 kV=2.4 kW=40.0 kvar=20.0 daily=loadcurve_s103c status=variable
New Load.s113a Bus1=113.1 Phases=1 Conn=Wye Model=2 kV=2.4 kW=40.0 kvar=20.0 daily=loadcurve_s113a status=variable
New Load.s43b Bus1=43.2 Phases=1 Conn=Wye Model=2 kV=2.4 kW=40.0 kvar=20.0 daily=loadcurve_s43b status=variable
New Load.s82a Bus1=82.1 Phases=1 Conn=Wye Model=1 kV=2.4 kW=40.0 kvar=20.0 daily=loadcurve_s82a status=variable
New Load.s90b Bus1=90.2 Phases=1 Conn=Wye Model=5 kV=2.4 kW=40.0 kvar=20.0 daily=loadcurve_s90b status=variable
New Load.s80b Bus1=80.2 Phases=1 Conn=Wye Model=1 kV=2.4 kW=40.0 kvar=20.0 daily=loadcurve_s80b status=variable
New Load.s11a Bus1=11.1 Phases=1 Conn=Wye Model=2 kV=2.4 kW=40.0 kvar=20.0 daily=loadcurve_s11a status=variable
New Load.s55a Bus1=55.1 Phases=1 Conn=Wye Model=2 kV=2.4 kW=20.0 kvar=10.0 daily=loadcurve_s55a status=variable
New Load.s111a Bus1=111.1 Phases=1 Conn=Wye Model=1 kV=2.4 kW=20.0 kvar=10.0 daily=loadcurve_s111a status=variable
New Load.s49c Bus1=49.3 Phases=1 Conn=Wye Model=1 kV=2.4 kW=35.0 kvar=20.0 daily=loadcurve_s49c status=variable
New Load.s109a Bus1=109.1 Phases=1 Conn=Wye Model=1 kV=2.4 kW=40.0 kvar=20.0 daily=loadcurve_s109a status=variable
New Load.s65c Bus1=65.3.1 Phases=1 Conn=Delta Model=2 kV=4.16 kW=70.0 kvar=50.0 daily=loadcurve_s65c status=variable
New Load.s70a Bus1=70.1 Phases=1 Conn=Wye Model=1 kV=2.4 kW=20.0 kvar=10.0 daily=loadcurve_s70a status=variable
New Load.s87b Bus1=87.2 Phases=1 Conn=Wye Model=1 kV=2.4 kW=40.0 kvar=20.0 daily=loadcurve_s87b status=variable
New Load.s59b Bus1=59.2 Phases=1 Conn=Wye Model=1 kV=2.4 kW=20.0 kvar=10.0 daily=loadcurve_s59b status=variable
New Load.s98a Bus1=98.1 Phases=1 Conn=Wye Model=1 kV=2.4 kW=40.0 kvar=20.0 daily=loadcurve_s98a status=variable
New Load.s86b Bus1=86.2 Phases=1 Conn=Wye Model=1 kV=2.4 kW=20.0 kvar=10.0 daily=loadcurve_s86b status=variable
New Load.s66c Bus1=66.3 Phases=1 Conn=Wye Model=1 kV=2.4 kW=75.0 kvar=35.0 daily=loadcurve_s66c status=variable
New Load.s38b Bus1=38.2 Phases=1 Conn=Wye Model=5 kV=2.4 kW=20.0 kvar=10.0 daily=loadcurve_s38b status=variable
New Load.s48 Bus1=48 Phases=3 Conn=Wye Model=2 kV=4.16 kW=210.0 kvar=150.0 daily=loadcurve_s48 status=variable
New Load.s51a Bus1=51.1 Phases=1 Conn=Wye Model=1 kV=2.4 kW=20.0 kvar=10.0 daily=loadcurve_s51a status=variable
New Load.s19a Bus1=19.1 Phases=1 Conn=Wye Model=1 kV=2.4 kW=40.0 kvar=20.0 daily=loadcurve_s19a status=variable
New Load.s53a Bus1=53.1 Phases=1 Conn=Wye Model=1 kV=2.4 kW=40.0 kvar=20.0 daily=loadcurve_s53a status=variable
New Load.s64b Bus1=64.2 Phases=1 Conn=Wye Model=5 kV=2.4 kW=75.0 kvar=35.0 daily=loadcurve_s64b status=variable
New Load.s9a Bus1=9.1 Phases=1 Conn=Wye Model=1 kV=2.4 kW=40.0 kvar=20.0 daily=loadcurve_s9a status=variable
New Load.s73c Bus1=73.3 Phases=1 Conn=Wye Model=1 kV=2.4 kW=40.0 kvar=20.0 daily=loadcurve_s73c status=variable
New Load.s77b Bus1=77.2 Phases=1 Conn=Wye Model=1 kV=2.4 kW=40.0 kvar=20.0 daily=loadcurve_s77b status=variable
New Load.s4c Bus1=4.3 Phases=1 Conn=Wye Model=1 kV=2.4 kW=40.0 kvar=20.0 daily=loadcurve_s4c status=variable

Appendix B5 – OpenDSS netlist of the reference network – SP1 - continued

B5-6- Loads - continued

New Load.s35a Bus1=35.1.2 Phases=1 Conn=Delta Model=1 kV=4.16 kW=40.0 kvar=20.0 daily=loadcurve_s35a status=variable
New Load.s100c Bus1=100.3 Phases=1 Conn=Wye Model=2 kV=2.4 kW=40.0 kvar=20.0 daily=loadcurve_s100c status=variable
New Load.s33a Bus1=33.1 Phases=1 Conn=Wye Model=5 kV=2.4 kW=40.0 kvar=20.0 daily=loadcurve_s33a status=variable
New Load.s69a Bus1=69.1 Phases=1 Conn=Wye Model=1 kV=2.4 kW=40.0 kvar=20.0 daily=loadcurve_s69a status=variable
New Load.s28a Bus1=28.1 Phases=1 Conn=Wye Model=5 kV=2.4 kW=40.0 kvar=20.0 daily=loadcurve_s28a status=variable
New Load.s71a Bus1=71.1 Phases=1 Conn=Wye Model=1 kV=2.4 kW=40.0 kvar=20.0 daily=loadcurve_s71a status=variable
New Load.s30c Bus1=30.3 Phases=1 Conn=Wye Model=1 kV=2.4 kW=40.0 kvar=20.0 daily=loadcurve_s30c status=variable
New Load.s10a Bus1=10.1 Phases=1 Conn=Wye Model=5 kV=2.4 kW=20.0 kvar=10.0 daily=loadcurve_s10a status=variable
New Load.s31c Bus1=31.3 Phases=1 Conn=Wye Model=1 kV=2.4 kW=20.0 kvar=10.0 daily=loadcurve_s31c status=variable
New Load.s65a Bus1=65.1.2 Phases=1 Conn=Delta Model=2 kV=4.16 kW=35.0 kvar=25.0 daily=loadcurve_s65a status=variable
New Load.s49a Bus1=49.1 Phases=1 Conn=Wye Model=1 kV=2.4 kW=35.0 kvar=25.0 daily=loadcurve_s49a status=variable
New Load.s58b Bus1=58.2 Phases=1 Conn=Wye Model=5 kV=2.4 kW=20.0 kvar=10.0 daily=loadcurve_s58b status=variable
New Load.s45a Bus1=45.1 Phases=1 Conn=Wye Model=5 kV=2.4 kW=20.0 kvar=10.0 daily=loadcurve_s45a status=variable
New Load.s56b Bus1=56.2 Phases=1 Conn=Wye Model=1 kV=2.4 kW=20.0 kvar=10.0 daily=loadcurve_s56b status=variable
New Load.s47 Bus1=47 Phases=3 Conn=Wye Model=5 kV=4.16 kW=105.0 kvar=75.0 daily=loadcurve_s47 status=variable
New Load.s114a Bus1=114.1 Phases=1 Conn=Wye Model=1 kV=2.4 kW=20.0 kvar=10.0 daily=loadcurve_s114a status=variable
New Load.s32c Bus1=32.3 Phases=1 Conn=Wye Model=1 kV=2.4 kW=20.0 kvar=10.0 daily=loadcurve_s32c status=variable
New Load.s42a Bus1=42.1 Phases=1 Conn=Wye Model=1 kV=2.4 kW=20.0 kvar=10.0 daily=loadcurve_s42a status=variable
New Load.s76c Bus1=76.3.1 Phases=1 Conn=Delta Model=5 kV=4.16 kW=70.0 kvar=50.0 daily=loadcurve_s76c status=variable
New Load.s41c Bus1=41.3 Phases=1 Conn=Wye Model=1 kV=2.4 kW=20.0 kvar=10.0 daily=loadcurve_s41c status=variable
New Load.s16c Bus1=16.3 Phases=1 Conn=Wye Model=1 kV=2.4 kW=40.0 kvar=20.0 daily=loadcurve_s16c status=variable
New Load.s2b Bus1=2.2 Phases=1 Conn=Wye Model=1 kV=2.4 kW=20.0 kvar=10.0 daily=loadcurve_s2b status=variable
New Load.s107b Bus1=107.2 Phases=1 Conn=Wye Model=1 kV=2.4 kW=40.0 kvar=20.0 daily=loadcurve_s107b status=variable
New Load.s60a Bus1=60.1 Phases=1 Conn=Wye Model=1 kV=2.4 kW=20.0 kvar=10.0 daily=loadcurve_s60a status=variable
New Load.s106b Bus1=106.2 Phases=1 Conn=Wye Model=1 kV=2.4 kW=40.0 kvar=20.0 daily=loadcurve_s106b status=variable
New Load.s39b Bus1=39.2 Phases=1 Conn=Wye Model=1 kV=2.4 kW=20.0 kvar=10.0 daily=loadcurve_s39b status=variable
New Load.s95b Bus1=95.2 Phases=1 Conn=Wye Model=1 kV=2.4 kW=20.0 kvar=10.0 daily=loadcurve_s95b status=variable
New Load.s34c Bus1=34.3 Phases=1 Conn=Wye Model=2 kV=2.4 kW=40.0 kvar=20.0 daily=loadcurve_s34c status=variable
New Load.s68a Bus1=68.1 Phases=1 Conn=Wye Model=1 kV=2.4 kW=20.0 kvar=10.0 daily=loadcurve_s68a status=variable
New Load.s17c Bus1=17.3 Phases=1 Conn=Wye Model=1 kV=2.4 kW=20.0 kvar=10.0 daily=loadcurve_s17c status=variable
New Load.s94a Bus1=94.1 Phases=1 Conn=Wye Model=1 kV=2.4 kW=40.0 kvar=20.0 daily=loadcurve_s94a status=variable

Appendix B5 – OpenDSS netlist of the reference network – SP1 - continued

B5-7- Capacitors

The capacitor banks are defined in a file called : Test_Capacitors.DSS. The capacitor is modeled as a negative load. The content is given below:

!CAPACITOR LOADSHAPES DEFINITION

New LoadShape.capacitor_c92c npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/capacitor_bank_curve_c92c.txt

New LoadShape.capacitor_c83 npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/capacitor_bank_curve_c83.txt

New LoadShape.capacitor_c88a npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/capacitor_bank_curve_c88a.txt

New LoadShape.capacitor_c90b npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/capacitor_bank_curve_c90b.txt

!CAPACITORS DEFINITION

New Load.c92c Bus1=92.3 Phases=1 kVAR=-50.0 kV=2.4 daily=capacitor_c92c status=variable

New Load.c83 Bus1=83 Phases=3 kVAR=-600.0 kV=4.16 daily=capacitor_c83 status=variable

New Load.c88a Bus1=88.1 Phases=1 kVAR=-50.0 kV=2.4 daily=capacitor_c88a status=variable

New Load.c90b Bus1=90.2 Phases=1 kVAR=-50.0 kV=2.4 daily=capacitor_c90b status=variable

Appendix B5 – OpenDSS netlist of the reference network – SP1 - continued

B5-8- Regulators

The regulators are defined in a file called : Test_Regulators.DSS. The content is given below:

!REGULATORS DEFINITION

New Transformer.reg4a phases=1 windings=2
~ buses=[160.1 160r.1] conns=[wye wye] kvs=[2.402 2.402] kvas=[2000.0 2000.0] Xhl=0.01

New Transformer.reg2a phases=1 windings=2
~ buses=[9.1 9r.1] conns=[wye wye] kvs=[2.402 2.402] kvas=[2000.0 2000.0] Xhl=0.01

New Transformer.reg3c phases=1 windings=2
~ buses=[25.3 25r.3] conns=[wye wye] kvs=[2.402 2.402] kvas=[2000.0 2000.0] Xhl=0.01

New Transformer.reg4c phases=1 windings=2
~ buses=[160.3 160r.3] conns=[wye wye] kvs=[2.402 2.402] kvas=[2000.0 2000.0] Xhl=0.01

New Transformer.reg4b phases=1 windings=2
~ buses=[160.2 160r.2] conns=[wye wye] kvs=[2.402 2.402] kvas=[2000.0 2000.0] Xhl=0.01

New Transformer.reg3a phases=1 windings=2
~ buses=[25.1 25r.1] conns=[wye wye] kvs=[2.402 2.402] kvas=[2000.0 2000.0] Xhl=0.01

Appendix B5 – OpenDSS netlist of the reference network – SP1 - continued

B5-9- Generators

The generators are defined in a file called : Test_Generators.DSS. The content is given below:

!GENERATORS DEFINITION

new LoadShape.3 npts=24 interval=1 mult=(File=LoadShape3.csv)

New Generator.d1 Bus1=1000 Phases=3 Model=1 kV=0.48 kW=400.0 pf=0.95 Xd=2.5 Xdp=0.183 Xdpp=0.137 daily=3

new LoadShape.3 npts=24 interval=1 mult=(File=LoadShape3.csv)

New Generator.d2 Bus1=900 Phases=3 Model=1 kV=0.48 kW=400.0 pf=0.95 Xd=2.5 Xdp=0.183 Xdpp=0.137 daily=3

Appendix B5 – OpenDSS netlist of the reference network – SP1 - continued

B5-10- Monitors

The monitors are defined in a file called : Test_Monitors.DSS. The content is given below:

!MONITORS DEFINITION

```
New Monitor.Mon_BR4 element=Line.BR4 terminal=1 mode=0 Vlpolar=no  
New Monitor.Mon_BR2 element=Line.BR2 terminal=1 mode=0 Vlpolar=no  
New Monitor.Mon_BR6 element=Line.BR6 terminal=1 mode=0 Vlpolar=no  
New Monitor.Mon_BR3 element=Line.BR3 terminal=1 mode=0 Vlpolar=no  
New Monitor.Mon_BR5 element=Line.BR5 terminal=1 mode=0 Vlpolar=no  
New Monitor.Mon_BR1 element=Line.BR1 terminal=1 mode=0 Vlpolar=no
```

Appendix B5 – OpenDSS netlist of the reference network – SP1 - continued

B5-11- Bus coordinates

The bus coordinates of the network are defined in a file called : Test_Buscoords.DSS. The content is given below in five blocks. For each block, the first column represents the bus name, the second and third being the corresponding (x,y) coordinates.

!BUS COORDINATES

DEFINITION

									95	2025	1125
									54	2325	1500
58	2075	1850	14	1200	2150	82	4025	175	75	4550	1575
77	3925	1375	7	1000	1500	61	3075	1300	64	3075	2625
99	4350	2100	88	2950	1300	25r	1500	3150	18	1500	2325
20	925	2325	52	2000	1500	106	3750	2725	31	1150	3375
160r	3175	1850	22	975	2625	108	3525	3050	38	2325	2000
8	1200	1500	84	4700	425	78	4025	1375	109	3975	3050
5	1025	1250	60	3075	1850	15	1500	1250	1000	1400	2450
83	4275	175	89	2775	1125	74	4150	1575	114	5125	2925
98	3800	2100	72	3525	1575	92	2550	825	96	2025	925
9	1200	1725	61s	3175	1300	112	4275	2925	53	2200	1500
24	950	2875	65	2650	2625	81	4025	425	51	2725	3275
73	3800	1575	79	4250	1375	46	2475	3025	57	2325	1850
104	4775	2450	12	1200	1275	40	1975	2575	103	4075	2450
4	700	1050	9r	1200	1725	50	2475	3275	55	2600	1500
37	1775	2000	44	1975	3025	23	1500	2875	150	100	1500
25	1500	3150	76	3525	1375	19	1250	2325	67	3525	1850
28	1500	3350	63	3075	2275	91	2550	1125	87	3050	1125
13	1500	1500	100	4650	2100	68	3725	1850	113	4800	2925
102	3750	2450	45	2175	3025	43	2475	2825	90	2775	900
450	5450	2100	29	1500	3650	3	700	1250	80	4025	900
86	3255	725	300	3245	4010	610	3275	1300	11	950	2150
93	2325	1125	59	1825	1850	101	3525	2450	111	4275	3625
85	4700	900	35	1975	2325	135	1600	2325	36	2075	2000
160	3175	1850	21	1500	2625	69	4000	1850	39	2650	2000
62	3075	2100	56	2875	1500	6	1275	1150	27	875	3150
1	700	1500	49	2225	3275	94	2325	850	30	1850	3650

APPENDIX B6

Power flow simulation results in SP1

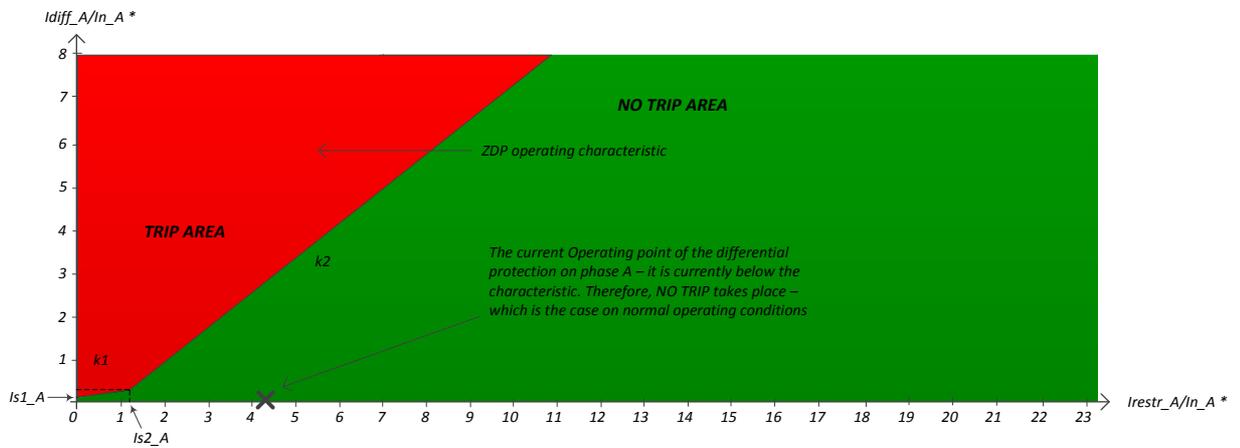
Extract of results (10 first simulation steps)

Appendix B6 – Power flow simulation – SP1

Simulation step 1/24

Zone : 1

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	21.59-61.62j	19.91+14.71j	35.66+63.99j
BR1	144.68-338.94j	-255.77+48.63j	173.28+264.82j
BR2	-69.29+180.16j	159.82-21.18j	-95.30-137.84j
BR3	-53.77+97.15j	115.83-12.77j	-42.34-63.00j



* In_x is the rated current of the phase x of the current zone. $x = A$ or B or C

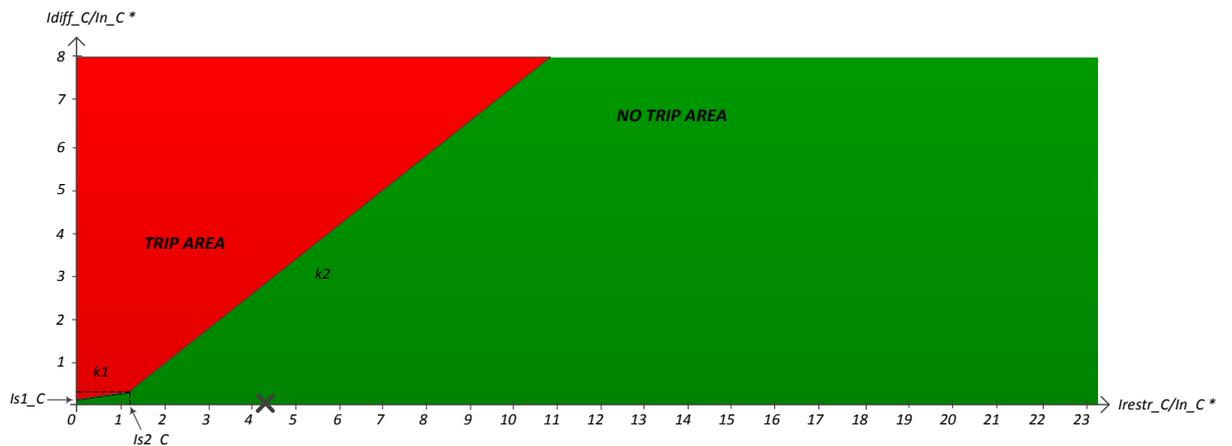
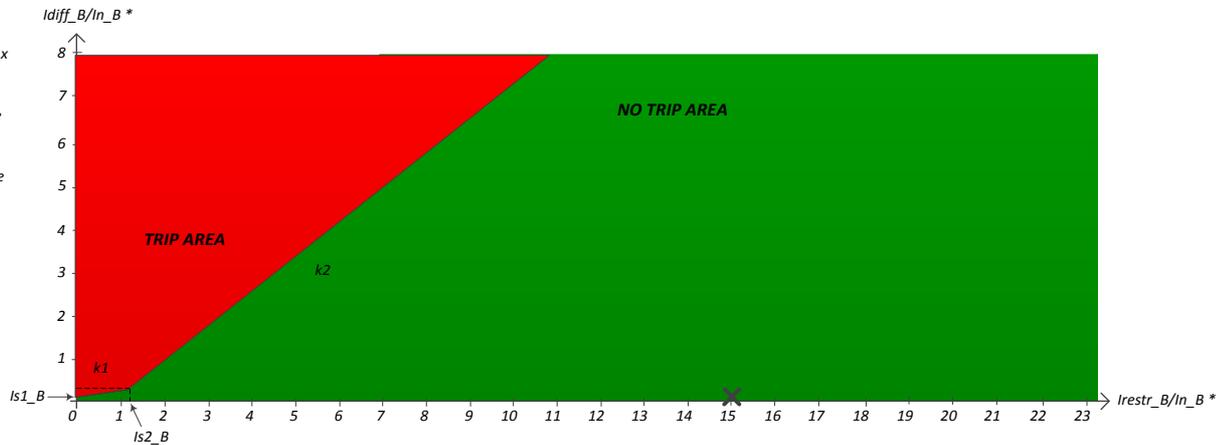
$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

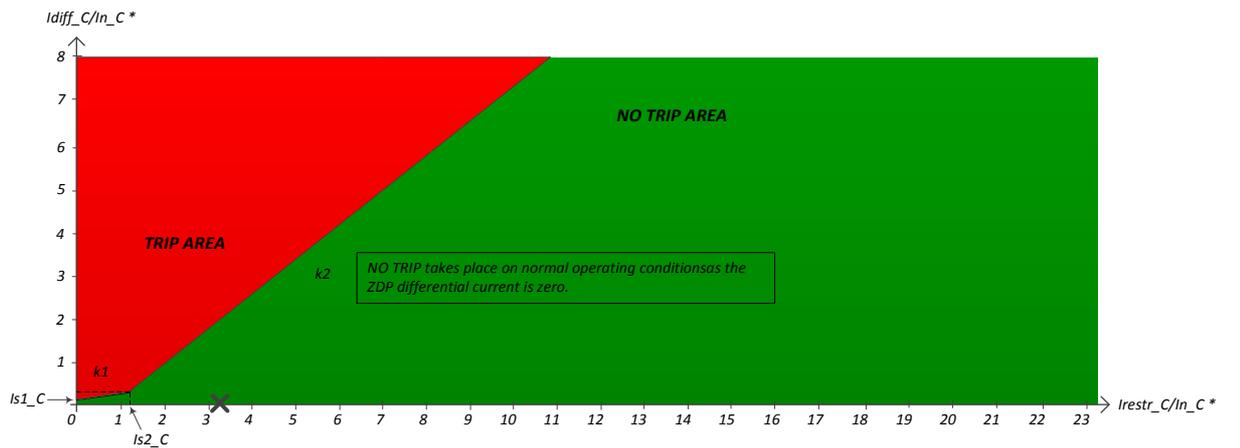
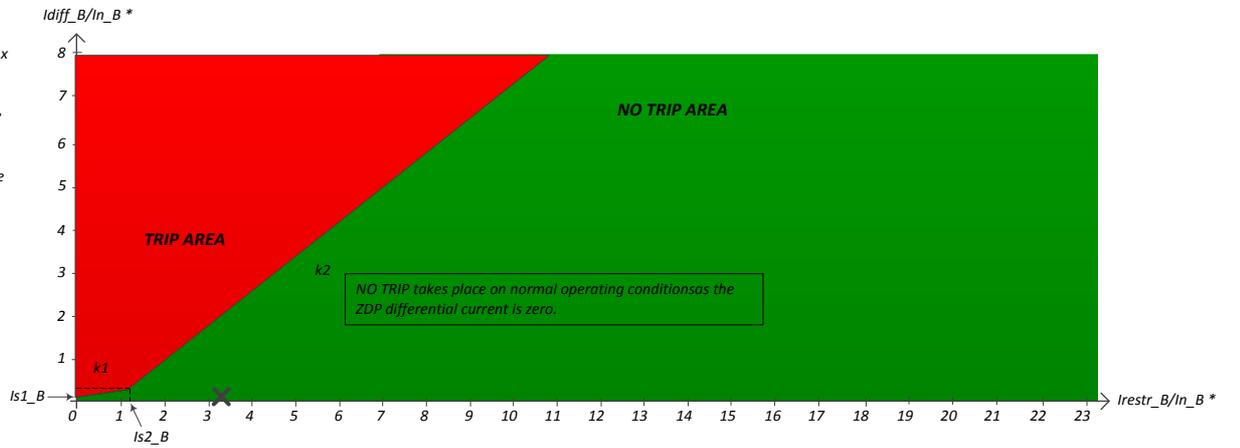
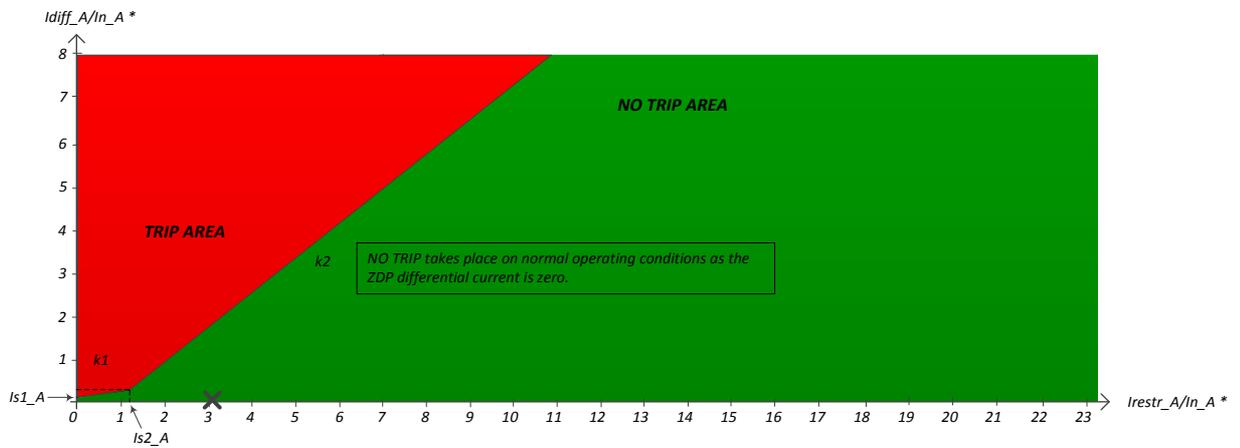


Appendix B6 – Power flow simulation – SP1 - continued

Simulation step 1/24

Zone : 2

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	36.08-70.84j	-72.02-0.36j	29.19+56.32j
BR2	69.29-180.16j	-159.82+21.18j	95.30+137.84j
BR4	-33.14+109.33j	87.80-21.62j	-66.15-81.51j
BR6	-0.00-0.00j	-0.00-0.00j	-0.00-0.00j



* In_x is the rated current of the phase x of the current zone. x = A or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

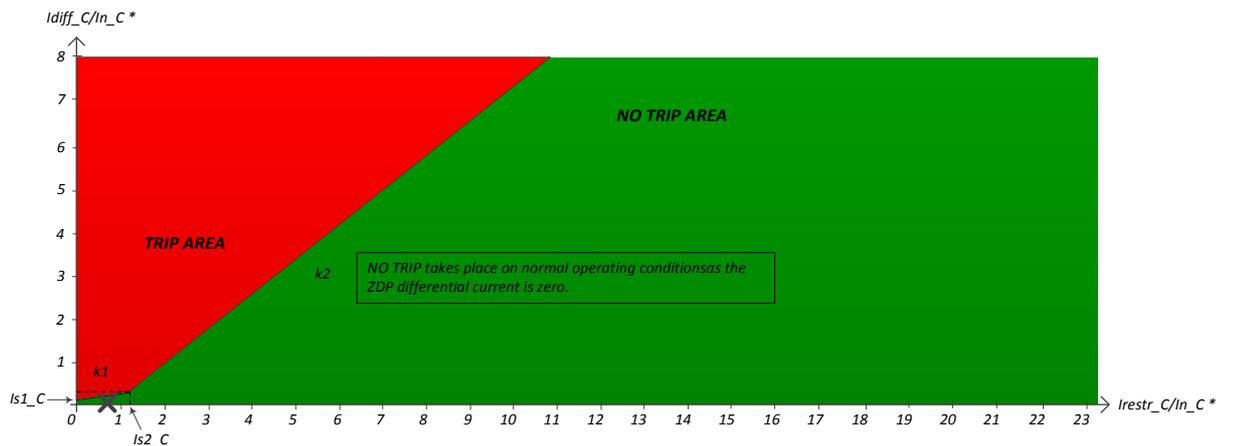
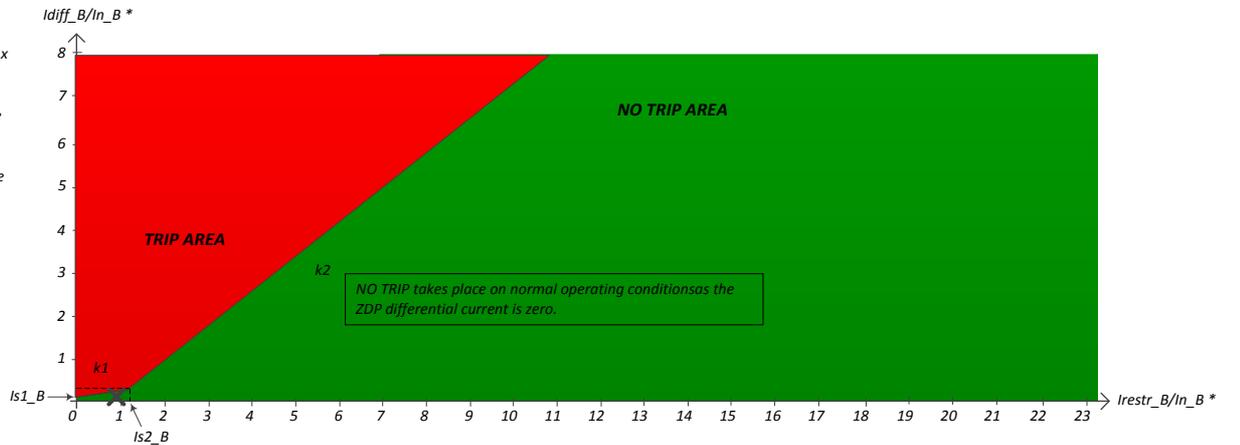
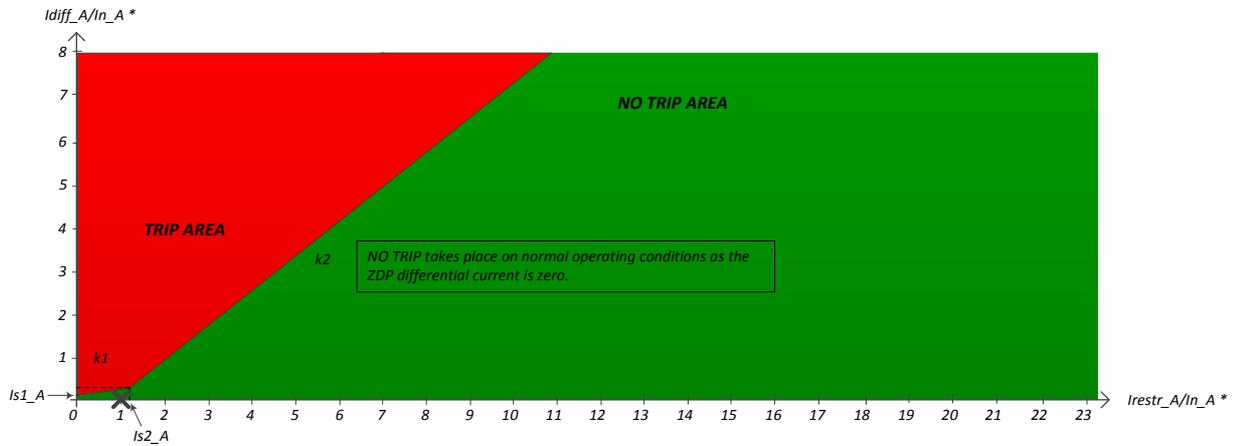
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix B6 – Power flow simulation – SP1 - continued

Simulation step 1/24

Zone : 3

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	53.75-97.13j	-115.79+12.81j	42.35+63.02j
BR3	53.77-97.15j	-115.83+12.77j	42.34+63.00j



* In_x is the rated current of the phase x of the current zone. $x = A$ or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

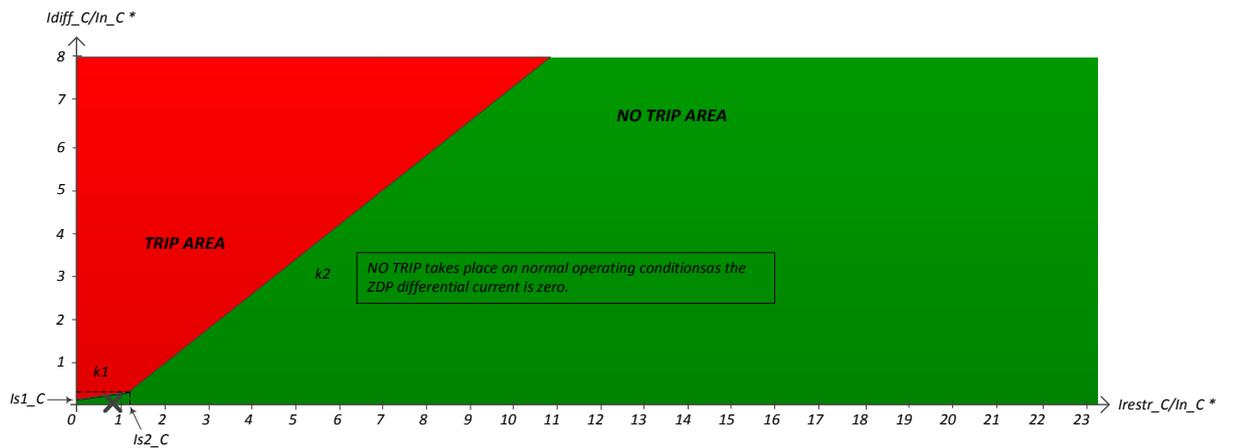
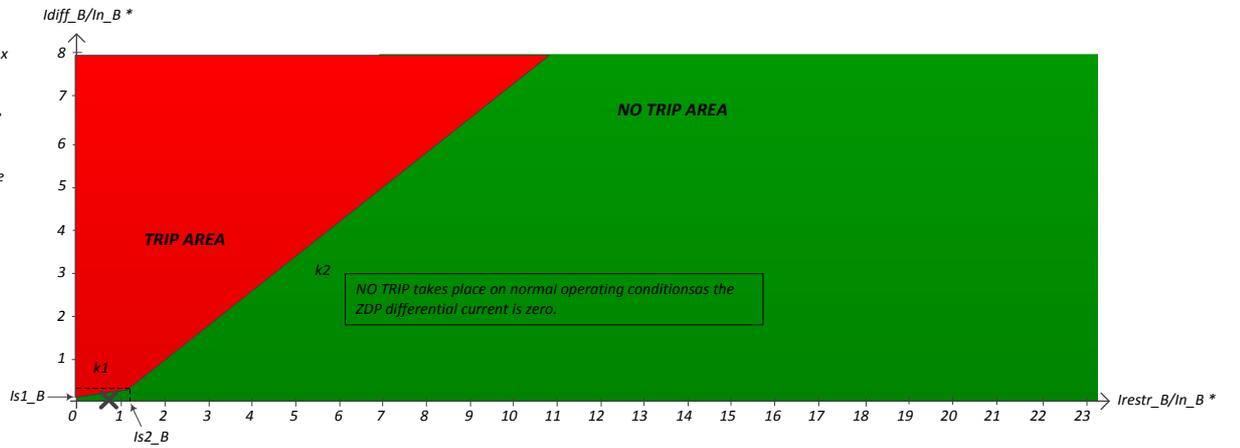
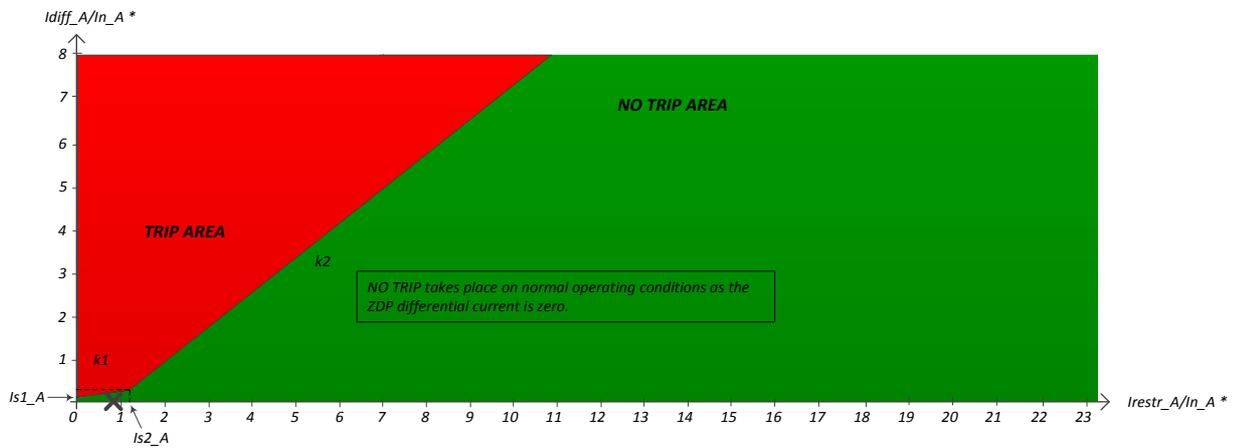
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix B6 – Power flow simulation – SP1 - continued

Simulation step 1/24

Zone : 4

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	6.84-65.22j	-57.48+22.64j	45.22+43.57j
BR4	33.14-109.33j	-87.80+21.62j	66.15+81.51j
BR5	-26.23+44.11j	30.32+0.95j	-20.97-37.96j



* In_x is the rated current of the phase x of the current zone. $x = A$ or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

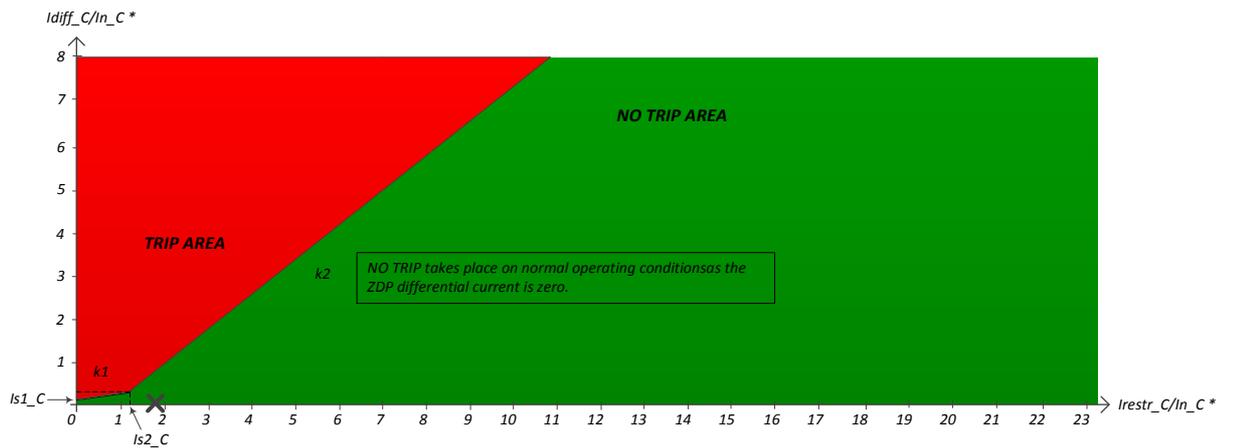
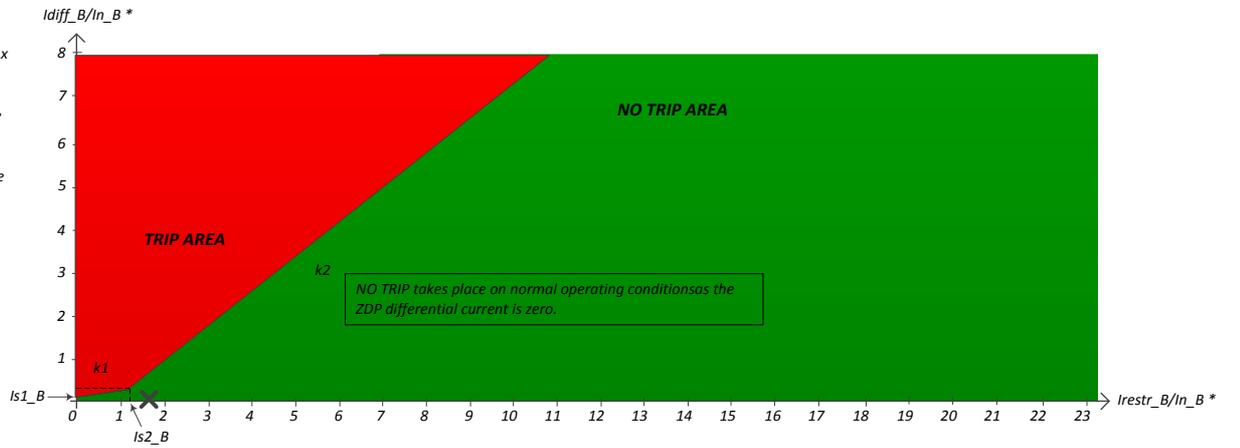
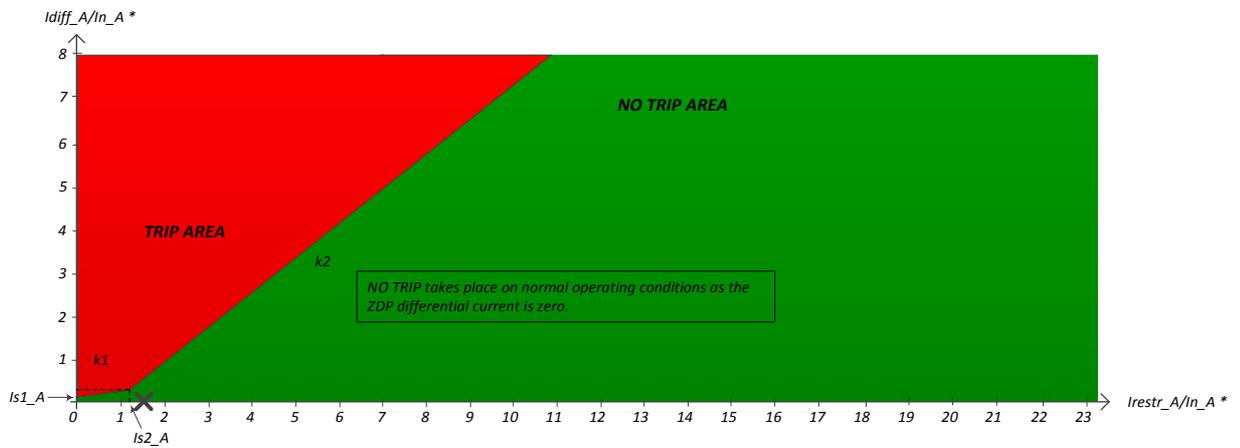
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix B6 – Power flow simulation – SP1 - continued

Simulation step 1/24

Zone : 5

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	26.21-44.11j	-30.32-0.93j	20.97+37.97j
BR5	26.23-44.11j	-30.32-0.95j	20.97+37.96j



* In_x is the rated current of the phase x of the current zone. $x = A$ or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

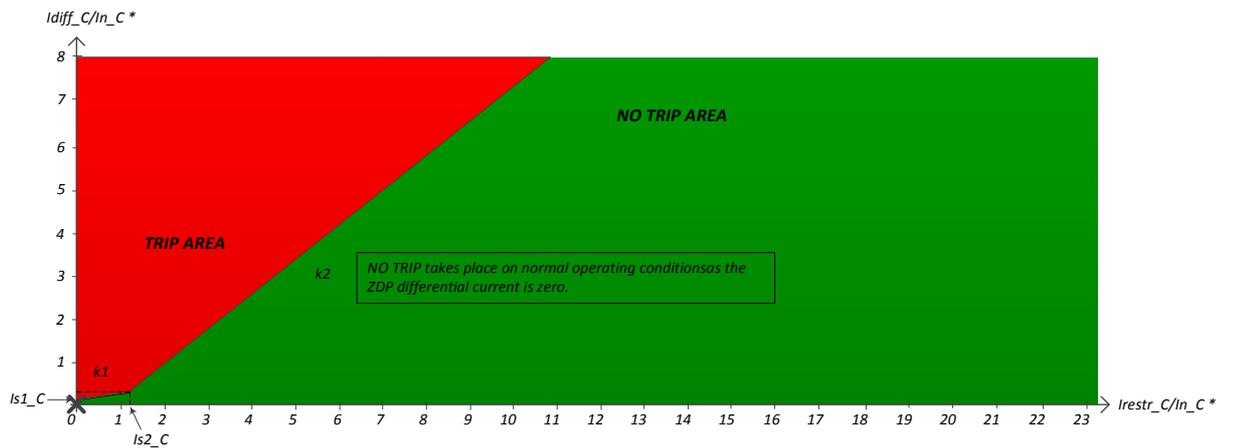
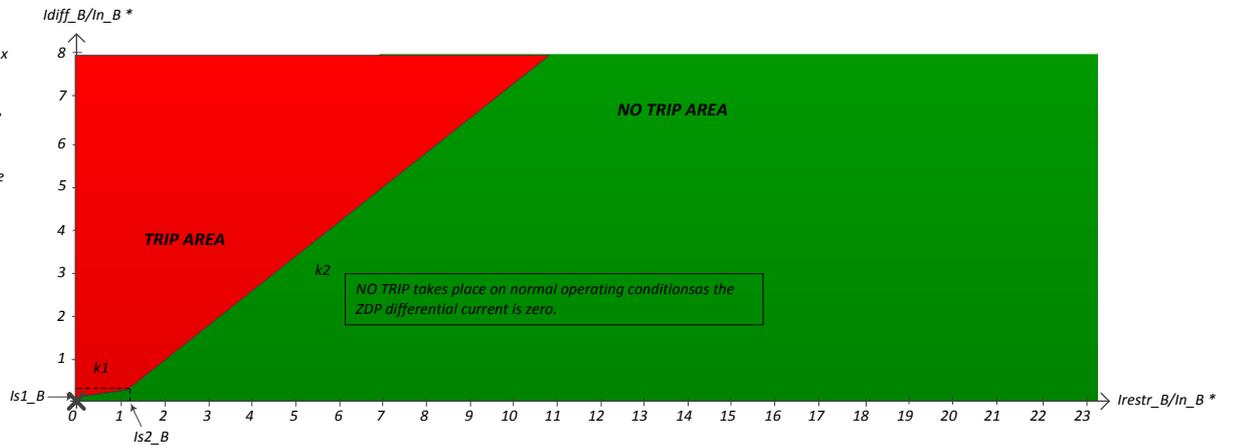
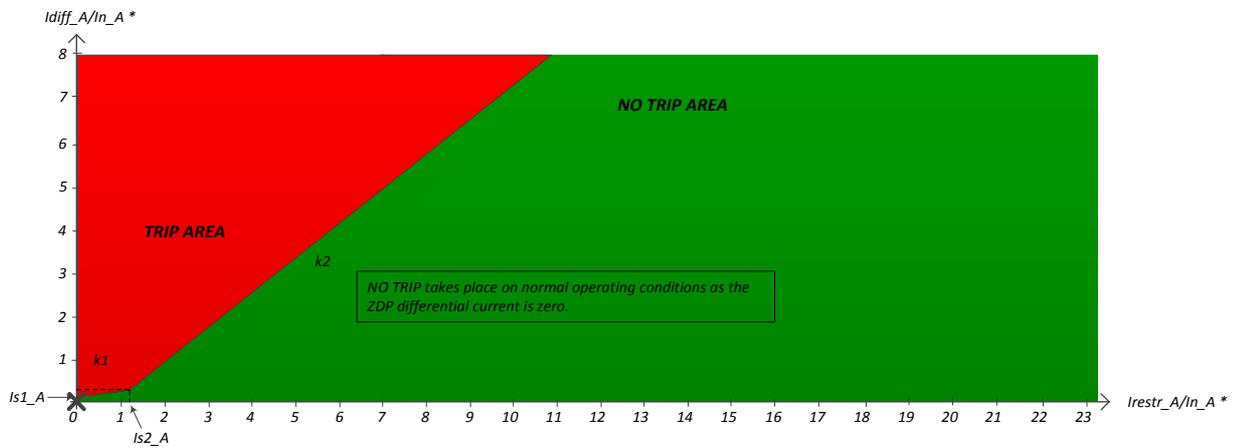
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix B6 – Power flow simulation – SP1 - continued

Simulation step 1/24

Zone : 6

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	0.00+0.00j	0.00+0.00j	0.00+0.00j
BR6	0.00+0.00j	0.00+0.00j	0.00+0.00j



* In_x is the rated current of the phase x of the current zone. x = A or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

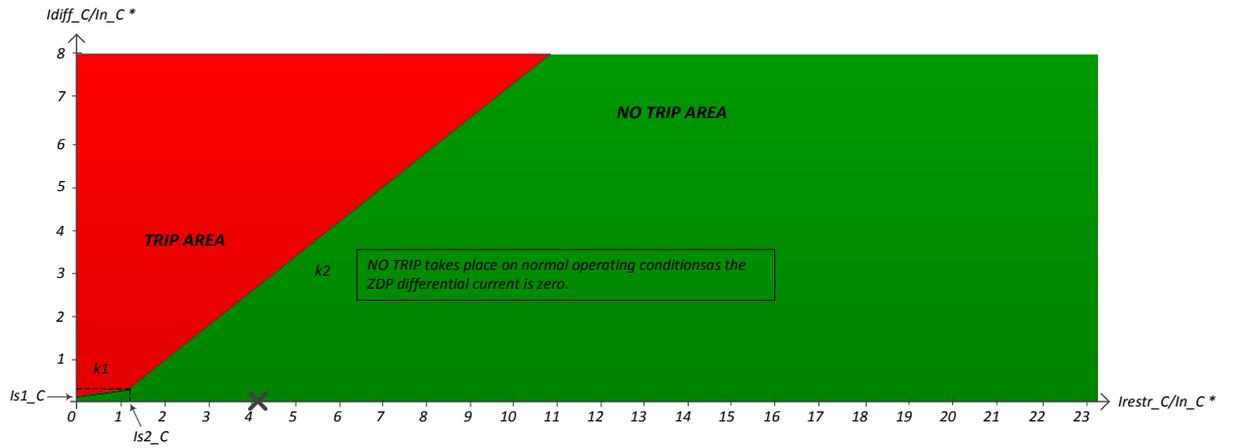
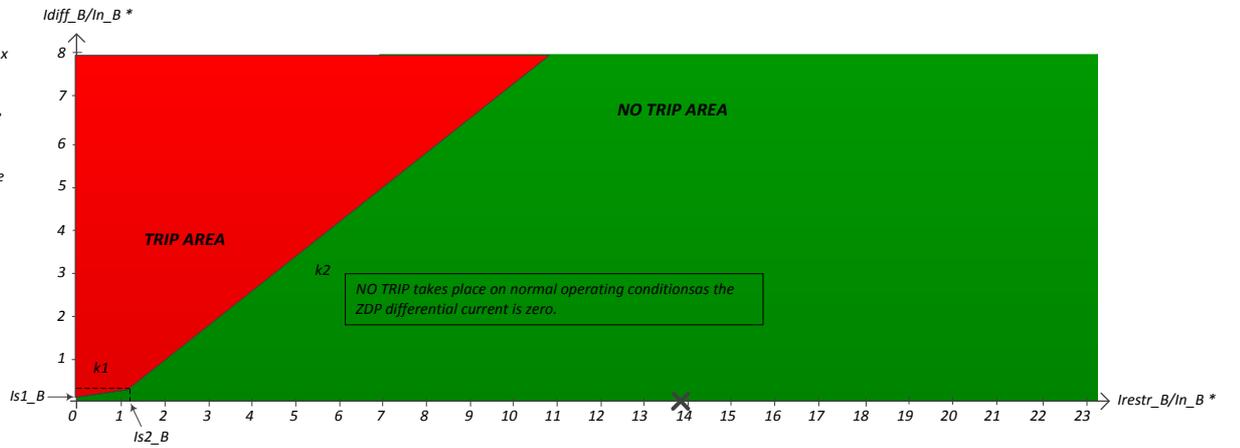
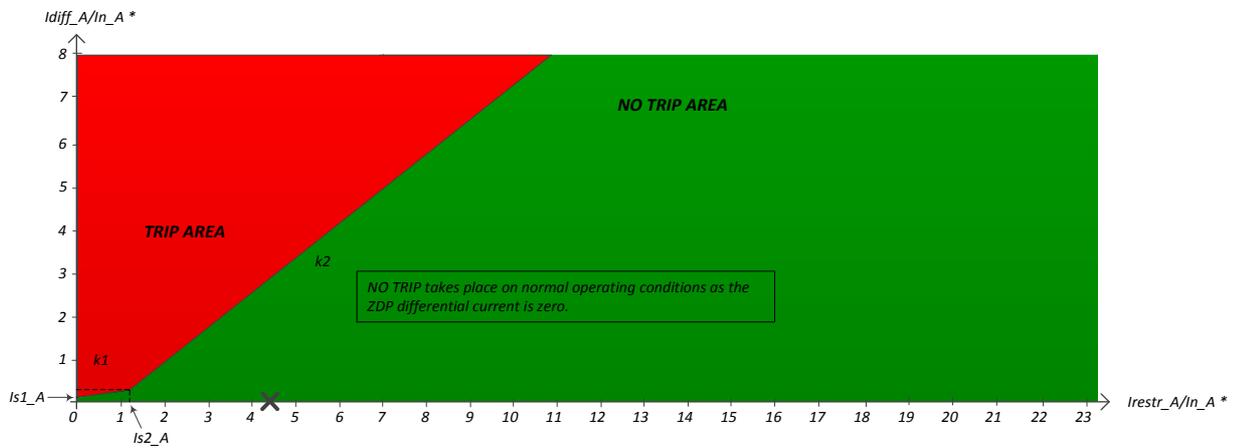
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix B6 – Power flow simulation – SP1

Simulation step 2/24

Zone : 1

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	27.83-73.40j	10.10+13.80j	39.33+77.94j
BR1	136.80-333.57j	-239.77+57.85j	176.07+252.64j
BR2	-51.19+155.79j	129.98-31.39j	-88.07-101.51j
BR3	-57.76+104.34j	119.86-12.69j	-48.69-73.17j



* In_x is the rated current of the phase x of the current zone. x = A or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

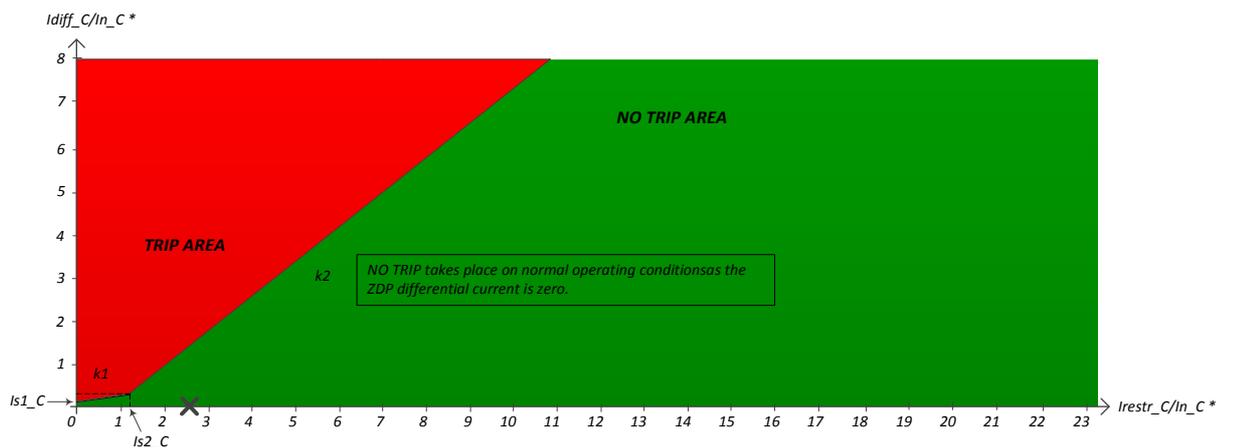
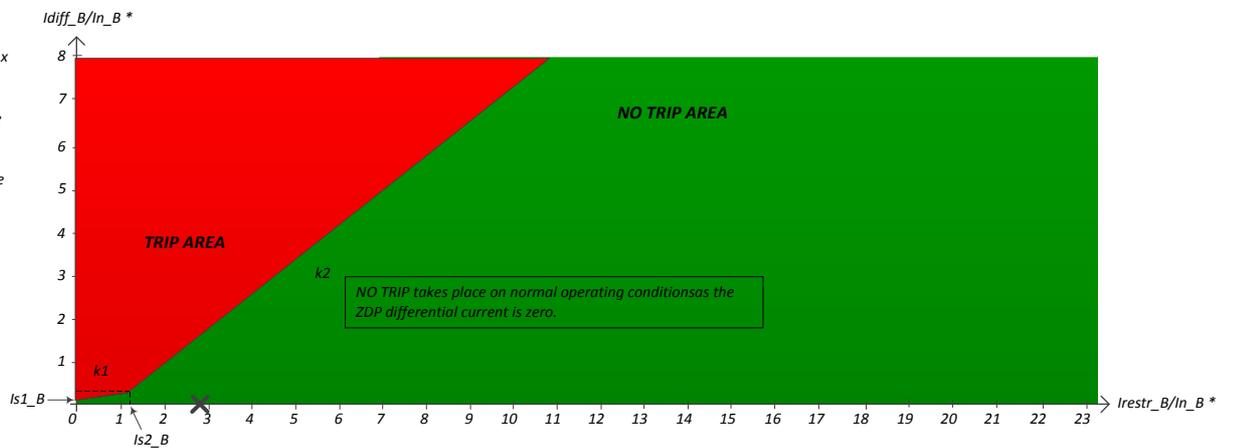
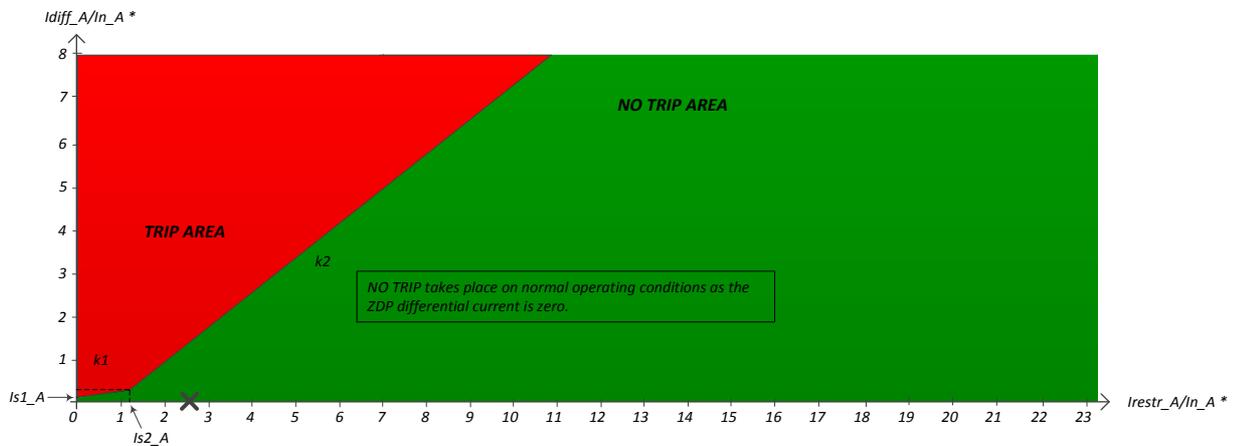
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix B6 – Power flow simulation – SP1 - continued

Simulation step 2/24

Zone : 2

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	38.90-78.30j	-69.74-0.25j	29.84+59.35j
BR2	51.19-155.79j	-129.98+31.39j	88.07+101.51j
BR4	-12.28+77.51j	60.26-31.73j	-58.27-42.14j
BR6	-0.00-0.00j	-0.00-0.00j	-0.00-0.00j



* In_x is the rated current of the phase x of the current zone. $x = A$ or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

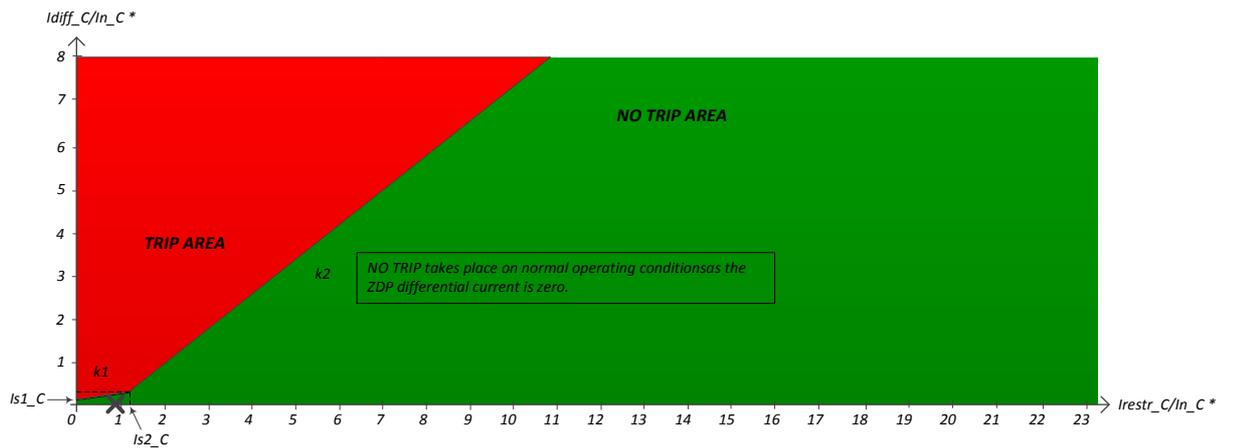
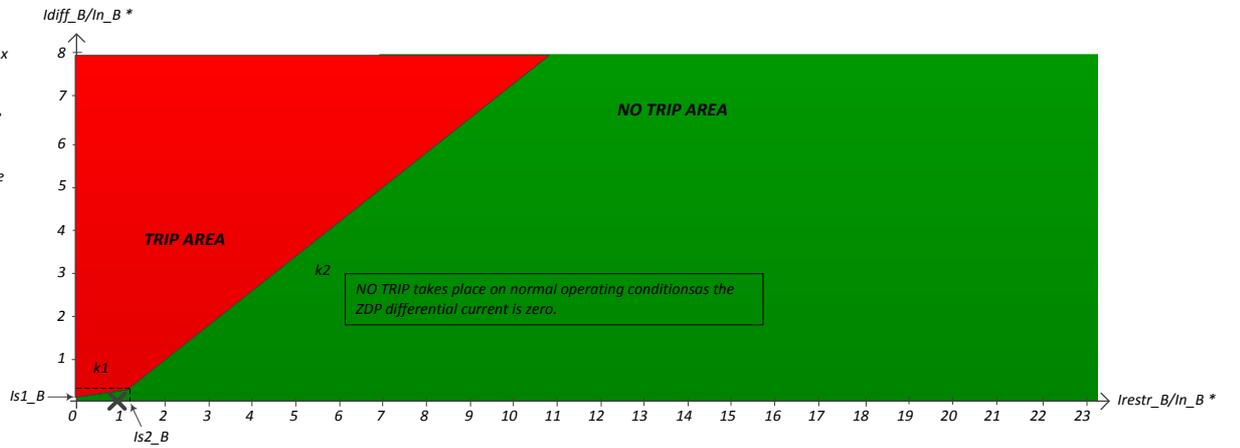
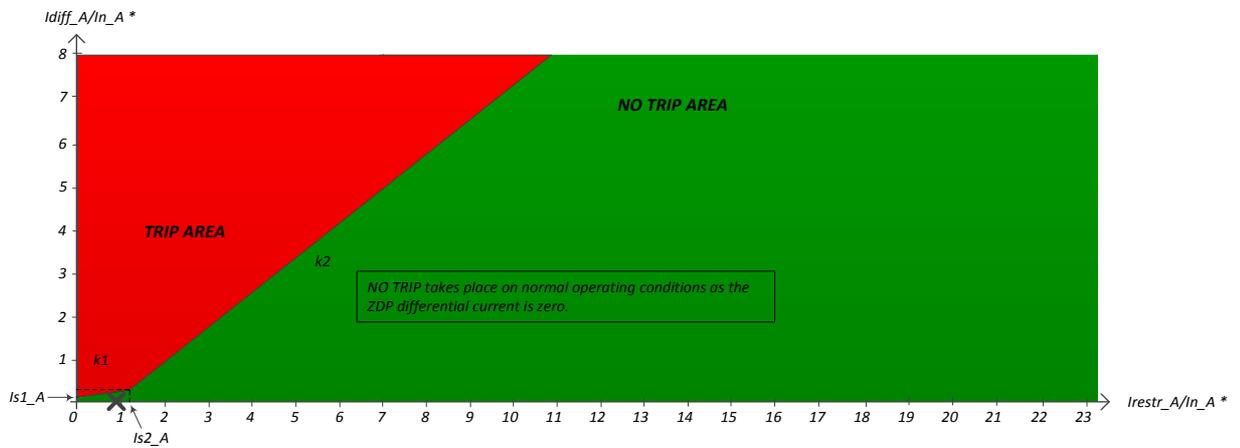
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix B6 – Power flow simulation – SP1 - continued

Simulation step 2/24

Zone : 3

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	57.76-104.31j	-119.85+12.73j	48.69+73.16j
BR3	57.76-104.34j	-119.86+12.69j	48.69+73.17j



* In_x is the rated current of the phase x of the current zone. $x = A$ or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

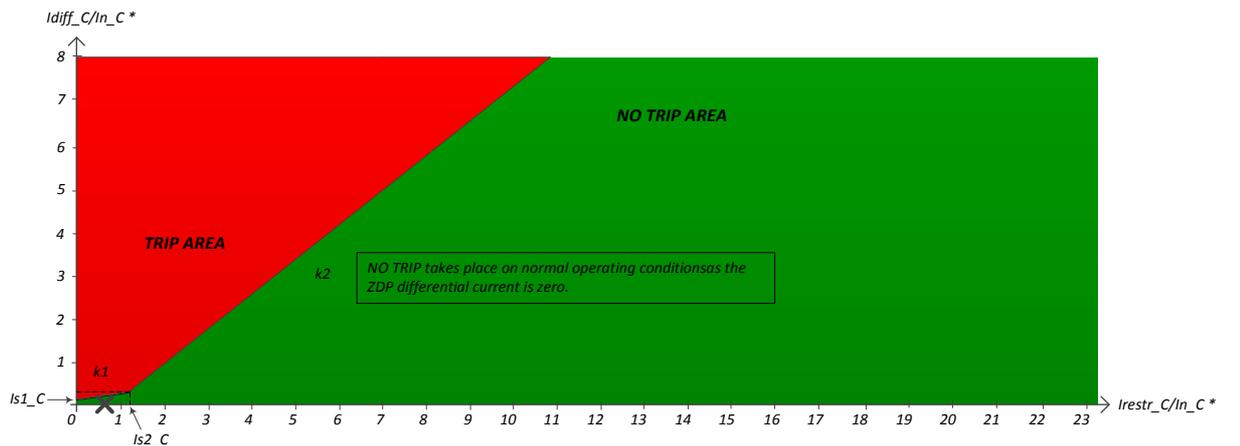
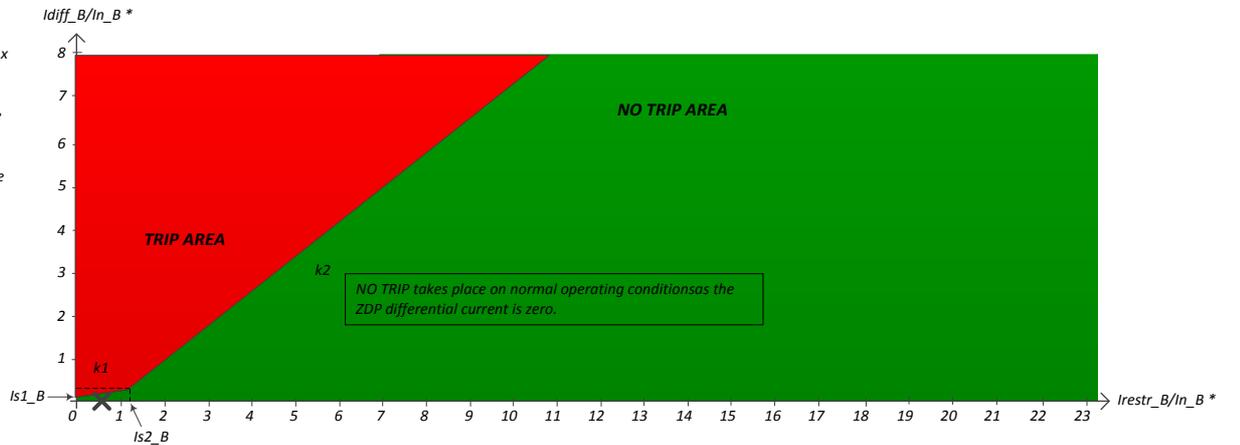
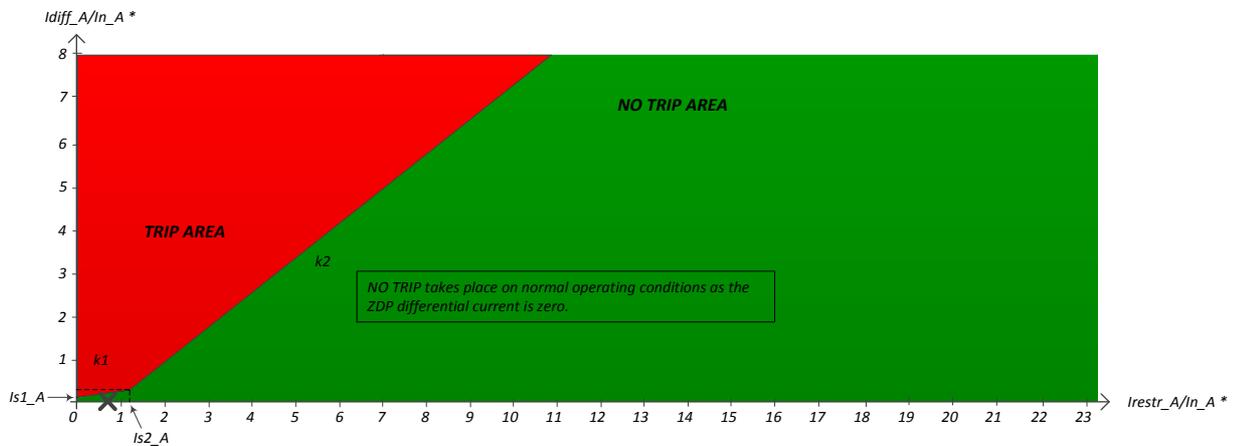
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix B6 – Power flow simulation – SP1 - continued

Simulation step 2/24

Zone : 4

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	14.62+32.55j	29.44-32.94j	-39.15-6.99j
BR4	26.92-44.90j	-30.86-1.15j	19.12+35.10j
BR5	-12.28+77.51j	60.26-31.73j	-58.27-42.14j



* In_x is the rated current of the phase x of the current zone. $x = A$ or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

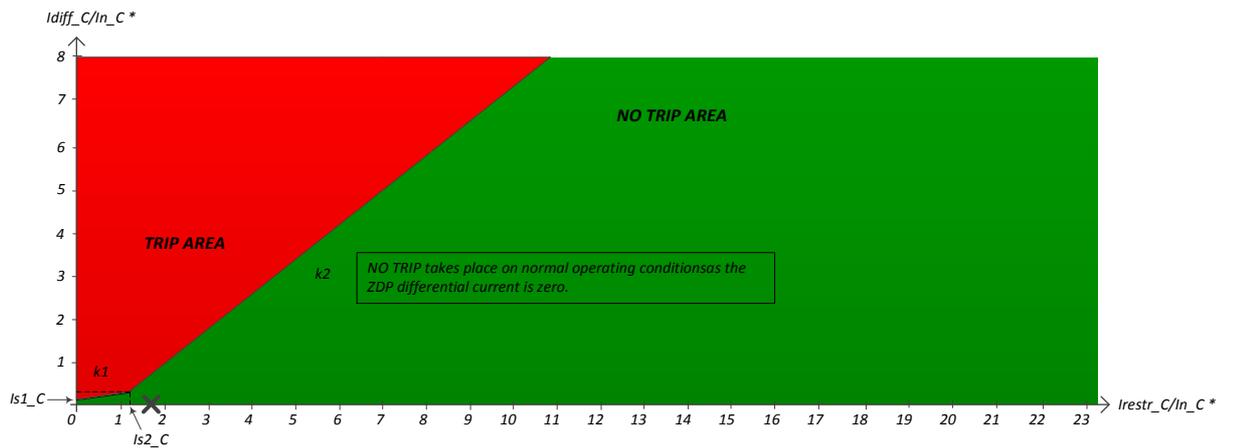
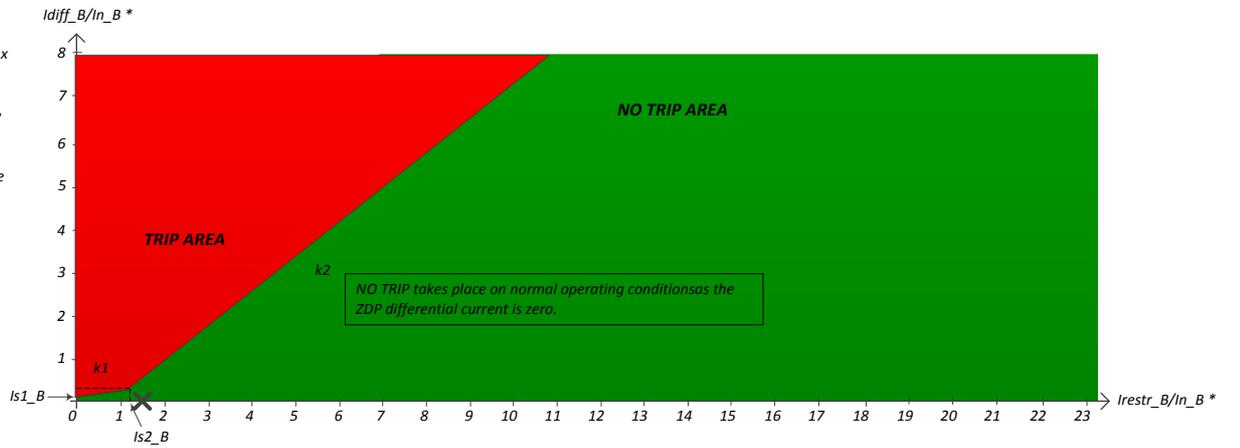
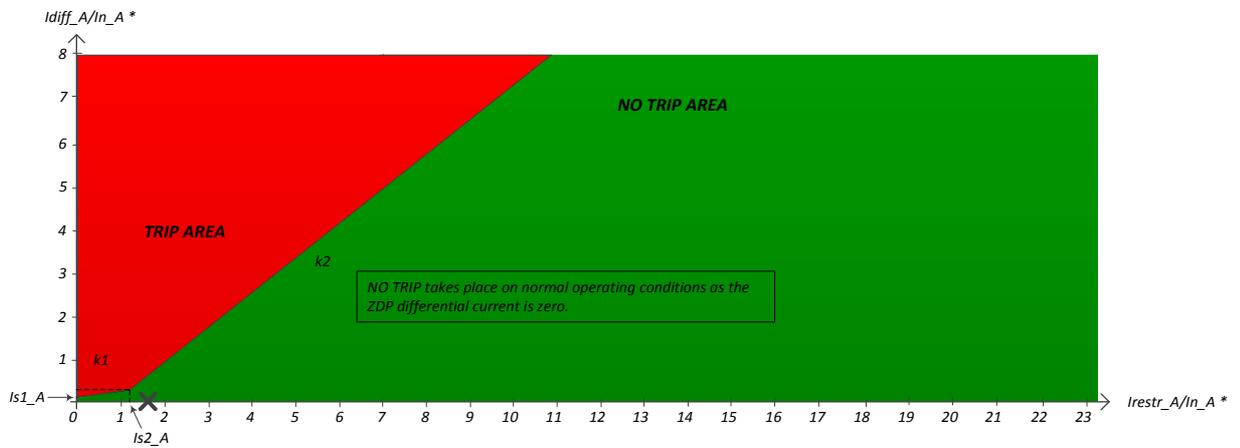
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix B6 – Power flow simulation – SP1 - continued

Simulation step 2/24

Zone : 5

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	26.91-44.88j	-30.85-1.14j	19.12+35.09j
BR5	26.92-44.90j	-30.86-1.15j	19.12+35.10j



* In_x is the rated current of the phase x of the current zone. $x = A$ or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

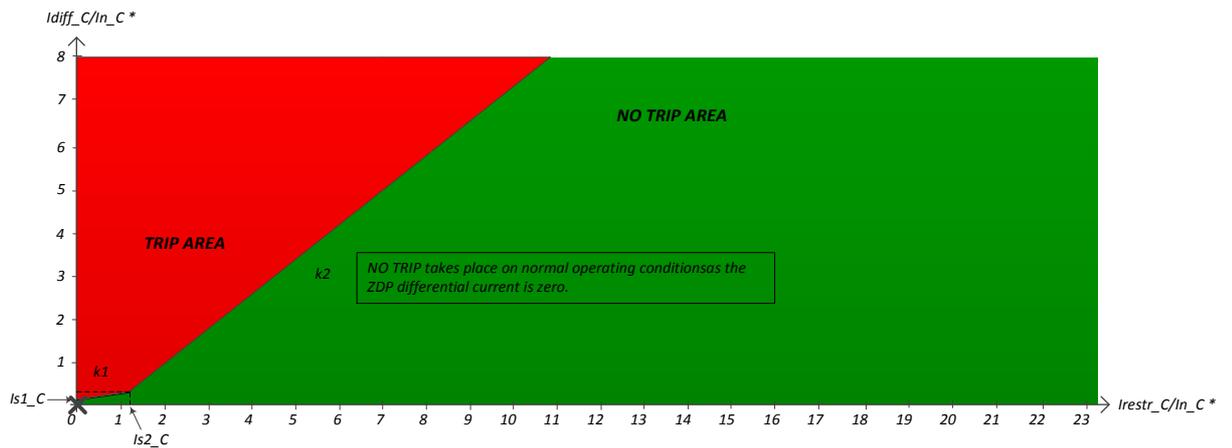
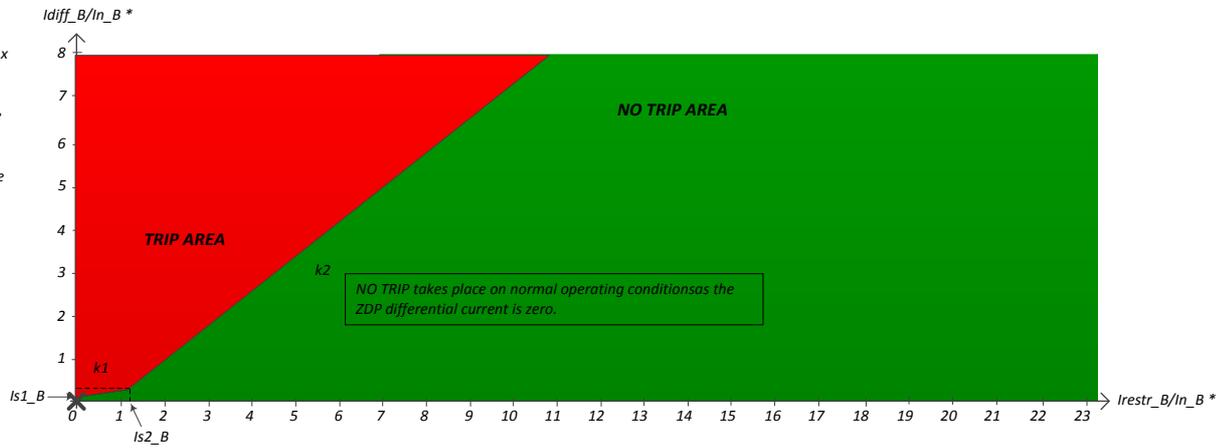
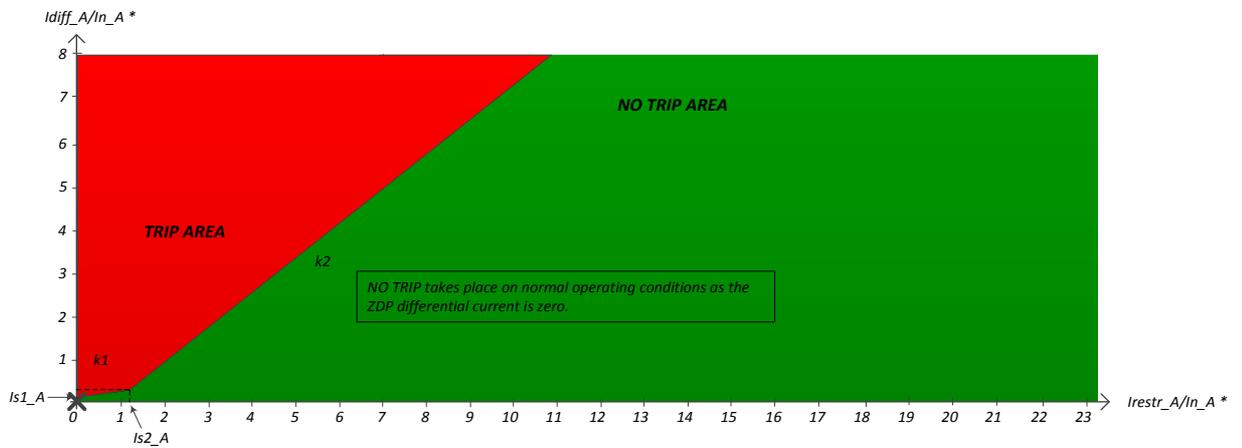
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix B6 – Power flow simulation – SP1 - continued

Simulation step 2/24

Zone : 6

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	0.00+0.00j	0.00+0.00j	0.00+0.00j
BR6	0.00+0.00j	0.00+0.00j	0.00+0.00j



* In_x is the rated current of the phase x of the current zone. $x = A$ or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

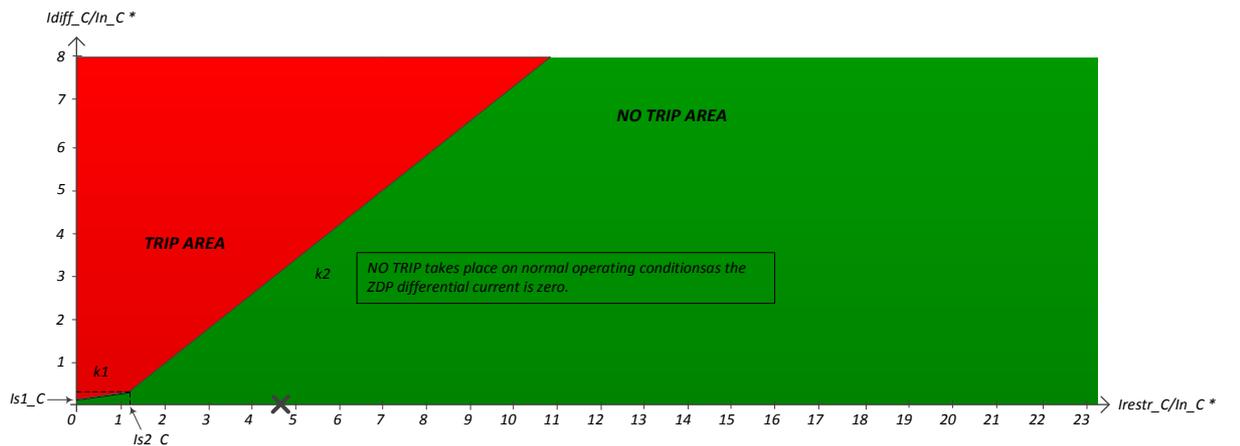
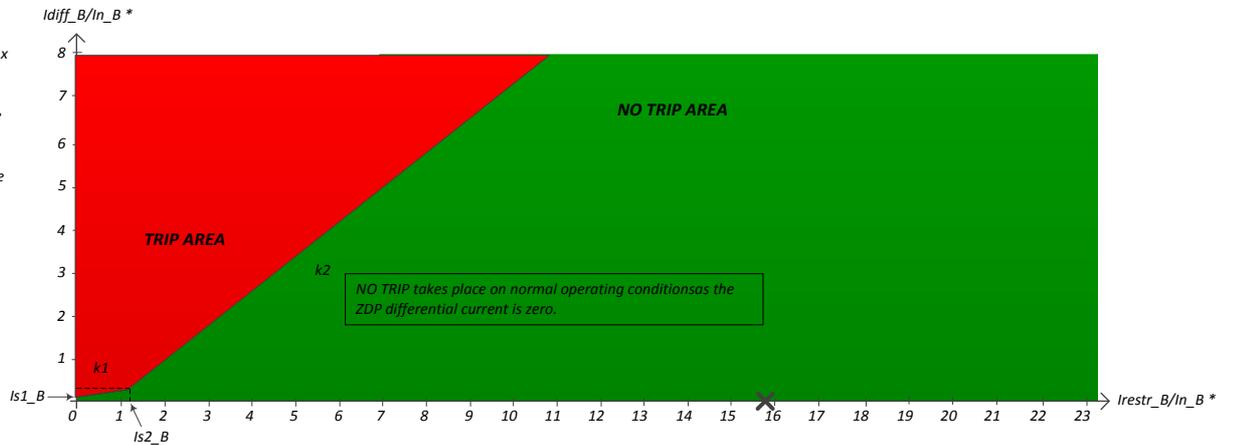
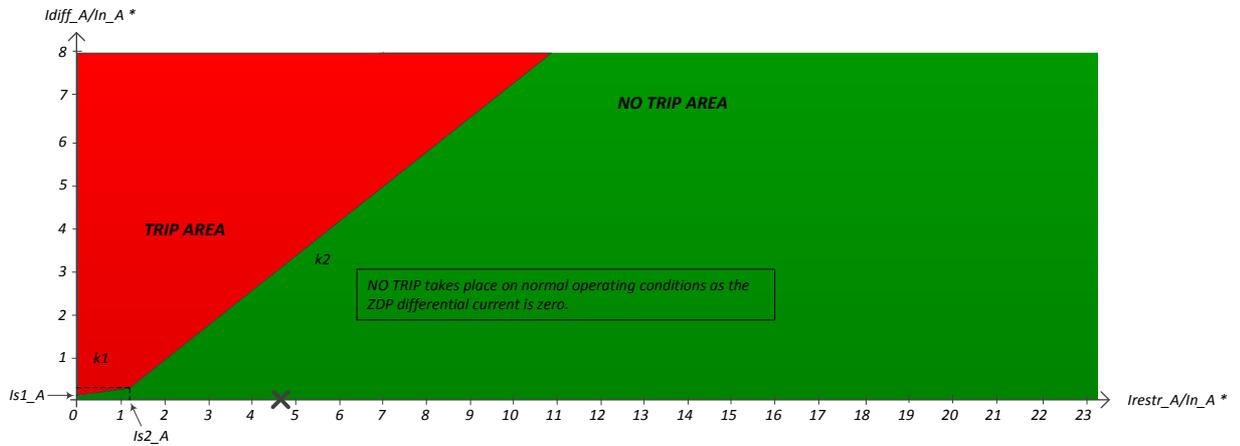
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix B6 – Power flow simulation – SP1

Simulation step 3/24

Zone : 1

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	27.62-74.34j	13.29+13.03j	42.73+82.16j
BR1	162.87-362.58j	-275.72+50.43j	184.54+294.33j
BR2	-81.67+193.56j	170.45-23.65j	-95.74-144.14j
BR3	-53.56+94.68j	118.55-13.77j	-46.08-68.03j



* In_x is the rated current of the phase x of the current zone. $x = A$ or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

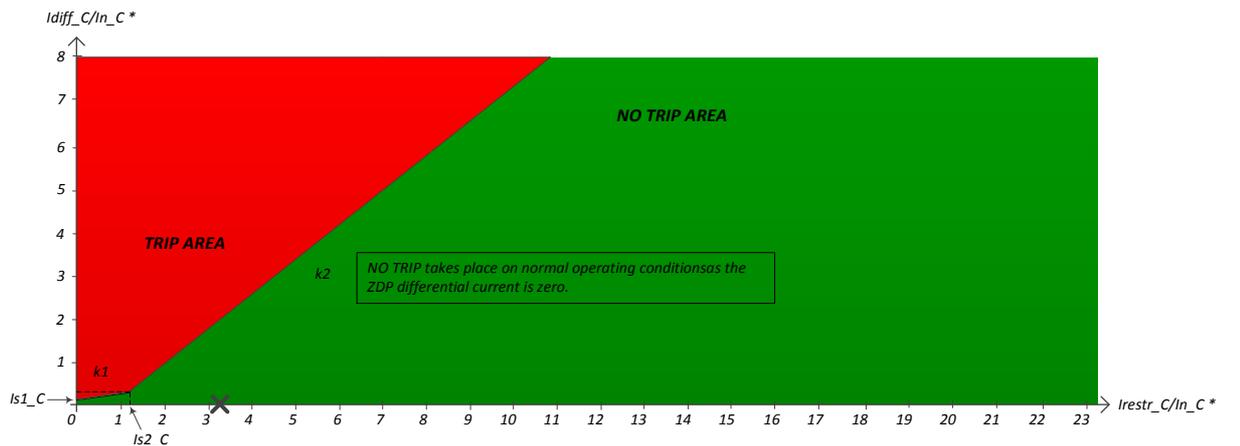
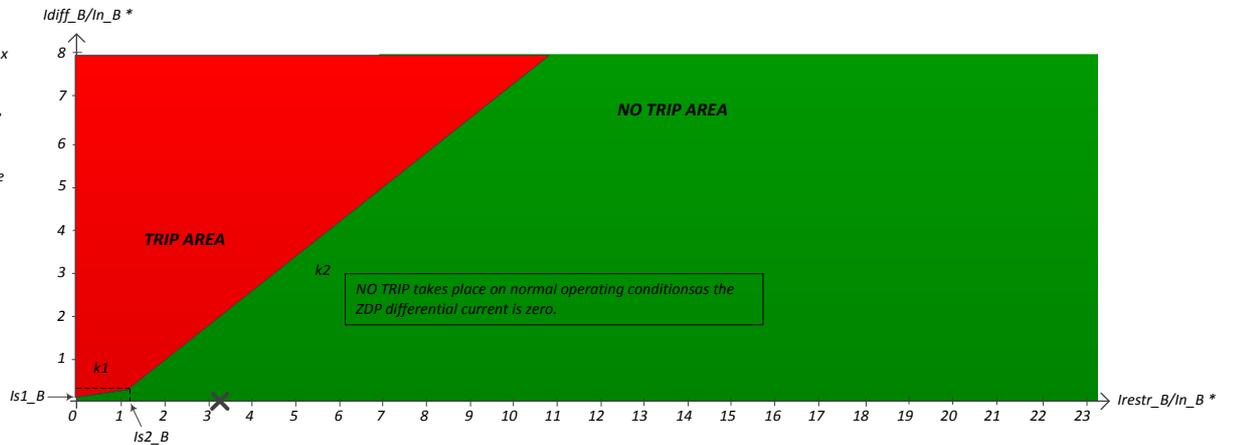
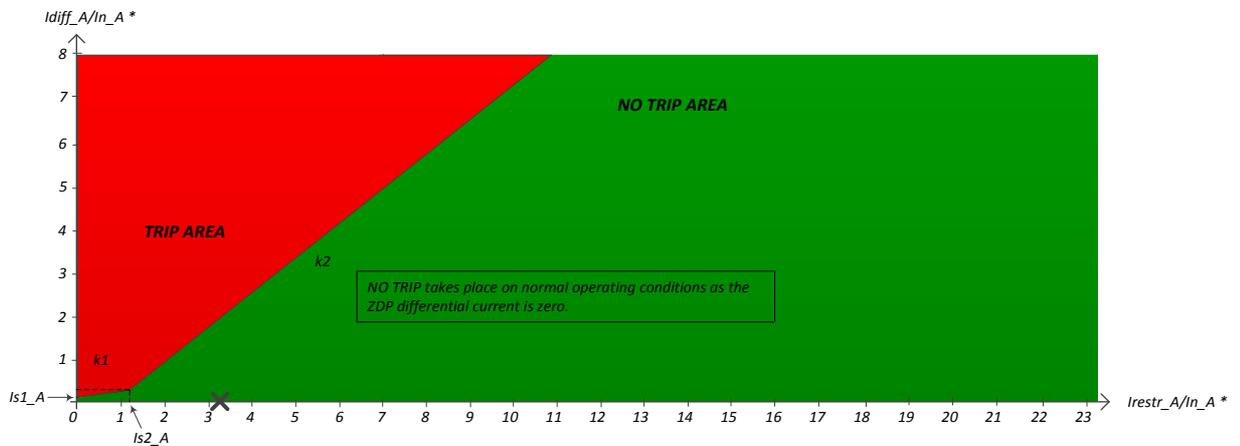
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix B6 – Power flow simulation – SP1 - continued

Simulation step 3/24

Zone : 2

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	35.42-73.46j	-66.75-1.24j	33.07+60.48j
BR2	81.67-193.56j	-170.45+23.65j	95.74+144.14j
BR4	-46.20+120.12j	103.71-24.96j	-62.72-83.67j
BR6	-0.00-0.00j	-0.00-0.00j	-0.00-0.00j



* In_x is the rated current of the phase x of the current zone. $x = A$ or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

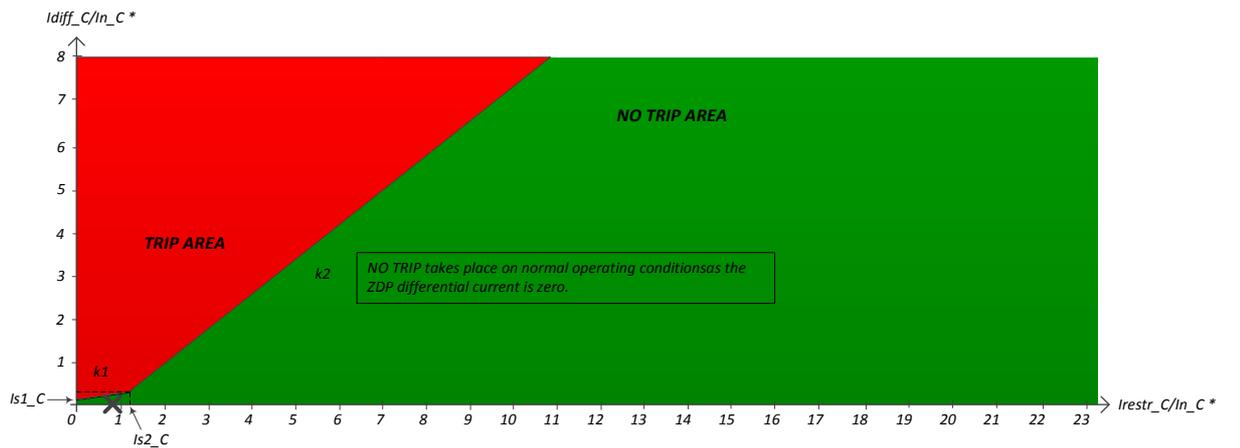
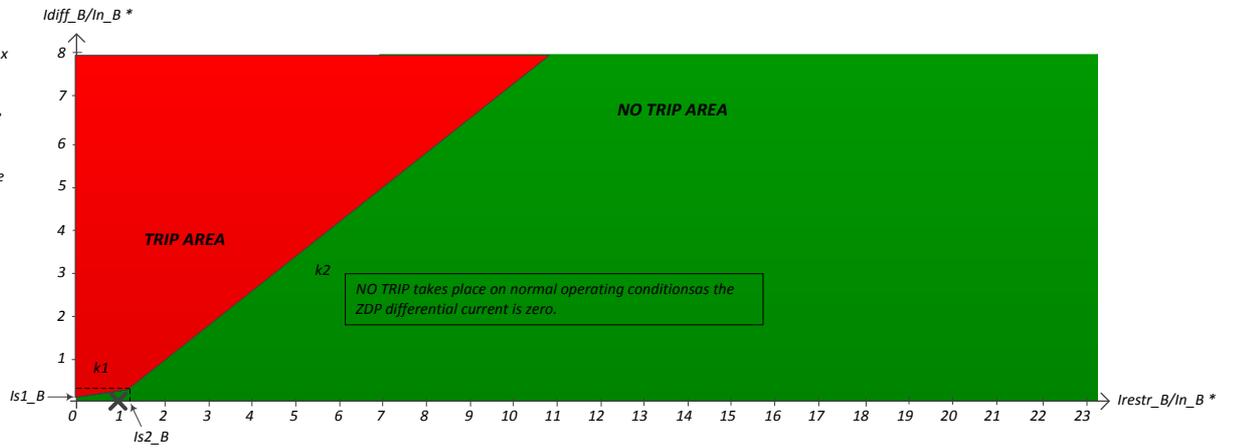
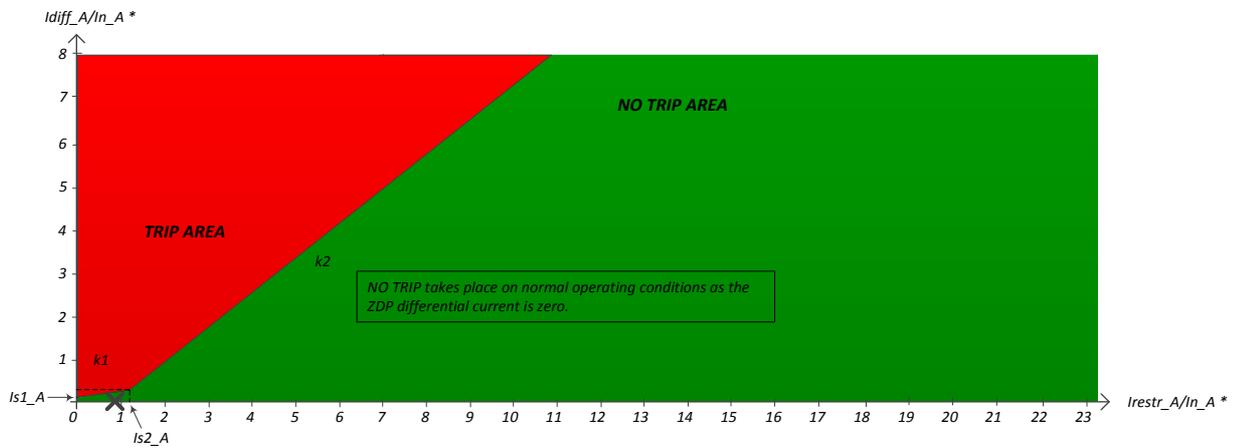
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix B6 – Power flow simulation – SP1 - continued

Simulation step 3/24

Zone : 3

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	53.53-94.67j	-118.54+13.82j	46.09+68.03j
BR3	53.56-94.68j	-118.55+13.77j	46.08+68.03j



* In_x is the rated current of the phase x of the current zone. $x = A$ or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

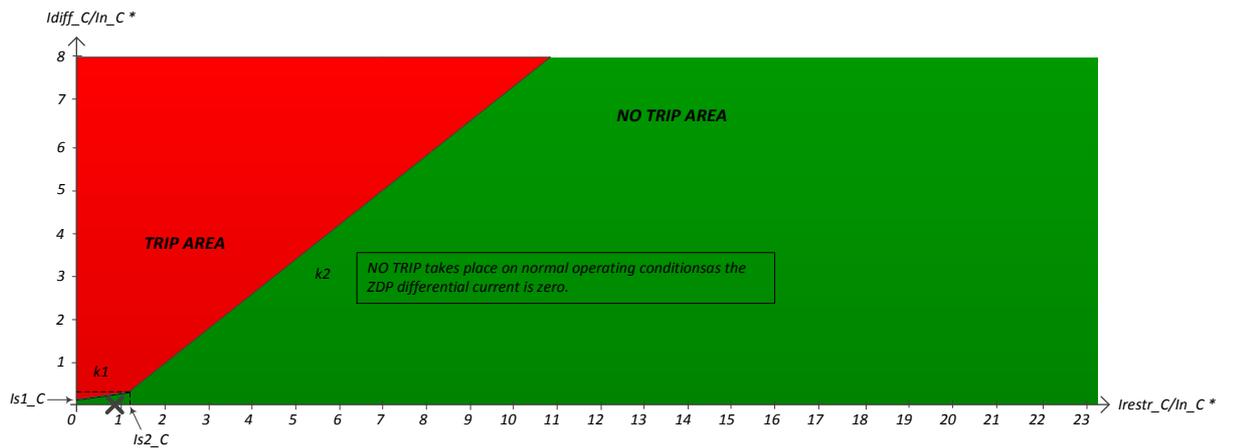
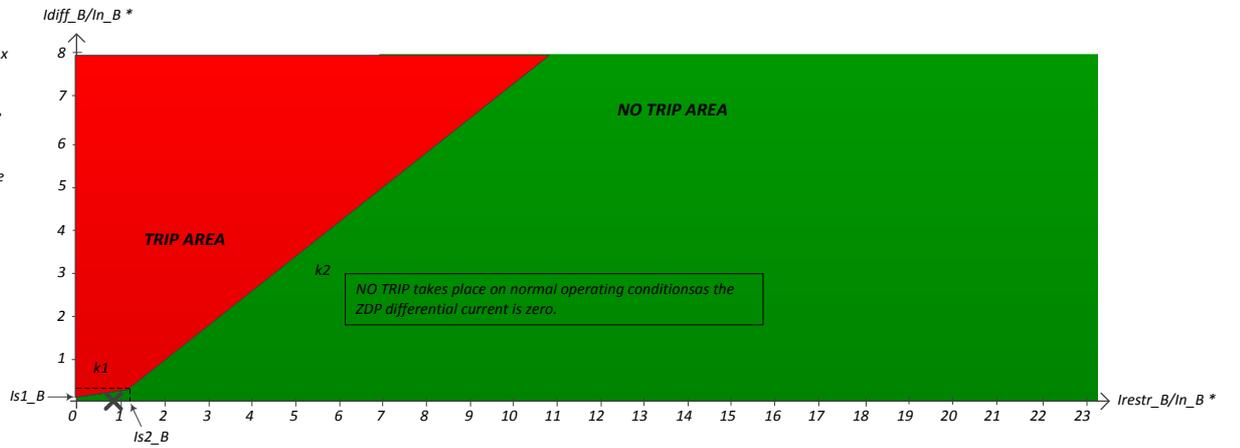
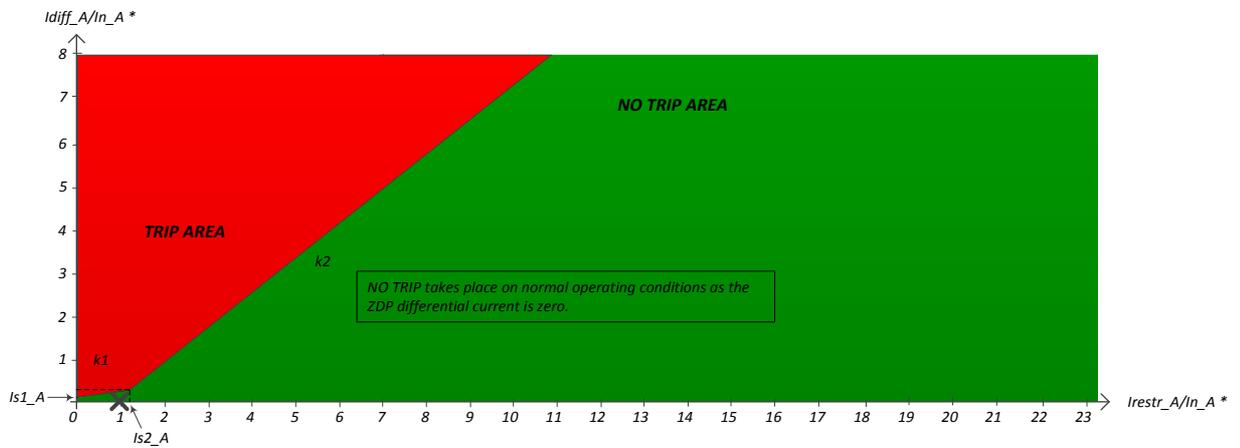
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix B6 – Power flow simulation – SP1 - continued

Simulation step 3/24

Zone : 4

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	19.80-75.15j	-68.55+26.02j	43.44+49.04j
BR4	46.20-120.12j	-103.71+24.96j	62.72+83.67j
BR5	-26.35+44.93j	35.16+1.01j	-19.30-34.64j



* In_x is the rated current of the phase x of the current zone. $x = A$ or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

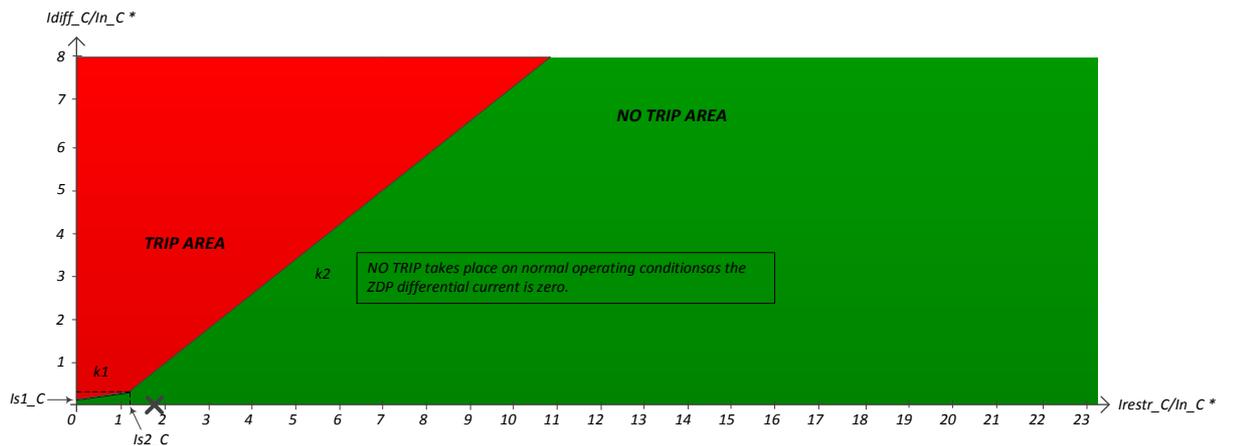
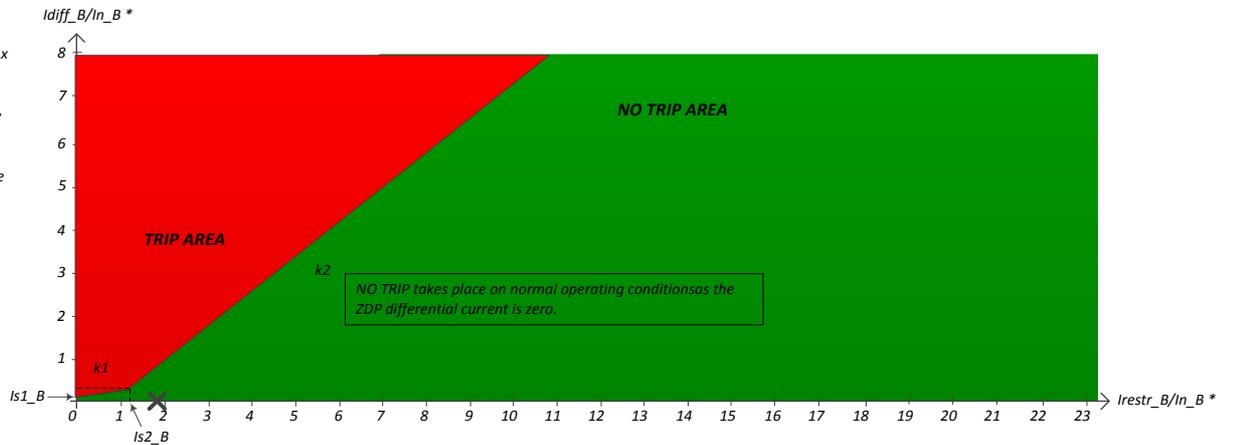
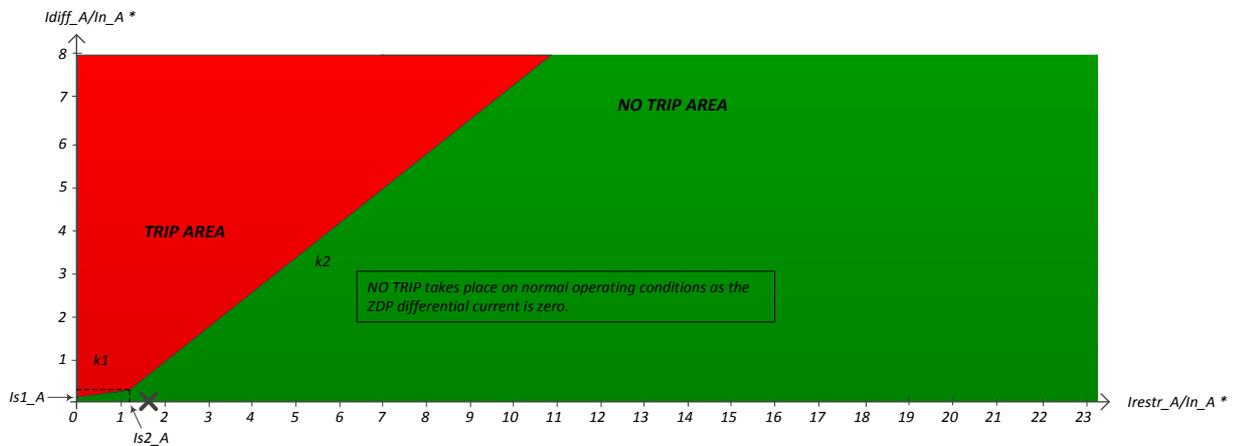
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix B6 – Power flow simulation – SP1 - continued

Simulation step 3/24

Zone : 5

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	26.34-44.92j	-35.17-0.99j	19.32+34.63j
BR5	26.35-44.93j	-35.16-1.01j	19.30+34.64j



* In_x is the rated current of the phase x of the current zone. $x = A$ or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

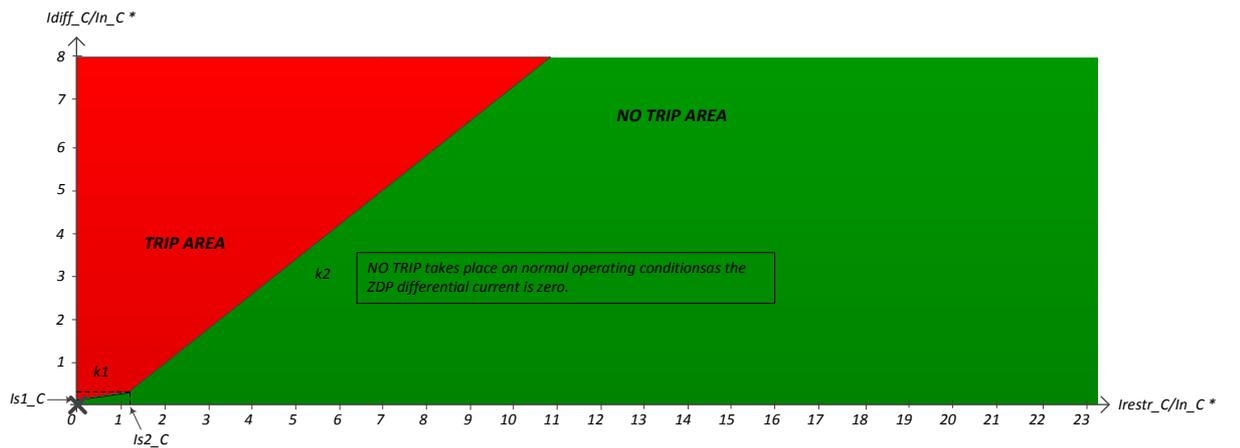
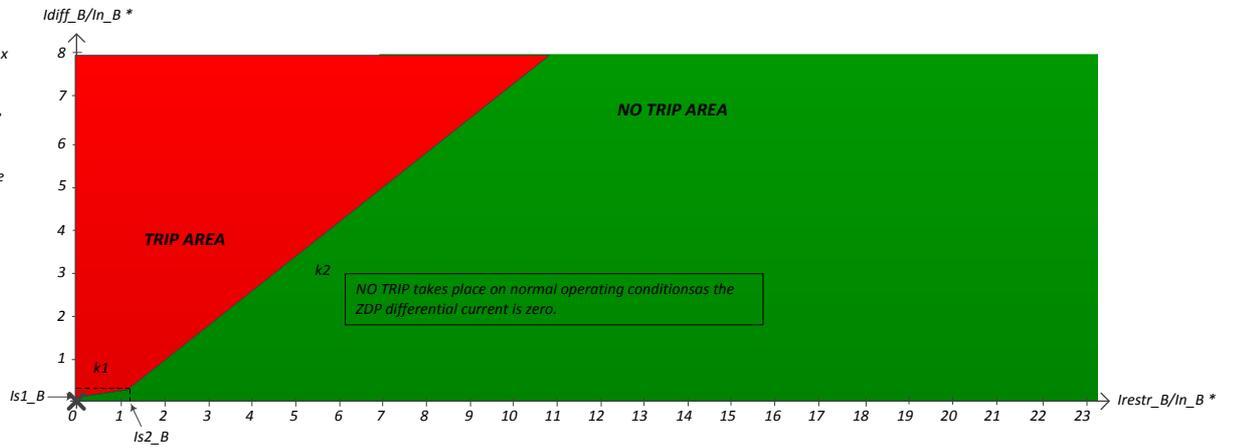
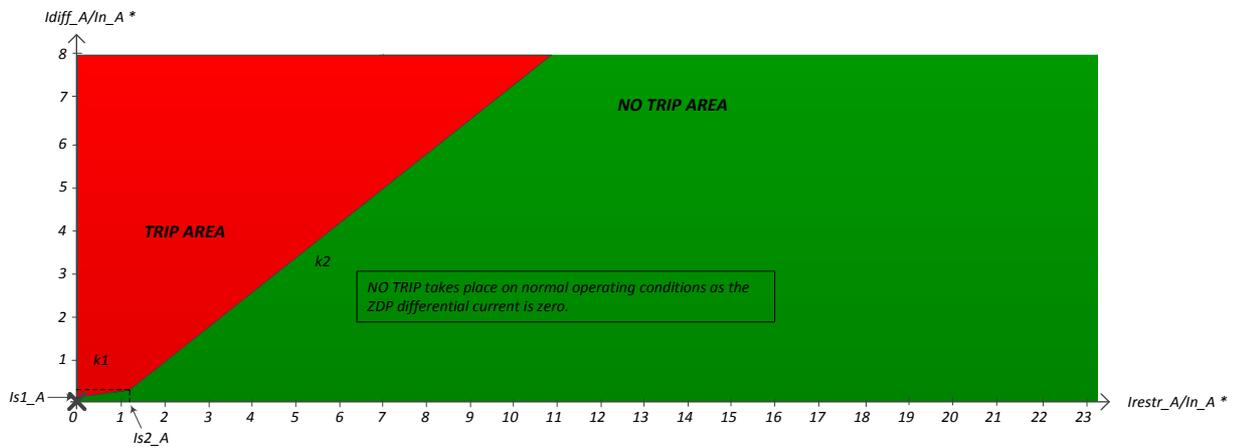
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix B6 – Power flow simulation – SP1 - continued

Simulation step 3/24

Zone : 6

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	0.00+0.00j	0.00+0.00j	0.00+0.00j
BR6	0.00+0.00j	0.00+0.00j	0.00+0.00j



* In_x is the rated current of the phase x of the current zone. $x = A$ or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

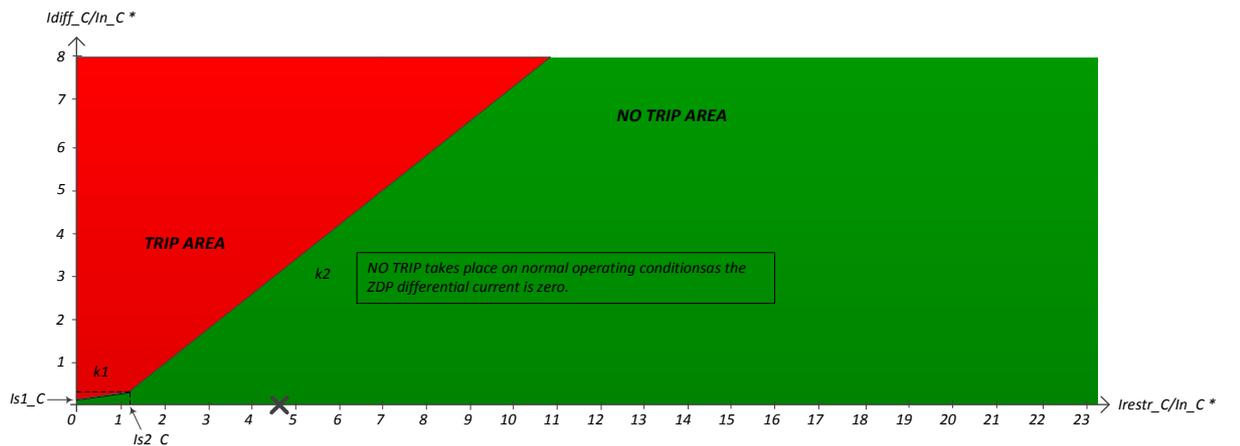
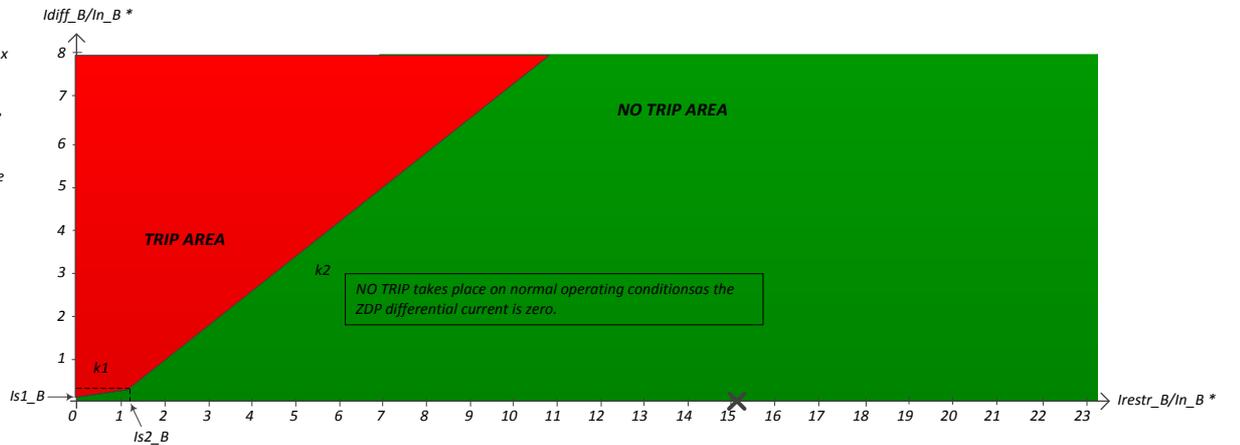
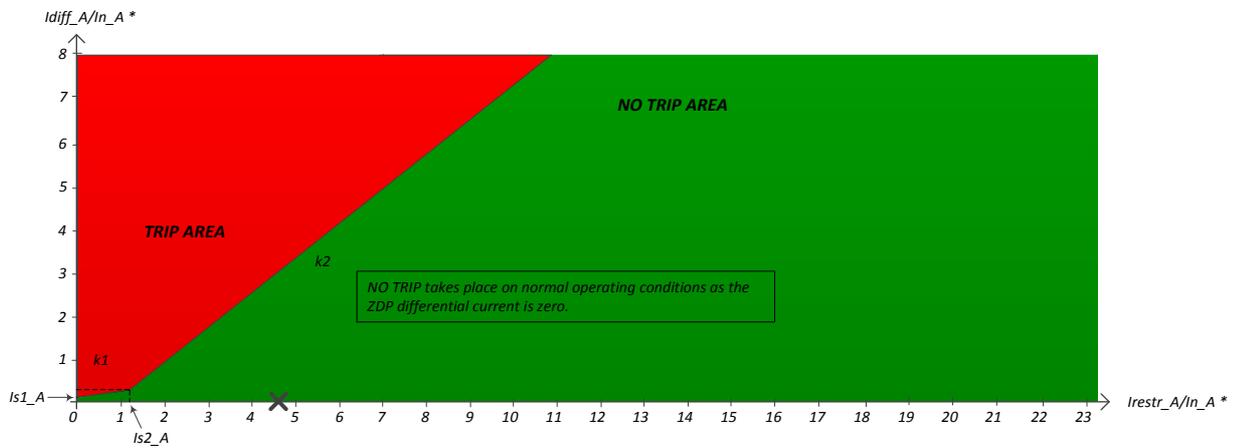
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix B6 – Power flow simulation – SP1

Simulation step 4/24

Zone : 1

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	31.23-75.92j	4.78+13.09j	42.22+82.26j
BR1	152.37-351.15j	-268.89+50.75j	183.47+281.53j
BR2	-68.20+174.84j	157.09-25.74j	-94.17-130.01j
BR3	-52.91+100.37j	116.55-11.95j	-47.11-69.28j



* In_x is the rated current of the phase x of the current zone. $x = A$ or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

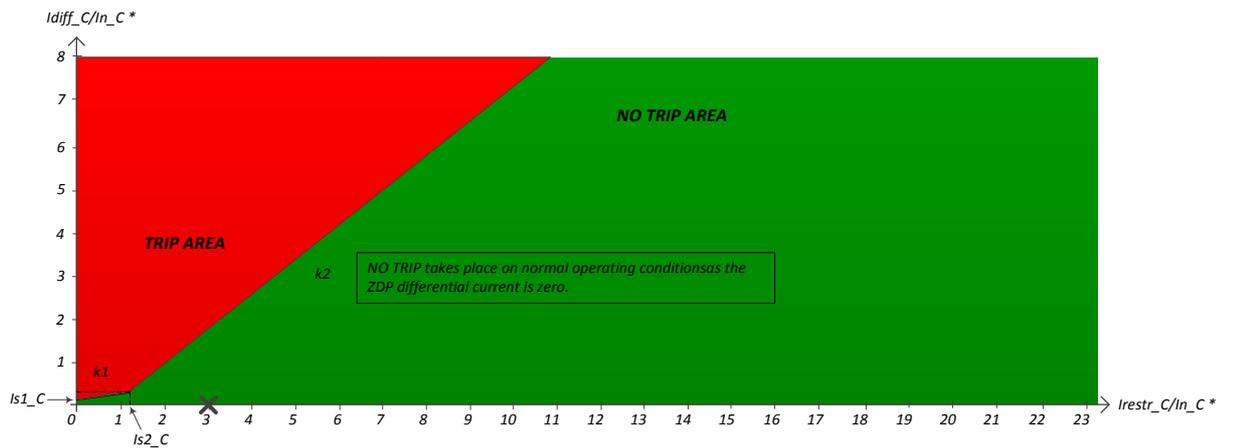
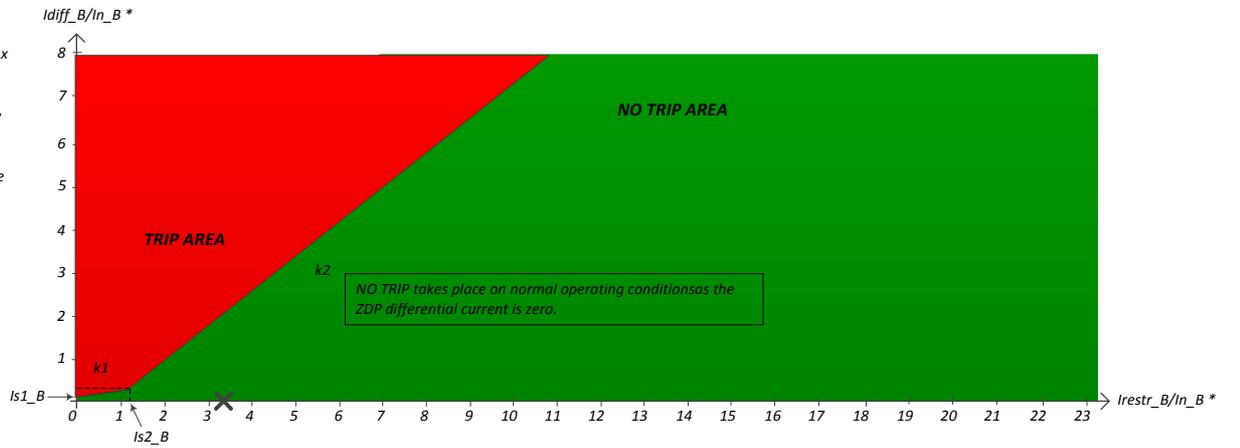
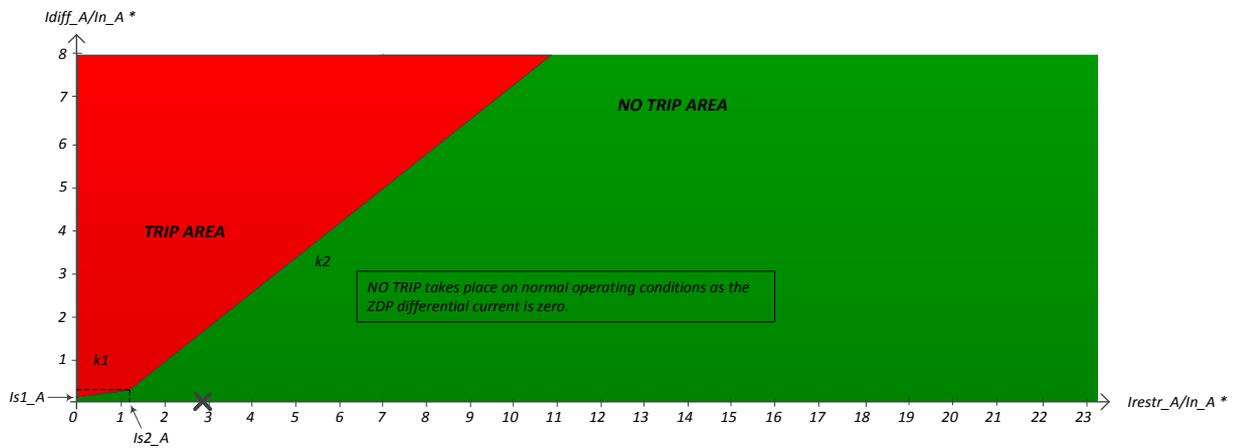
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix B6 – Power flow simulation – SP1 - continued

Simulation step 4/24

Zone : 2

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	37.07-76.27j	-66.37+0.45j	32.46+64.30j
BR2	68.20-174.84j	-157.09+25.74j	94.17+130.01j
BR4	-31.09+98.60j	90.72-25.37j	-61.75-65.71j
BR6	-0.00-0.00j	-0.00-0.00j	-0.00-0.00j



* In_x is the rated current of the phase x of the current zone. $x = A$ or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

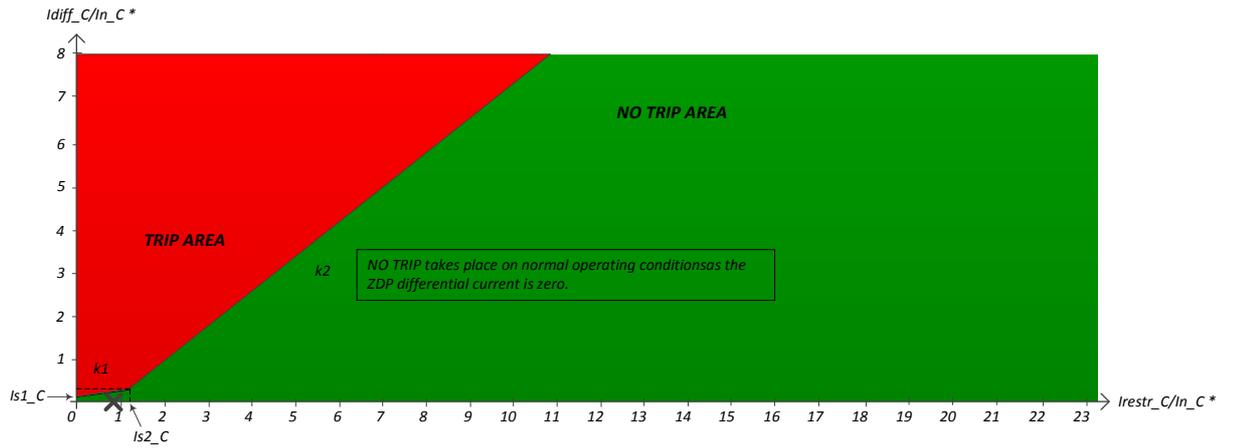
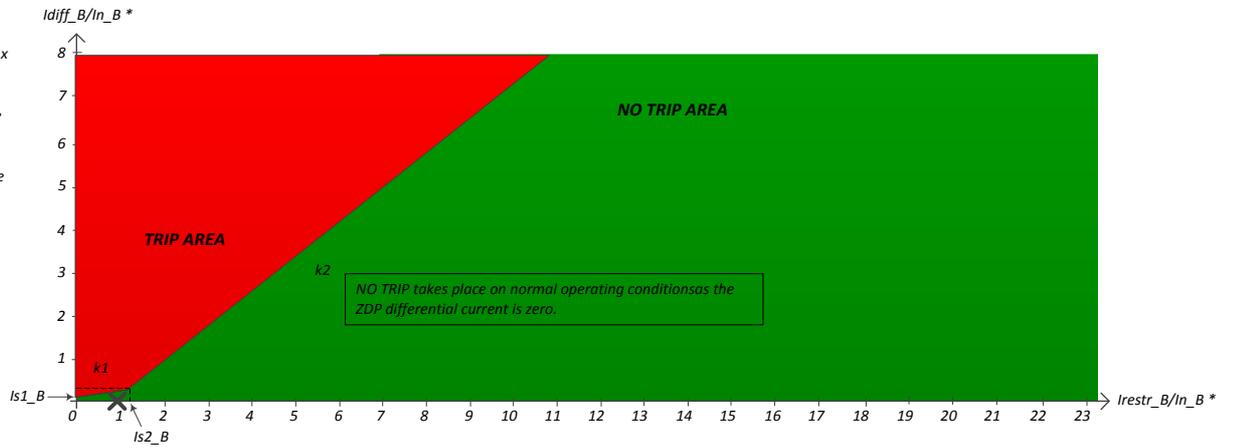
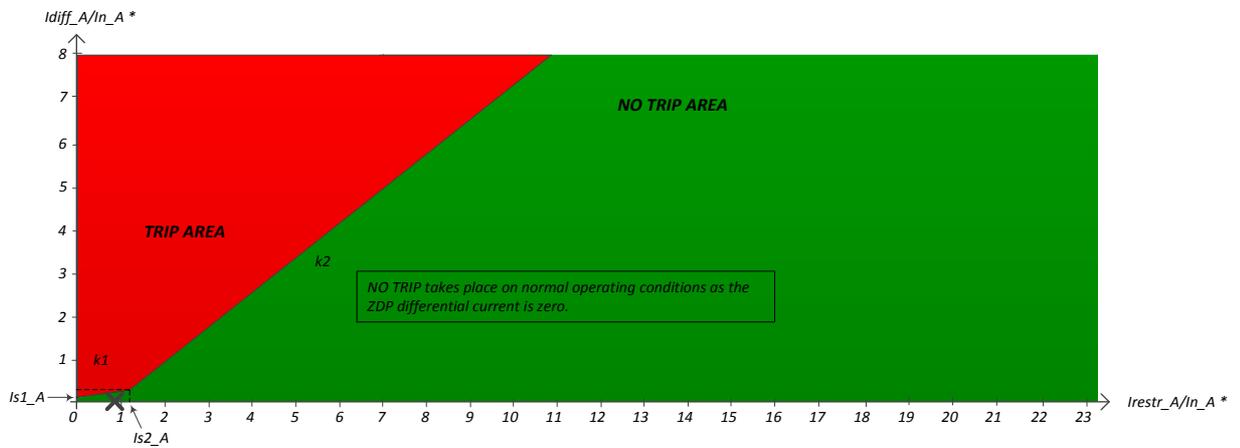
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix B6 – Power flow simulation – SP1 - continued

Simulation step 4/24

Zone : 3

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	52.90-100.37j	-116.55+11.99j	47.11+69.28j
BR3	52.91-100.37j	-116.55+11.95j	47.11+69.28j



* In_x is the rated current of the phase x of the current zone. $x = A$ or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

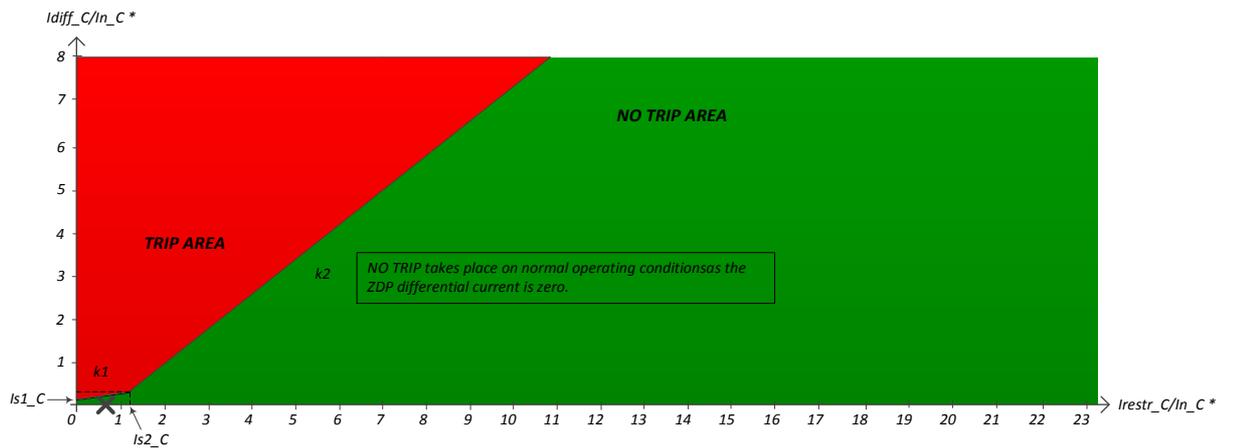
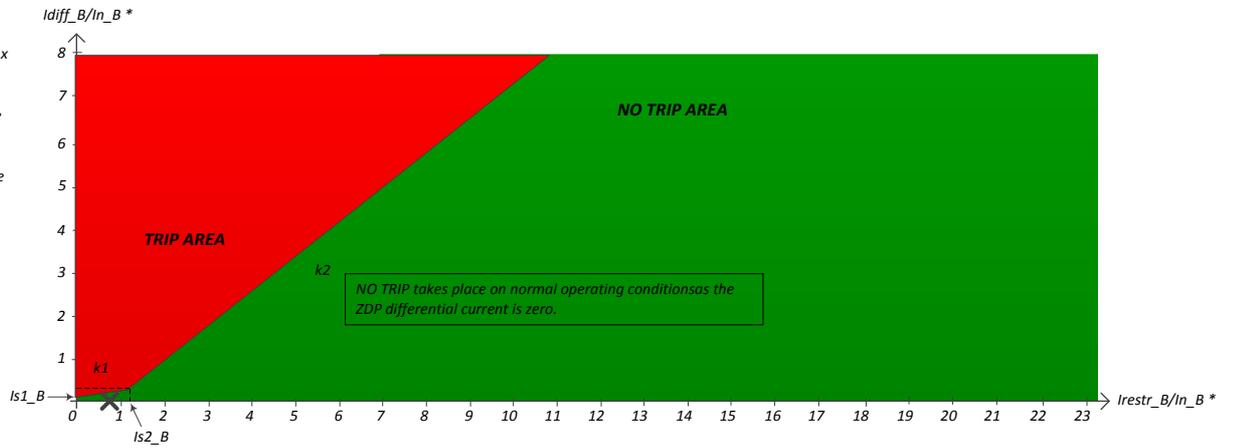
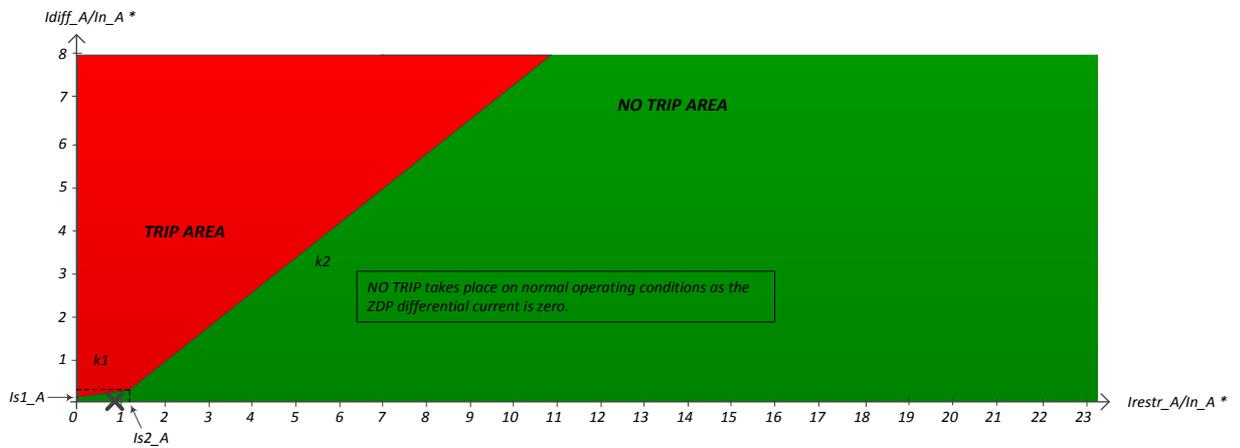
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix B6 – Power flow simulation – SP1 - continued

Simulation step 4/24

Zone : 4

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	4.88-54.47j	-59.62+26.41j	41.45+29.01j
BR4	31.09-98.60j	-90.72+25.37j	61.75+65.71j
BR5	-26.35+44.93j	31.10+0.97j	-20.34-36.71j



* In_x is the rated current of the phase x of the current zone. $x = A$ or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

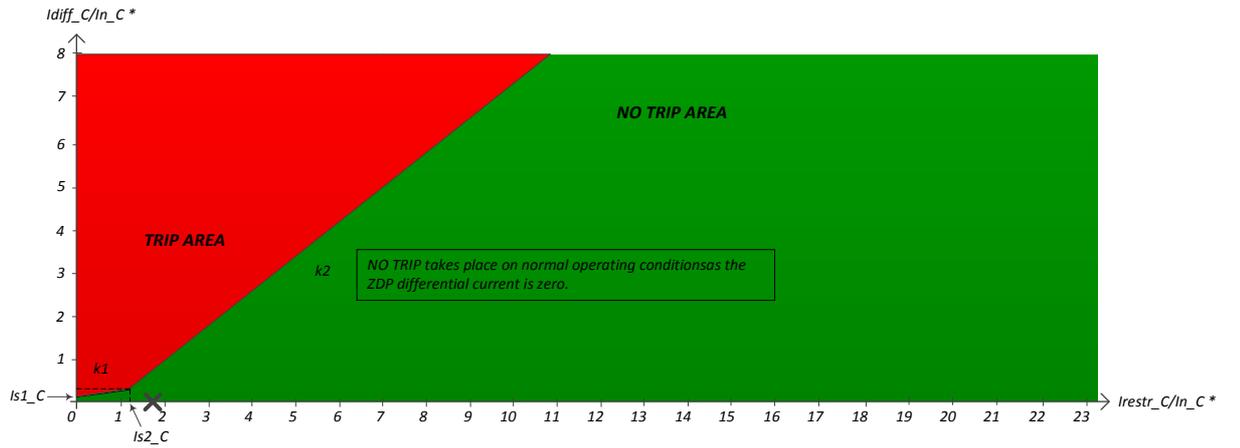
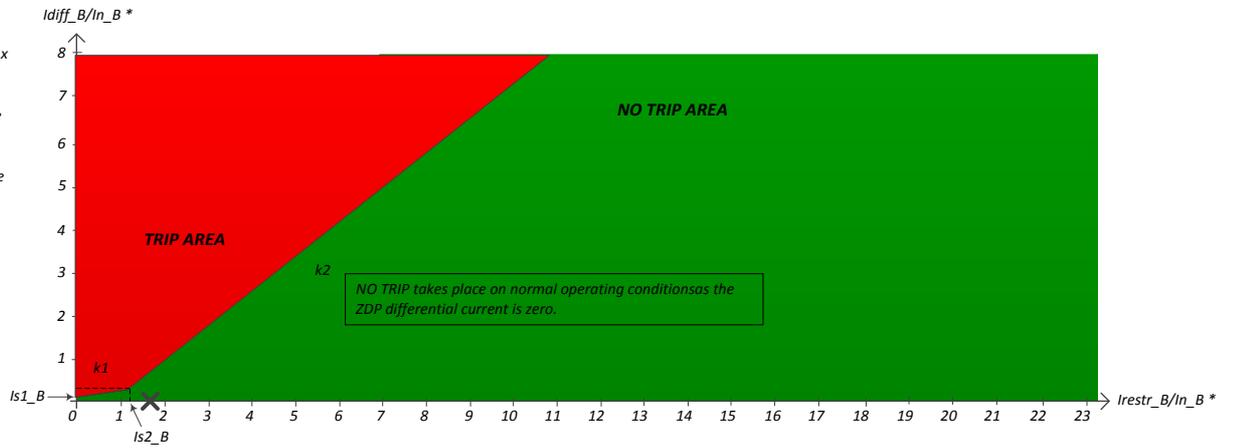
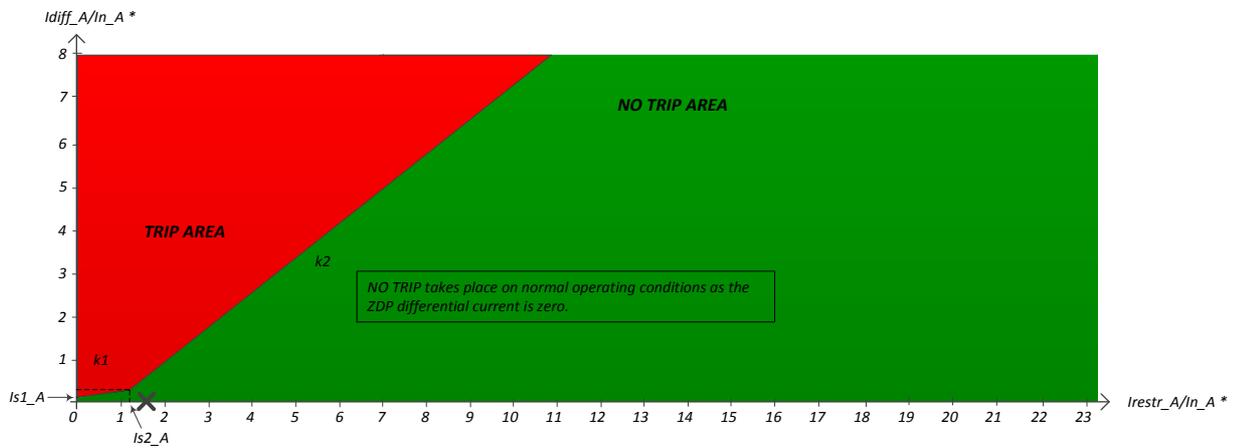
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix B6 – Power flow simulation – SP1 - continued

Simulation step 4/24

Zone : 5

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	26.14-44.11j	-31.10-0.95j	20.35+36.71j
BR5	26.15-44.11j	-31.10-0.97j	20.34+36.71j



* In_x is the rated current of the phase x of the current zone. $x = A$ or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

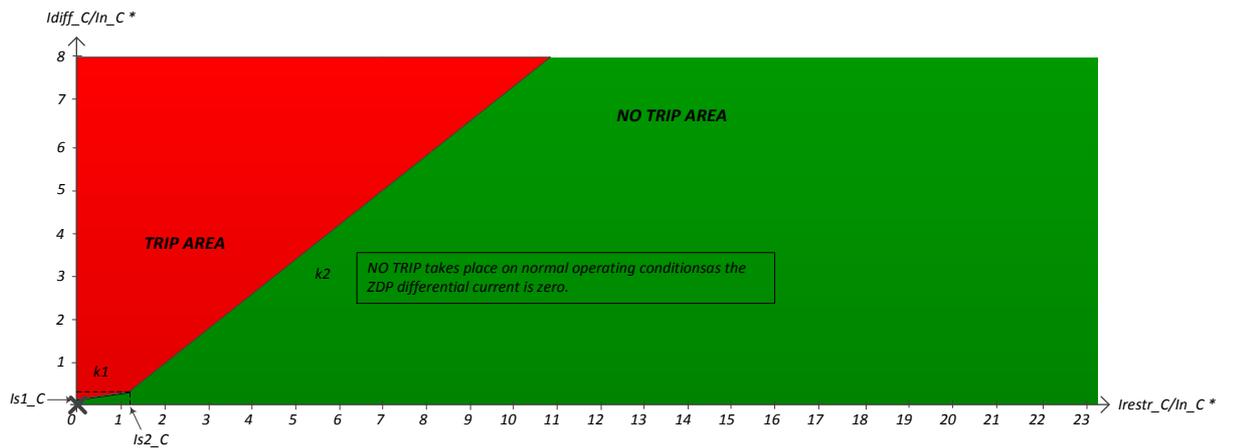
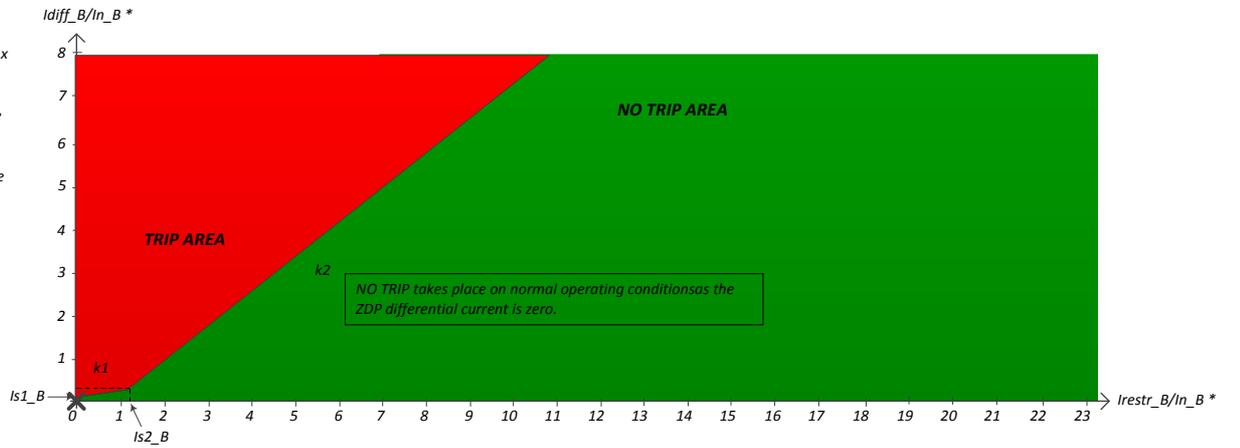
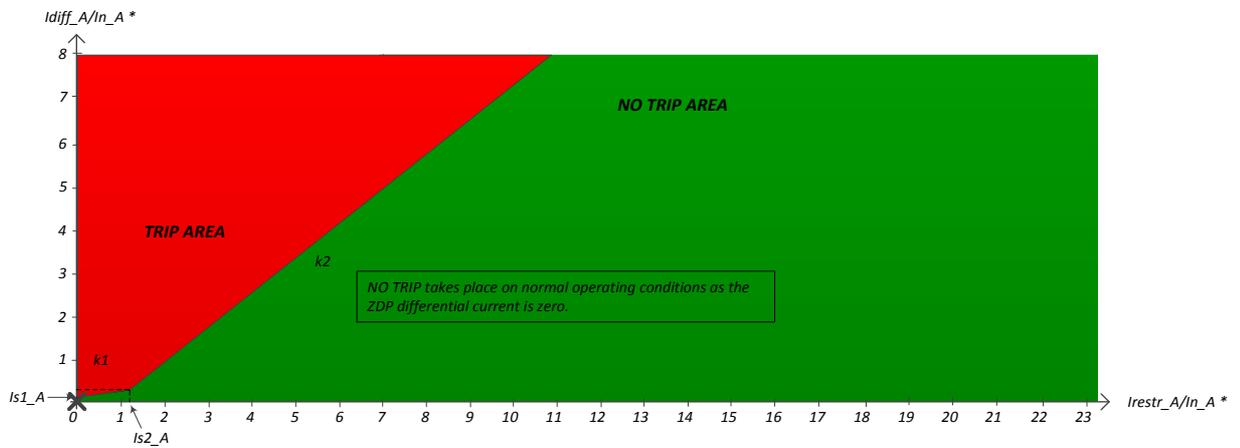
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix B6 – Power flow simulation – SP1 - continued

Simulation step 4/24

Zone : 6

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	0.00+0.00j	0.00+0.00j	0.00+0.00j
BR6	0.00+0.00j	0.00+0.00j	0.00+0.00j



* In_x is the rated current of the phase x of the current zone. $x = A$ or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

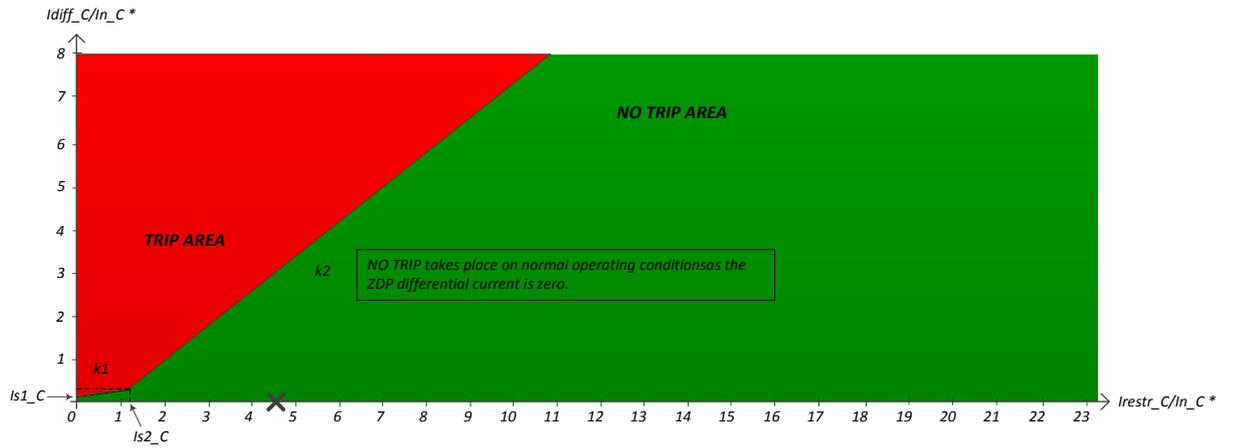
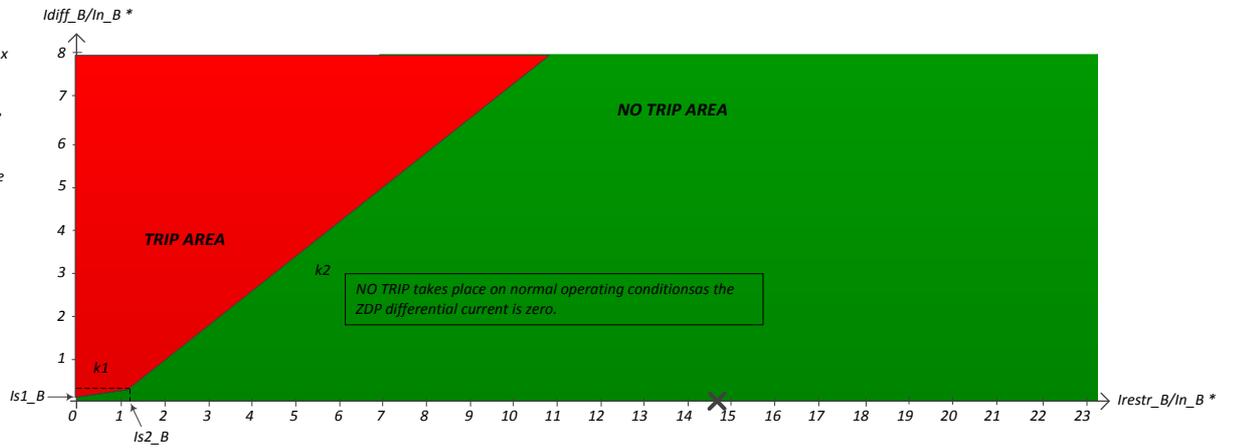
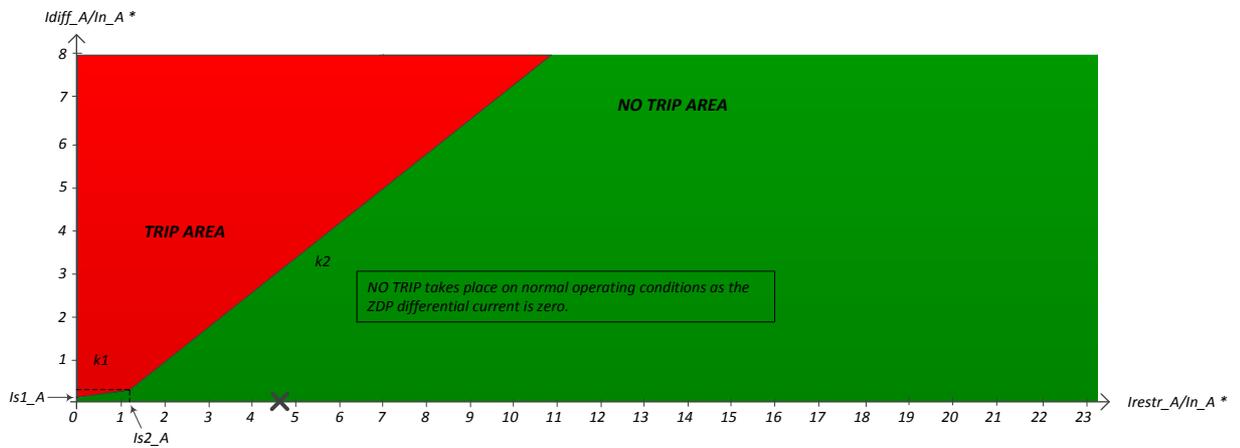
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix B6 – Power flow simulation – SP1

Simulation step 5/24

Zone : 1

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	27.35-74.20j	9.80+12.52j	41.88+83.13j
BR1	153.31-354.56j	-259.25+48.23j	182.24+287.92j
BR2	-73.18+183.88j	154.93-23.31j	-93.68-135.46j
BR3	-52.75+96.46j	114.08-12.43j	-46.68-69.32j



* In_x is the rated current of the phase x of the current zone. $x = A$ or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

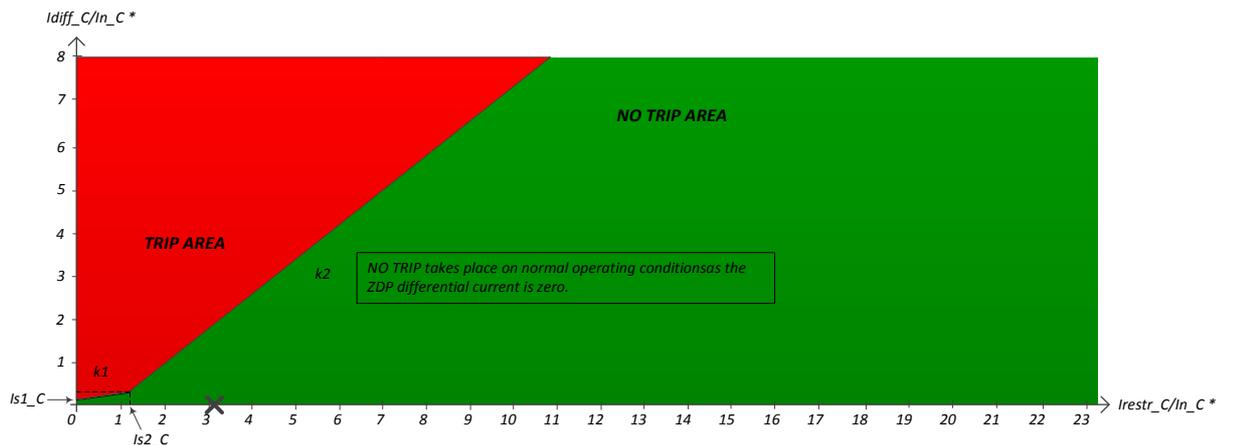
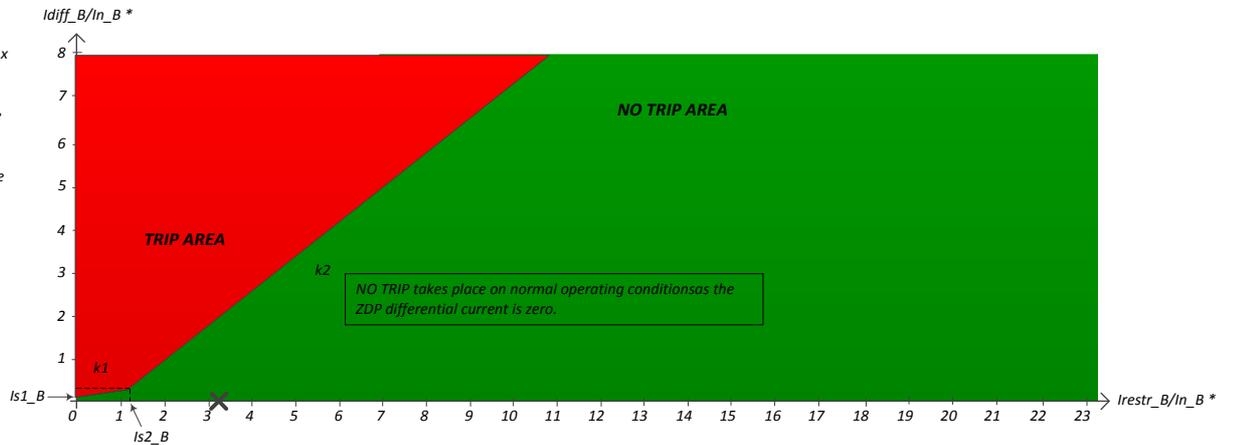
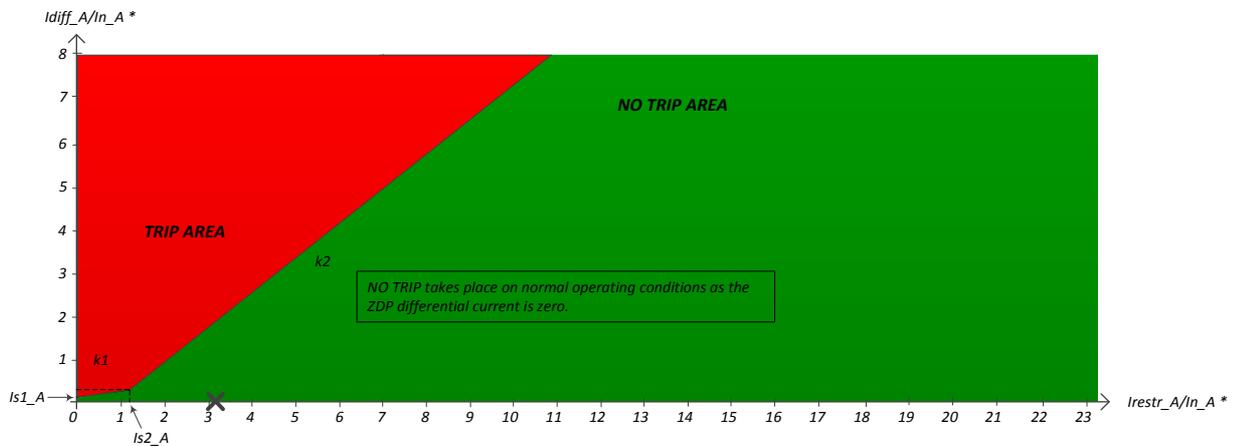
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix B6 – Power flow simulation – SP1 - continued

Simulation step 5/24

Zone : 2

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	40.61-80.27j	-64.86-0.05j	29.50+56.93j
BR2	73.18-183.88j	-154.93+23.31j	93.68+135.46j
BR4	-32.52+103.63j	90.08-23.42j	-64.22-78.53j
BR6	-0.00-0.00j	-0.00-0.00j	-0.00-0.00j



* In_x is the rated current of the phase x of the current zone. $x = A$ or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

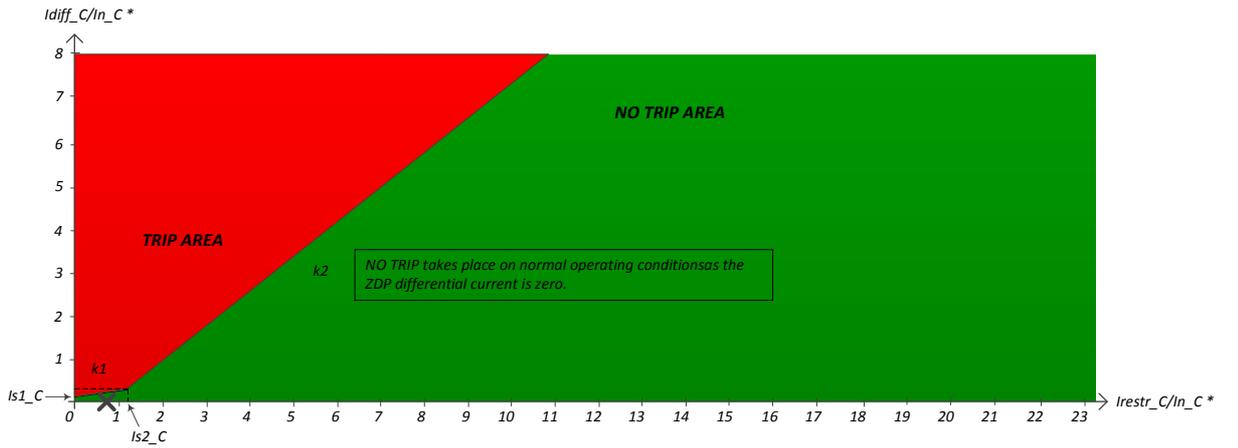
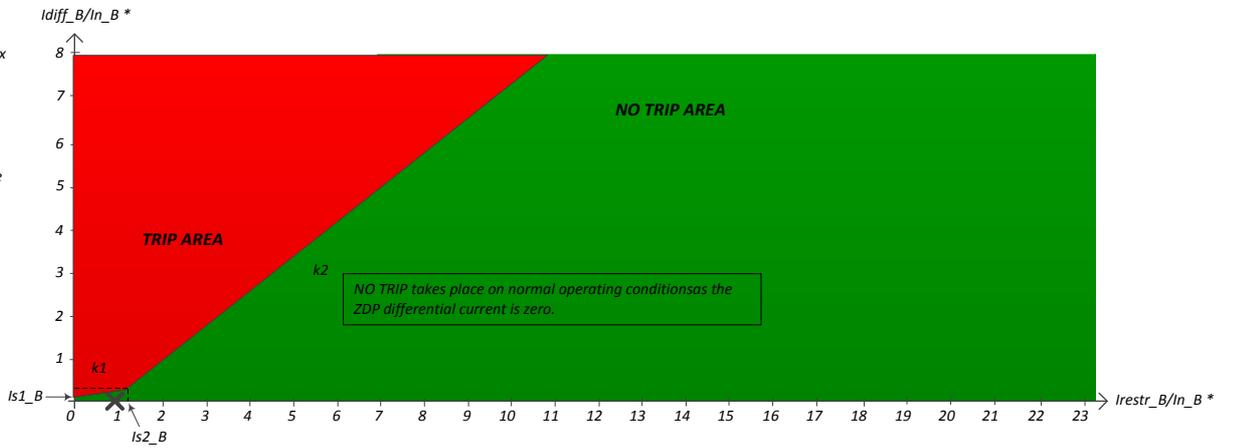
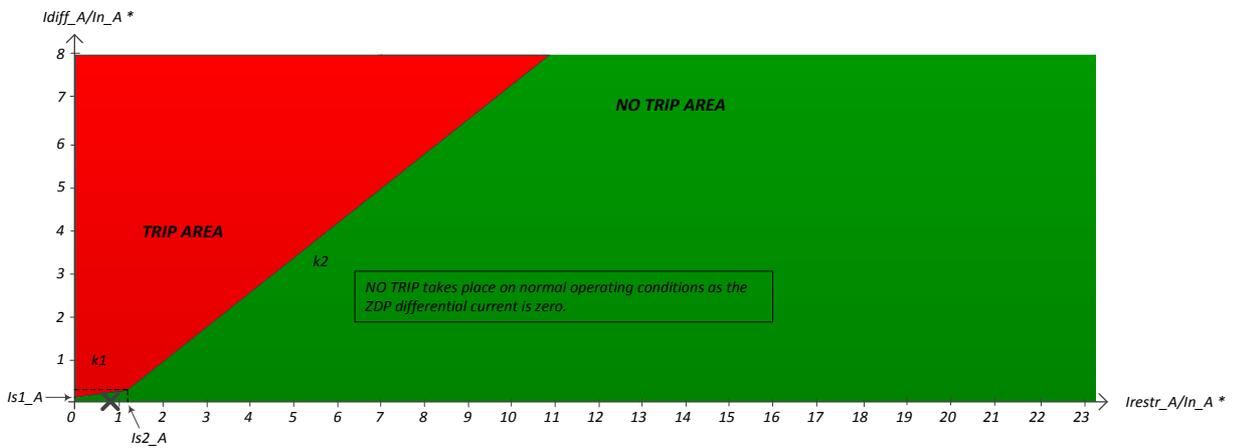
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix B6 – Power flow simulation – SP1 - continued

Simulation step 5/24

Zone : 3

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	52.72-96.44j	-114.08+12.46j	46.69+69.32j
BR3	52.75-96.46j	-114.08+12.43j	46.68+69.32j



* In_x is the rated current of the phase x of the current zone. $x = A$ or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

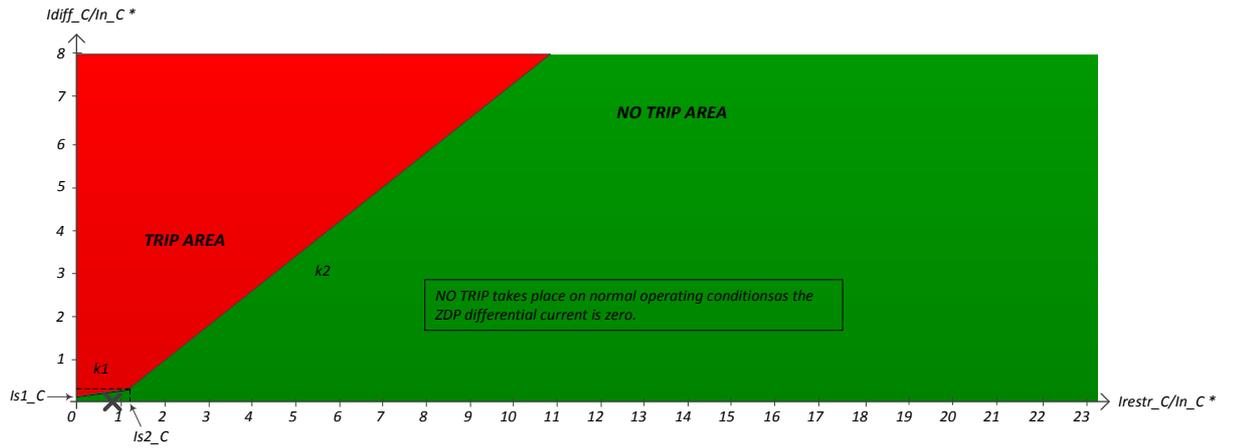
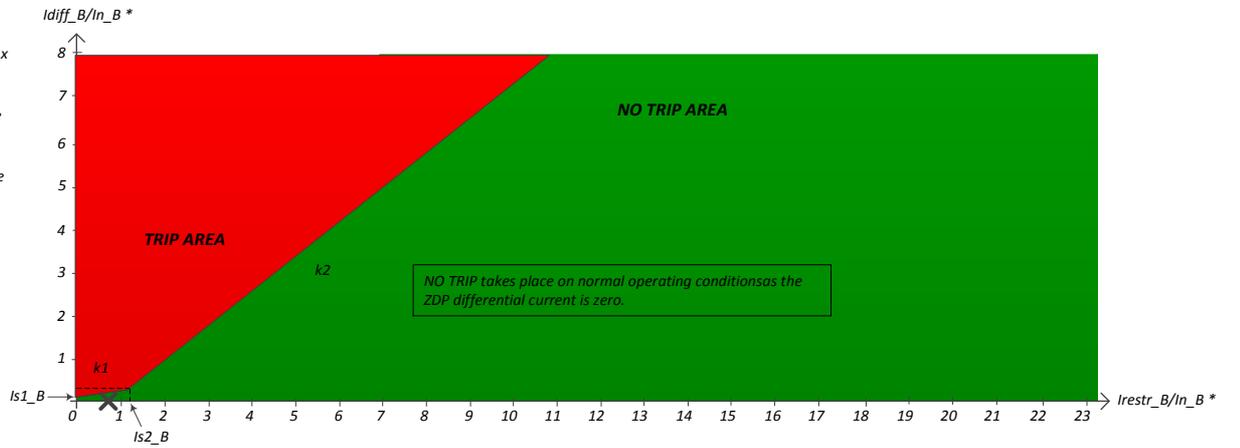
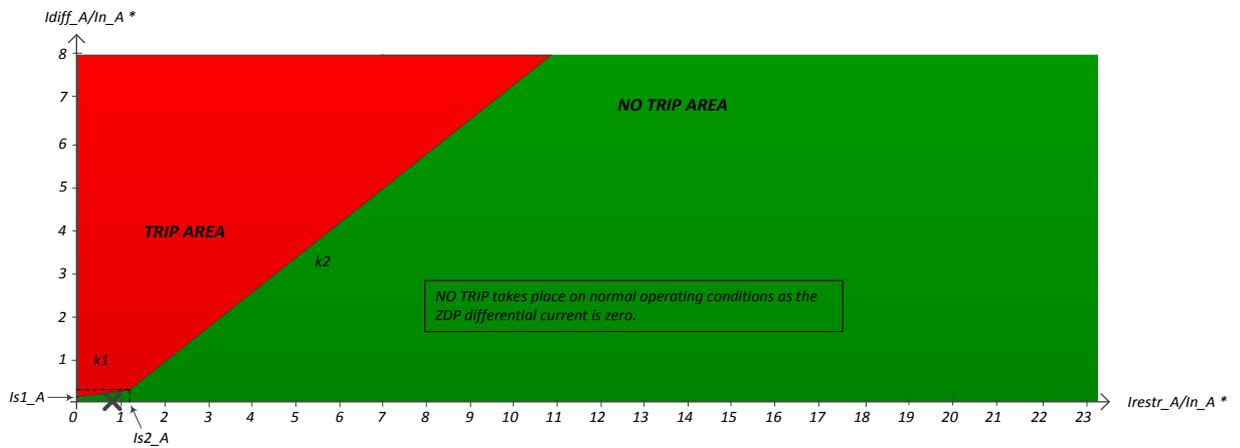
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix B6 – Power flow simulation – SP1 - continued

Simulation step 5/24

Zone : 4

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	5.61-58.11j	-61.96+24.40j	43.12+40.51j
BR4	32.52-103.63j	-90.08+23.42j	64.22+78.53j
BR5	-26.86+45.51j	28.11+0.91j	-21.14-38.03j



* In_x is the rated current of the phase x of the current zone. $x = A$ or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

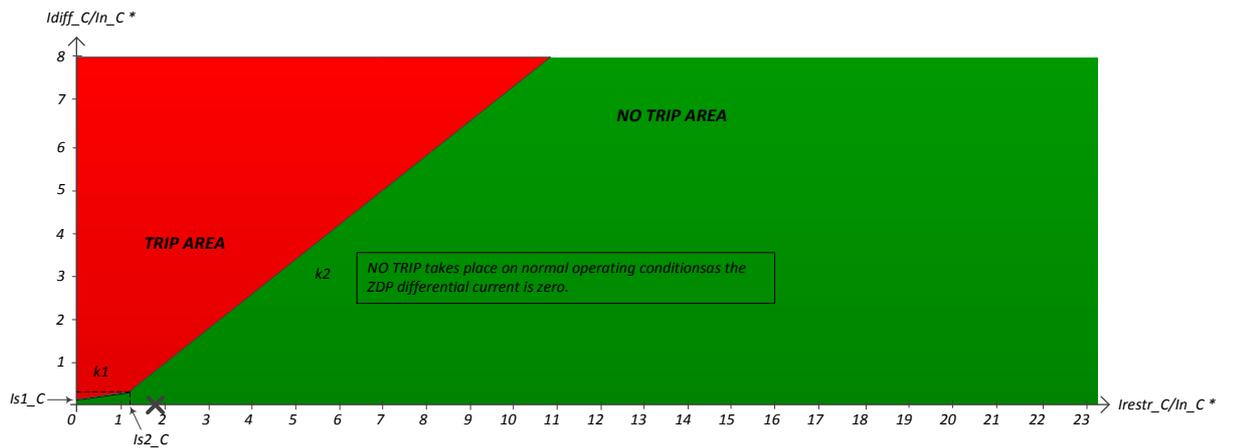
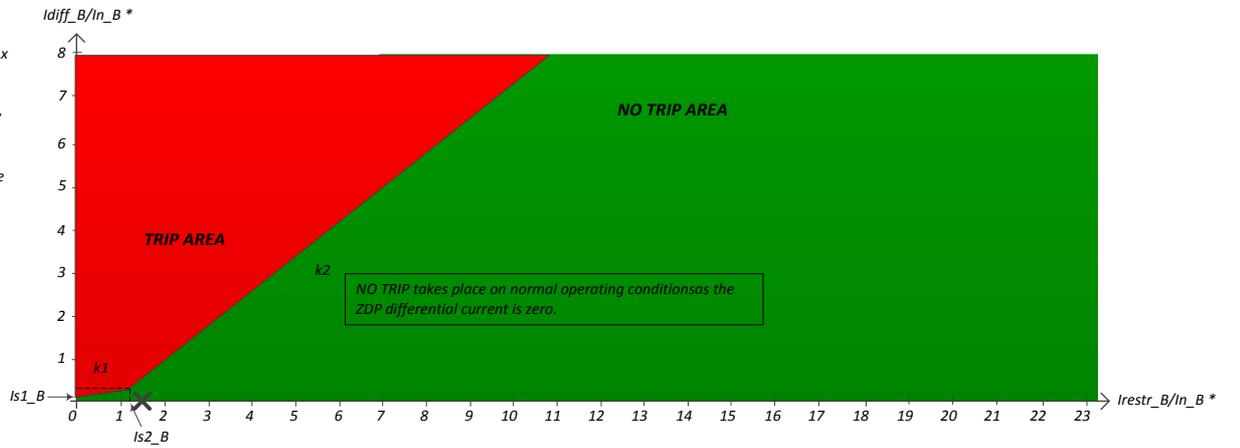
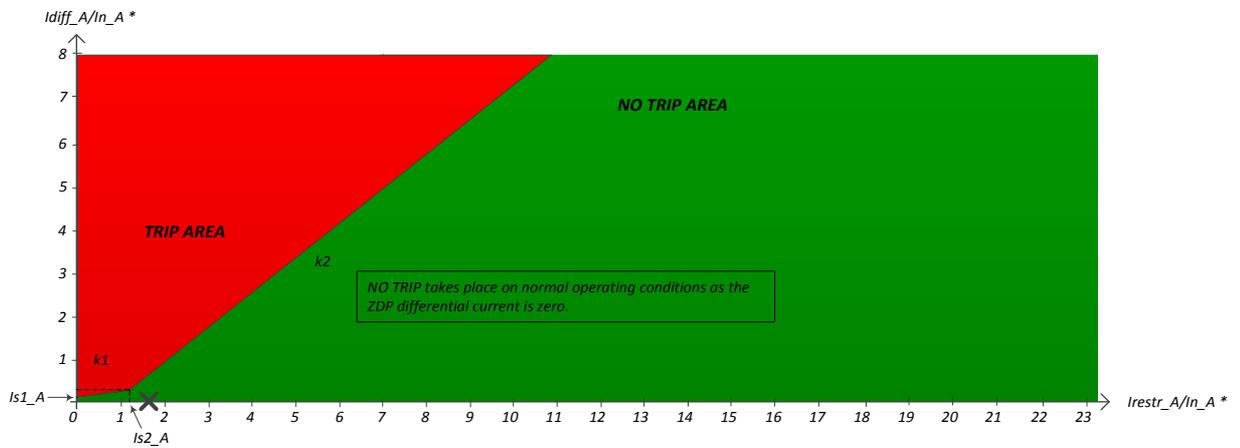
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix B6 – Power flow simulation – SP1 - continued

Simulation step 5/24

Zone : 5

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	26.84-45.50j	-28.12-0.90j	21.15+38.02j
BR5	26.86-45.51j	-28.11-0.91j	21.14+38.03j



* In_x is the rated current of the phase x of the current zone. $x = A$ or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

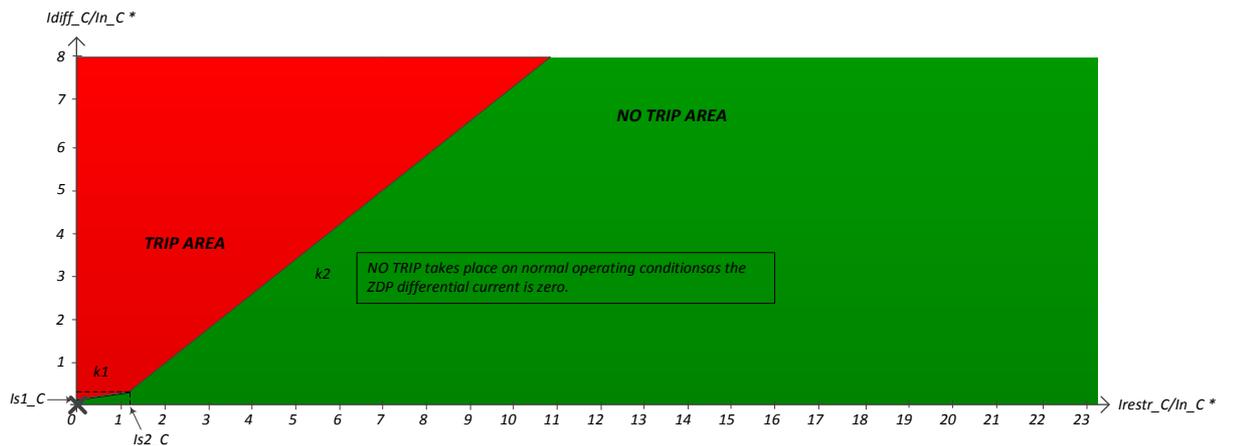
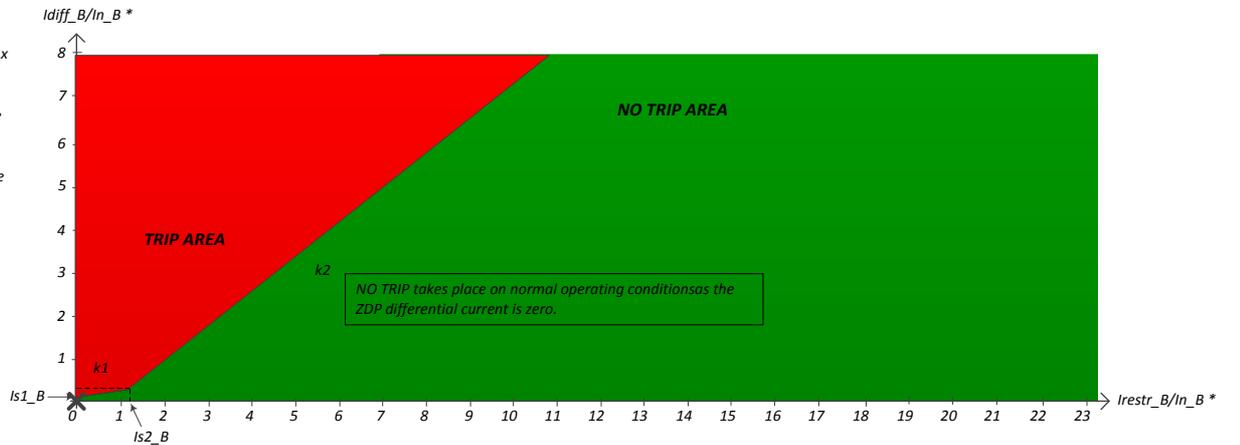
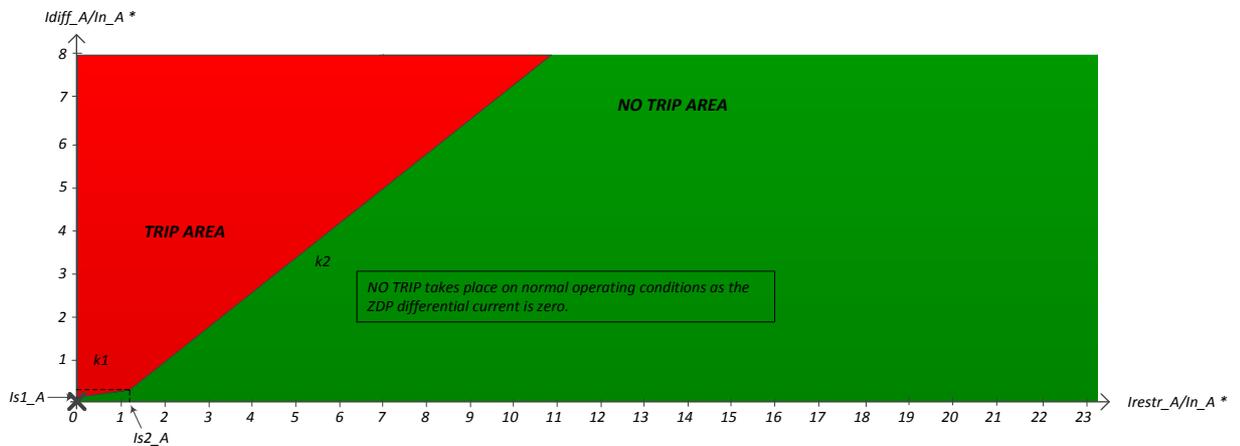
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix B6 – Power flow simulation – SP1 - continued

Simulation step 5/24

Zone : 6

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	0.00+0.00j	0.00+0.00j	0.00+0.00j
BR6	0.00+0.00j	0.00+0.00j	0.00+0.00j



* In_x is the rated current of the phase x of the current zone. $x = A$ or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

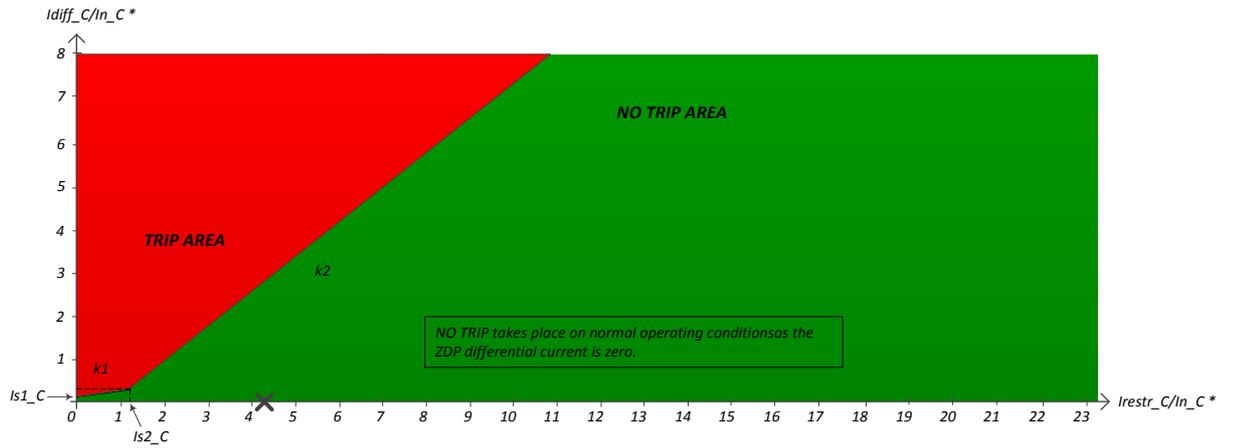
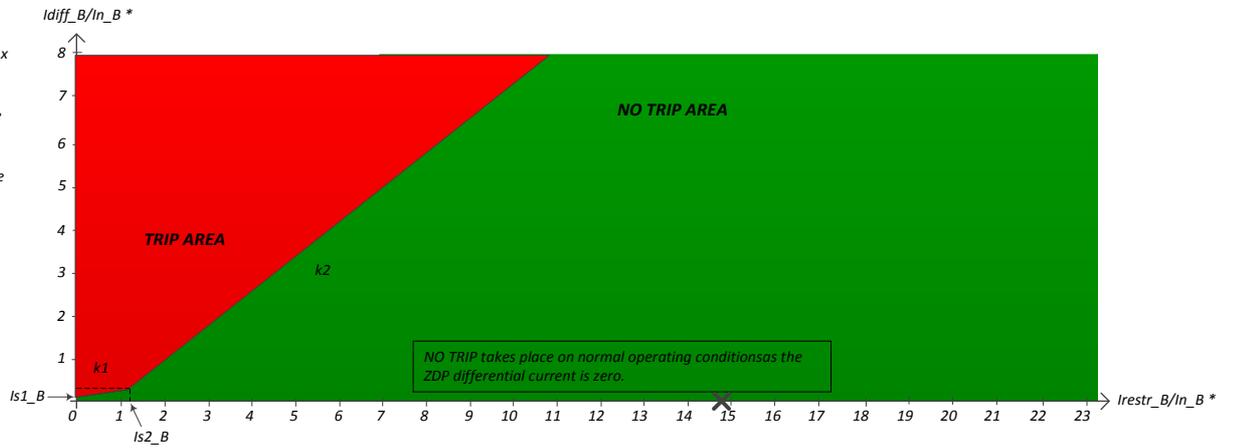
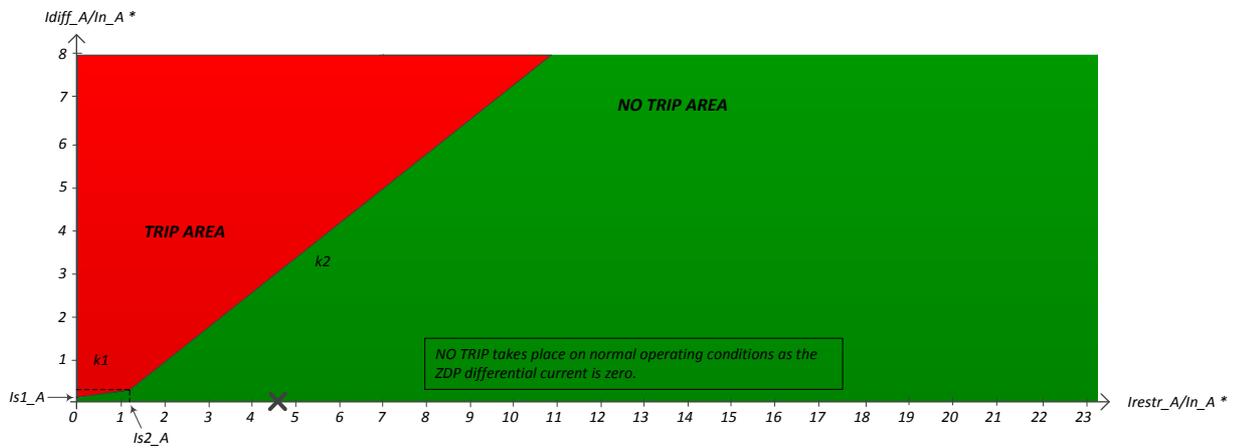
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix B6 – Power flow simulation – SP1

Simulation step 6/24

Zone : 1

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	29.20-74.88j	11.83+13.10j	41.11+81.36j
BR1	147.86-340.37j	-254.46+59.00j	177.28+260.28j
BR2	-64.64+166.48j	145.02-32.50j	-87.73-106.78j
BR3	-54.00+99.00j	121.25-13.44j	-48.46-72.15j



* In_x is the rated current of the phase x of the current zone. $x = A$ or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

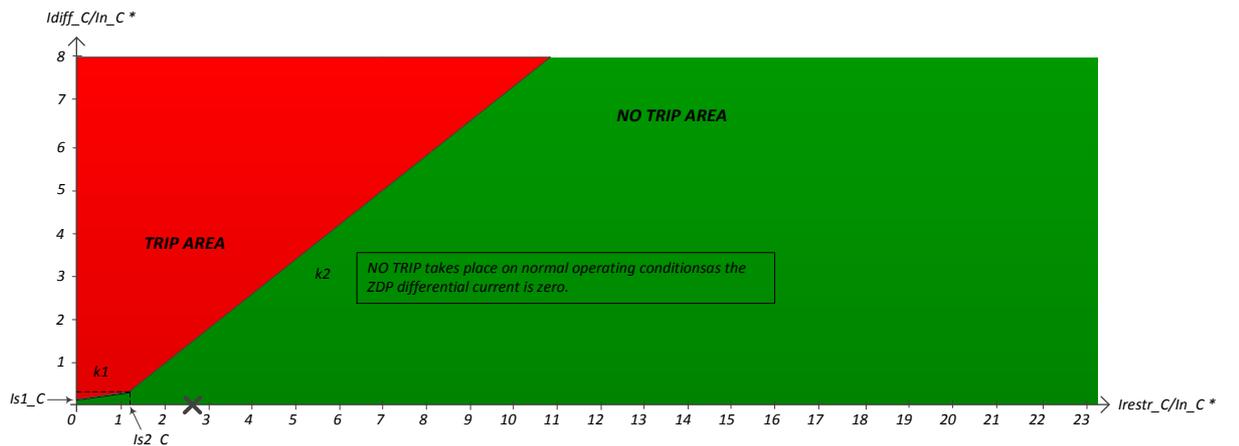
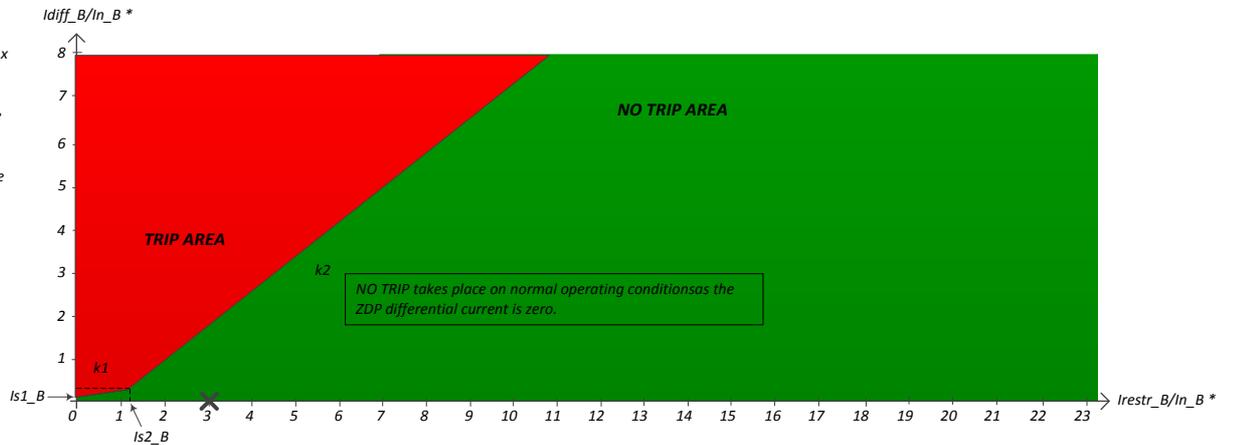
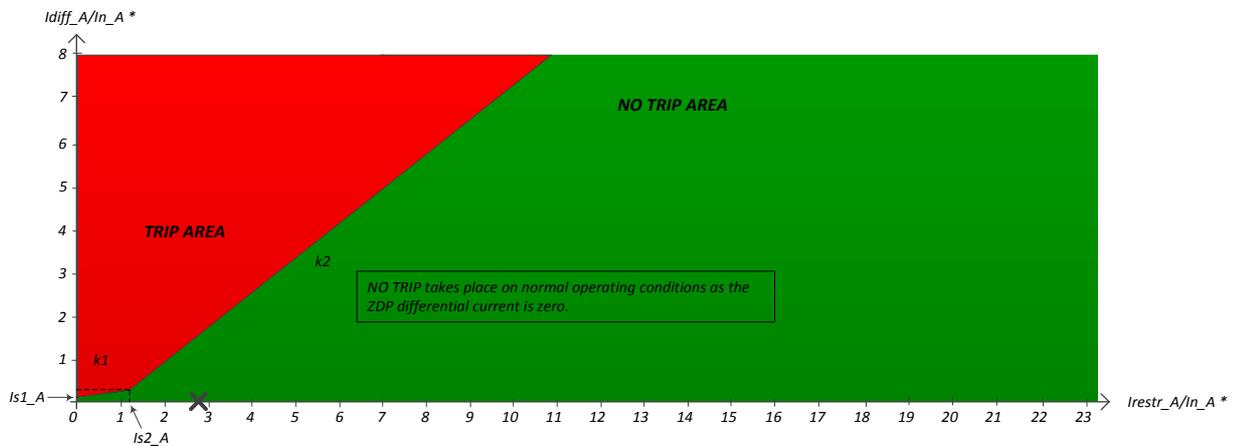
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix B6 – Power flow simulation – SP1 - continued

Simulation step 6/24

Zone : 2

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	37.93-76.61j	-69.43-1.82j	30.80+59.08j
BR2	64.64-166.48j	-145.02+32.50j	87.73+106.78j
BR4	-26.66+89.89j	75.58-34.40j	-56.97-47.70j
BR6	-0.00-0.00j	-0.00-0.00j	-0.00-0.00j



* In_x is the rated current of the phase x of the current zone. $x = A$ or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

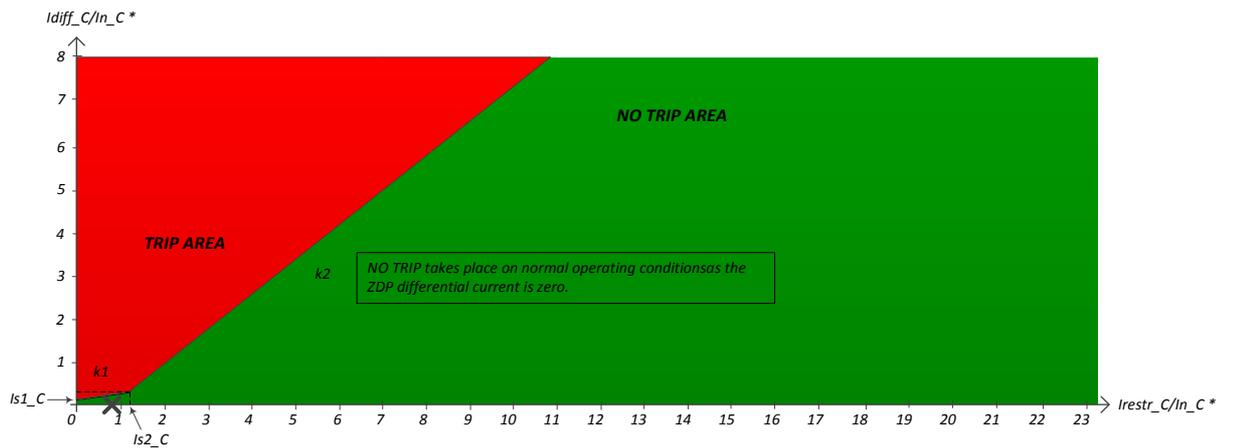
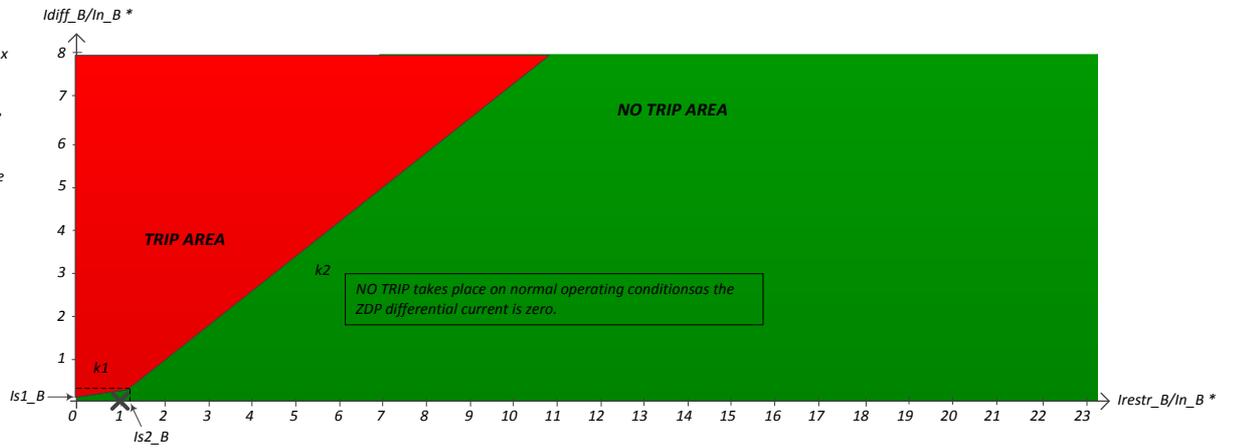
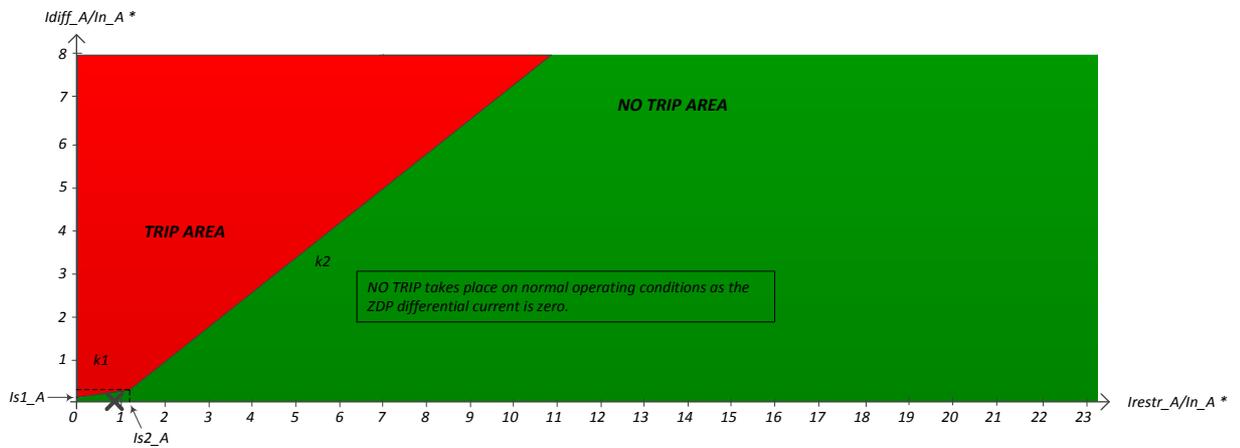
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix B6 – Power flow simulation – SP1 - continued

Simulation step 6/24

Zone : 3

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	53.98-98.99j	-121.24+13.46j	48.47+72.15j
BR3	54.00-99.00j	-121.25+13.44j	48.46+72.15j



* In_x is the rated current of the phase x of the current zone. $x = A$ or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

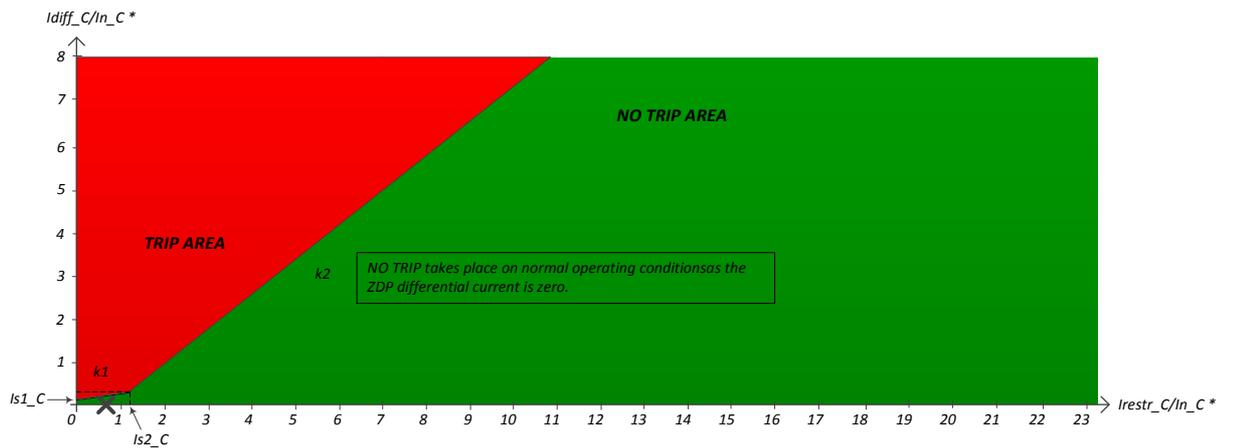
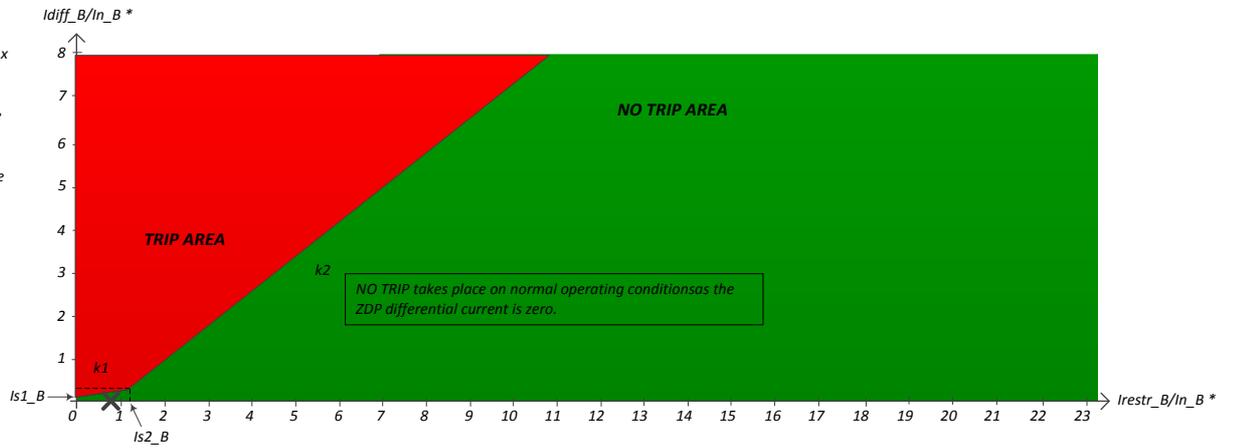
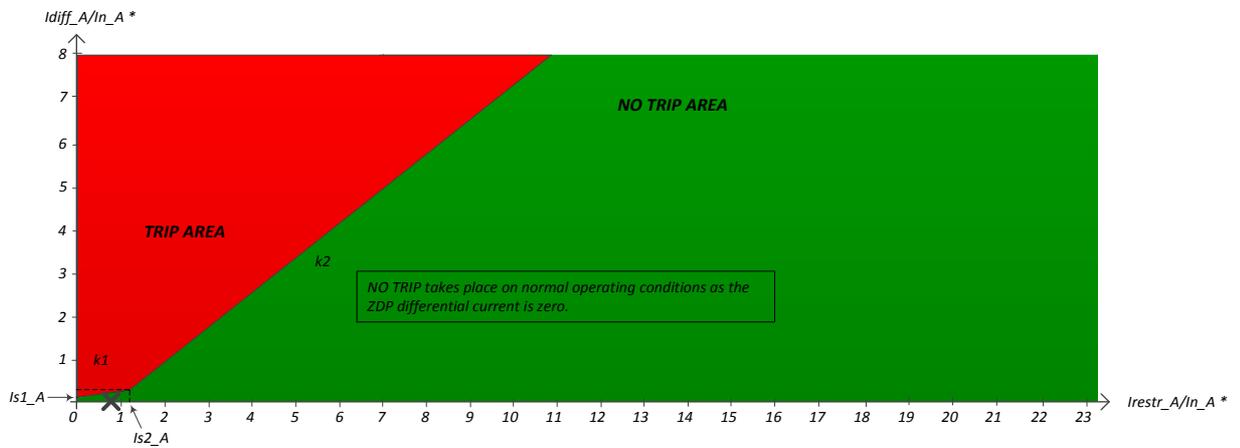
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix B6 – Power flow simulation – SP1 - continued

Simulation step 6/24

Zone : 4

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	-0.22-44.76j	-43.53+35.56j	38.55+13.94j
BR4	26.66-89.89j	-75.58+34.40j	56.97+47.70j
BR5	-26.82+45.11j	32.04+1.11j	-18.44-33.75j



* In_x is the rated current of the phase x of the current zone. $x = A$ or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

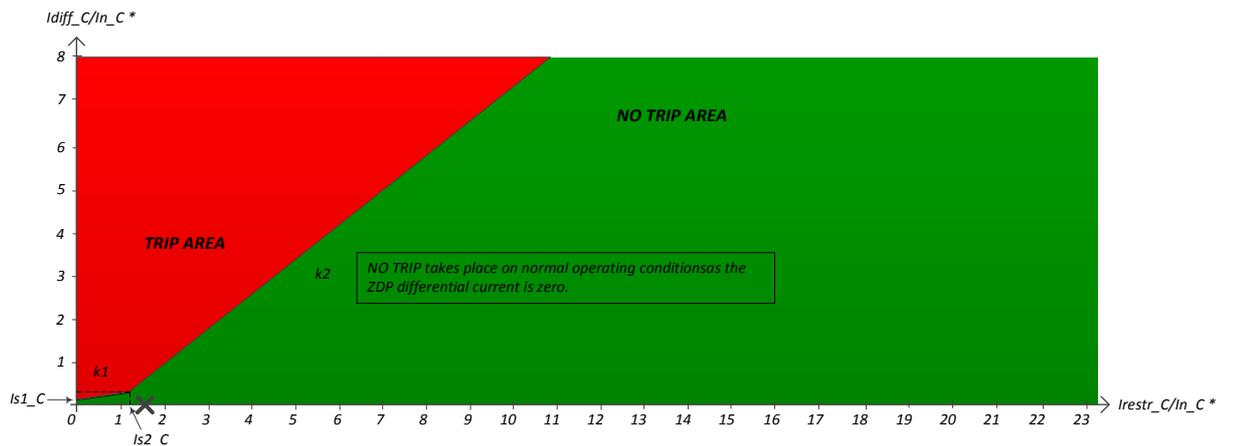
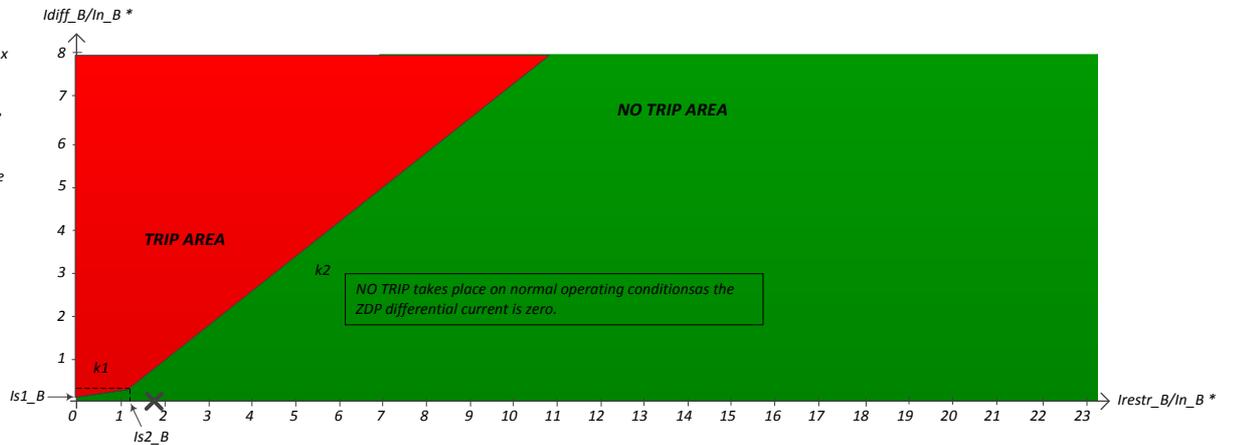
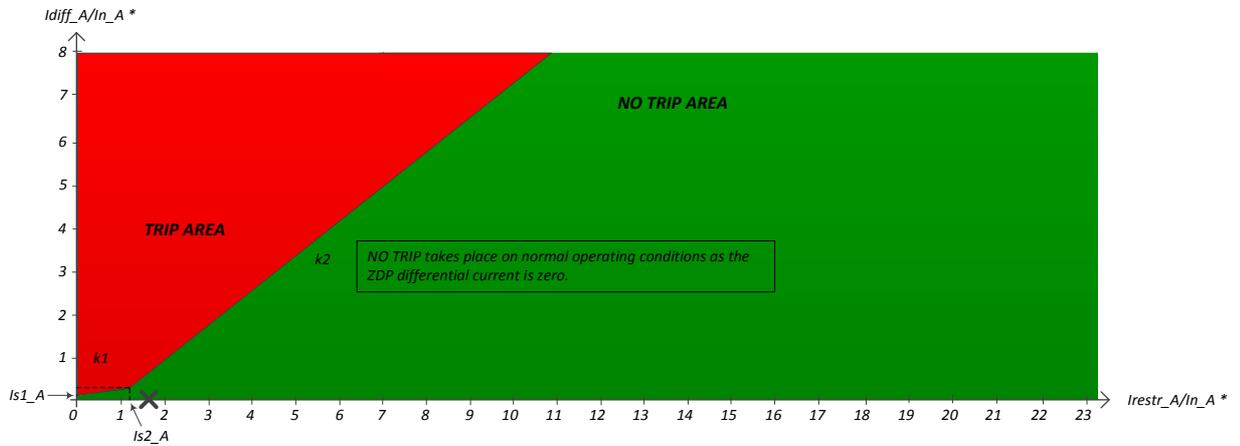
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix B6 – Power flow simulation – SP1 - continued

Simulation step 6/24

Zone : 5

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	26.82-45.11j	-32.03-1.09j	18.45+33.75j
BR5	26.82-45.11j	-32.04-1.11j	18.44+33.75j



* In_x is the rated current of the phase x of the current zone. $x = A$ or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

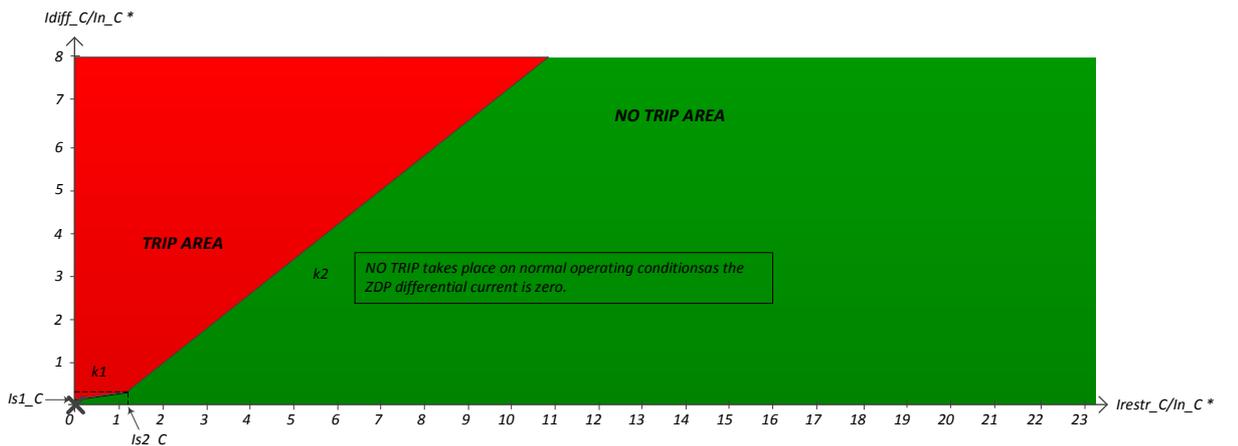
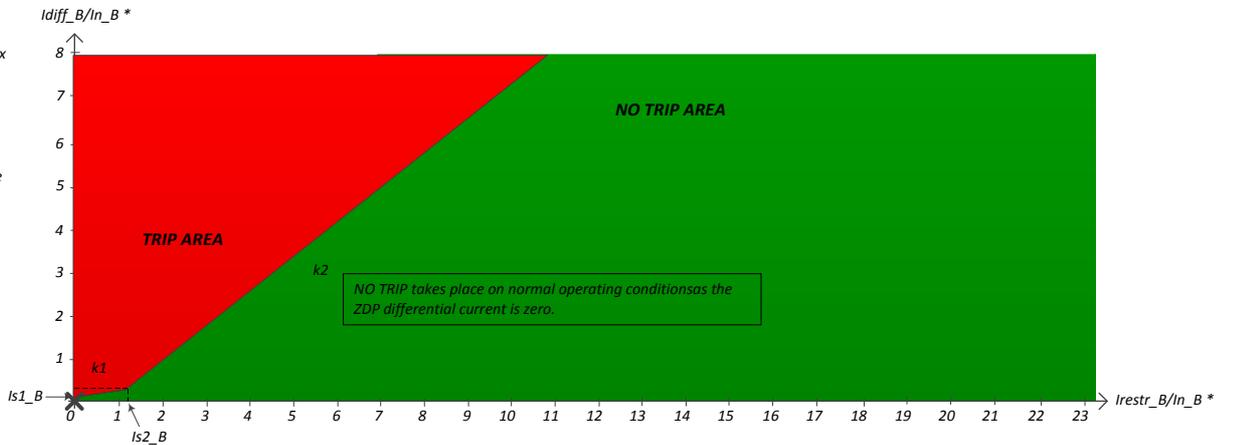
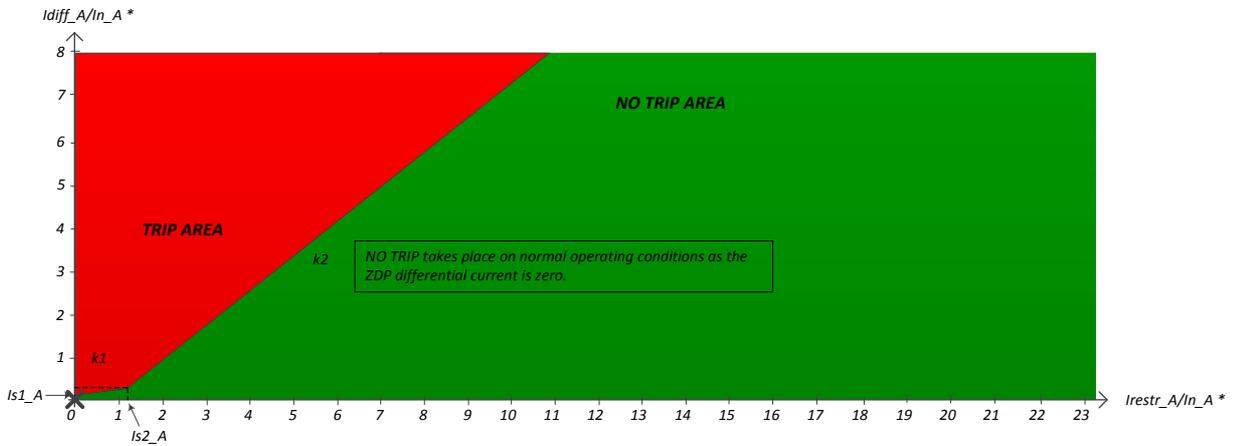
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix B6 – Power flow simulation – SP1 - continued

Simulation step 6/24

Zone : 6

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	0.00+0.00j	0.00+0.00j	0.00+0.00j
BR6	0.00+0.00j	0.00+0.00j	0.00+0.00j



* In_x is the rated current of the phase x of the current zone. $x = A$ or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

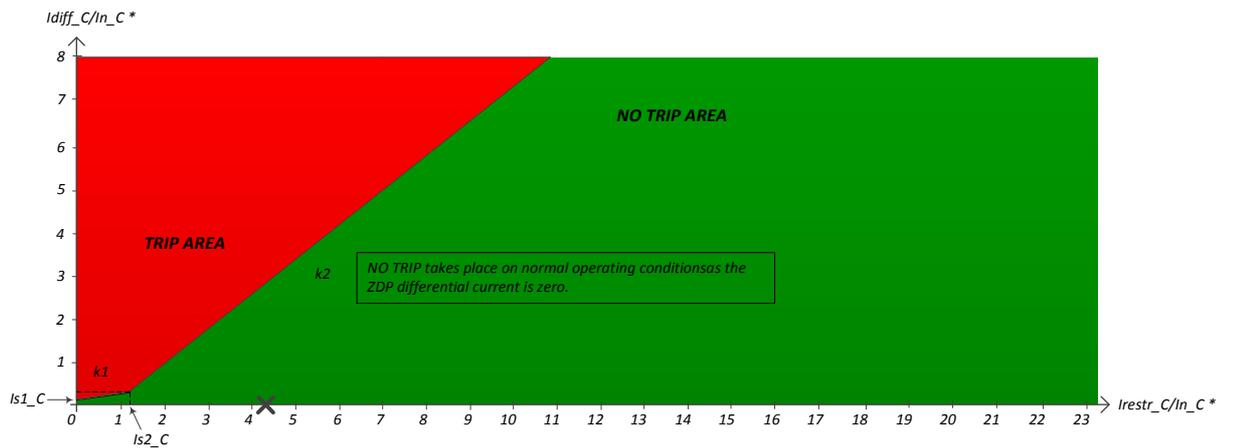
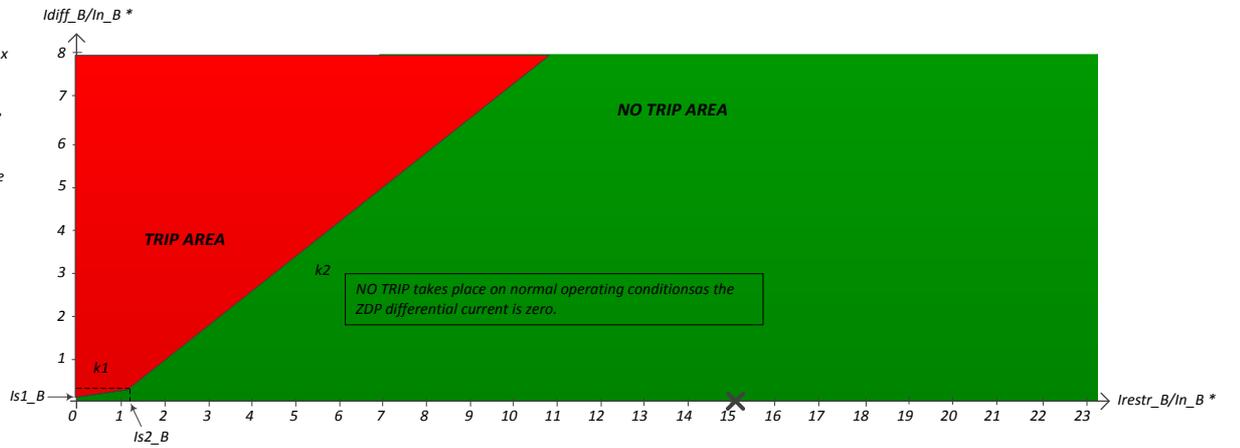
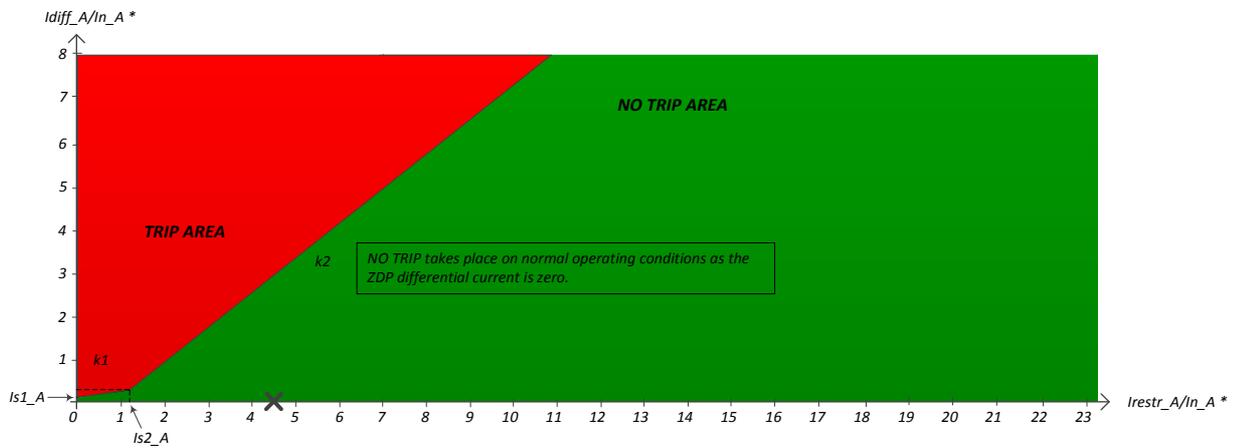
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix B6 – Power flow simulation – SP1

Simulation step 7/24

Zone : 1

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	27.68-71.76j	9.62+13.63j	38.96+77.71j
BR1	154.40-349.05j	-263.03+55.93j	175.55+264.24j
BR2	-72.14+176.50j	163.82-30.66j	-91.27-119.01j
BR3	-54.54+100.77j	108.82-11.68j	-45.33-67.52j



* In_x is the rated current of the phase x of the current zone. $x = A$ or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

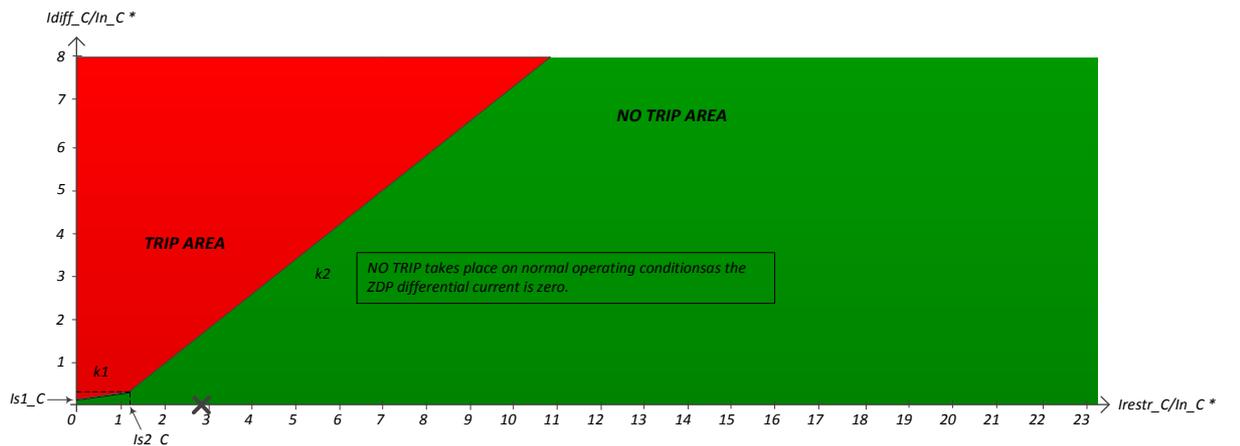
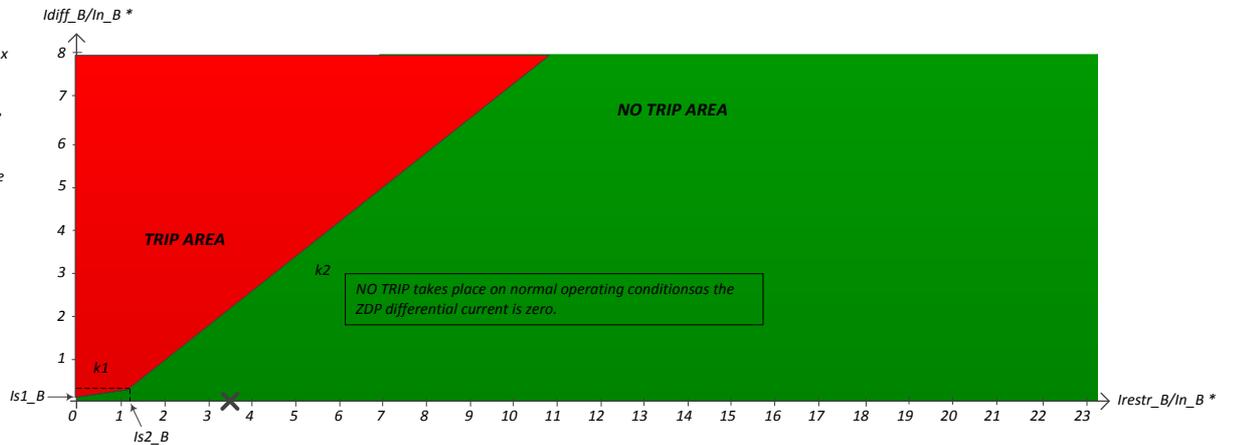
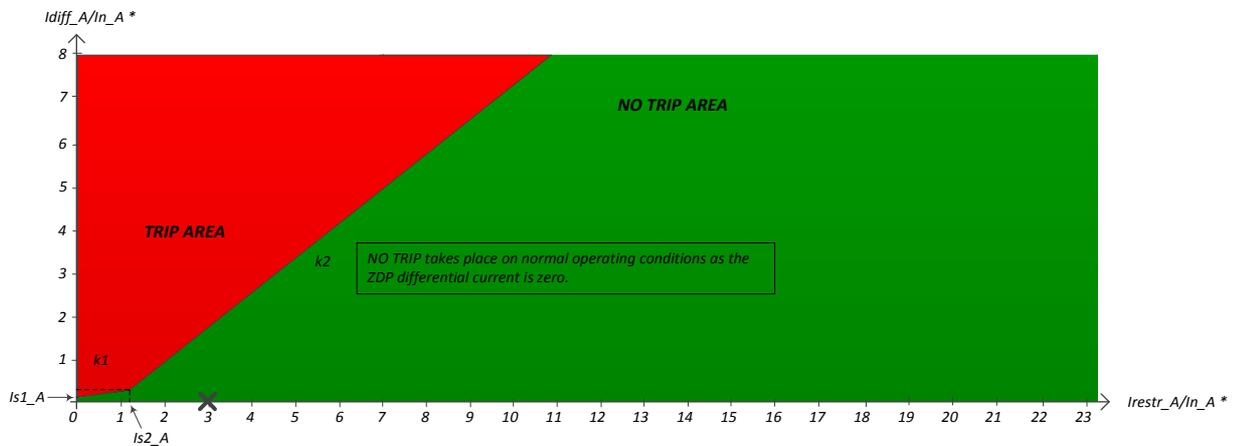
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix B6 – Power flow simulation – SP1 - continued

Simulation step 7/24

Zone : 2

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	37.87-79.77j	-72.29-1.15j	28.93+58.05j
BR2	72.14-176.50j	-163.82+30.66j	91.27+119.01j
BR4	-34.23+96.74j	91.52-31.87j	-62.38-60.96j
BR6	-0.00-0.00j	-0.00-0.00j	-0.00-0.00j



* In_x is the rated current of the phase x of the current zone. $x = A$ or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

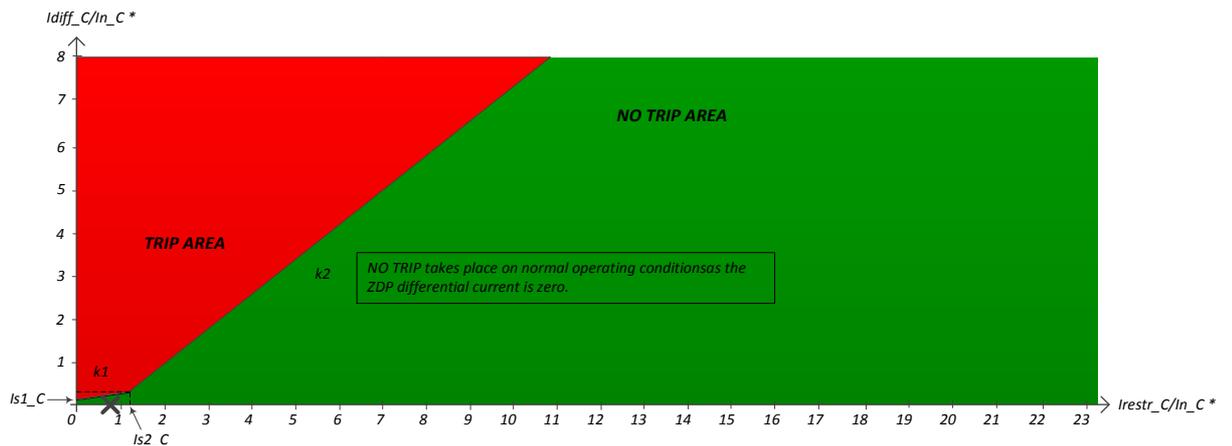
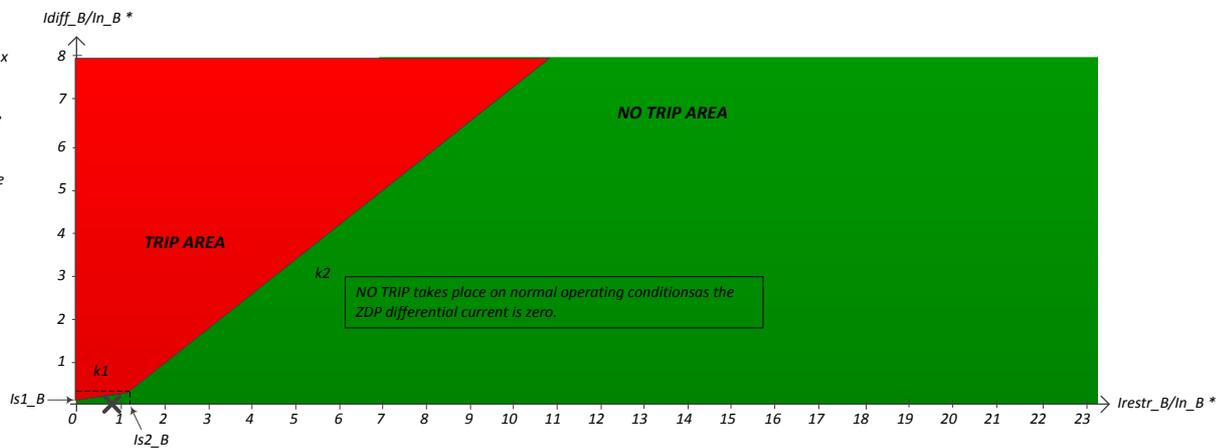
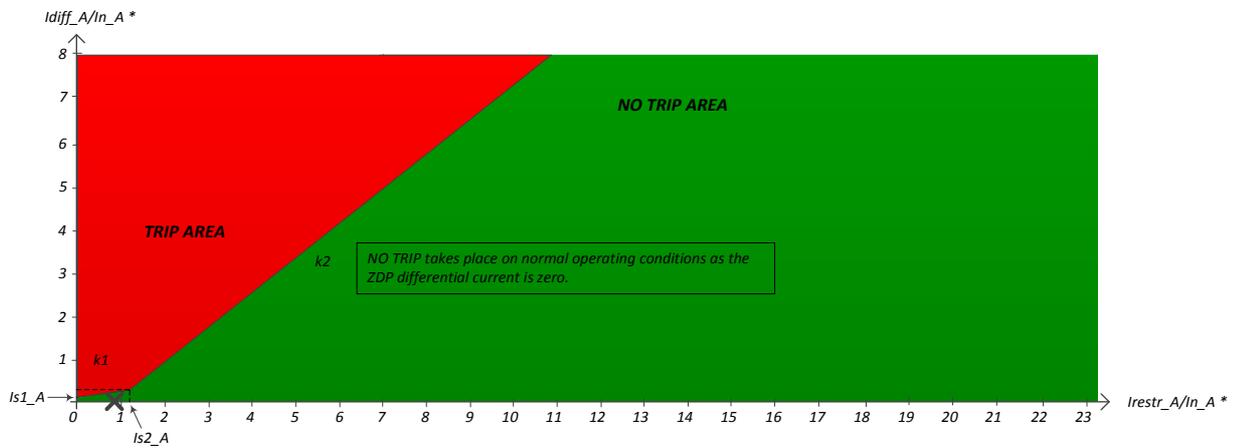
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix B6 – Power flow simulation – SP1 - continued

Simulation step 7/24

Zone : 3

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	54.52-100.74j	-108.81+11.72j	45.34+67.52j
BR3	54.54-100.77j	-108.82+11.68j	45.33+67.52j



* In_x is the rated current of the phase x of the current zone. $x = A$ or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

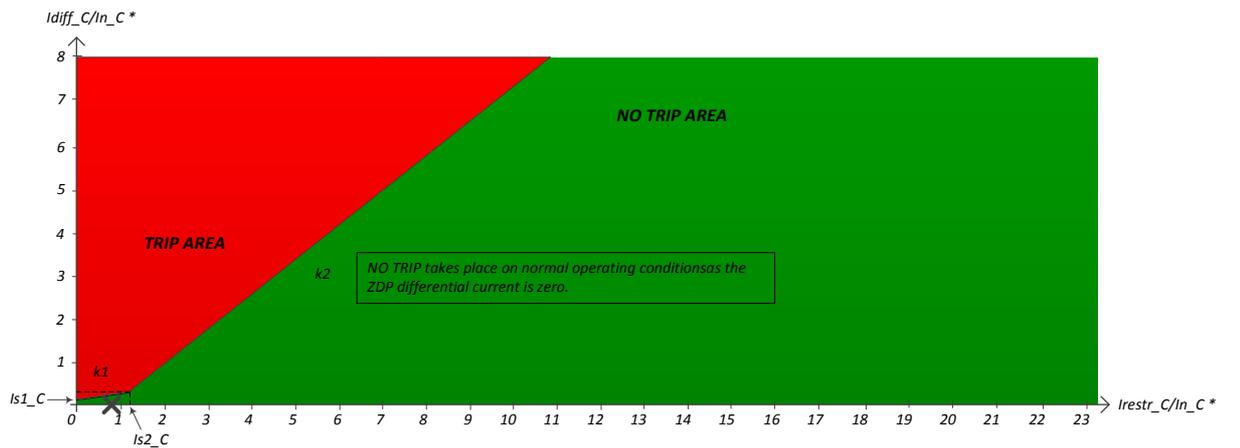
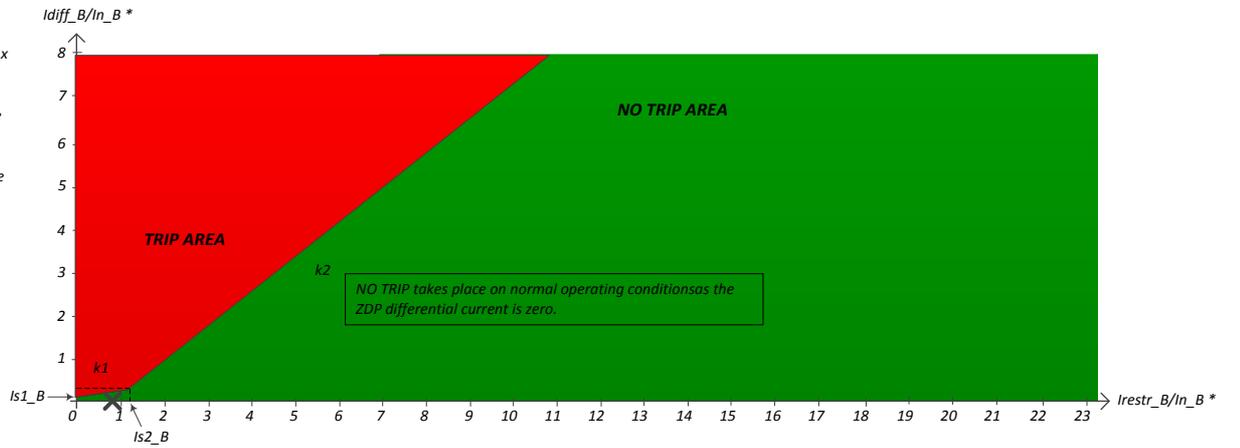
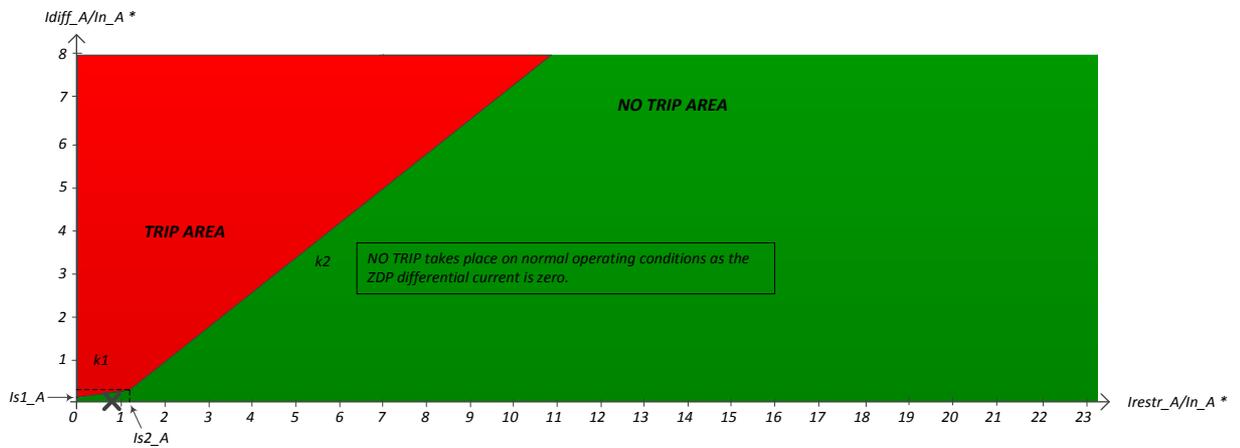
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix B6 – Power flow simulation – SP1 - continued

Simulation step 7/24

Zone : 4

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	7.12-51.03j	-58.08+32.98j	40.28+20.75j
BR4	34.23-96.74j	-91.52+31.87j	62.38+60.96j
BR5	-27.05+45.68j	33.43+1.05j	-22.12-40.23j



* In_x is the rated current of the phase x of the current zone. $x = A$ or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

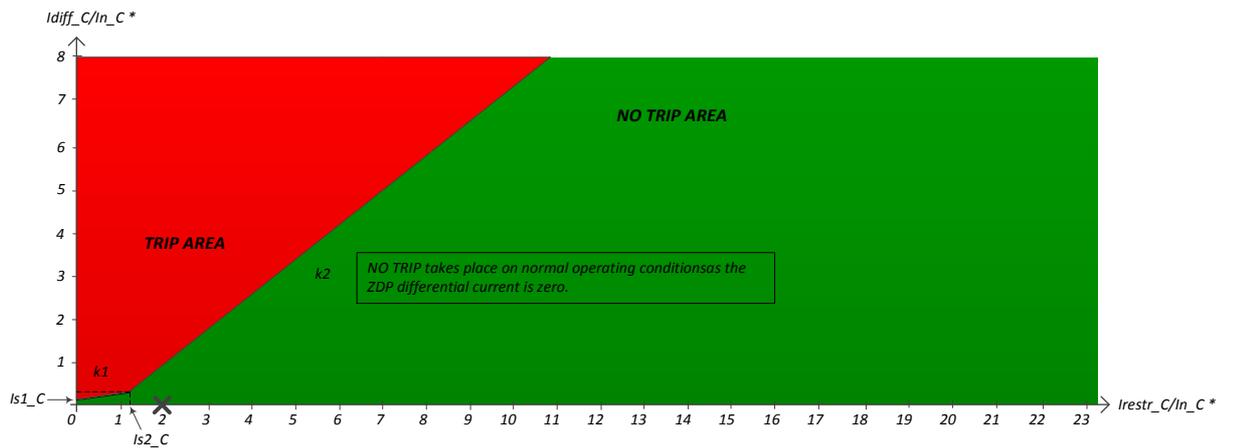
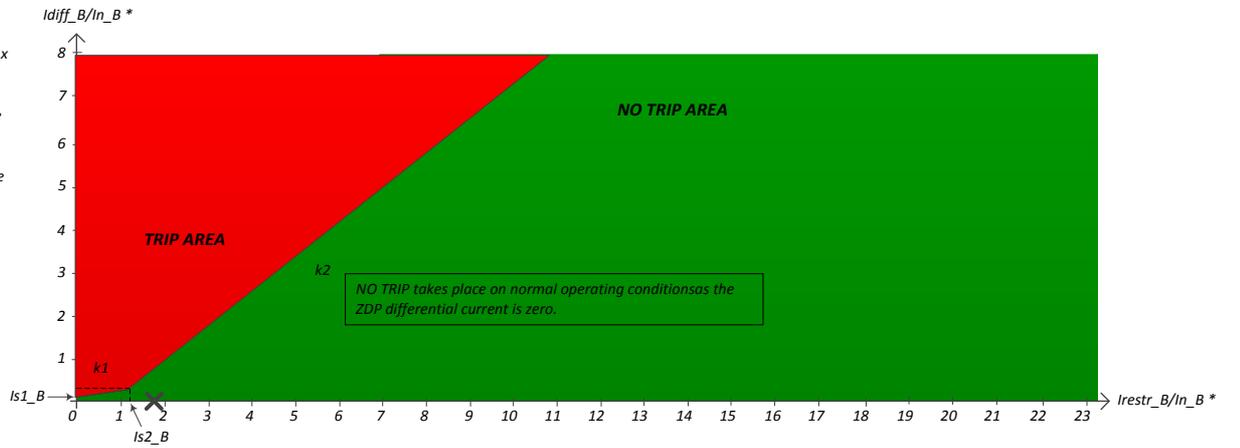
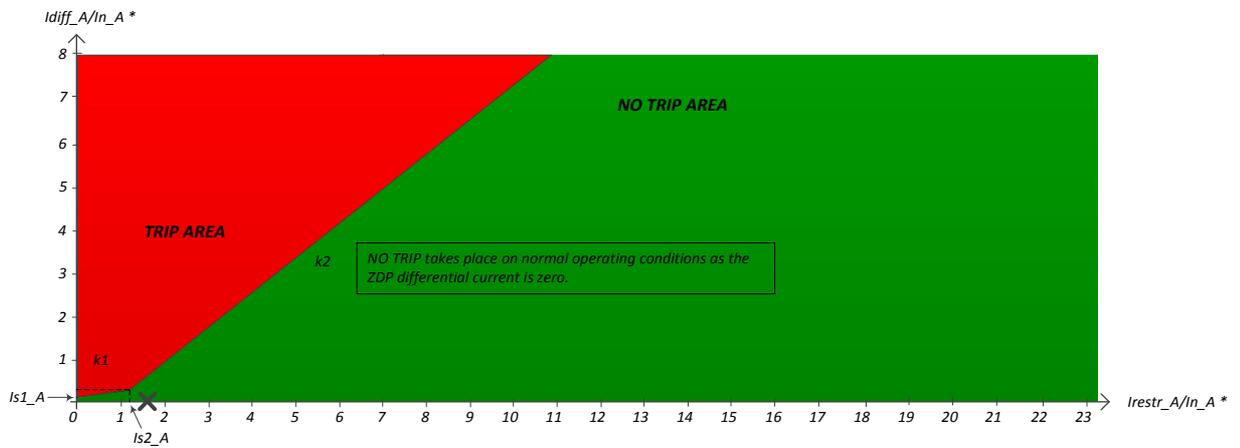
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix B6 – Power flow simulation – SP1 - continued

Simulation step 7/24

Zone : 5

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	27.05-45.68j	-33.44-1.04j	22.13+40.23j
BR5	27.05-45.68j	-33.43-1.05j	22.12+40.23j



* In_x is the rated current of the phase x of the current zone. $x = A$ or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

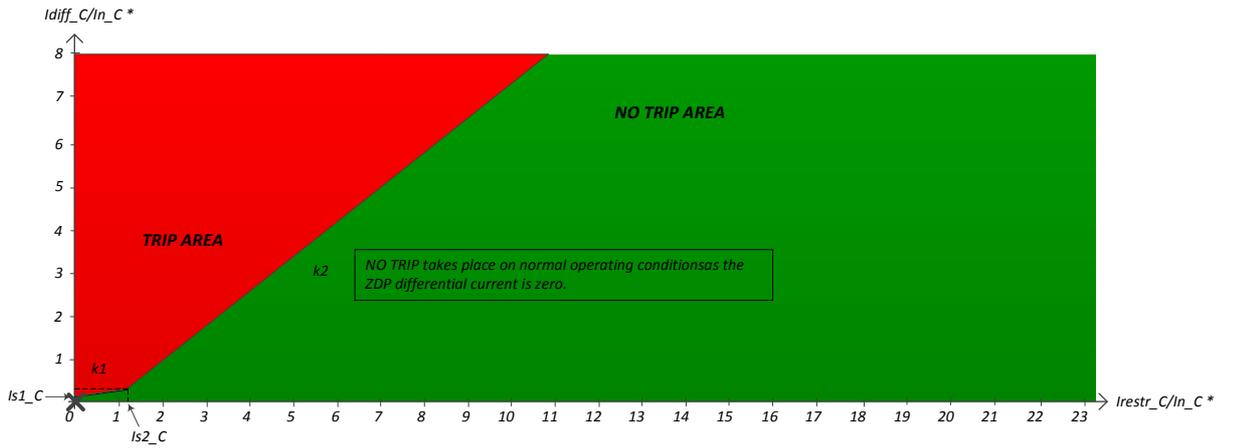
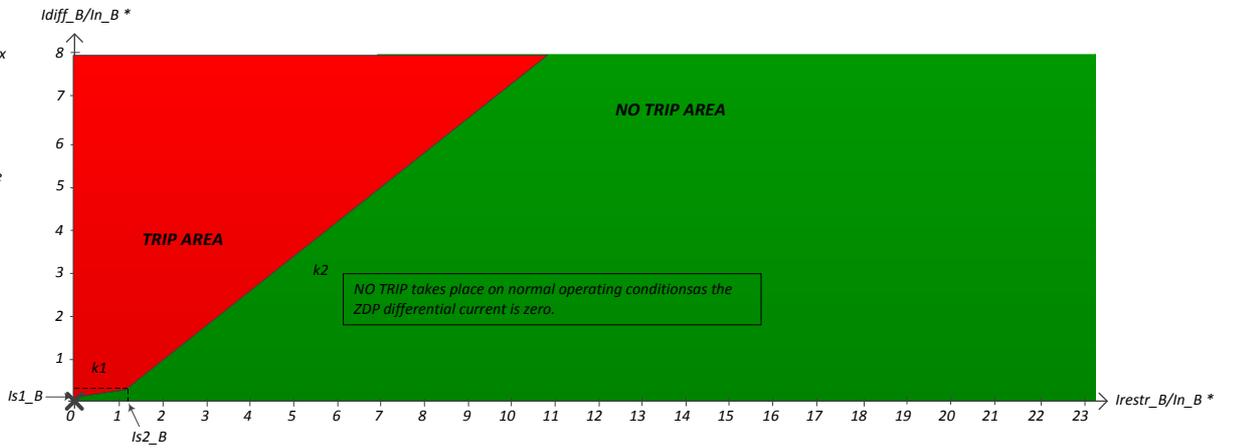
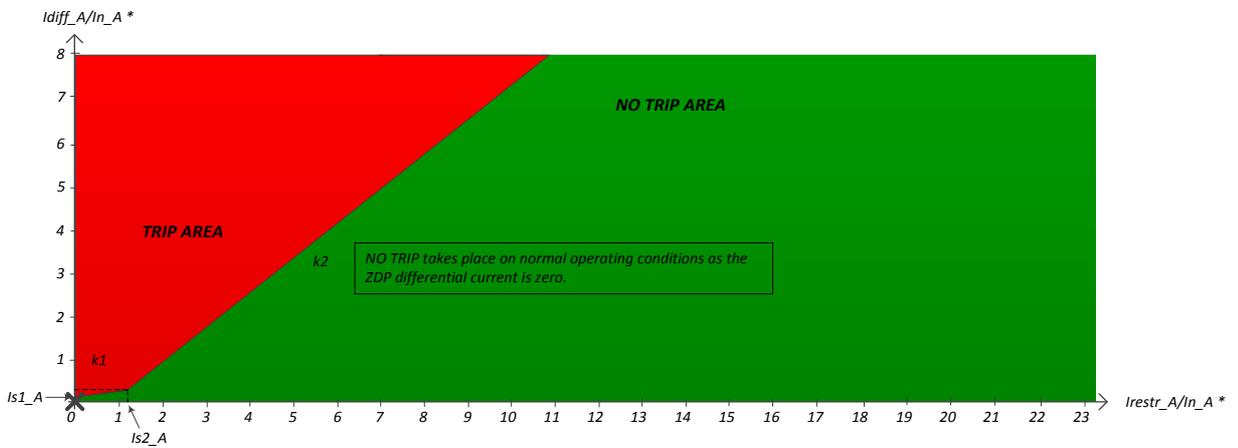
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix B6 – Power flow simulation – SP1 - continued

Simulation step 7/24

Zone : 6

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	0.00+0.00j	0.00+0.00j	0.00+0.00j
BR6	0.00+0.00j	0.00+0.00j	0.00+0.00j



* In_x is the rated current of the phase x of the current zone. $x = A$ or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

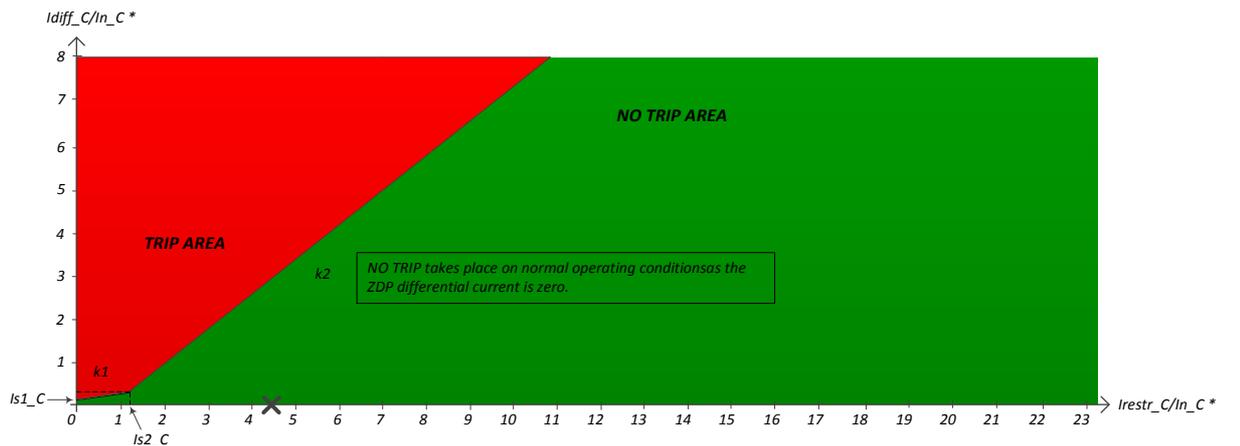
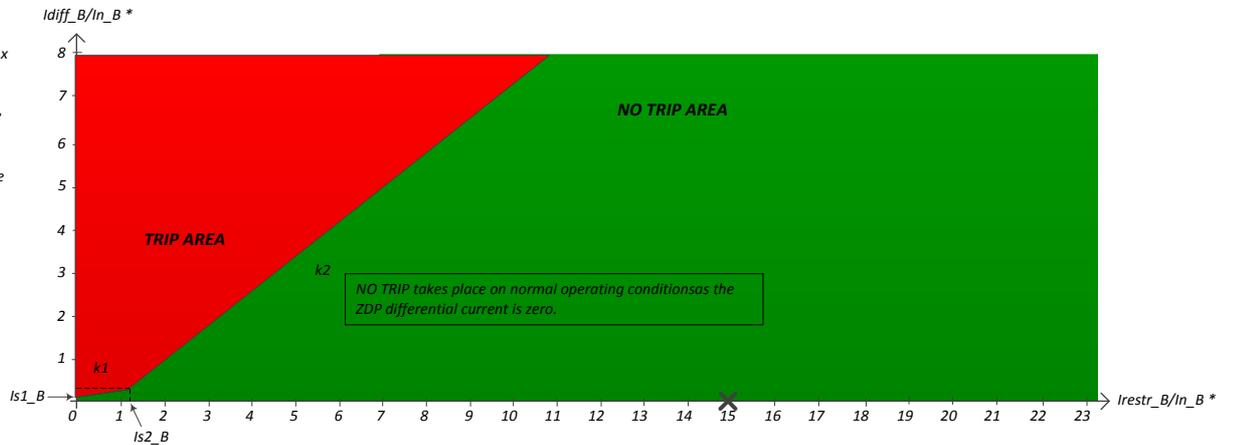
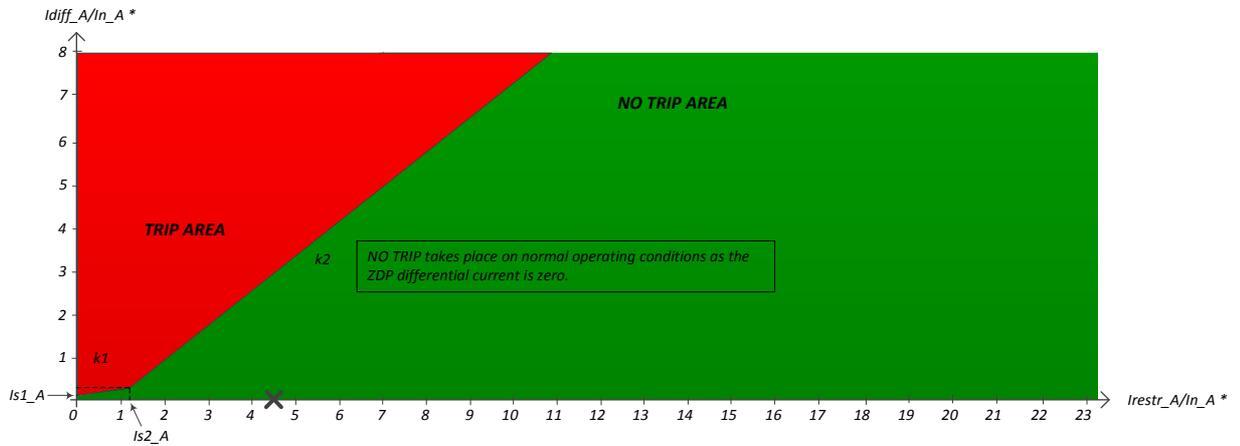
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix B6 – Power flow simulation – SP1

Simulation step 8/24

Zone : 1

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	25.58-68.35j	12.10+14.07j	37.41+72.51j
BR1	150.28-347.31j	-260.79+52.63j	177.63+271.88j
BR2	-67.31+172.56j	150.27-24.90j	-90.37-125.85j
BR3	-57.34+106.40j	122.60-13.71j	-49.85-73.52j



* In_x is the rated current of the phase x of the current zone. $x = A$ or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

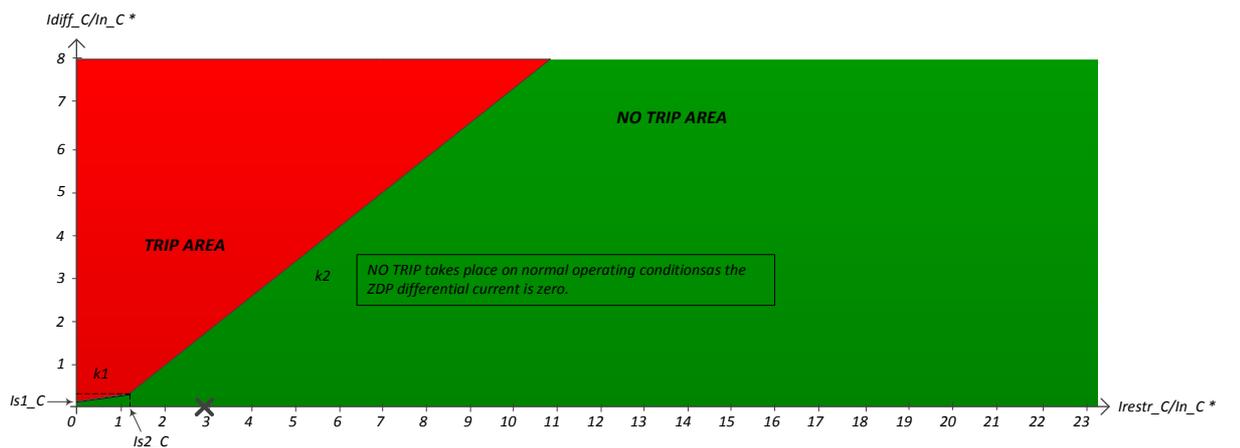
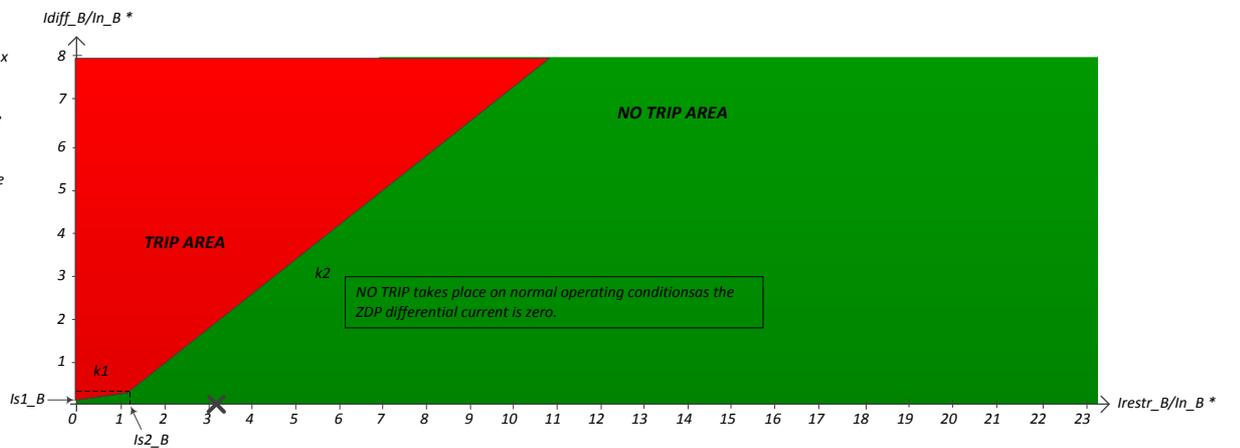
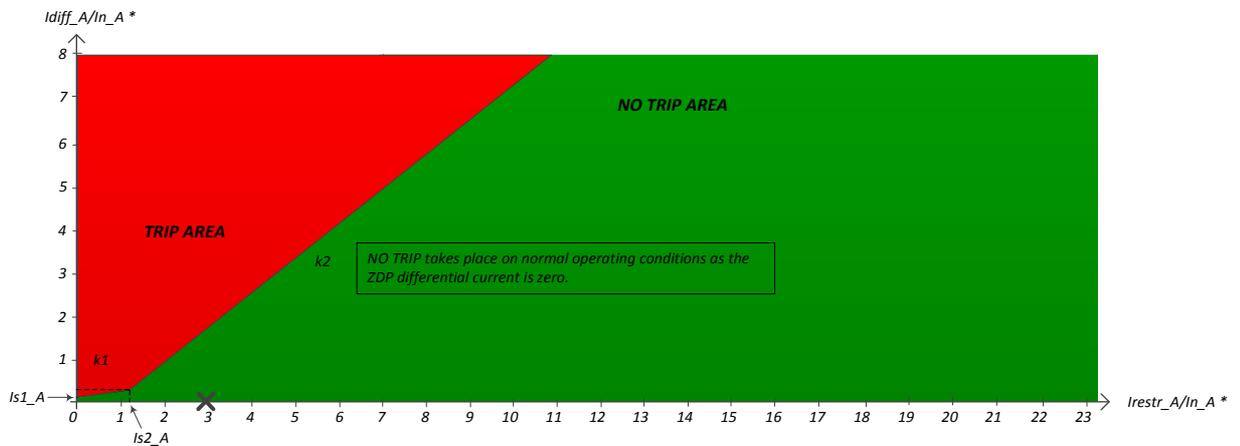
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix B6 – Power flow simulation – SP1 - continued

Simulation step 8/24

Zone : 2

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	35.11-73.18j	-68.62-0.87j	31.20+60.44j
BR2	67.31-172.56j	-150.27+24.90j	90.37+125.85j
BR4	-32.16+99.40j	81.66-25.84j	-59.22-65.41j
BR6	-0.00-0.00j	-0.00-0.00j	-0.00-0.00j



* In_x is the rated current of the phase x of the current zone. $x = A$ or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

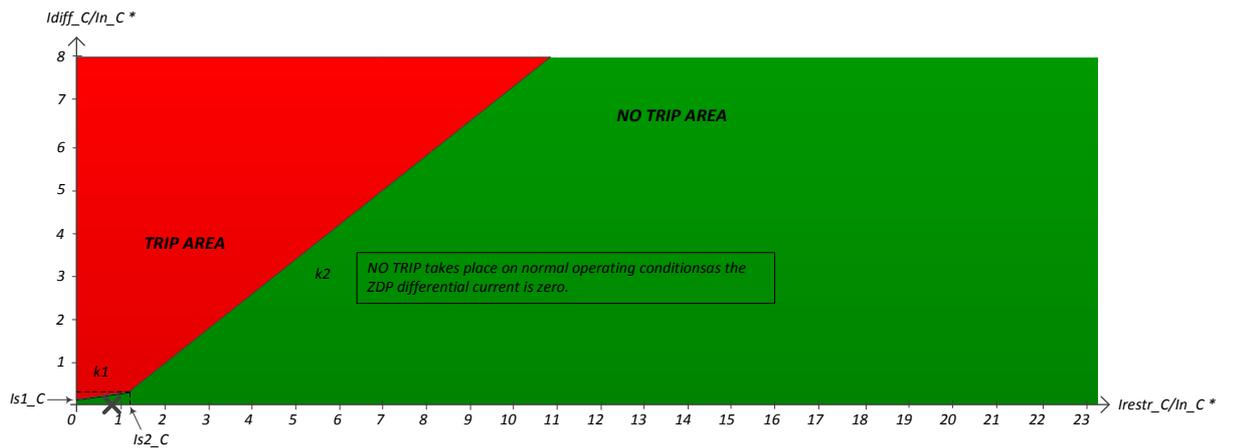
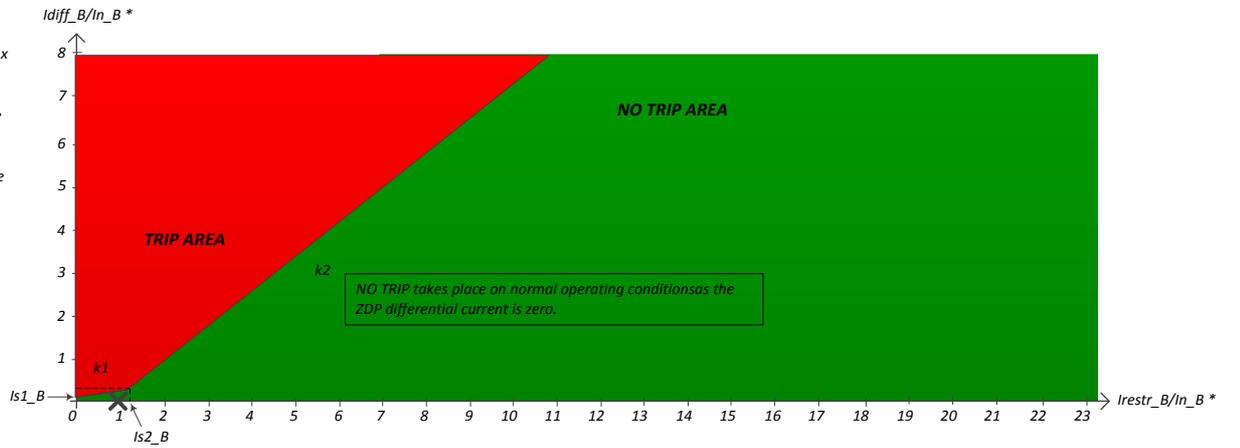
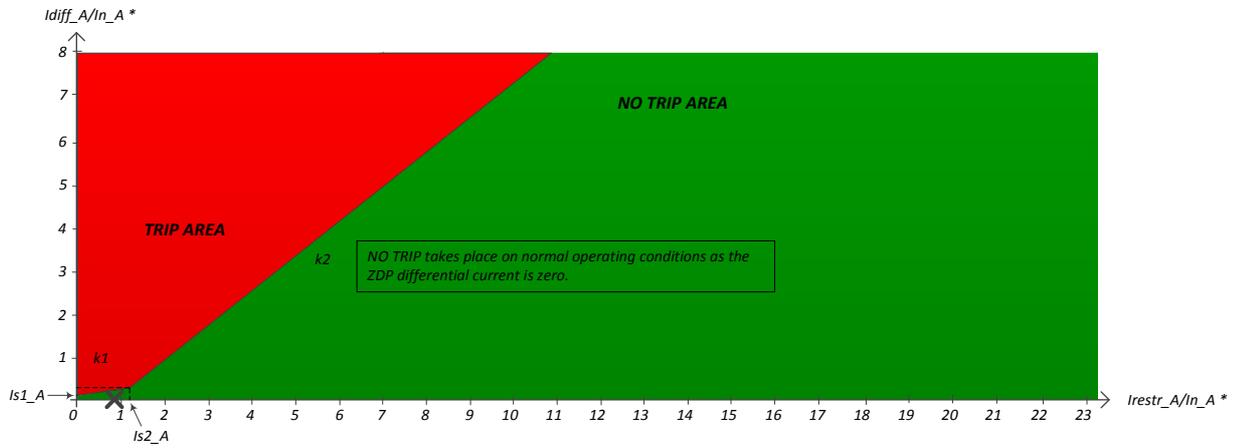
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix B6 – Power flow simulation – SP1 - continued

Simulation step 8/24

Zone : 3

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	57.30-106.38j	-122.59+13.74j	49.85+73.52j
BR3	57.34-106.40j	-122.60+13.71j	49.85+73.52j



* In_x is the rated current of the phase x of the current zone. $x = A$ or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

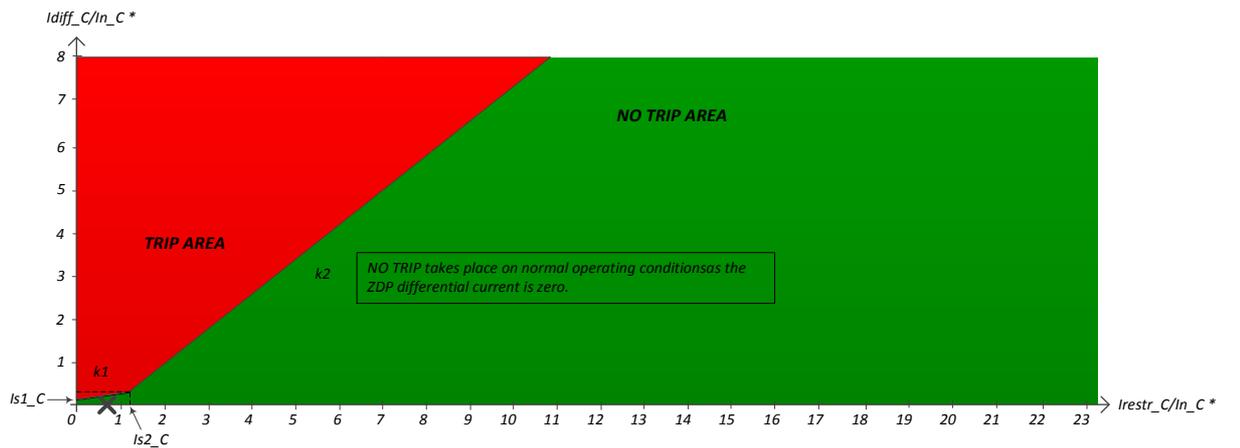
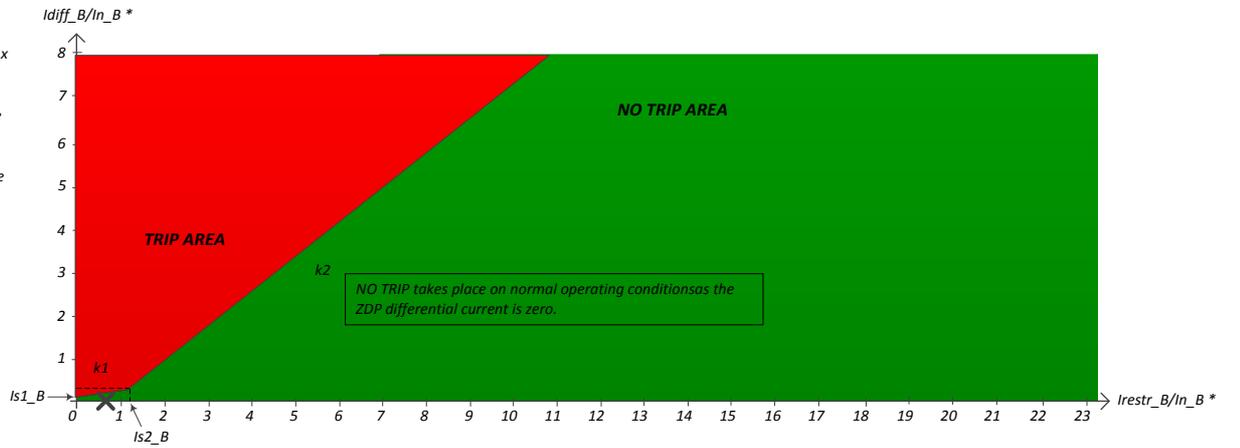
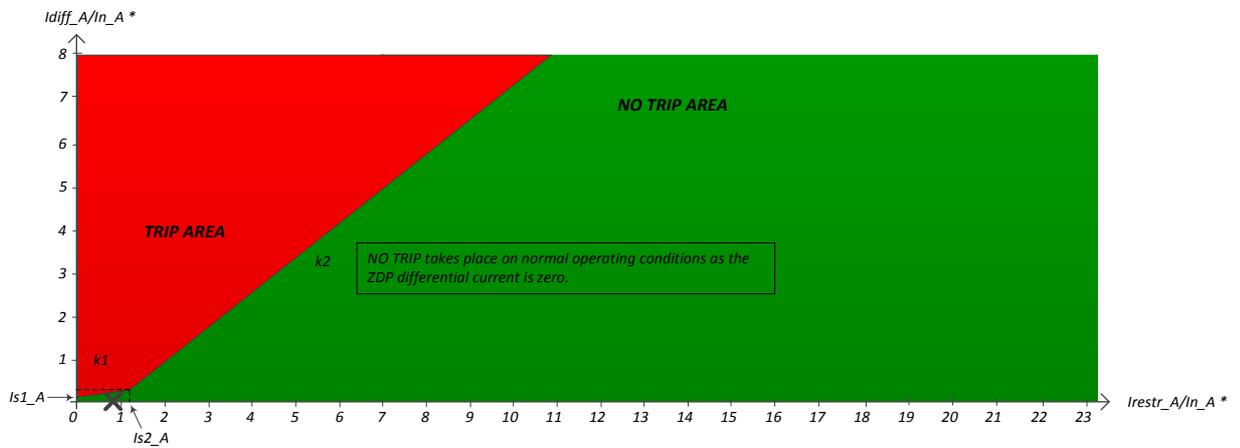
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix B6 – Power flow simulation – SP1 - continued

Simulation step 8/24

Zone : 4

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	4.90-53.41j	-54.42+26.80j	39.30+29.21j
BR4	32.16-99.40j	-81.66+25.84j	59.22+65.41j
BR5	-27.22+45.96j	27.25+0.89j	-19.96-36.21j



* In_x is the rated current of the phase x of the current zone. $x = A$ or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

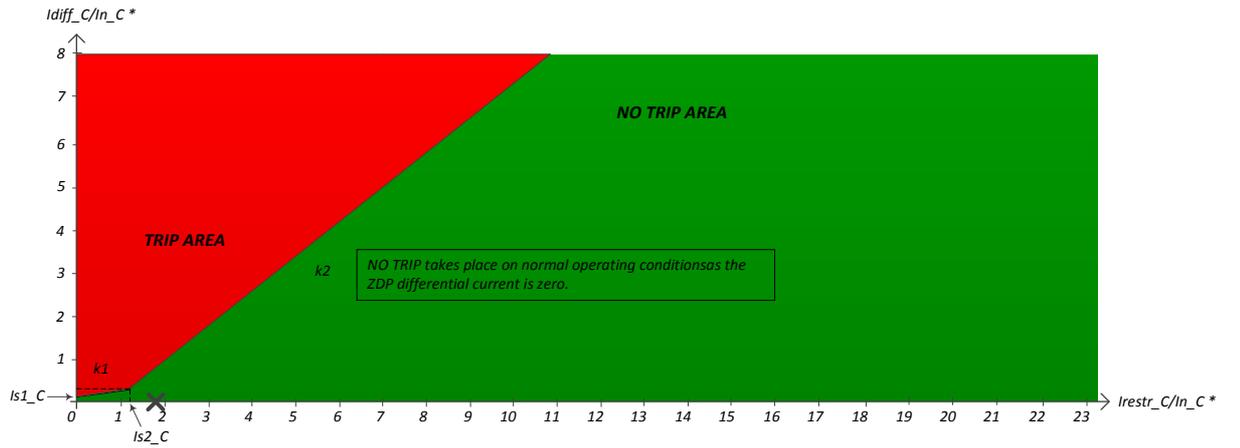
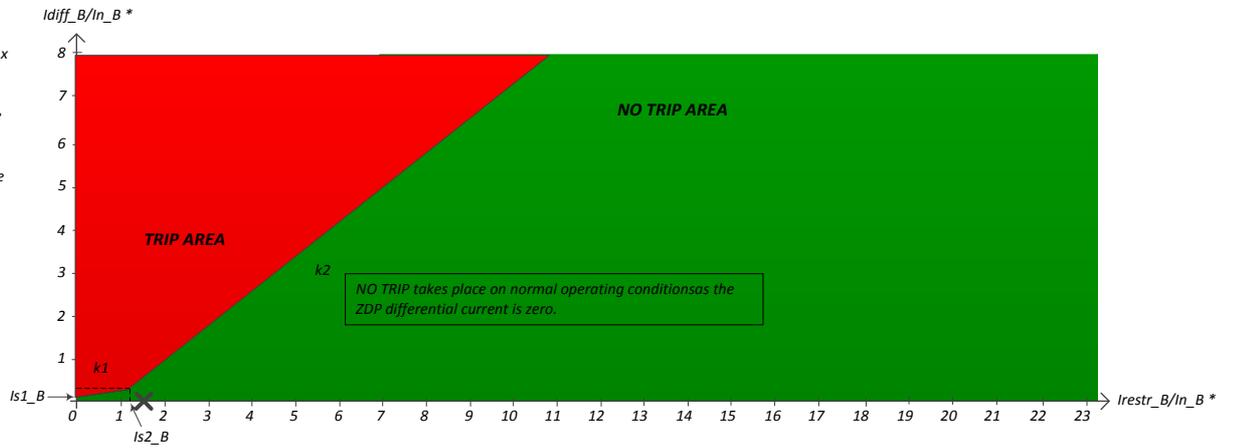
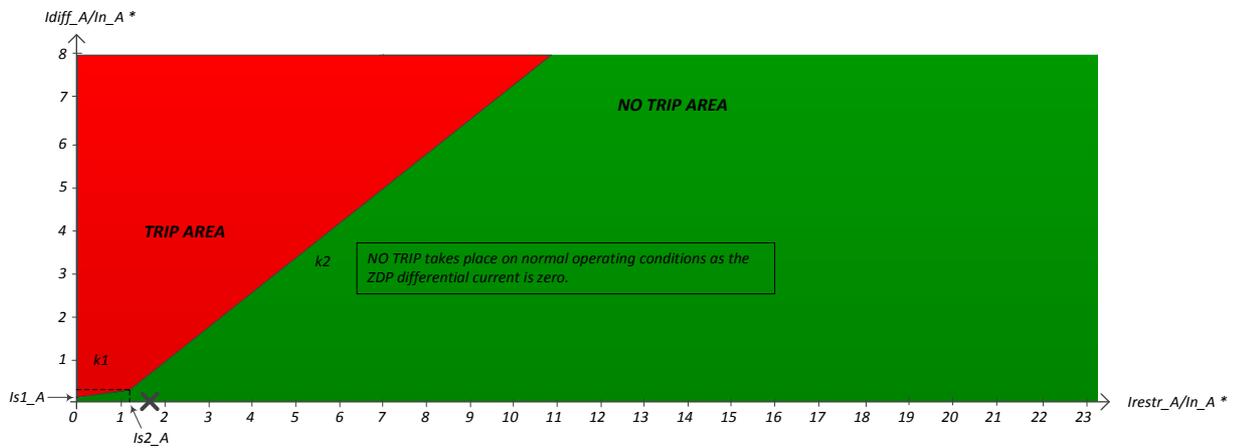
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix B6 – Power flow simulation – SP1 - continued

Simulation step 8/24

Zone : 5

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	27.20-45.94j	-27.25-0.88j	19.97+36.21j
BR5	27.22-45.96j	-27.25-0.89j	19.96+36.21j



* In_x is the rated current of the phase x of the current zone. $x = A$ or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

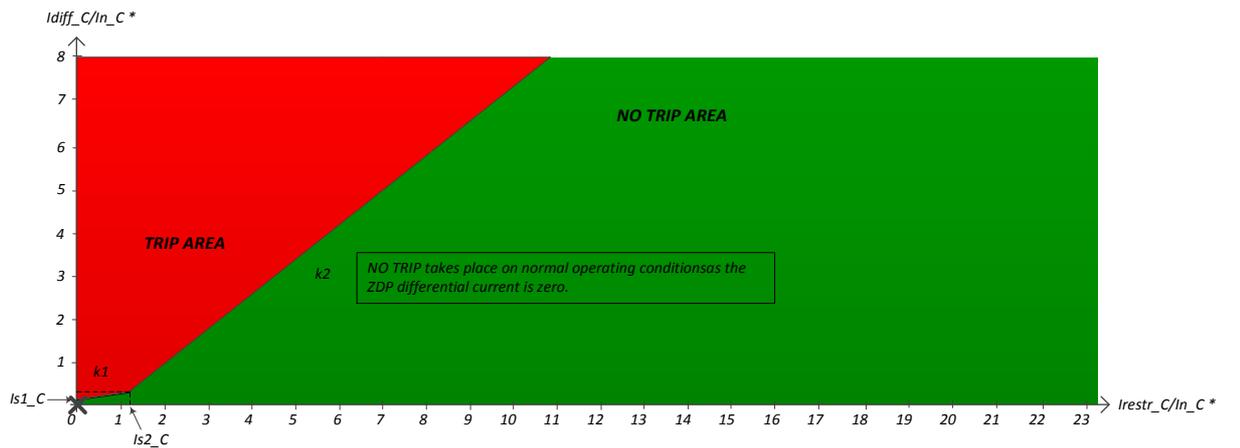
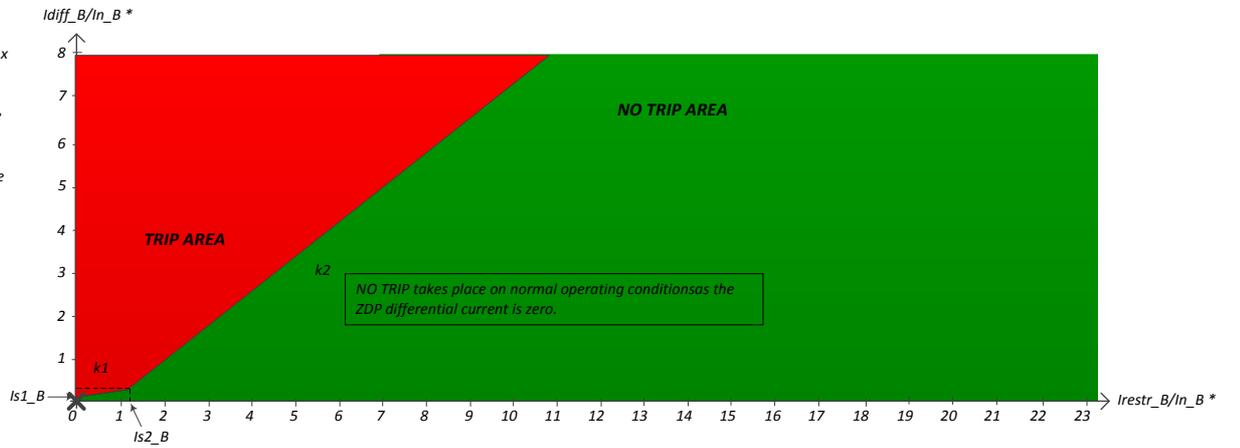
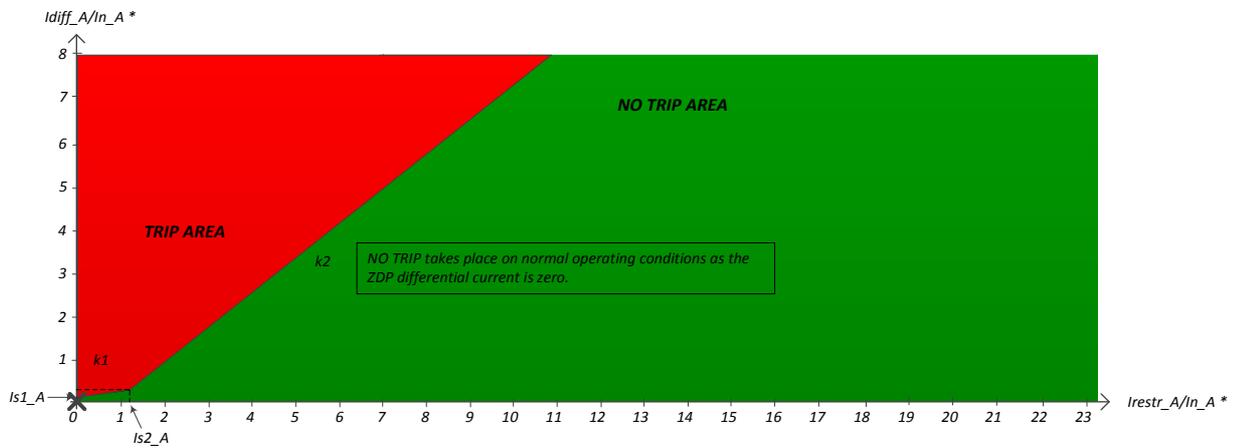
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix B6 – Power flow simulation – SP1 - continued

Simulation step 8/24

Zone : 6

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	0.00+0.00j	0.00+0.00j	0.00+0.00j
BR6	0.00+0.00j	0.00+0.00j	0.00+0.00j



* In_x is the rated current of the phase x of the current zone. $x = A$ or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

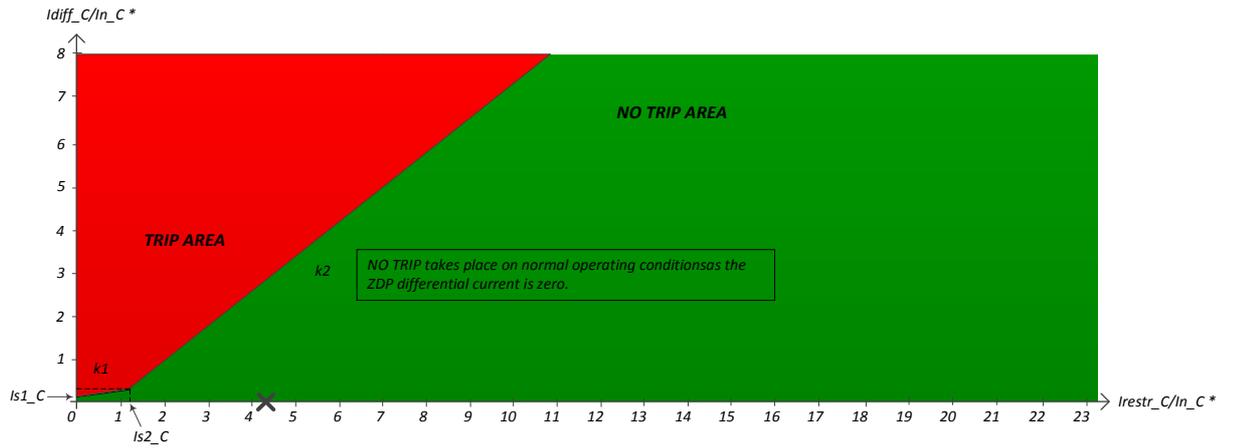
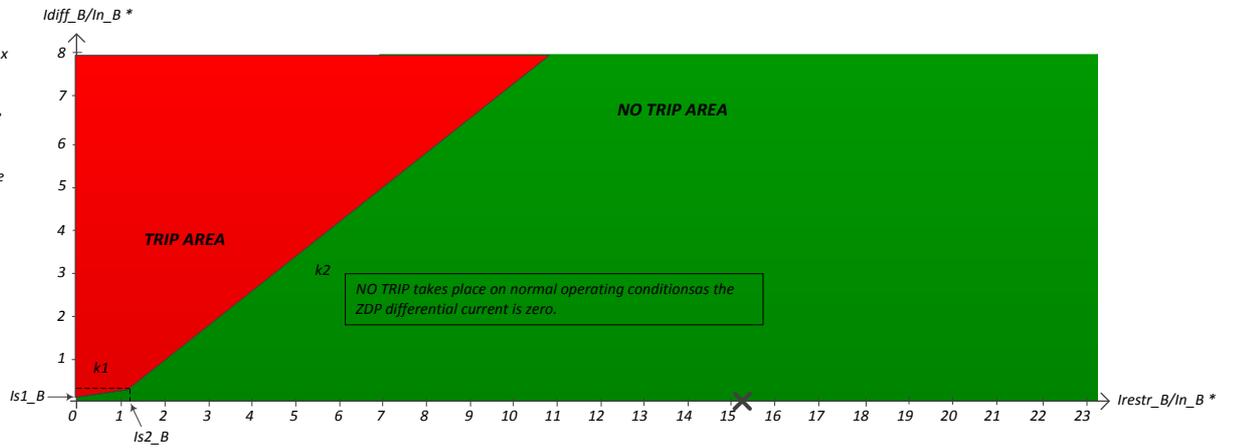
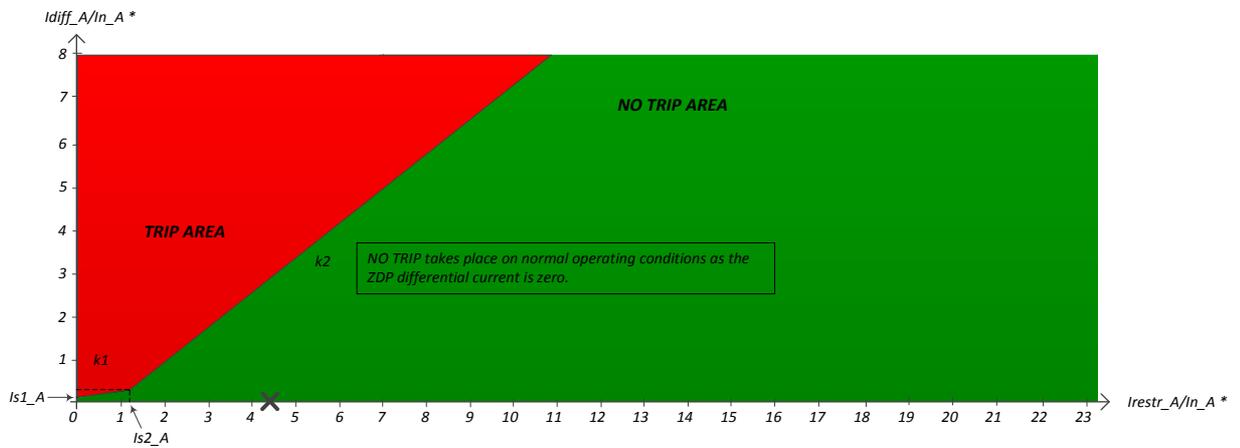
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix B6 – Power flow simulation – SP1

Simulation step 9/24

Zone : 1

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	24.59-70.22j	17.73+14.11j	38.15+71.89j
BR1	144.35-336.40j	-257.78+53.31j	181.08+261.96j
BR2	-63.56+161.95j	152.23-26.58j	-92.47-115.23j
BR3	-56.18+104.21j	123.26-12.65j	-50.48-74.85j



* In_x is the rated current of the phase x of the current zone. $x = A$ or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

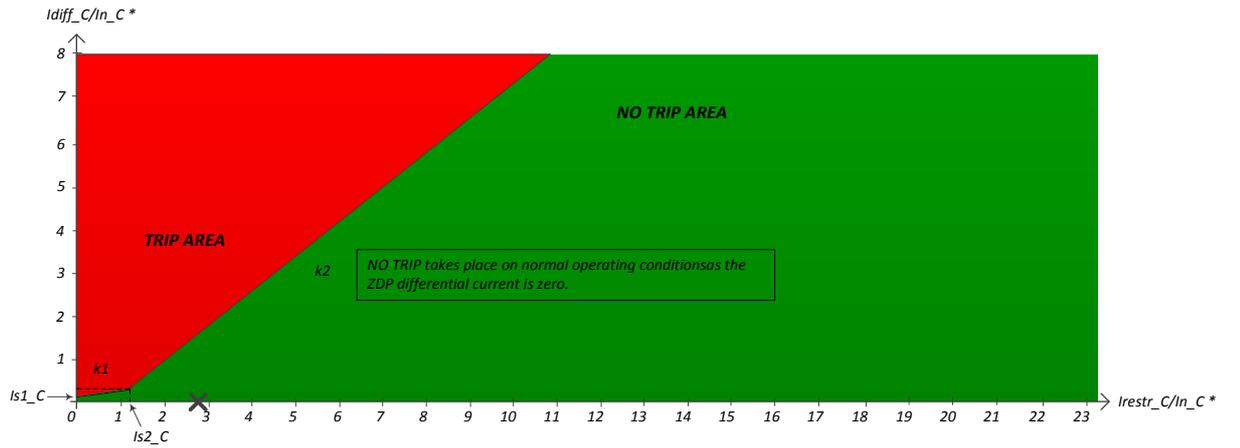
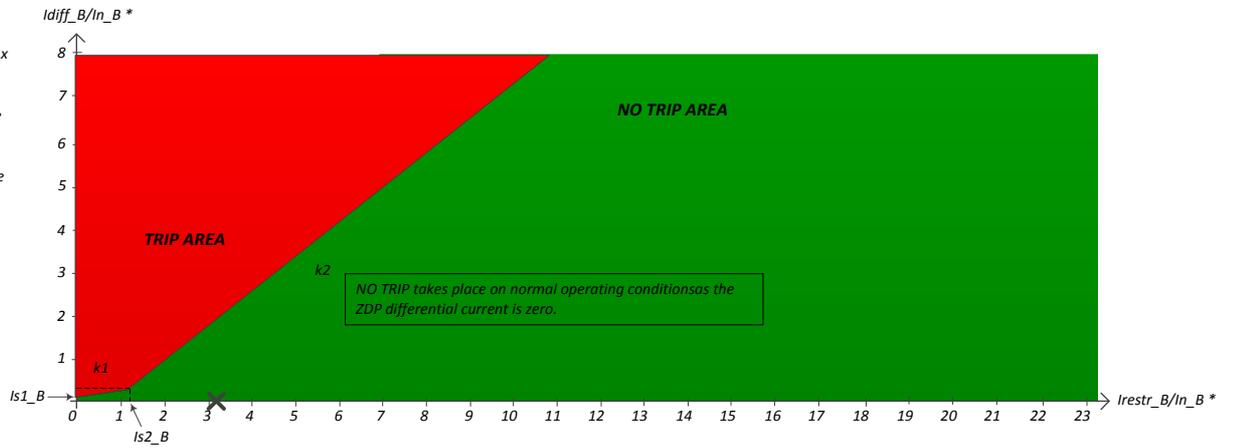
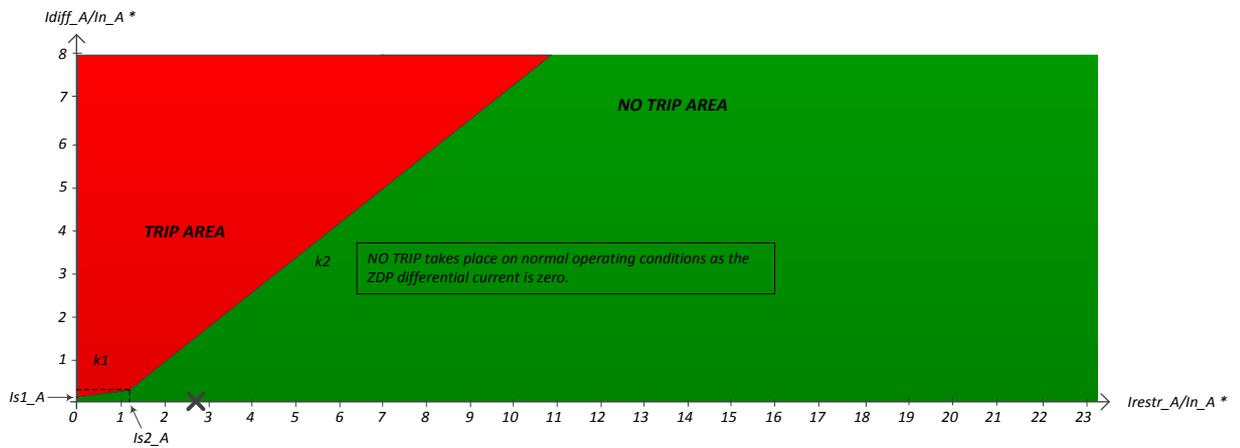
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix B6 – Power flow simulation – SP1 - continued

Simulation step 9/24

Zone : 2

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	35.76-71.97j	-72.50-1.30j	32.25+61.03j
BR2	63.56-161.95j	-152.23+26.58j	92.47+115.23j
BR4	-27.75+90.00j	79.72-27.96j	-60.28-54.20j
BR6	-0.00-0.00j	-0.00-0.00j	-0.00-0.00j



* In_x is the rated current of the phase x of the current zone. x = A or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

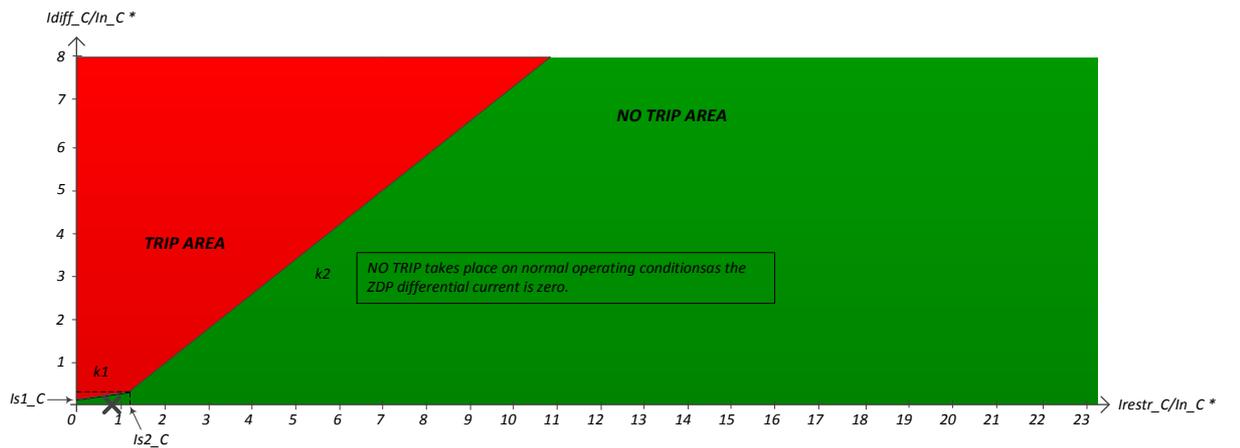
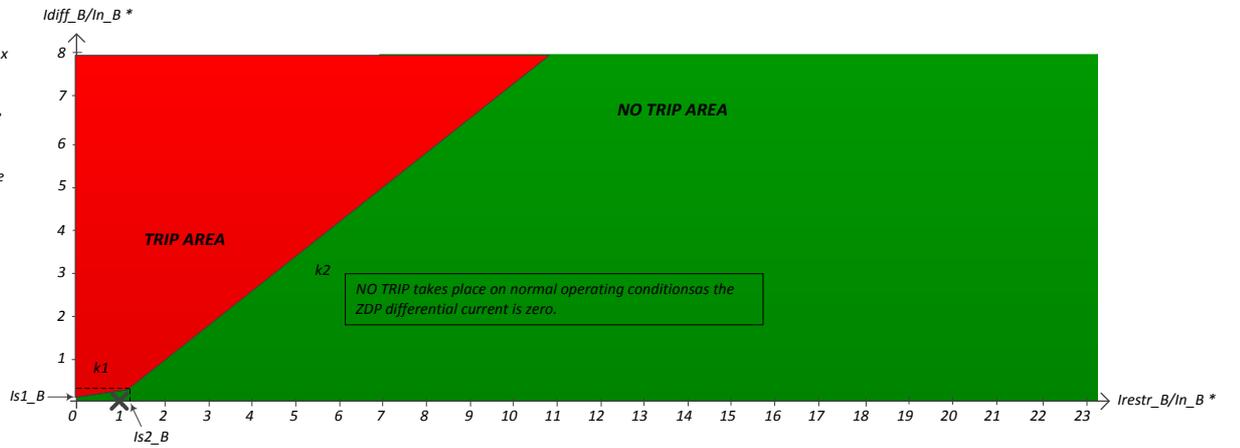
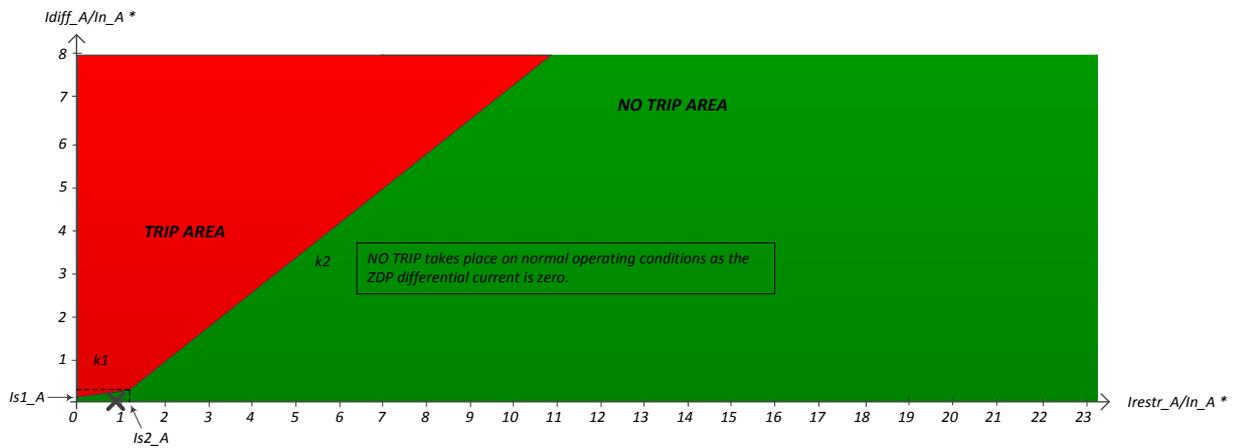
k1, k2 : slopes - k1=30% & k2=80%

Appendix B6 – Power flow simulation – SP1 - continued

Simulation step 9/24

Zone : 3

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	56.15-104.18j	-123.24+12.70j	50.49+74.86j
BR3	56.18-104.21j	-123.26+12.65j	50.48+74.85j



* In_x is the rated current of the phase x of the current zone. $x = A$ or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

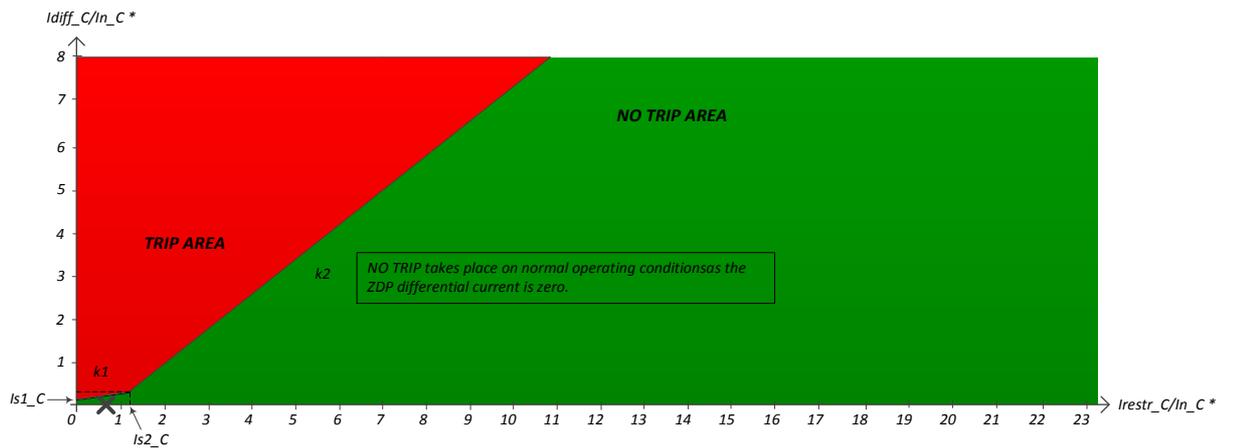
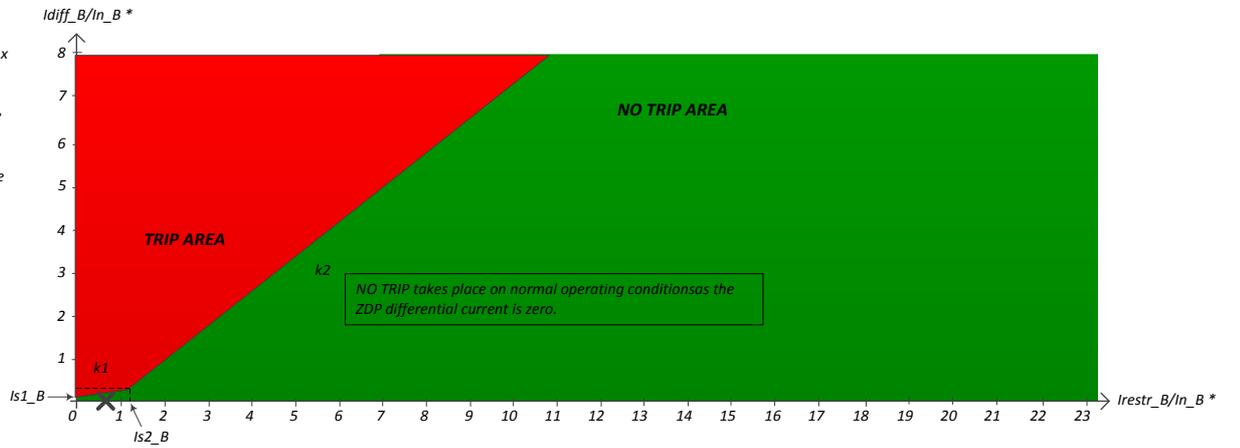
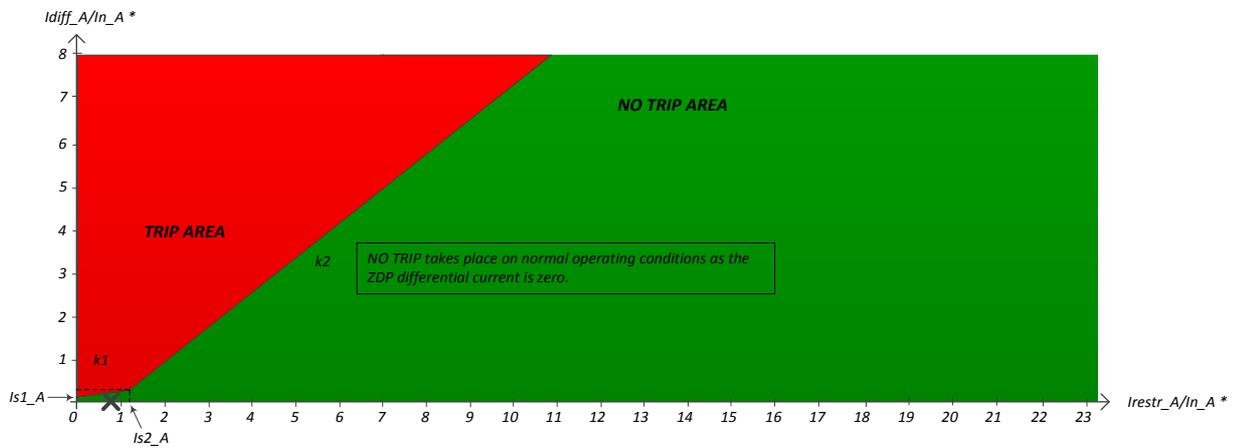
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix B6 – Power flow simulation – SP1 - continued

Simulation step 9/24

Zone : 4

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	-0.02-43.47j	-49.49+29.00j	42.21+21.15j
BR4	27.75-90.00j	-79.72+27.96j	60.28+54.20j
BR5	-27.72+46.52j	30.22+0.99j	-18.10-33.04j



* In_x is the rated current of the phase x of the current zone. x = A or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

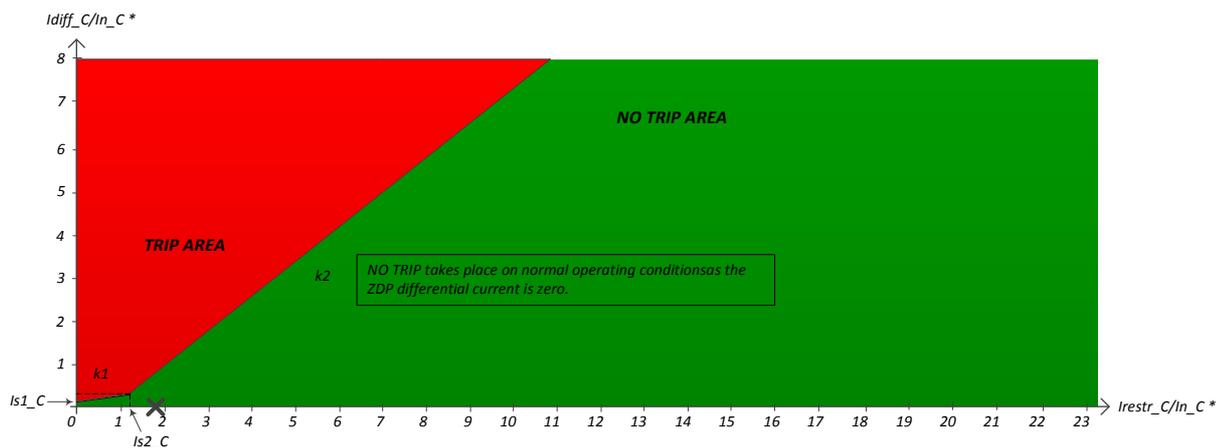
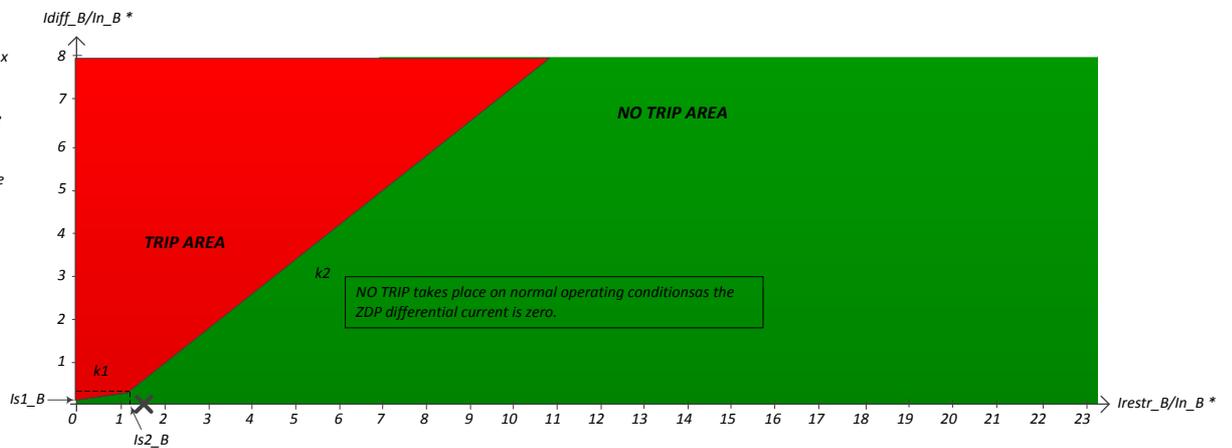
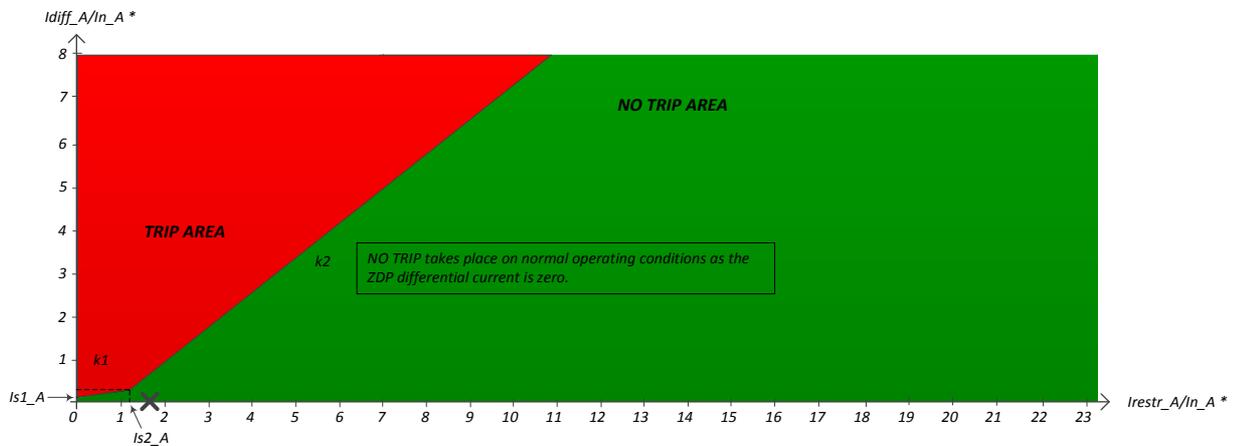
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix B6 – Power flow simulation – SP1 - continued

Simulation step 9/24

Zone : 5

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	27.70-46.52j	-30.23-0.98j	18.11+33.04j
BR5	27.72-46.52j	-30.22-0.99j	18.10+33.04j



* In_x is the rated current of the phase x of the current zone. $x = A$ or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

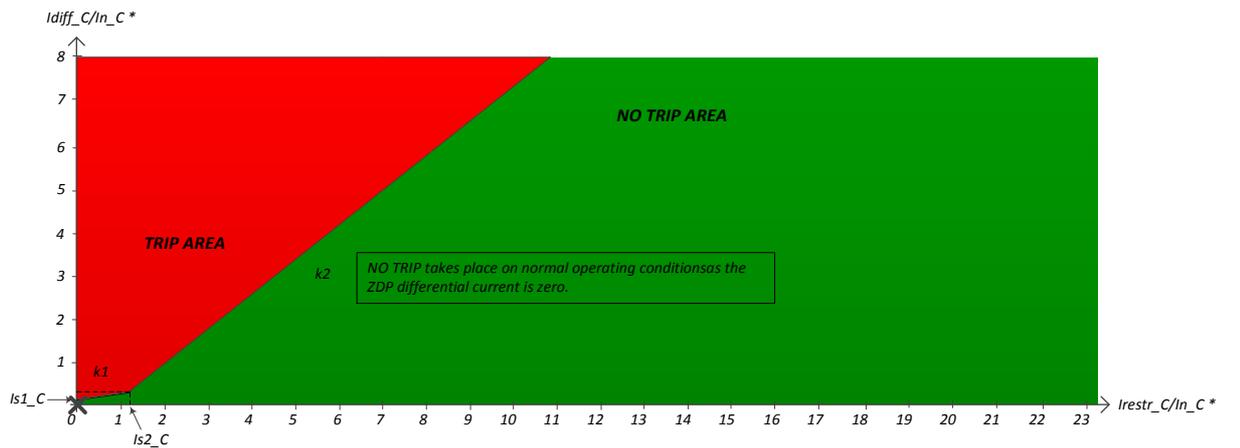
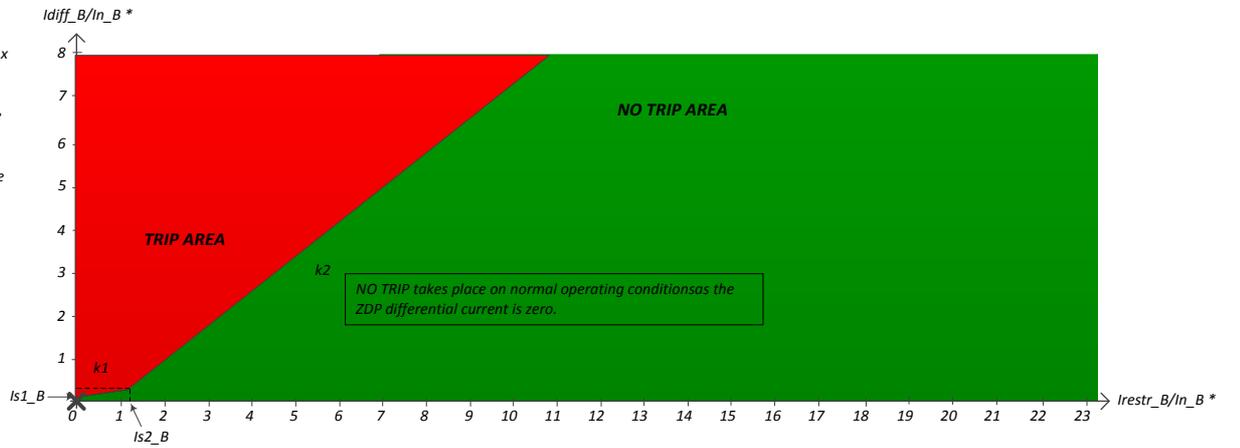
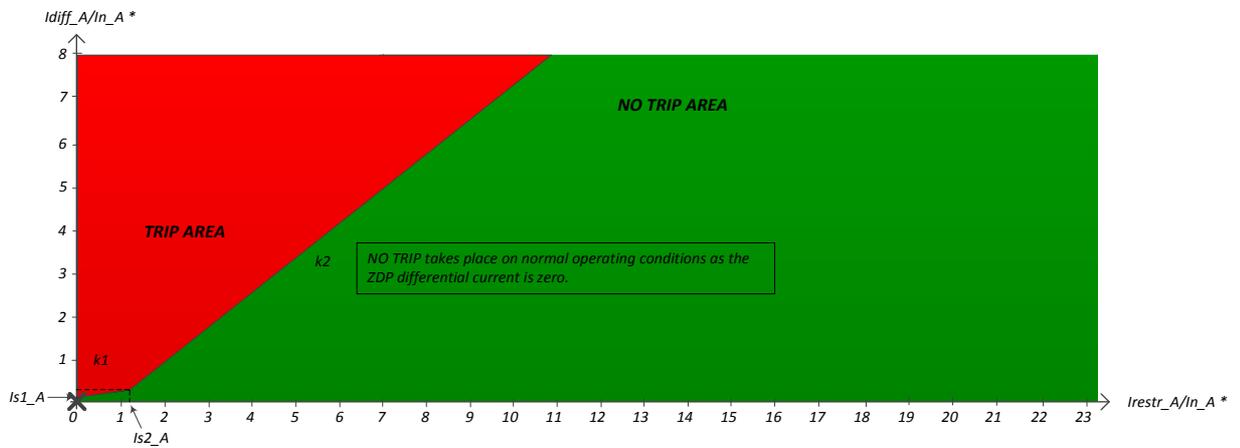
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix B6 – Power flow simulation – SP1 - continued

Simulation step 9/24

Zone : 6

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	0.00+0.00j	0.00+0.00j	0.00+0.00j
BR6	0.00+0.00j	0.00+0.00j	0.00+0.00j



* In_x is the rated current of the phase x of the current zone. $x = A$ or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

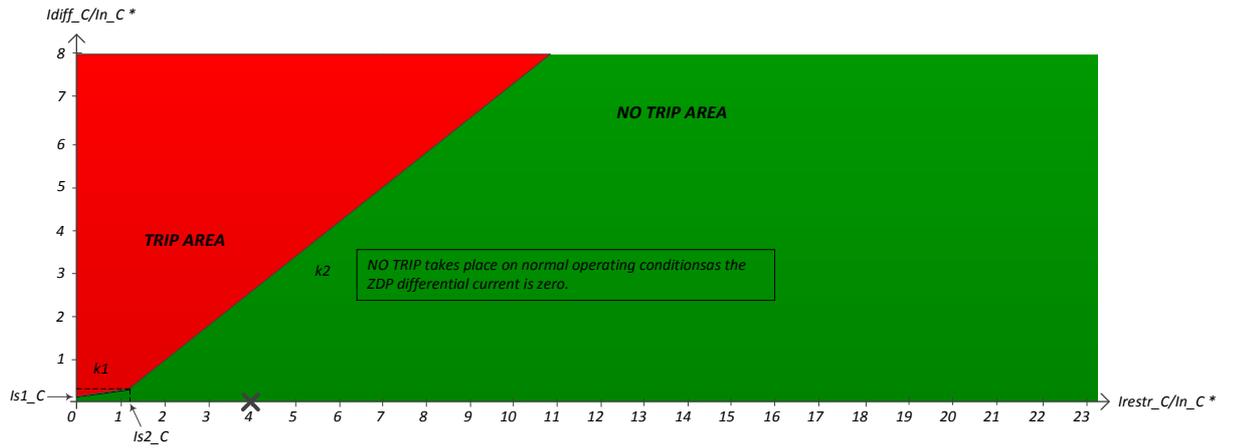
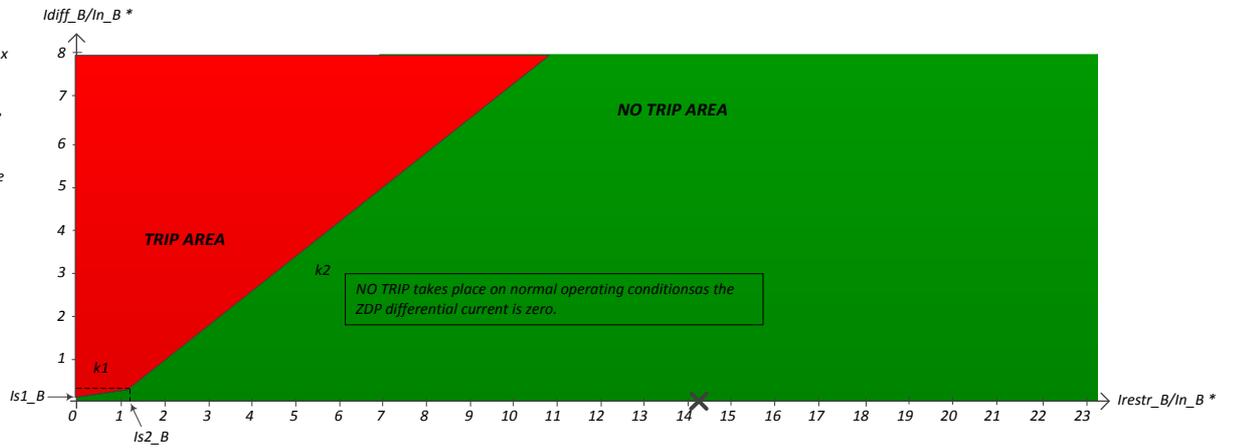
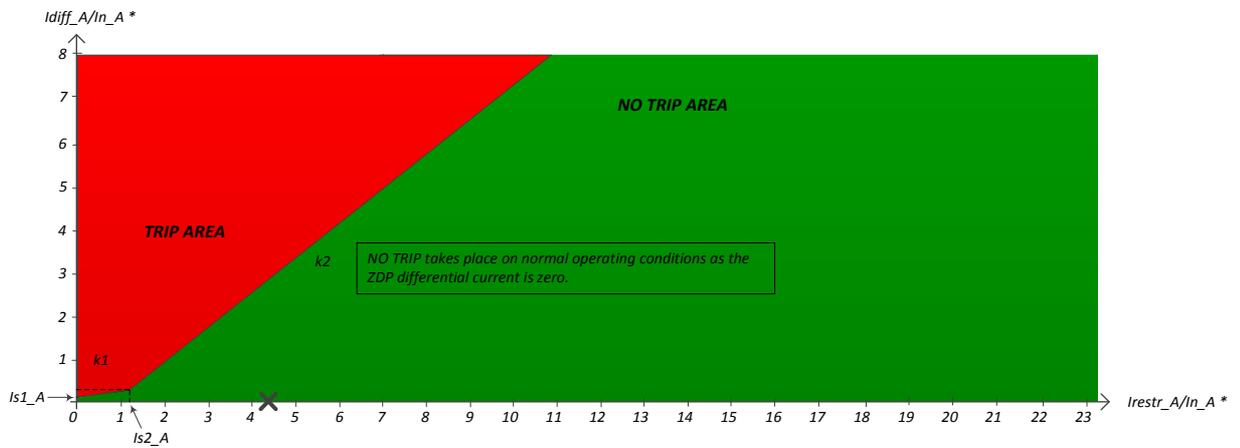
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix B6 – Power flow simulation – SP1

Simulation step 10/24

Zone : 1

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	19.73-62.00j	17.55+15.00j	35.83+70.97j
BR1	140.78-332.54j	-237.73+58.44j	168.38+246.35j
BR2	-65.87+171.13j	145.71-31.22j	-86.05-105.91j
BR3	-55.14+99.39j	109.55-12.25j	-46.51-69.48j



* In_x is the rated current of the phase x of the current zone. $x = A$ or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

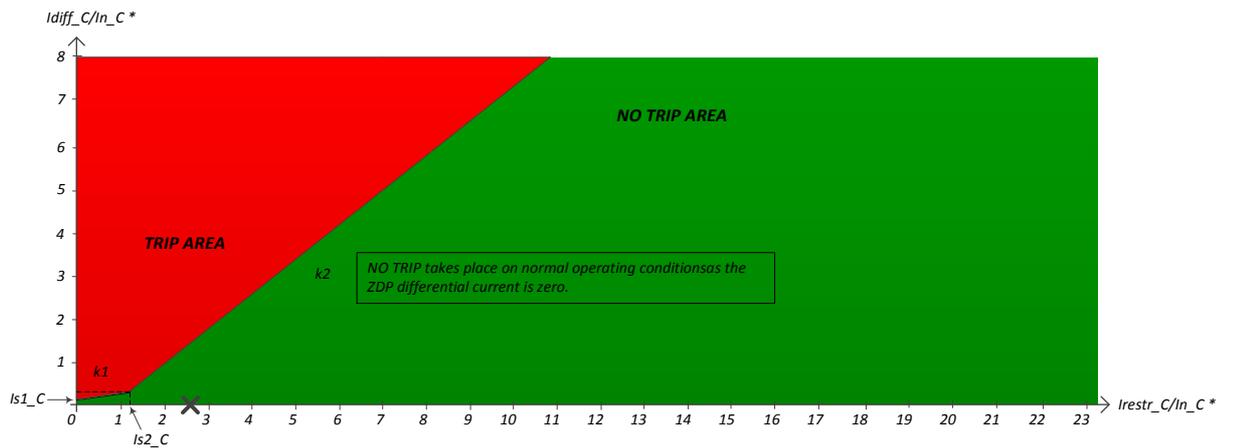
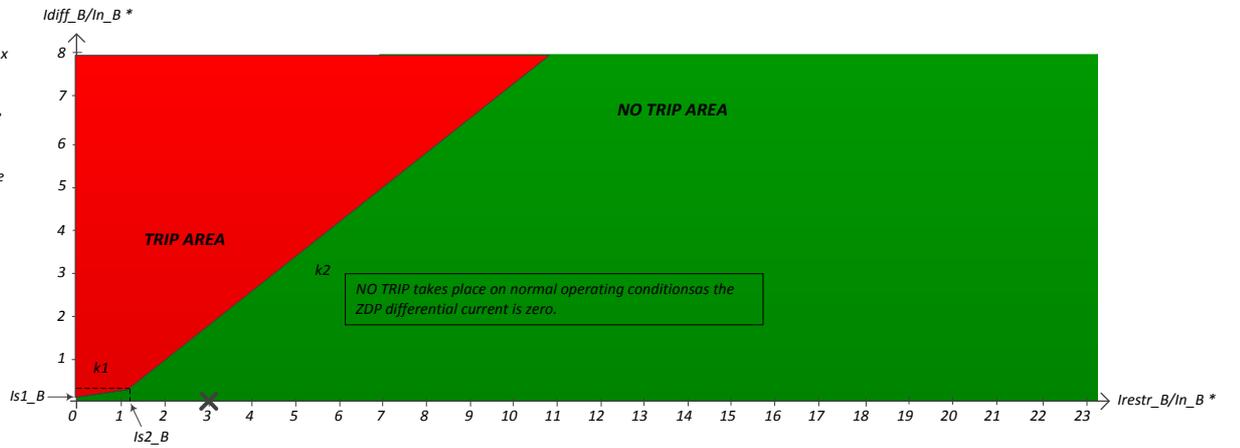
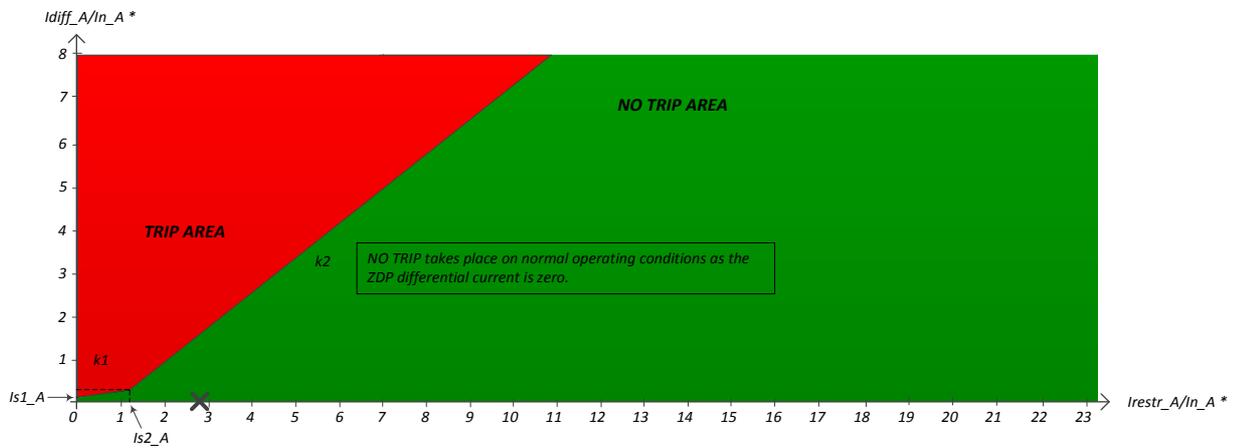
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix B6 – Power flow simulation – SP1 - continued

Simulation step 10/24

Zone : 2

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	38.89-79.24j	-69.07-1.27j	26.74+53.44j
BR2	65.87-171.13j	-145.71+31.22j	86.05+105.91j
BR4	-26.94+91.91j	76.64-32.55j	-59.34-52.46j
BR6	-0.00-0.00j	-0.00-0.00j	-0.00-0.00j



* In_x is the rated current of the phase x of the current zone. $x = A$ or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

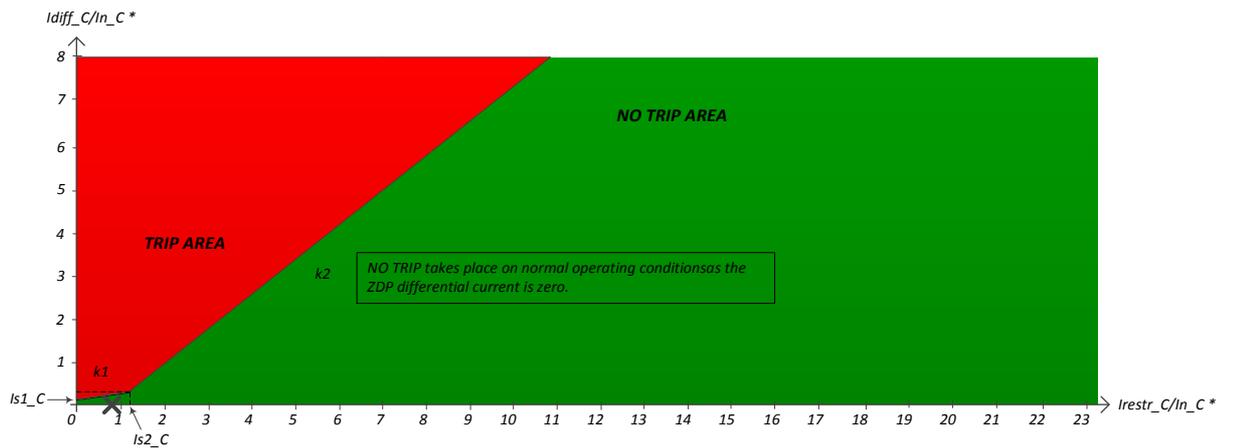
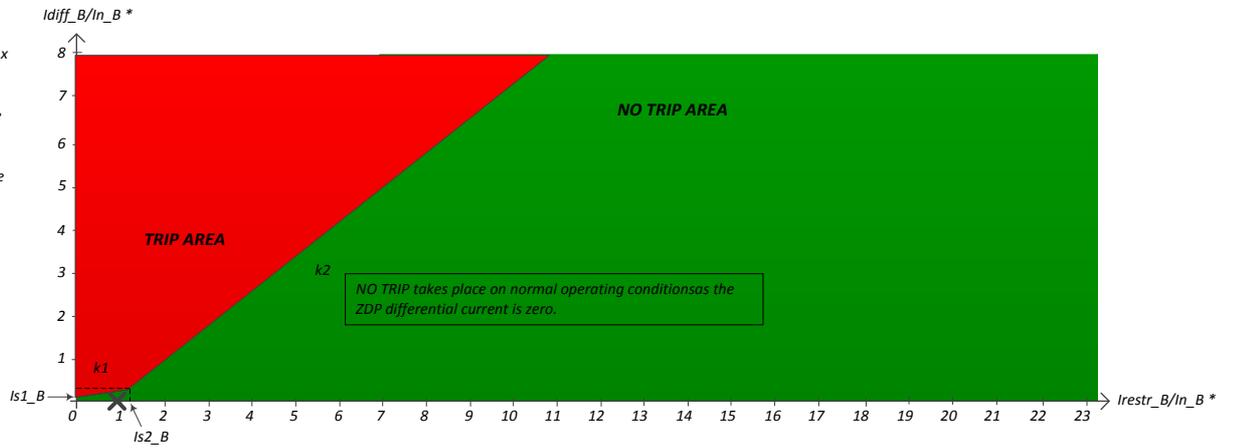
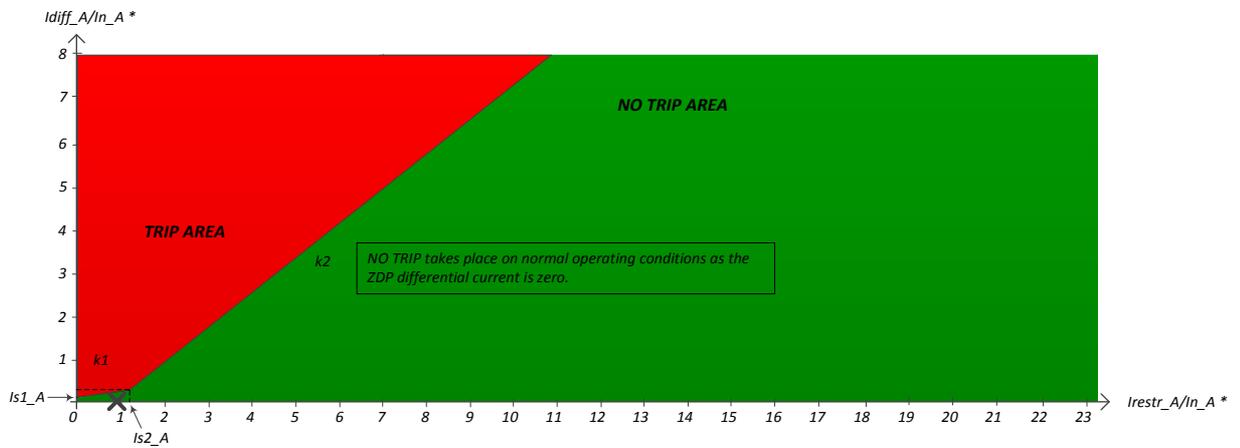
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix B6 – Power flow simulation – SP1 - continued

Simulation step 10/24

Zone : 3

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	55.11-99.38j	-109.53+12.29j	46.52+69.48j
BR3	55.14-99.39j	-109.55+12.25j	46.51+69.48j



* In_x is the rated current of the phase x of the current zone. $x = A$ or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

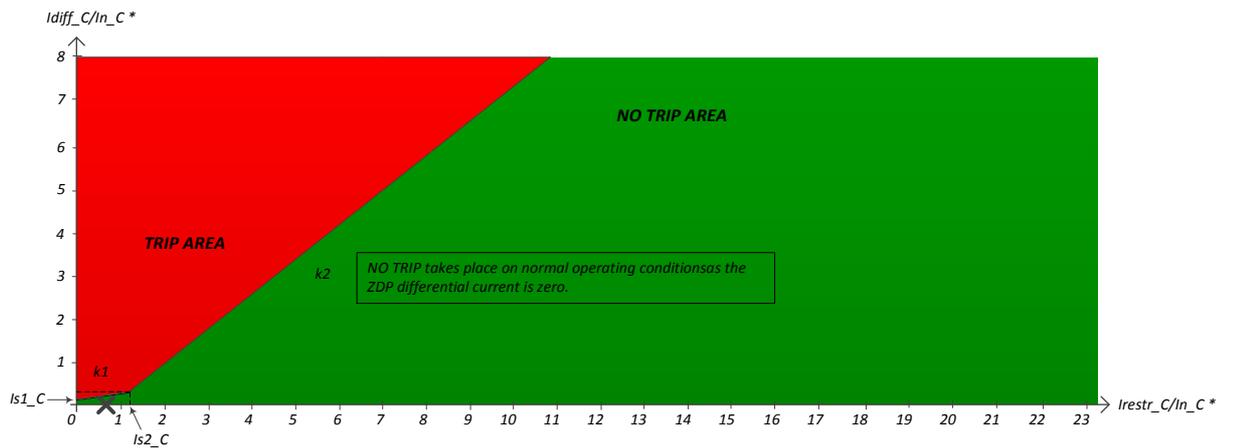
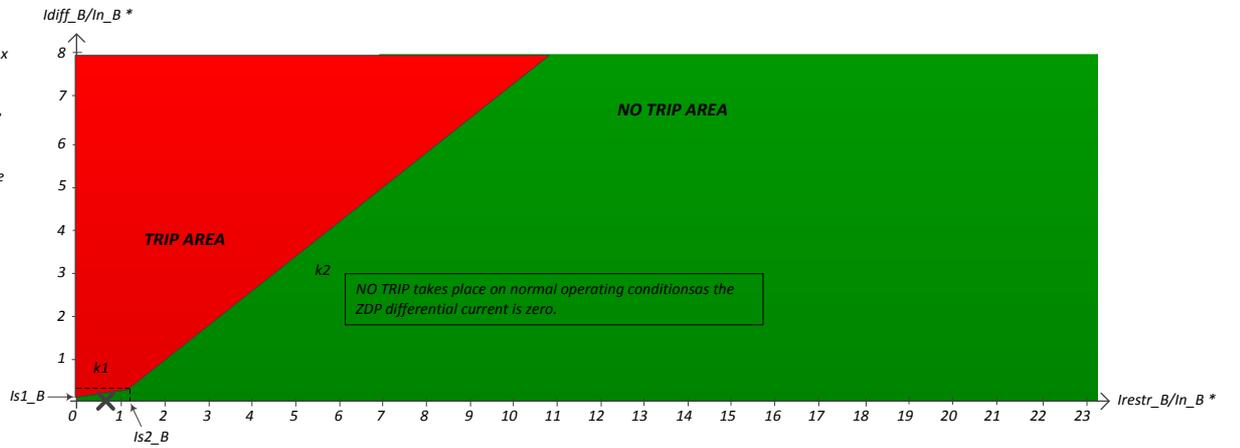
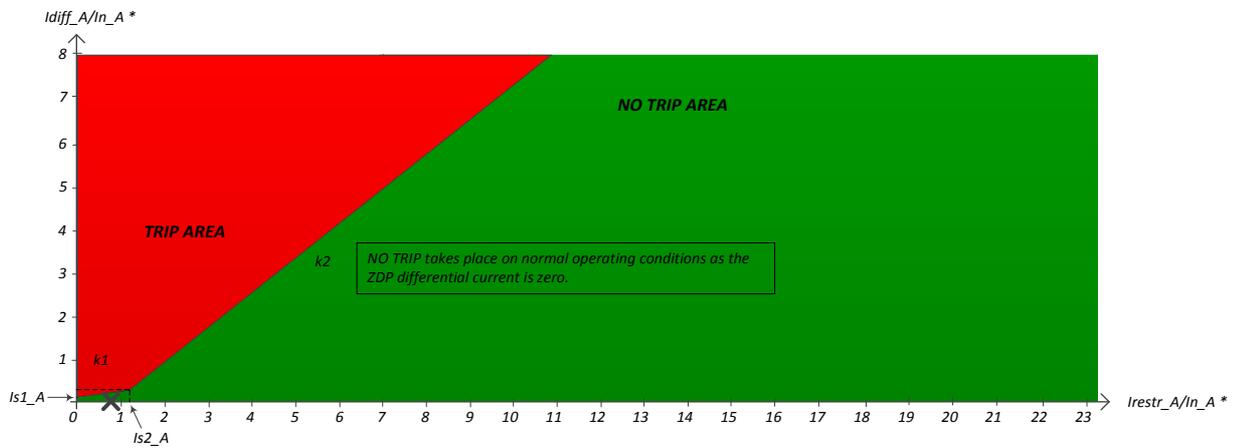
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix B6 – Power flow simulation – SP1 - continued

Simulation step 10/24

Zone : 4

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	0.41-47.39j	-43.87+33.76j	40.93+18.53j
BR4	26.94-91.91j	-76.64+32.55j	59.34+52.46j
BR5	-26.49+44.47j	32.75+1.16j	-18.43-33.93j



* In_x is the rated current of the phase x of the current zone. $x = A$ or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

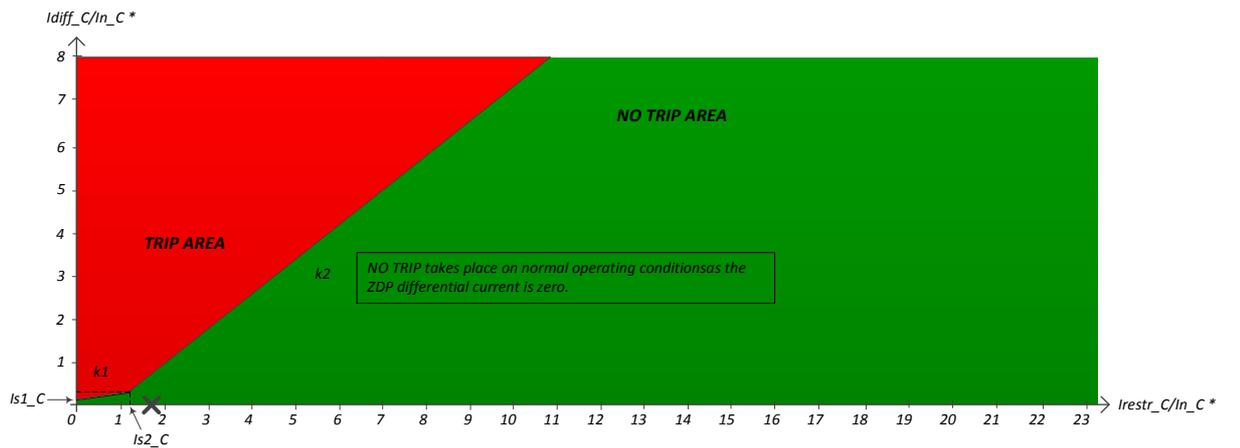
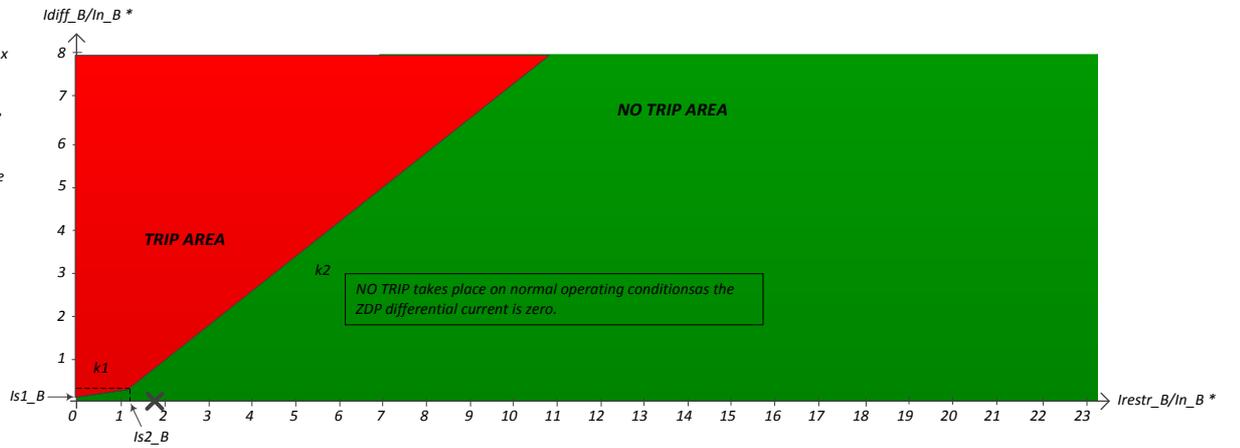
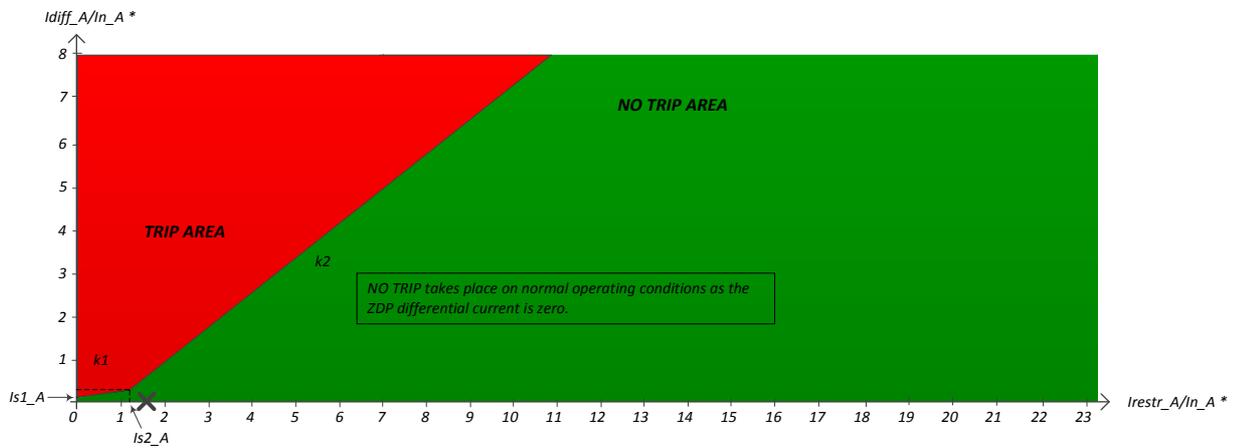
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix B6 – Power flow simulation – SP1 - continued

Simulation step 10/24

Zone : 5

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	26.46-44.47j	-32.74-1.14j	18.44+33.93j
BR5	26.49-44.47j	-32.75-1.16j	18.43+33.93j



* In_x is the rated current of the phase x of the current zone. $x = A$ or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

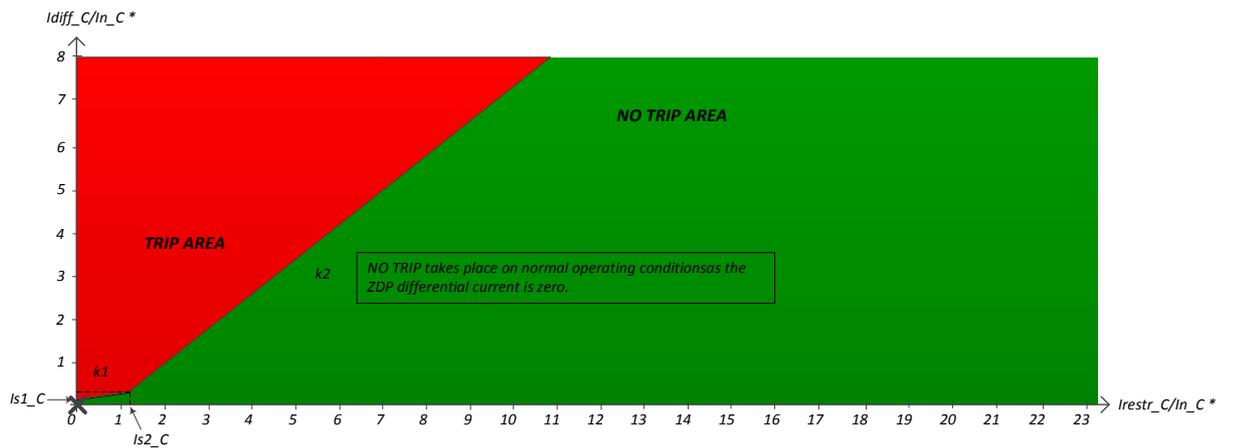
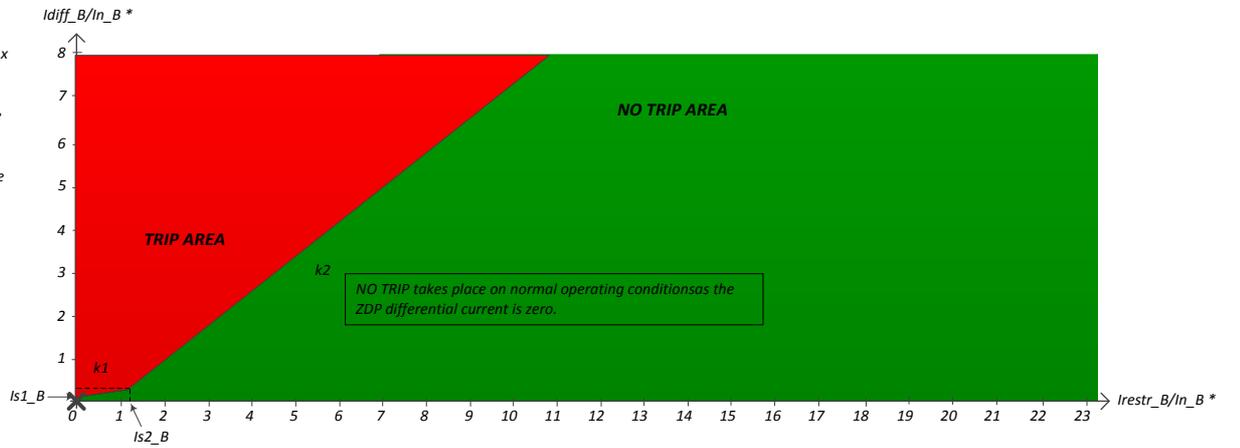
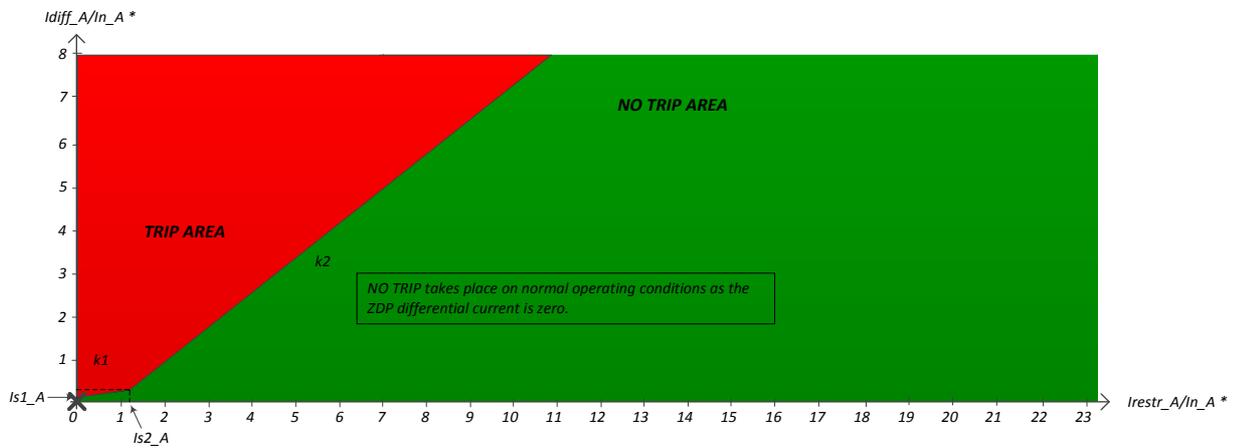
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix B6 – Power flow simulation – SP1 - continued

Simulation step 10/24

Zone : 6

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	0.00+0.00j	0.00+0.00j	0.00+0.00j
BR6	0.00+0.00j	0.00+0.00j	0.00+0.00j



* In_x is the rated current of the phase x of the current zone. $x = A$ or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

APPENDIX B7

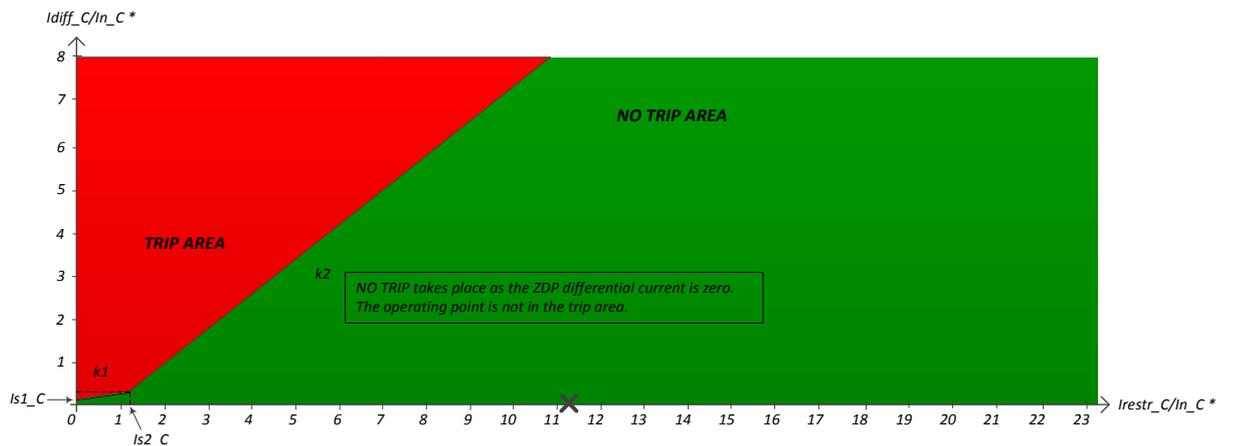
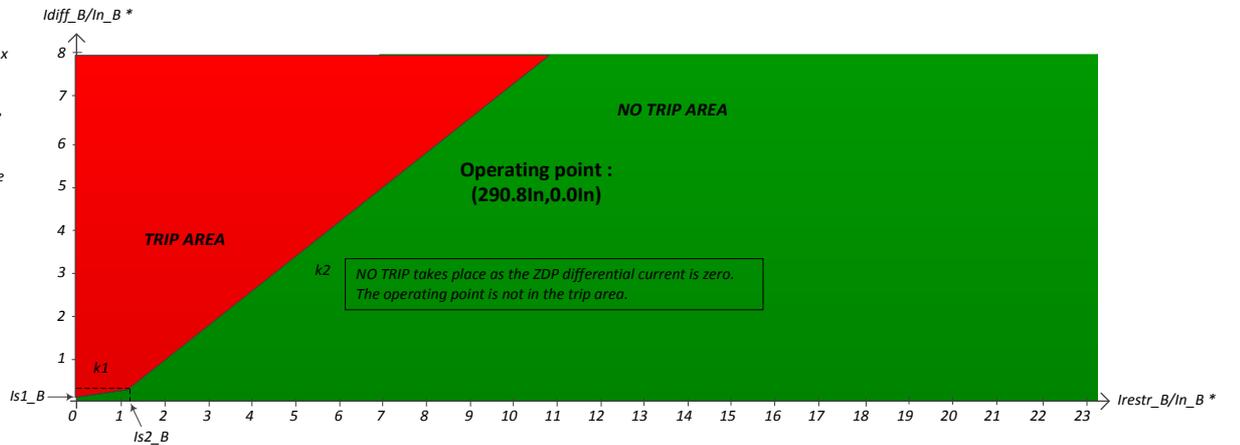
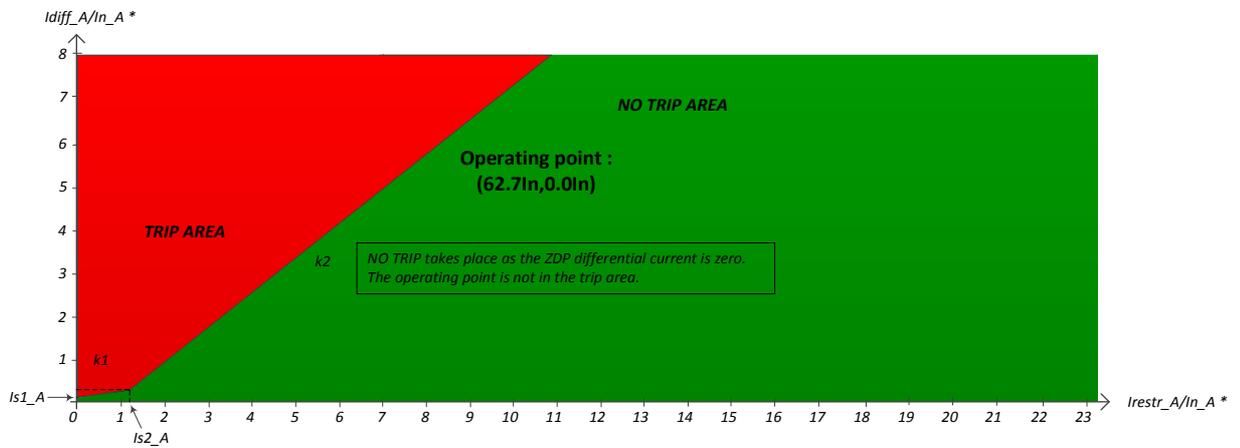
Short-circuit simulation results in SP1

Appendix B7 – Short-circuit simulation – SP1

[Fault at bus 35 in Zone 3 - Fault on phase = AB – Fault resistance R = 0 ohms]

Zone : 1

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	457.38+311.30j	659.55-130.17j	563.22+60.92j
BR1	150.90-4512.31j	-2611.91+3622.32j	744.44+301.55j
BR2	-161.74-273.21j	-238.25+241.28j	-127.23-157.73j
BR3	468.23+5096.83j	3509.71-3993.77j	-54.00-82.91j



* In_x is the rated current of the phase x of the current zone. x = A or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

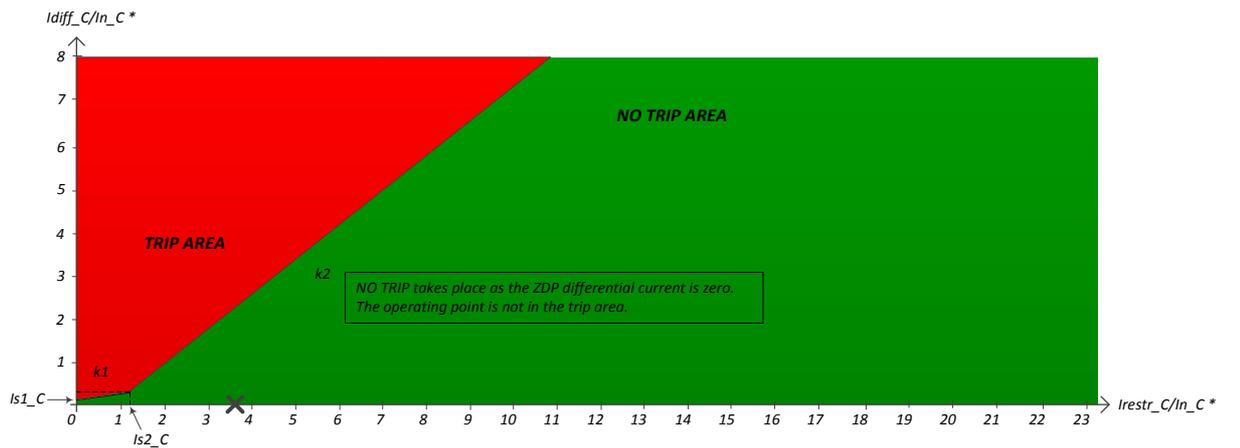
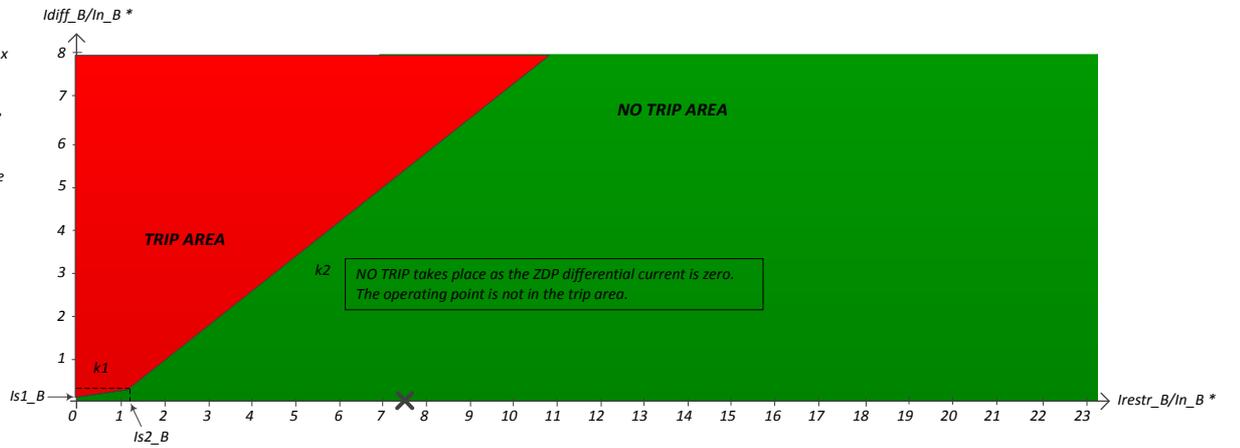
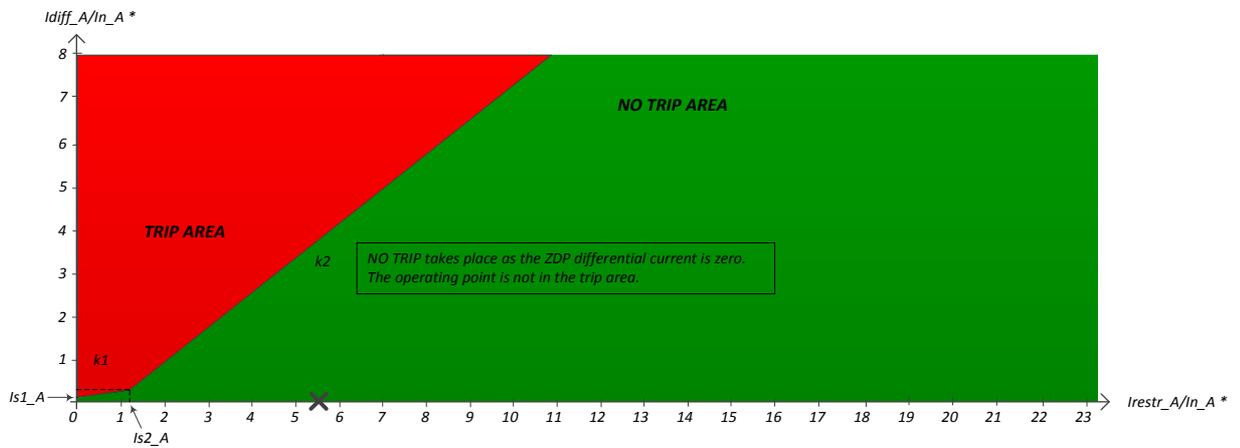
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix B7 – Short-circuit simulation – SP1

[Fault at bus 35 in Zone 3 - Fault on phase = AB – Fault resistance R = 0 ohms]

Zone : 2

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	5.71-47.15j	-35.31-5.11j	36.24+63.38j
BR2	161.74+273.21j	238.25-241.28j	127.23+157.73j
BR4	-156.00-320.35j	-273.54+236.17j	-91.03-94.35j
BR6	-0.00-0.00j	-0.00-0.00j	-0.00-0.00j



* In_x is the rated current of the phase x of the current zone. x = A or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

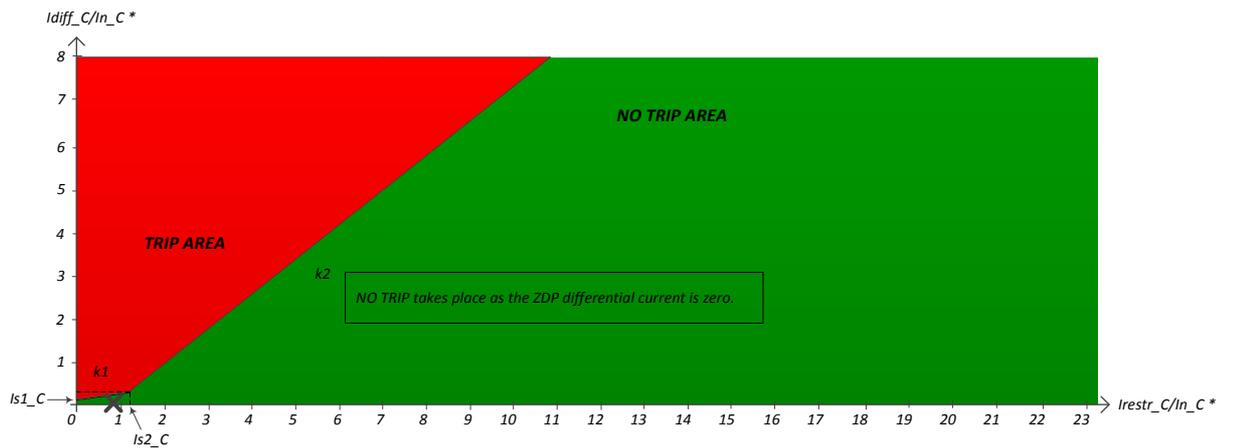
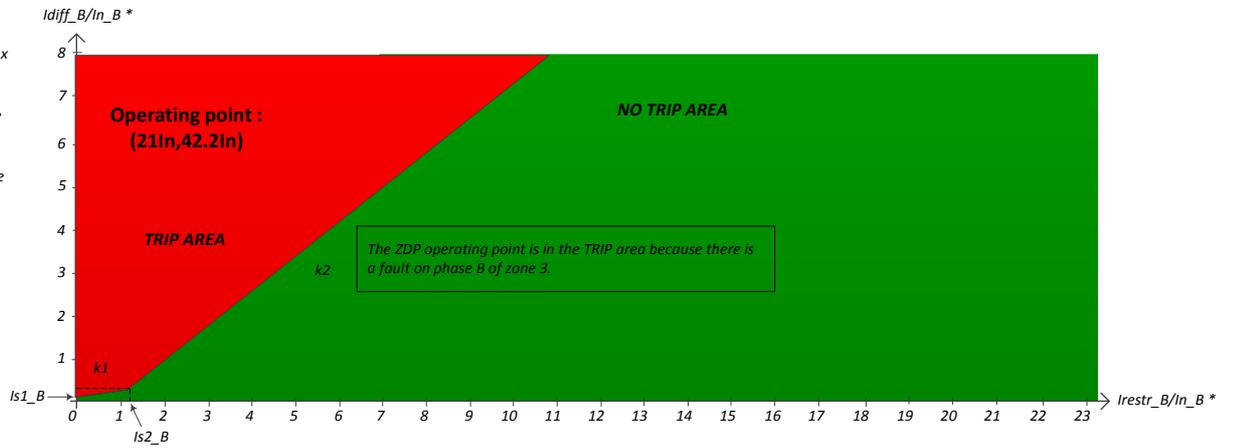
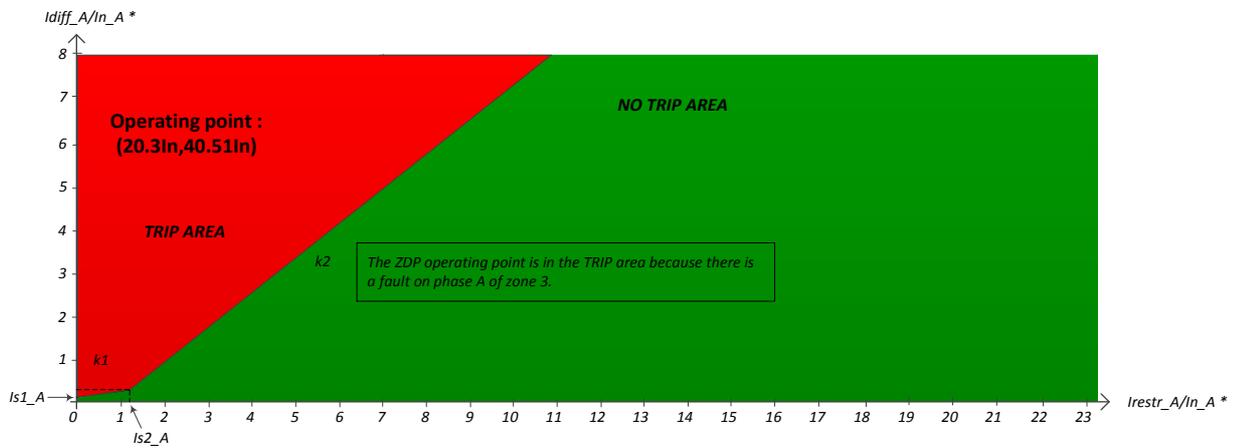
k1, k2 : slopes - k1=30% & k2=80%

Appendix B7 – Short-circuit simulation – SP1

[Fault at bus 35 in Zone 3 - Fault on phase = AB – Fault resistance R = 0 ohms]

Zone : 3

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	-0.01-0.31j	-0.00-0.31j	54.01+82.92j
BR3	-468.23-5096.83j	-3509.71+3993.77j	54.00+82.91j



* In_x is the rated current of the phase x of the current zone. x = A or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

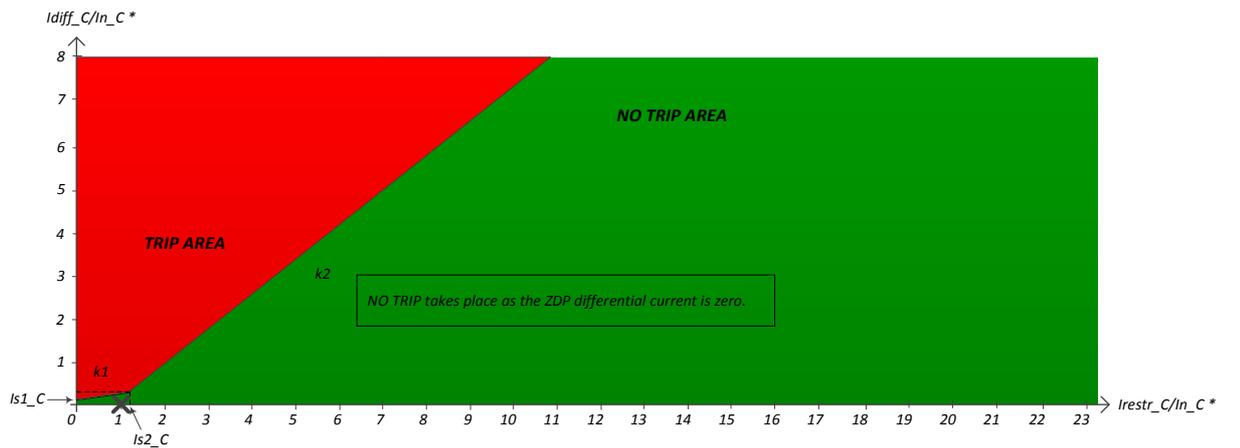
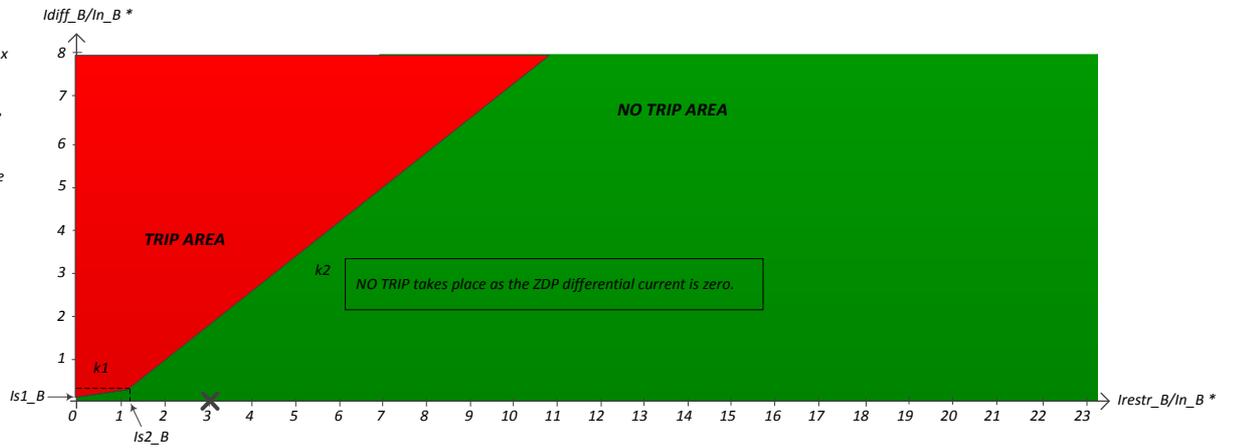
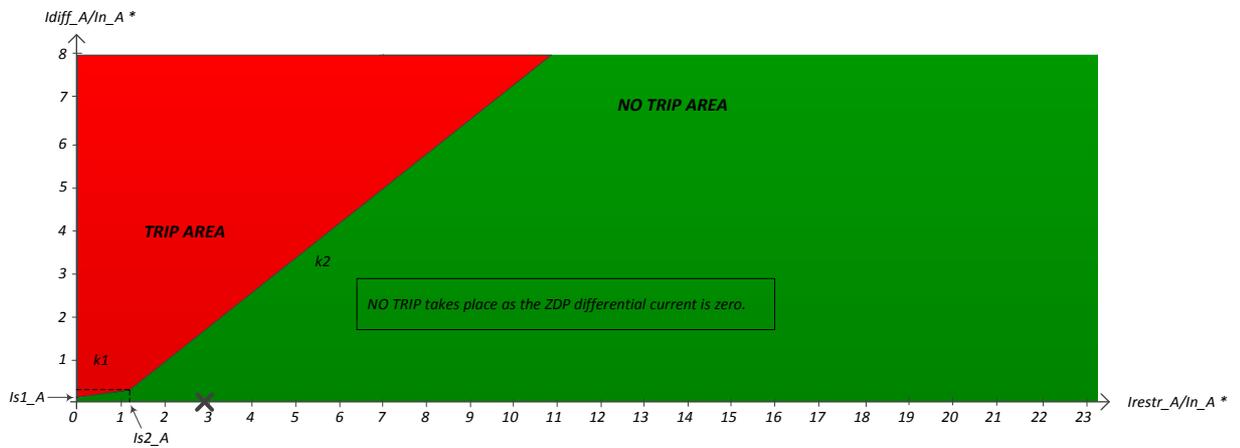
k1, k2 : slopes - k1=30% & k2=80%

Appendix B7 – Short-circuit simulation – SP1

[Fault at bus 35 in Zone 3 - Fault on phase = AB – Fault resistance R = 0 ohms]

Zone : 4

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	148.83+349.66j	290.16-233.89j	68.47+54.16j
BR4	156.00+320.35j	273.54-236.17j	91.03+94.35j
BR5	-7.15+29.28j	16.64+2.27j	-22.58-40.19j



* In_x is the rated current of the phase x of the current zone. x = A or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

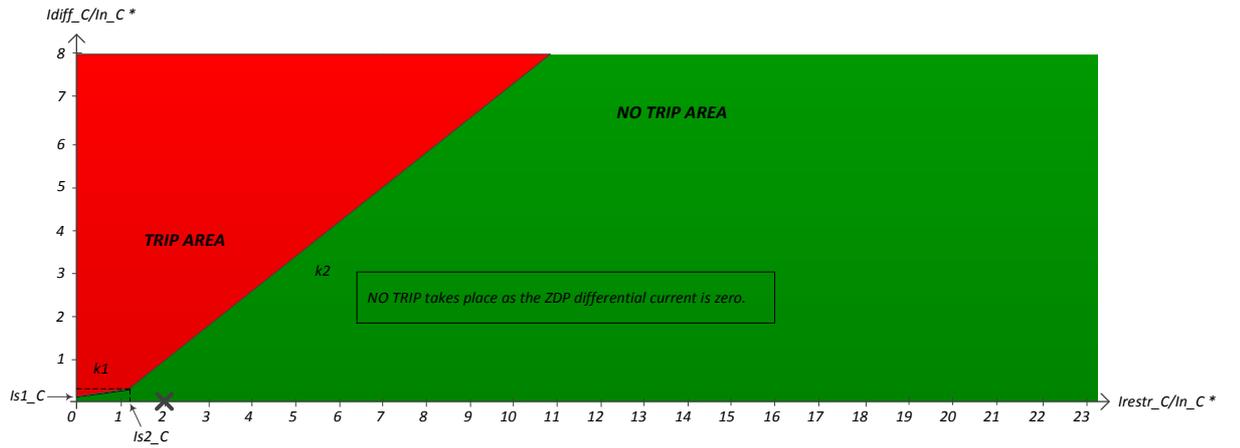
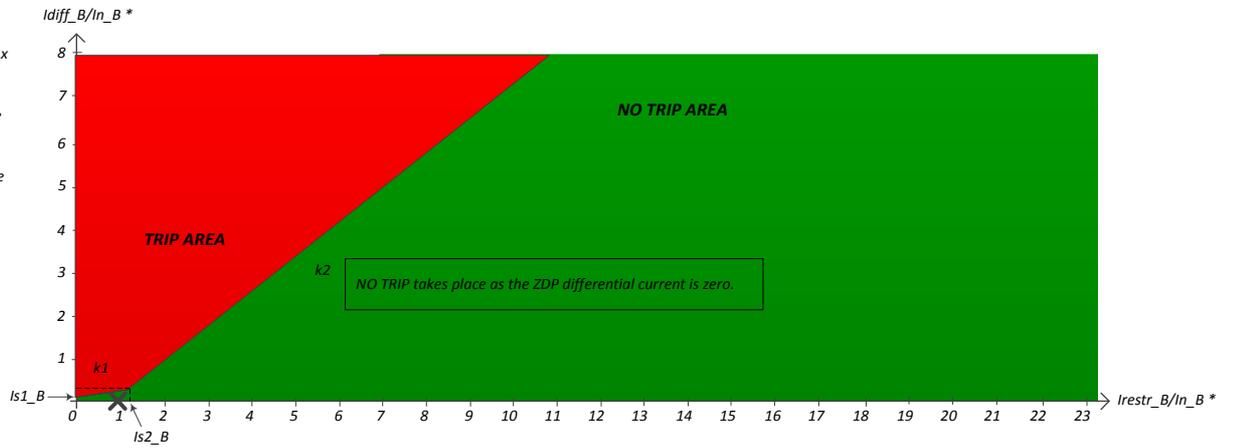
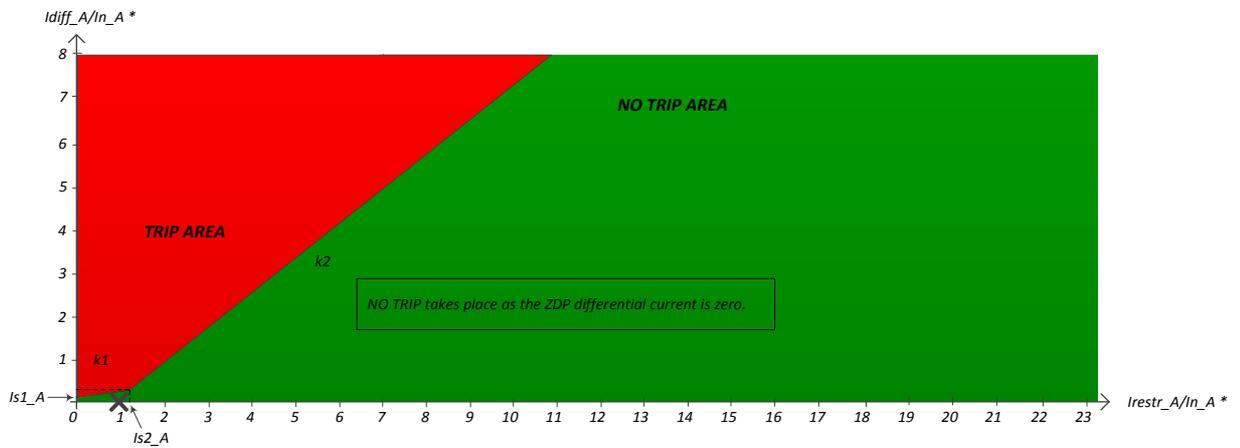
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix B7 – Short-circuit simulation – SP1

[Fault at bus 35 in Zone 3 - Fault on phase = AB – Fault resistance R = 0 ohms]

Zone : 5

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	7.14-29.27j	-16.66-2.27j	22.59+40.18j
BR5	7.15-29.28j	-16.64-2.27j	22.58+40.19j



* In_x is the rated current of the phase x of the current zone. x = A or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

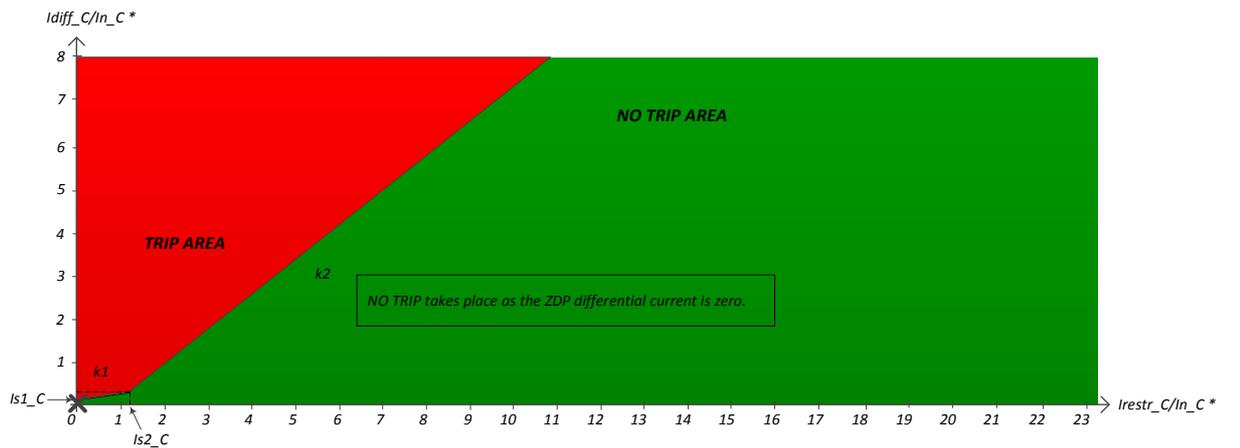
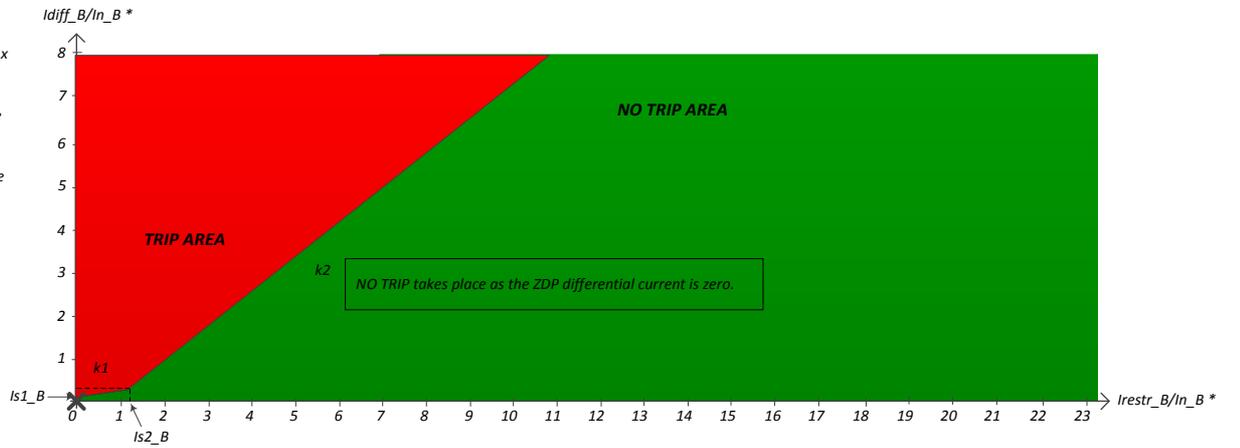
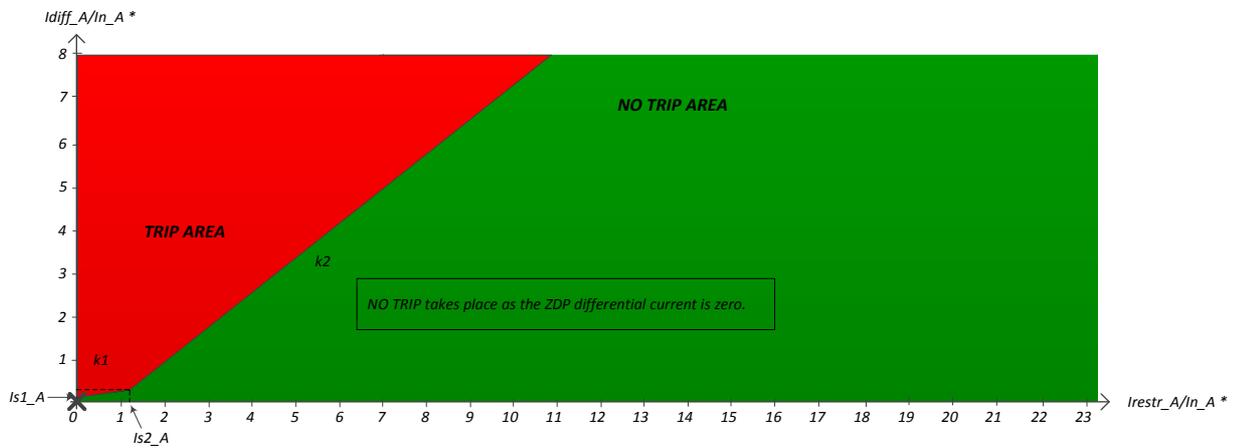
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix B7 – Short-circuit simulation – SP1

[Fault at bus 35 in Zone 3 - Fault on phase = AB – Fault resistance R = 0 ohms]

Zone : 6

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	-0.00+0.00j	-0.00-0.00j	0.00-0.00j
BR6	0.00+0.00j	0.00+0.00j	0.00+0.00j



* In_x is the rated current of the phase x of the current zone. x = A or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

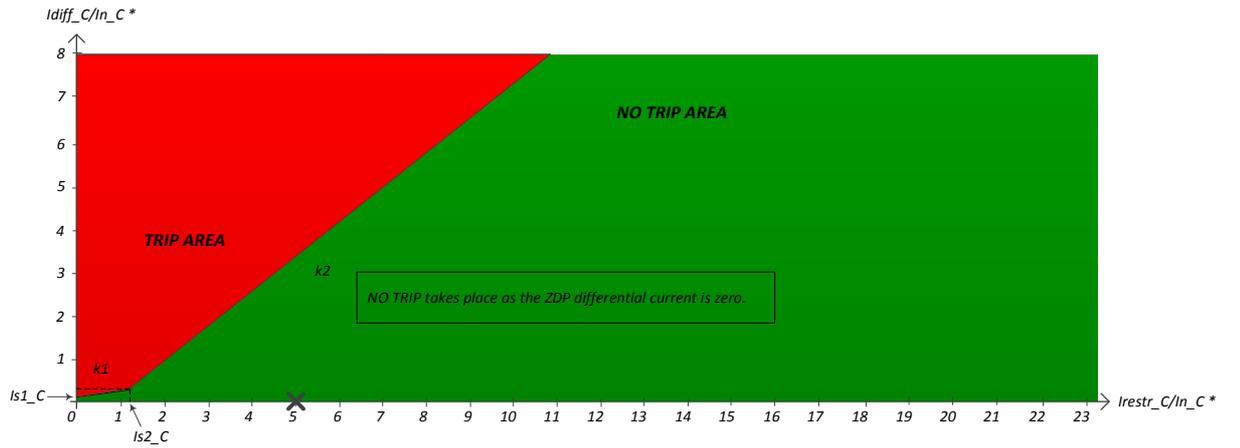
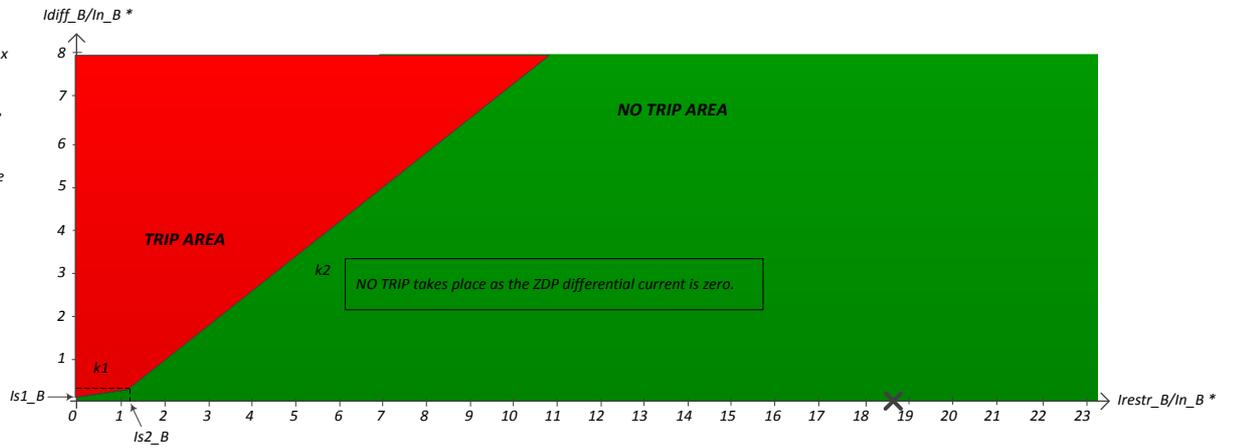
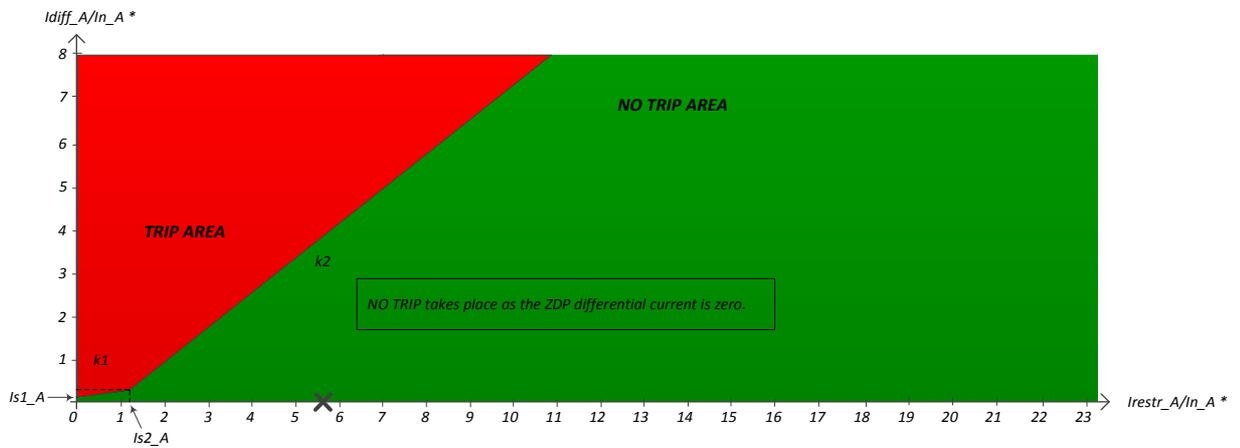
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix B7 – Short-circuit simulation – SP1

[Fault at bus 35 in Zone 3 - Fault on phase = AB – Fault resistance R = 50 ohms]

Zone : 1

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	38.04-79.06j	8.71+24.95j	46.91+94.28j
BR1	297.55-367.30j	-323.97-38.82j	108.94+352.17j
BR2	-159.18+142.51j	155.76+59.76j	-6.18-176.71j
BR3	-100.32+145.70j	176.93+3.98j	-55.85-81.18j



* In_x is the rated current of the phase x of the current zone. x = A or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

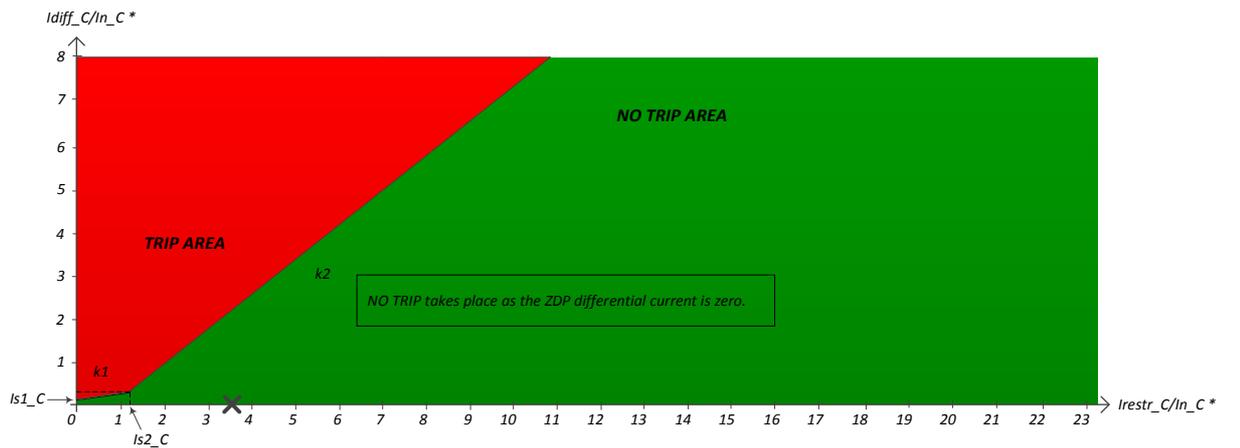
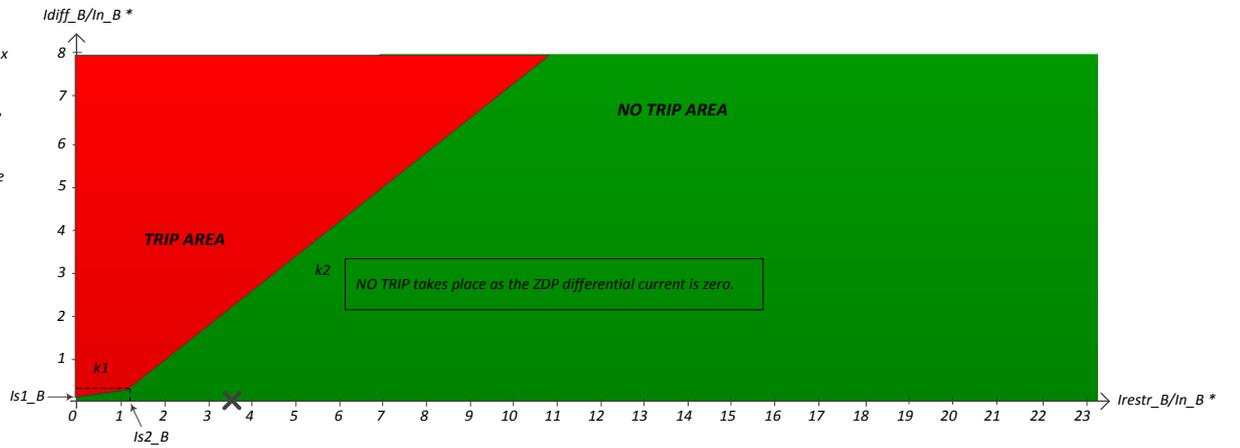
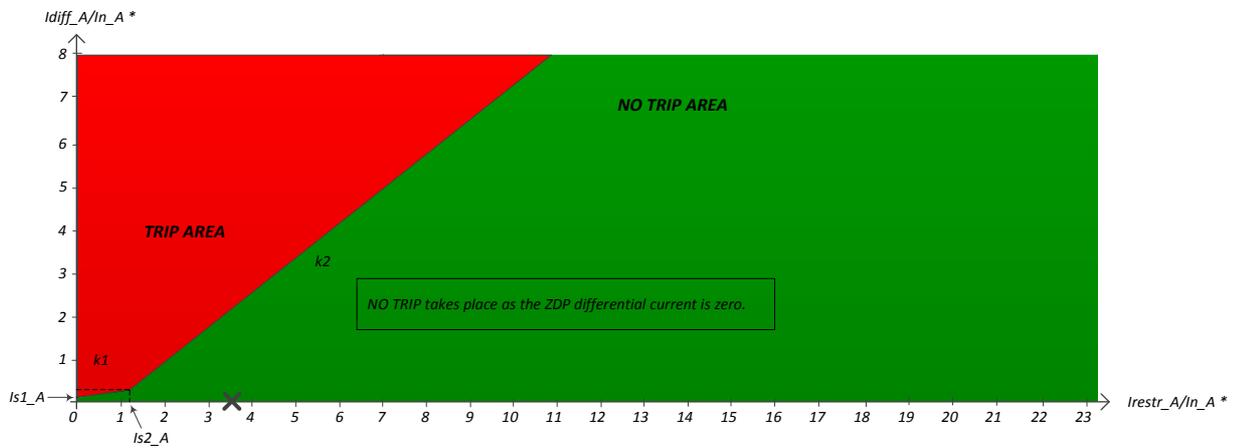
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix B7 – Short-circuit simulation – SP1

[Fault at bus 35 in Zone 3 - Fault on phase = AB – Fault resistance R = 50 ohms]

Zone : 2

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	42.53-92.77j	-79.85+0.67j	38.71+70.43j
BR2	159.18-142.51j	-155.76-59.76j	6.18+176.71j
BR4	-116.63+49.75j	75.94+60.36j	32.48-106.29j
BR6	-0.00-0.00j	-0.00-0.00j	-0.00-0.00j



* In_x is the rated current of the phase x of the current zone. x = A or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

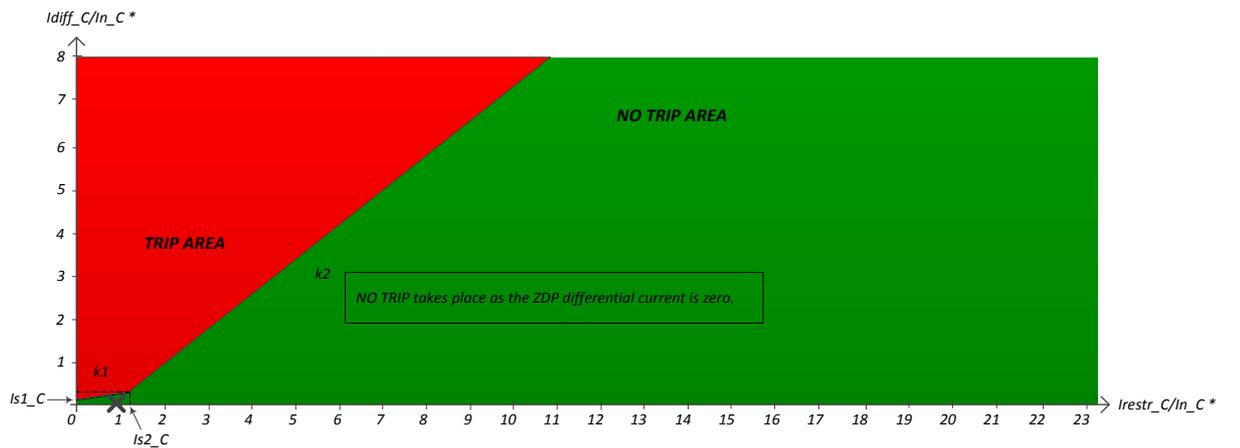
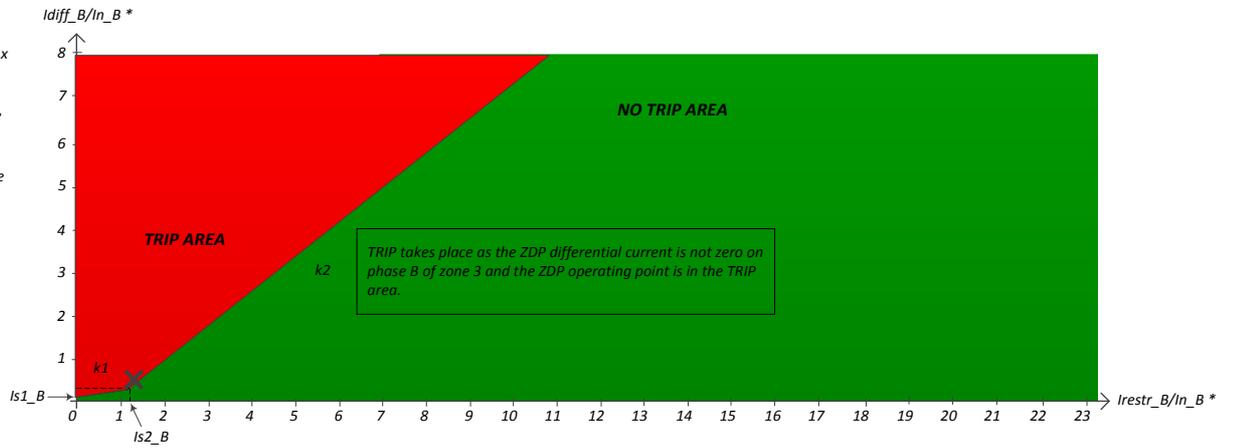
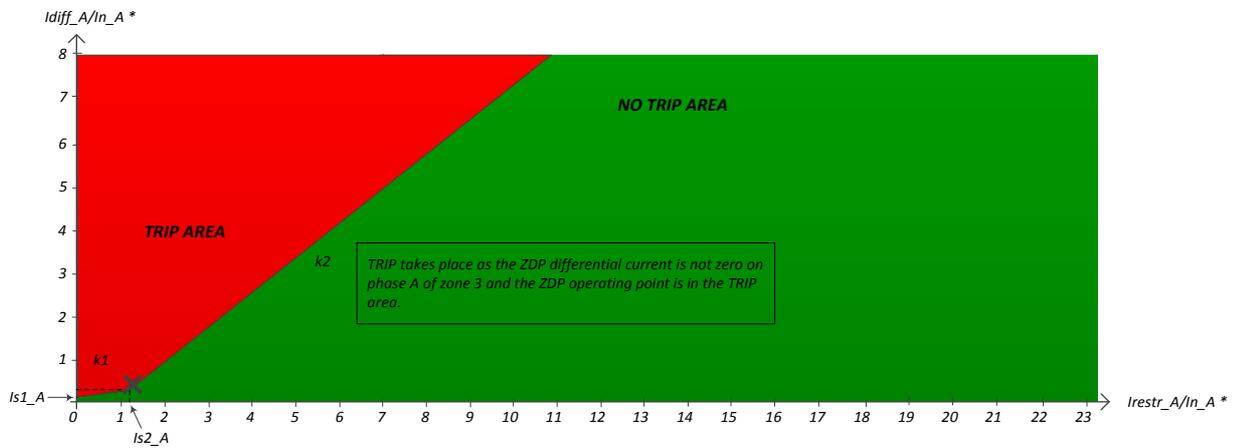
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix B7 – Short-circuit simulation – SP1

[Fault at bus 35 in Zone 3 - Fault on phase = AB – Fault resistance R = 50 ohms]

Zone : 3

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	62.36-120.32j	-135.48+17.68j	55.86+81.17j
BR3	100.32-145.70j	-176.93-3.98j	55.85+81.18j



* In_x is the rated current of the phase x of the current zone. x = A or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

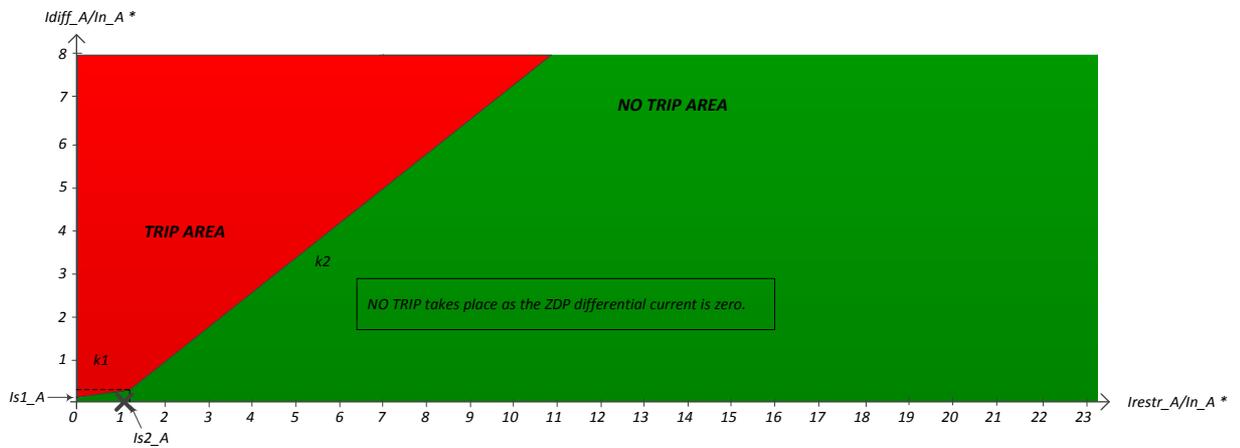
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix B7 – Short-circuit simulation – SP1

[Fault at bus 35 in Zone 3 - Fault on phase = AB – Fault resistance R = 50 ohms]

Zone : 4

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	85.23+7.73j	-37.51-60.00j	-56.74+64.47j
BR4	116.63-49.75j	-75.94-60.36j	-32.48+106.29j
BR5	-31.43+57.47j	38.45+0.29j	-24.27-41.81j



* I_{n_x} is the rated current of the phase x of the current zone. x = A or B or C

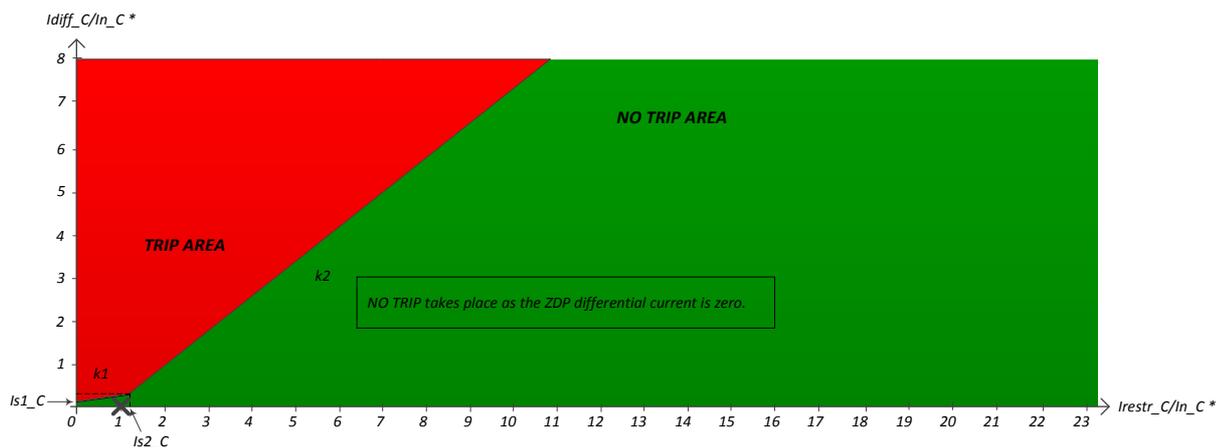
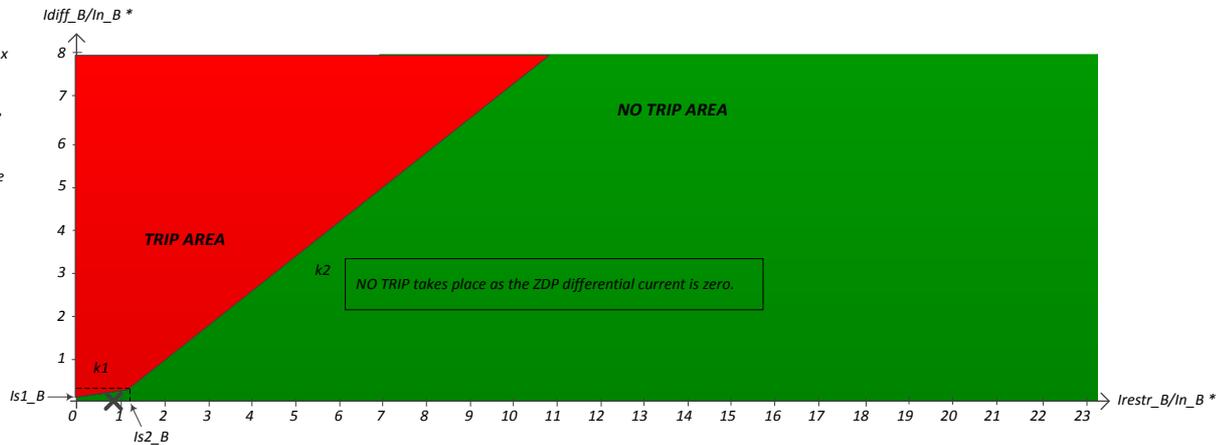
I_{diff_x} is the differential current on the phase x of the current zone.

I_{restr_x} is the restraining current on the phase x of the current zone.

I_{s1_x} is the differential current pick-up setting. It is set to 10% of the phase x rated current.

I_{s2_x} is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

k_1, k_2 : slopes - $k_1=30\%$ & $k_2=80\%$

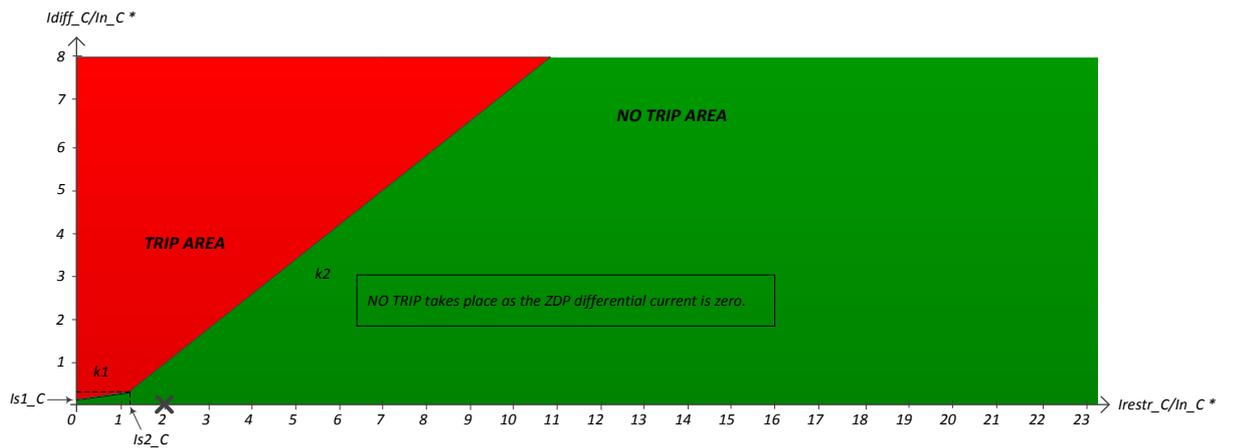
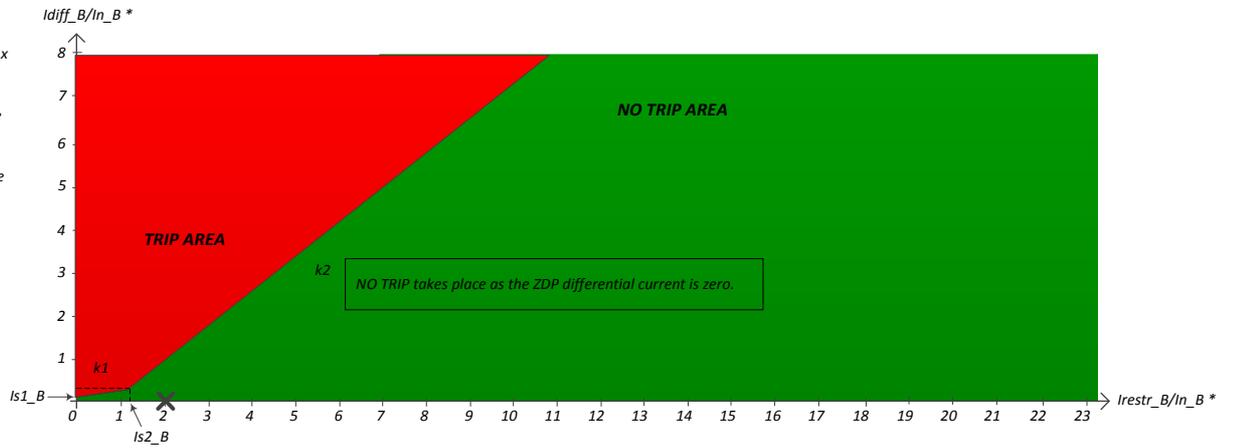
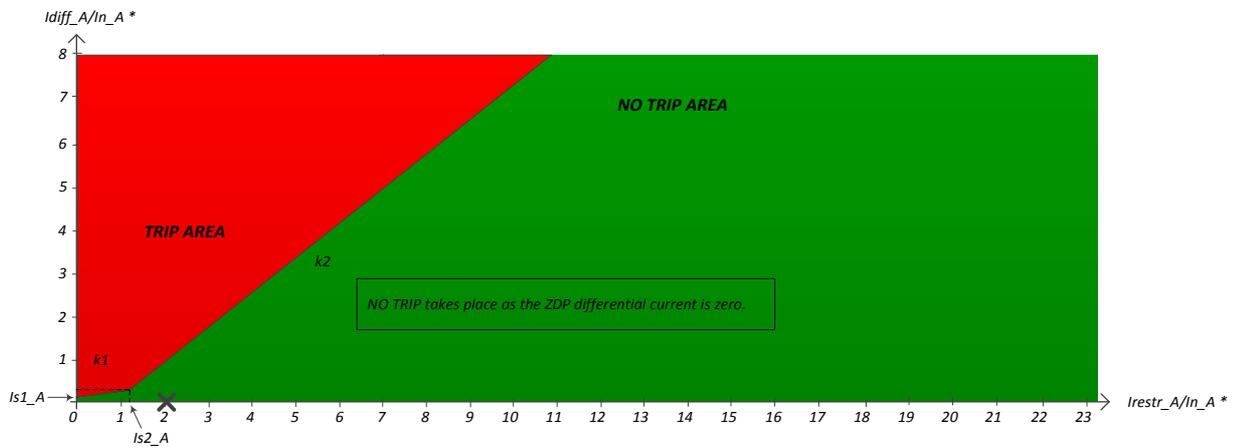


Appendix B7 – Short-circuit simulation – SP1

[Fault at bus 35 in Zone 3 - Fault on phase = AB – Fault resistance R = 50 ohms]

Zone : 5

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	31.44-57.43j	-38.45-0.28j	24.29+41.81j
BR5	31.43-57.47j	-38.45-0.29j	24.27+41.81j



* I_{n_x} is the rated current of the phase x of the current zone. x = A or B or C

I_{diff_x} is the differential current on the phase x of the current zone.

I_{restr_x} is the restraining current on the phase x of the current zone.

I_{s1_x} is the differential current pick-up setting. It is set to 10% of the phase x rated current.

I_{s2_x} is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

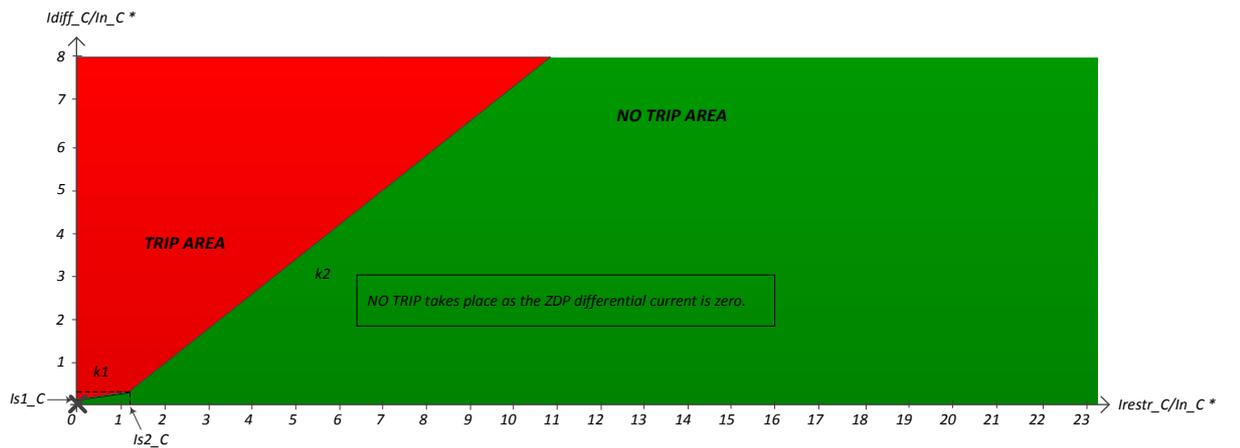
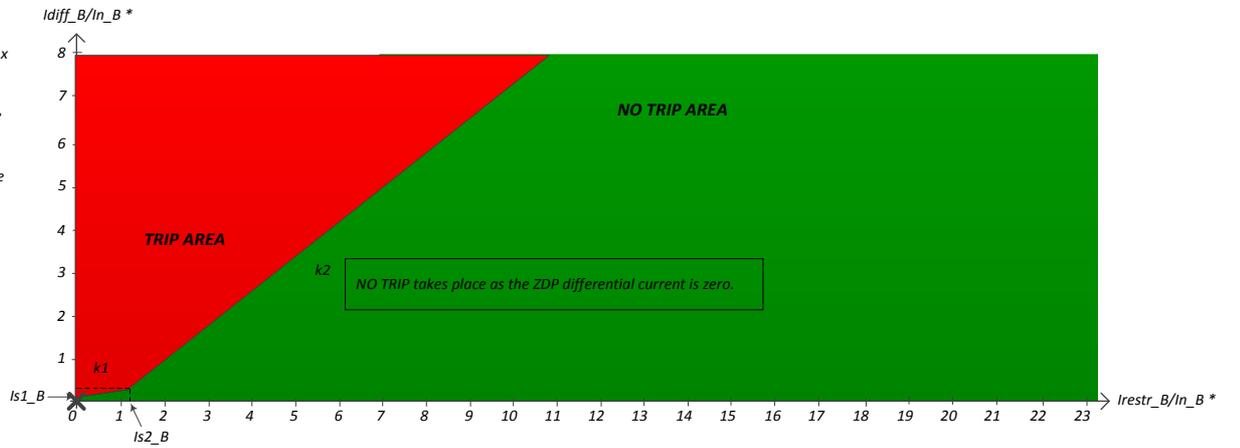
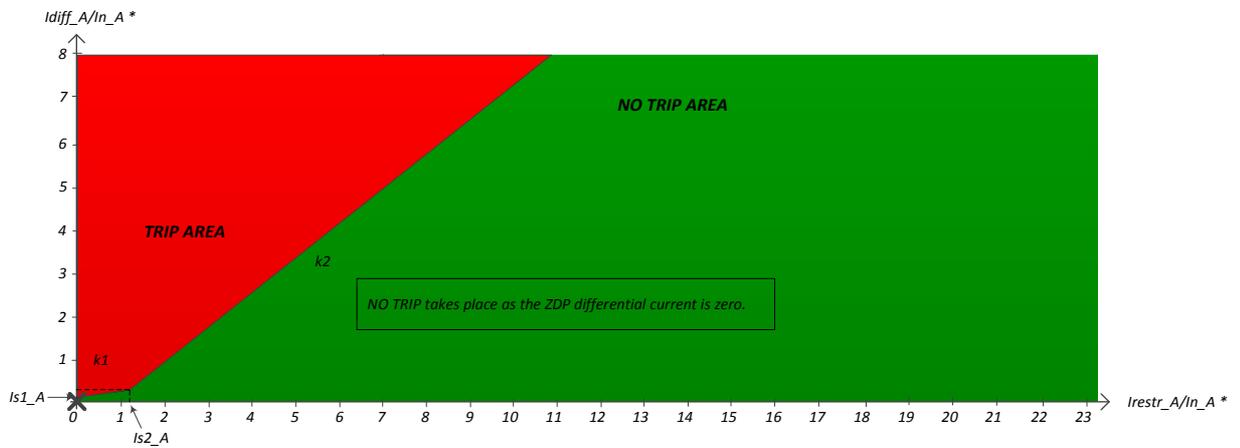
k_1, k_2 : slopes - $k_1=30\%$ & $k_2=80\%$

Appendix B7 – Short-circuit simulation – SP1

[Fault at bus 35 in Zone 3 - Fault on phase = AB – Fault resistance R = 50 ohms]

Zone : 6

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	-0.00+0.00j	-0.00-0.00j	0.00-0.00j
BR6	0.00+0.00j	0.00+0.00j	0.00+0.00j



* In_x is the rated current of the phase x of the current zone. x = A or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

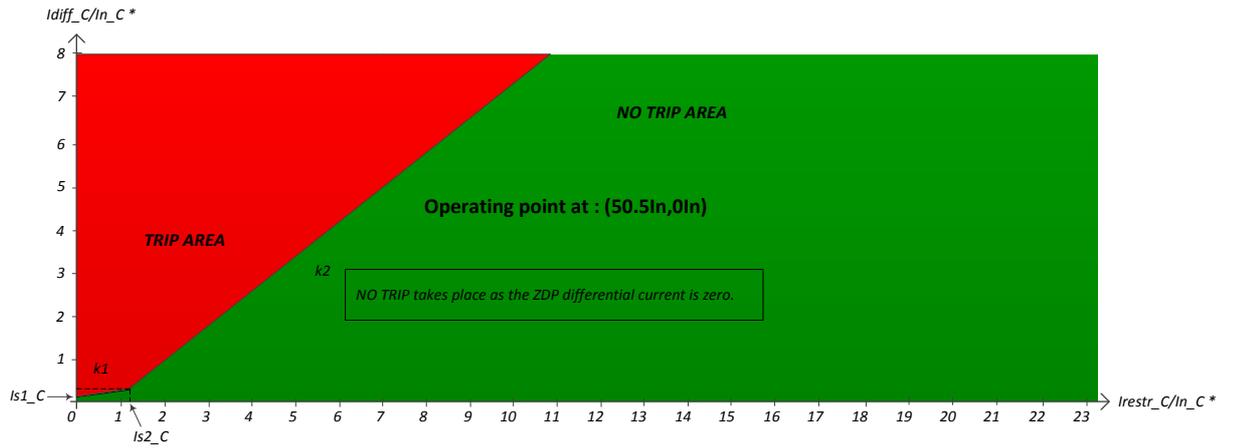
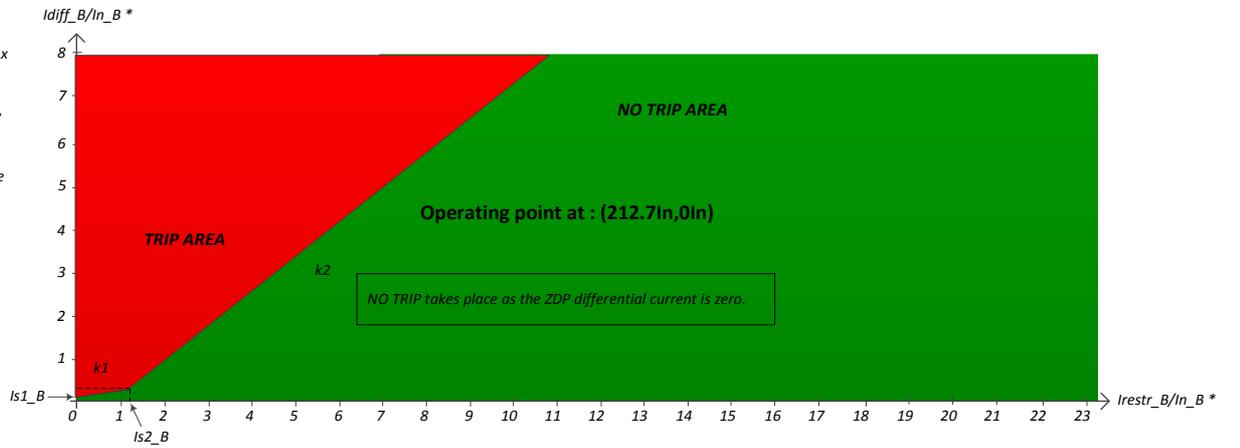
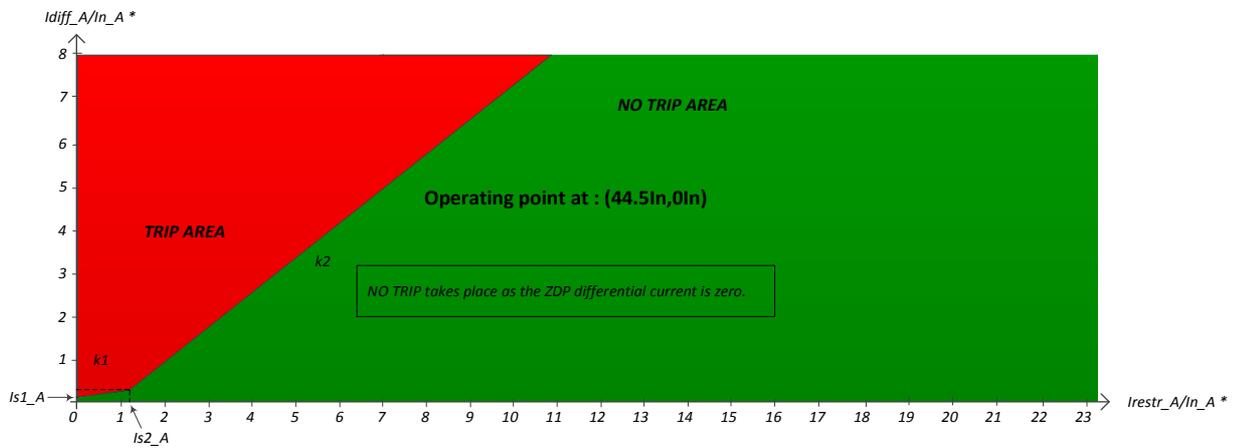
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix B7 – Short-circuit simulation – SP1

[Fault at bus 61s in Zone 6 - Fault on phase = ABC – Fault resistance R = 0 ohms]

Zone : 1

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	39.89+103.13j	135.42-74.97j	-114.70-15.27j
BR1	-446.33-3582.03j	-2888.32+2453.72j	3455.00+1137.01j
BR2	515.46+3622.56j	2954.40-2514.04j	-3539.25-1113.74j
BR3	-29.23+62.63j	69.34-14.65j	-30.47-38.53j



* In_x is the rated current of the phase x of the current zone. x = A or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

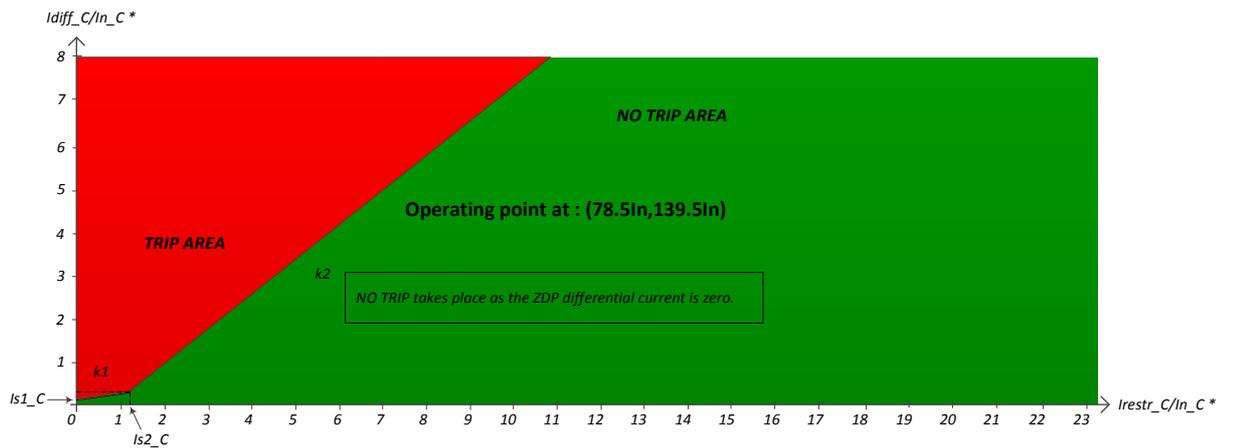
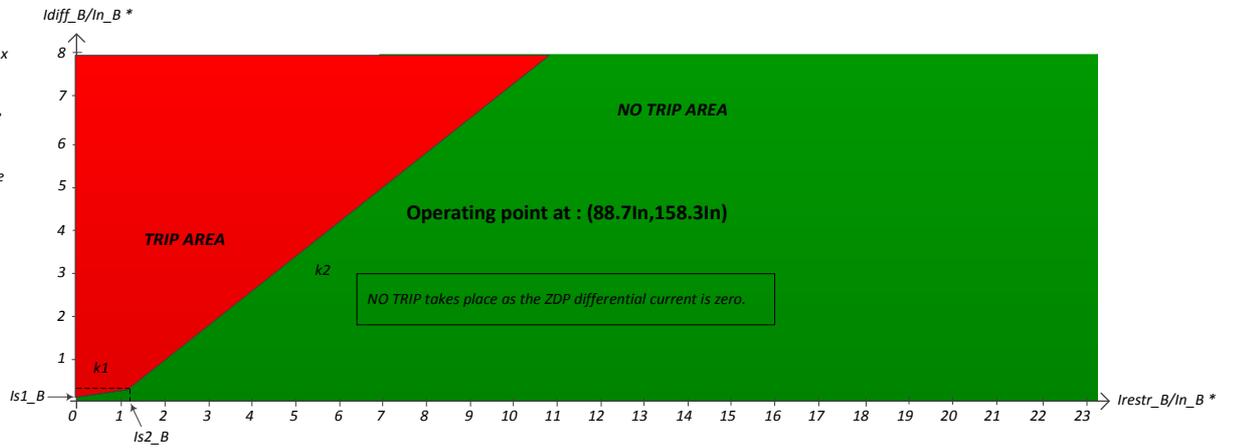
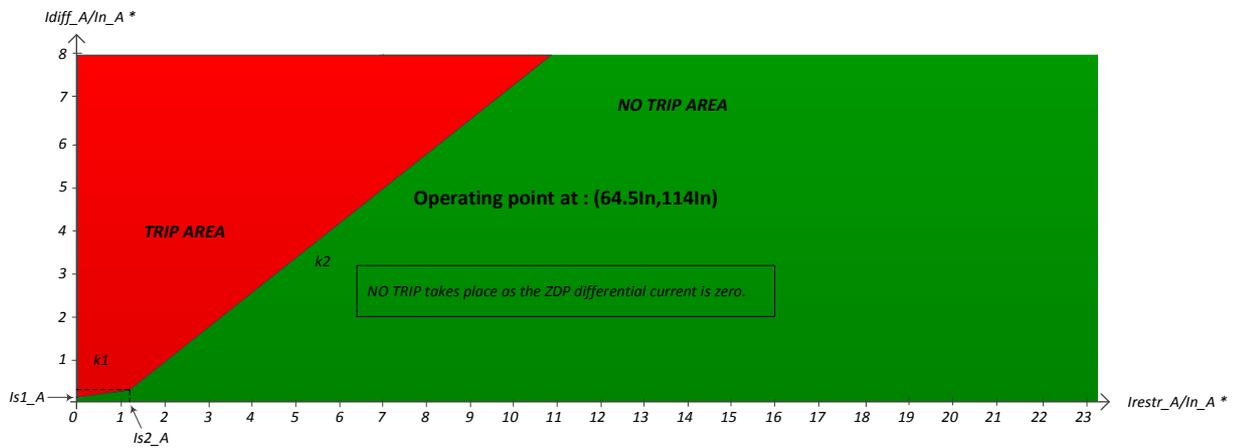
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix B7 – Short-circuit simulation – SP1

[Fault at bus 61s in Zone 6 - Fault on phase = ABC – Fault resistance R = 0 ohms]

Zone : 2

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	10.46-22.32j	-15.55+0.37j	6.10+9.16j
BR2	-492.95-4057.64j	-3347.22+2723.46j	3911.34+1370.35j
BR4	-32.97+457.39j	408.38-209.79j	-378.18-265.76j
BR6	-515.46-3622.56j	-2954.40+2514.04j	3539.25+1113.74j



* In_x is the rated current of the phase x of the current zone. x = A or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

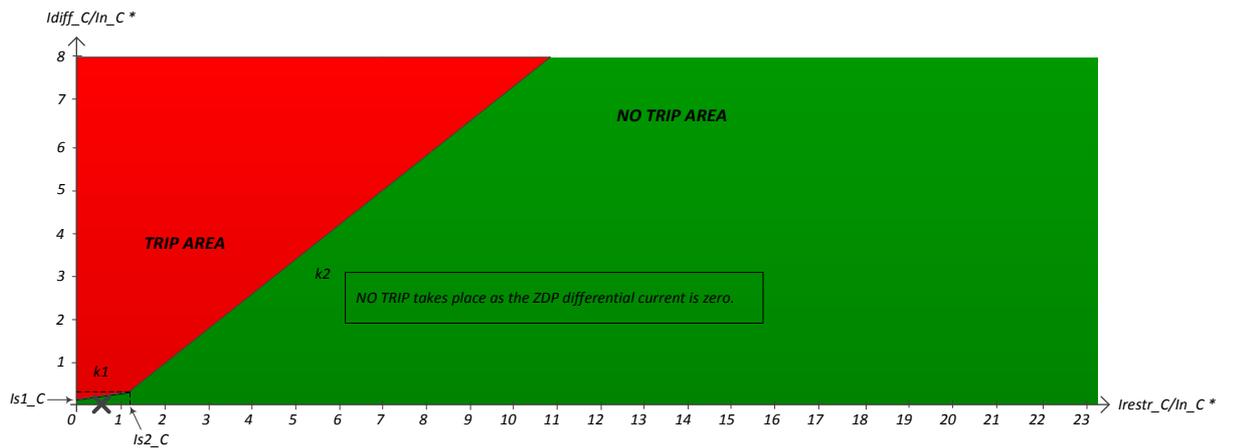
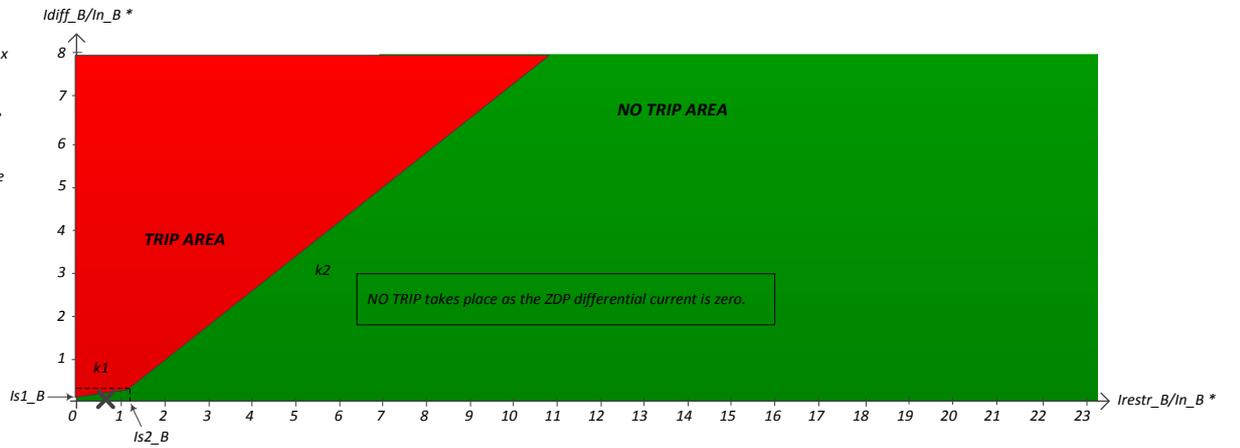
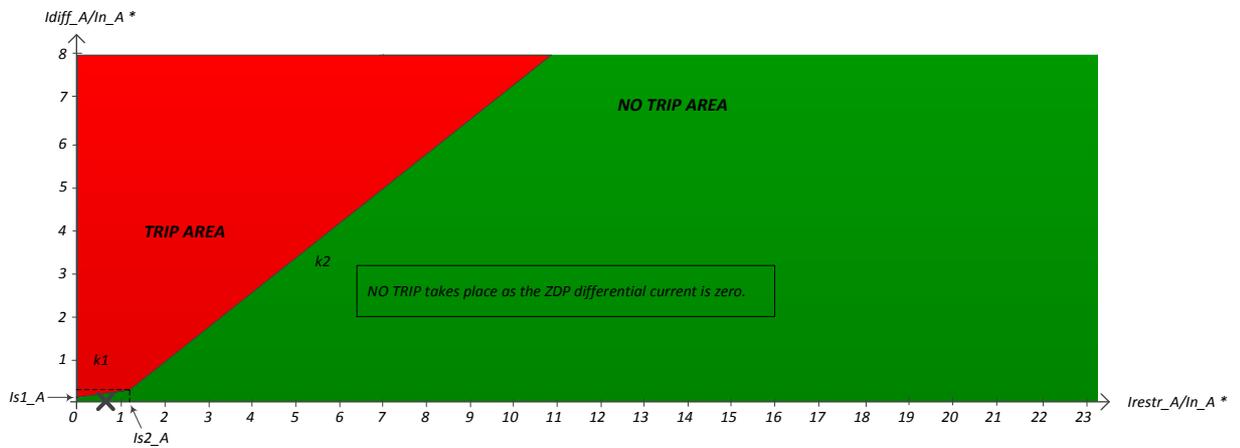
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix B7 – Short-circuit simulation – SP1

[Fault at bus 61s in Zone 6 - Fault on phase = ABC – Fault resistance R = 0 ohms]

Zone : 3

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	29.23-62.66j	-69.33+14.65j	30.46+38.54j
BR3	29.23-62.63j	-69.34+14.65j	30.47+38.53j



* In_x is the rated current of the phase x of the current zone. x = A or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

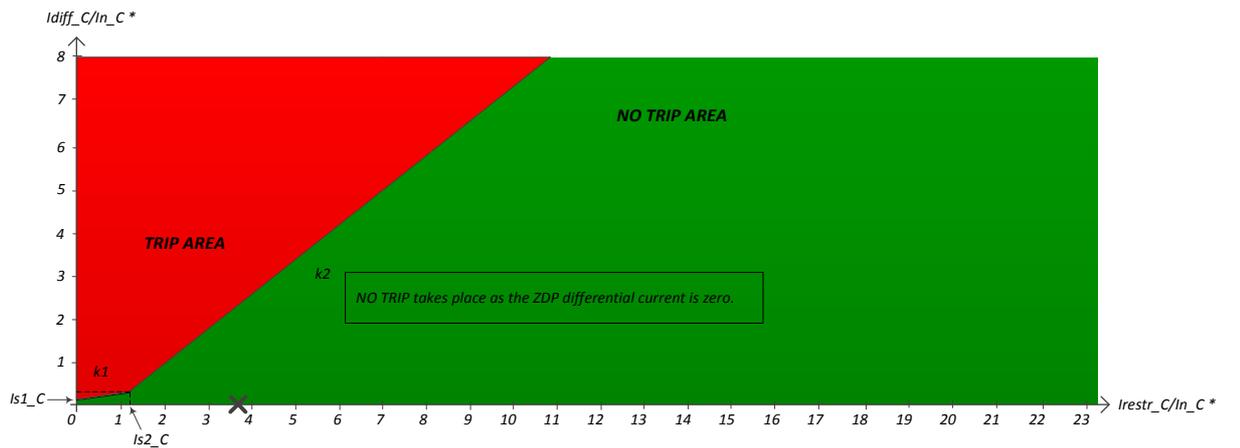
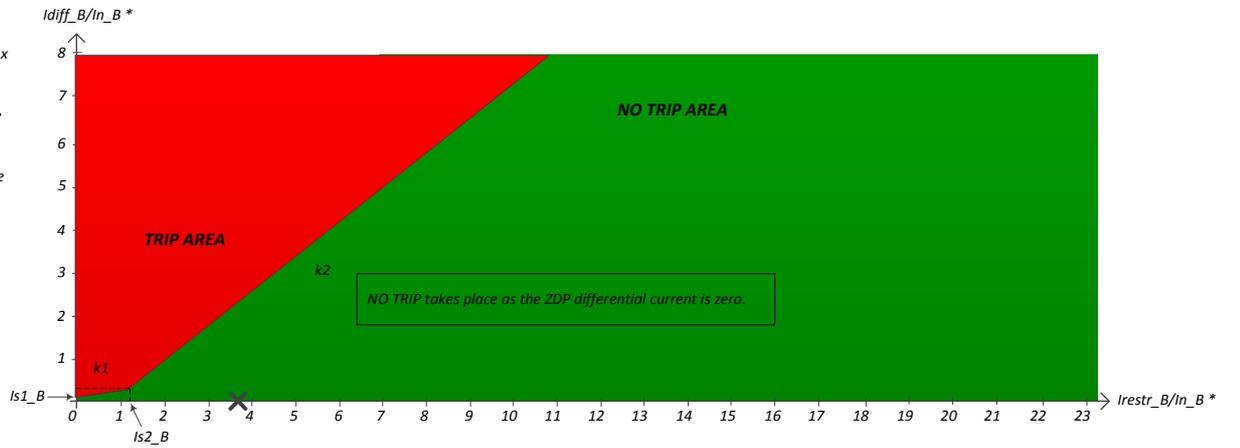
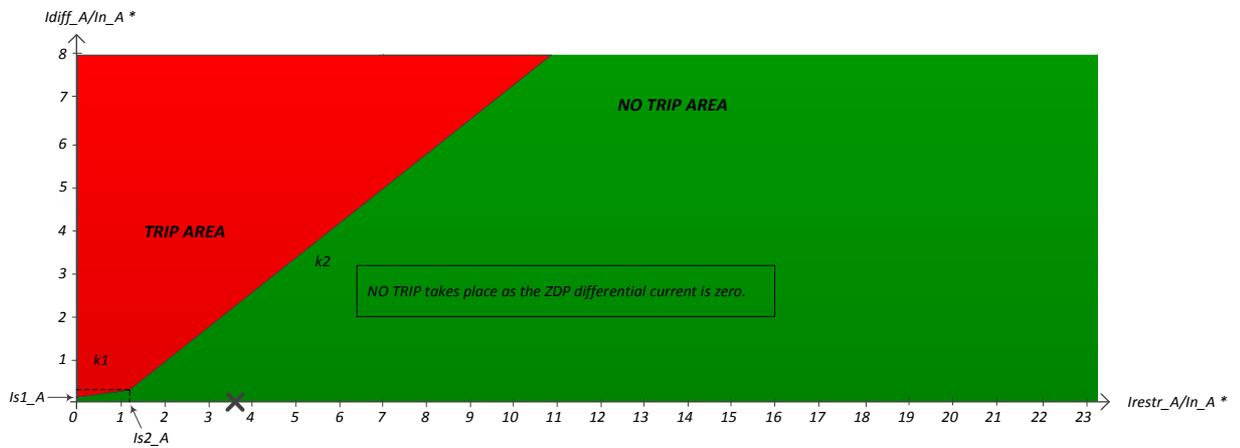
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix B7 – Short-circuit simulation – SP1

[Fault at bus 61s in Zone 6 - Fault on phase = ABC – Fault resistance R = 0 ohms]

Zone : 4

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	-36.52+465.27j	413.50-209.41j	-382.08-271.40j
BR4	-32.97+457.39j	408.38-209.79j	-378.18-265.76j
BR5	-3.54+7.87j	5.12+0.38j	-3.91-5.63j



* In_x is the rated current of the phase x of the current zone. x = A or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

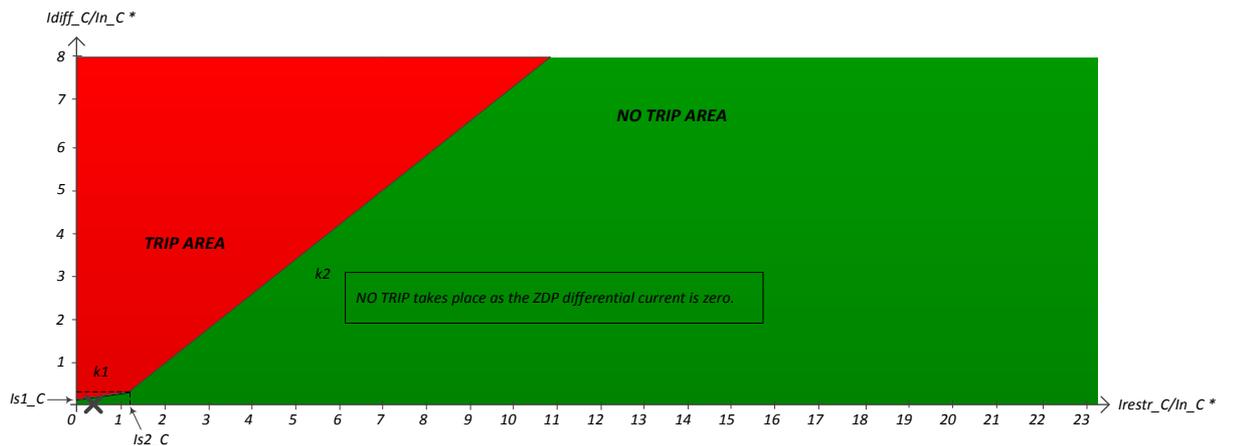
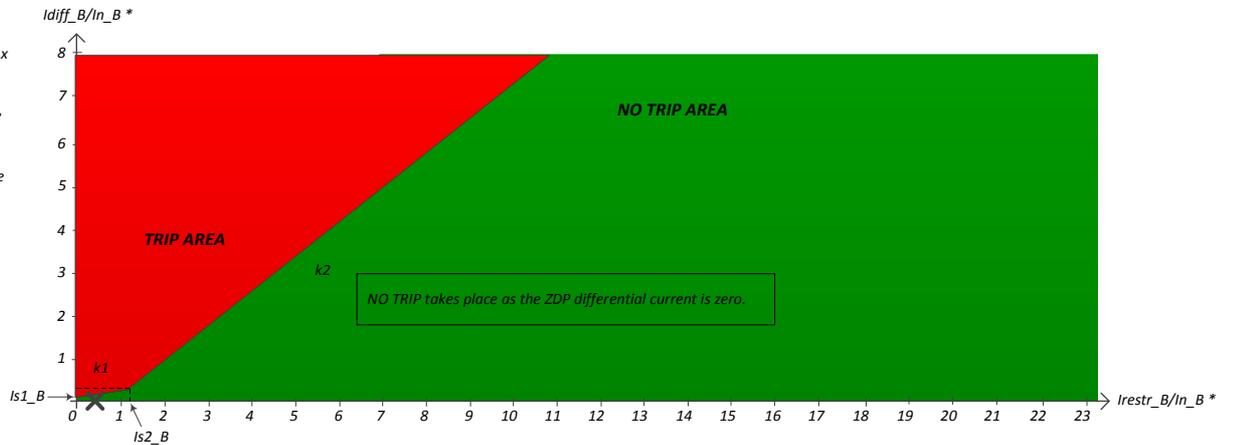
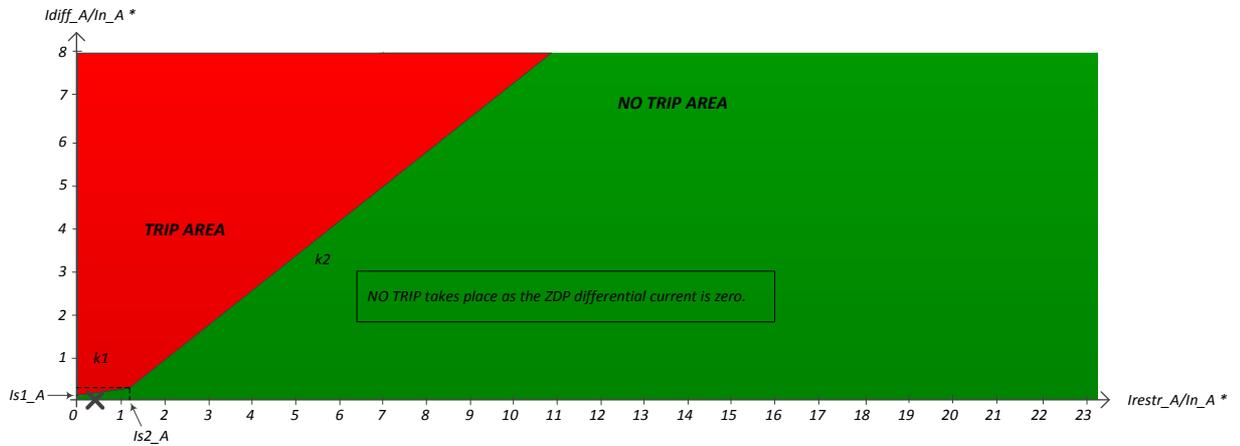
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix B7 – Short-circuit simulation – SP1

[Fault at bus 61s in Zone 6 - Fault on phase = ABC – Fault resistance R = 0 ohms]

Zone : 5

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	3.55-7.86j	-5.12-0.38j	3.91+5.63j
BR5	3.54-7.87j	-5.12-0.38j	3.91+5.63j



* In_x is the rated current of the phase x of the current zone. x = A or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

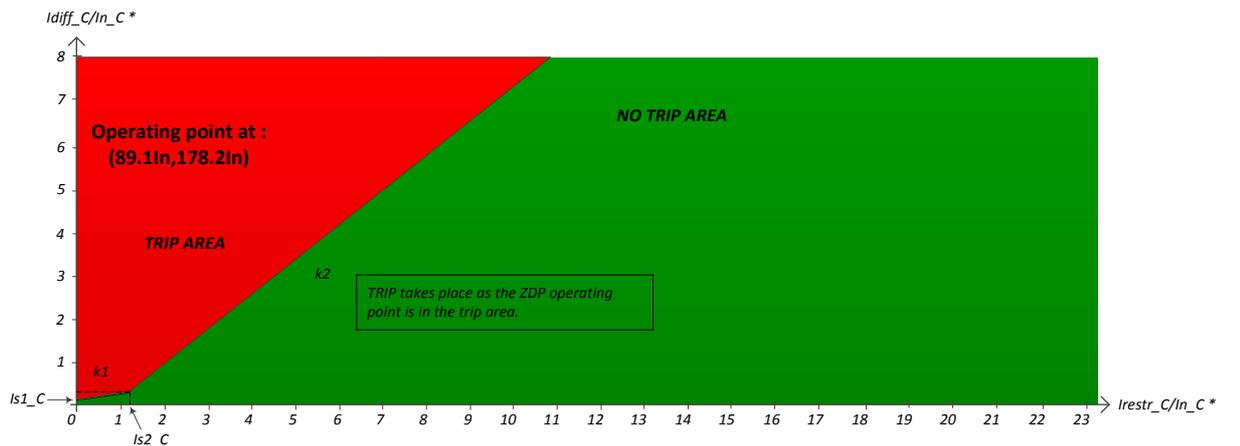
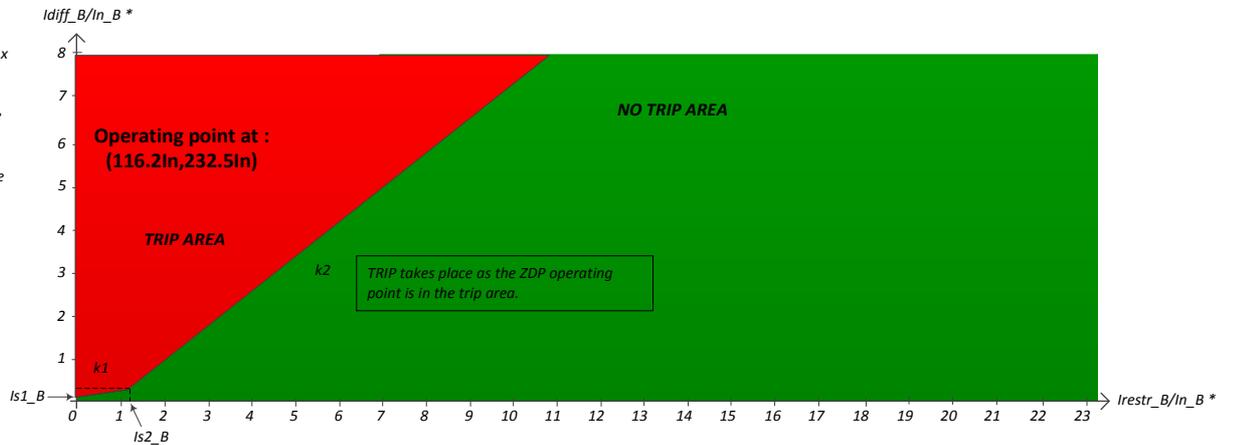
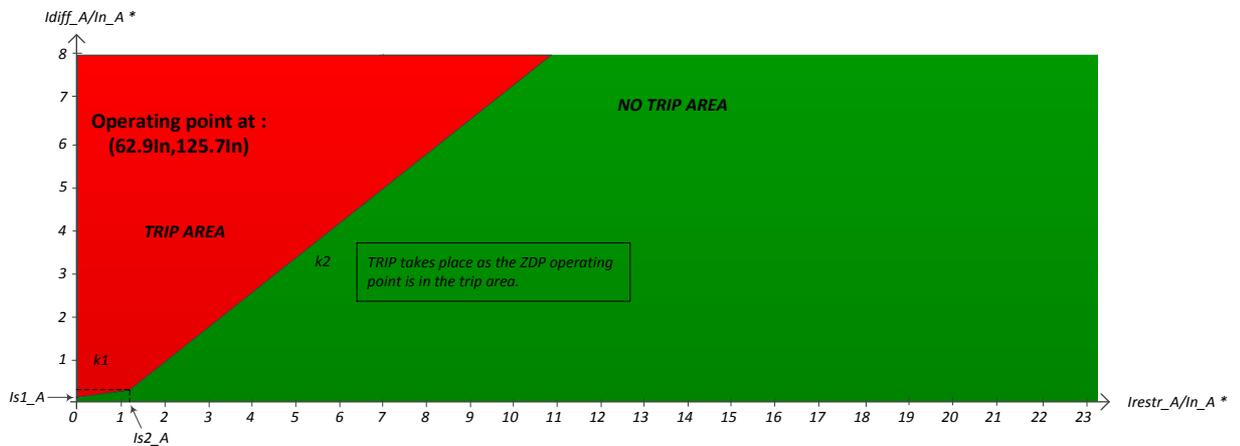
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix B7 – Short-circuit simulation – SP1

[Fault at bus 61s in Zone 6 - Fault on phase = ABC – Fault resistance R = 0 ohms]

Zone : 6

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	-0.00+0.00j	-0.00-0.00j	0.00-0.00j
BR6	-492.95-4057.64j	-3347.22+2723.46j	3911.34+1370.35j



* In_x is the rated current of the phase x of the current zone. x = A or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

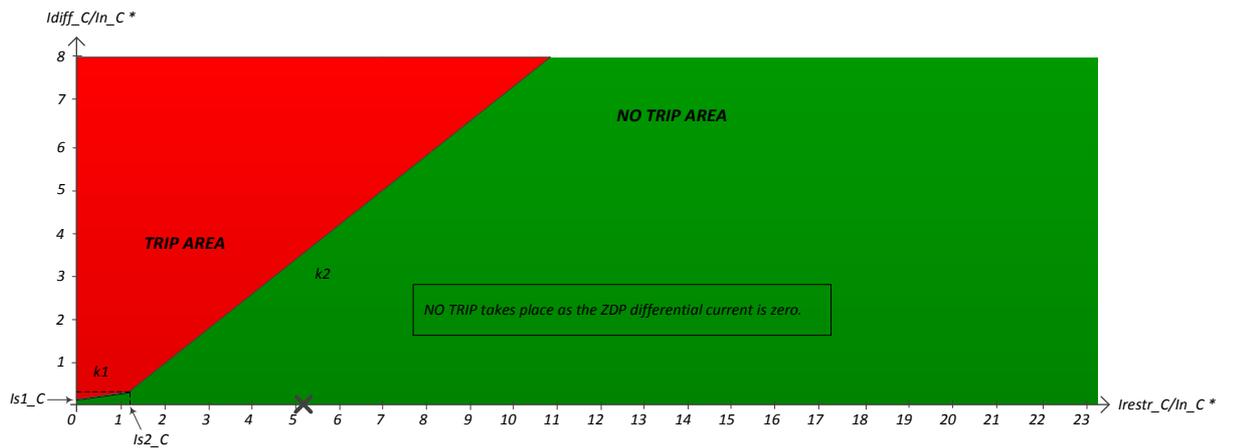
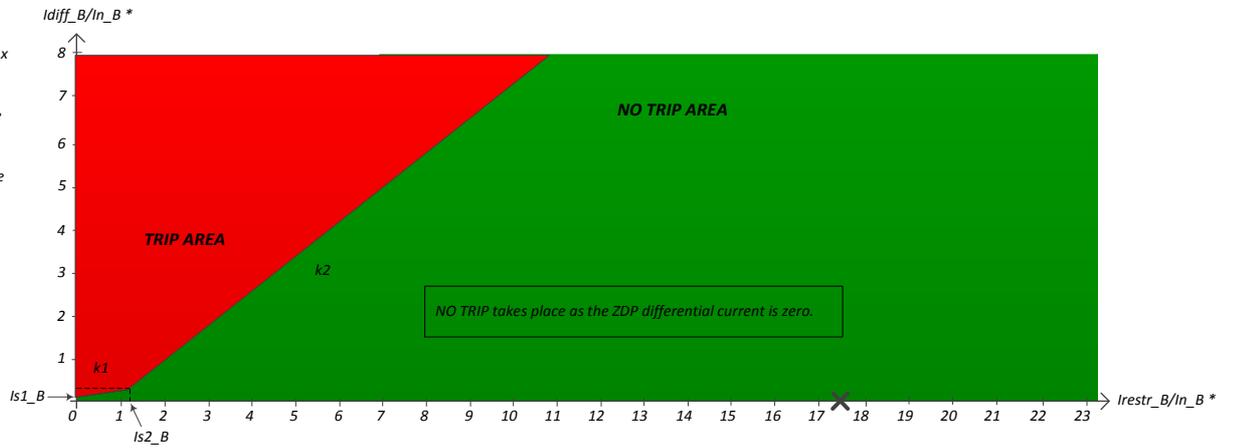
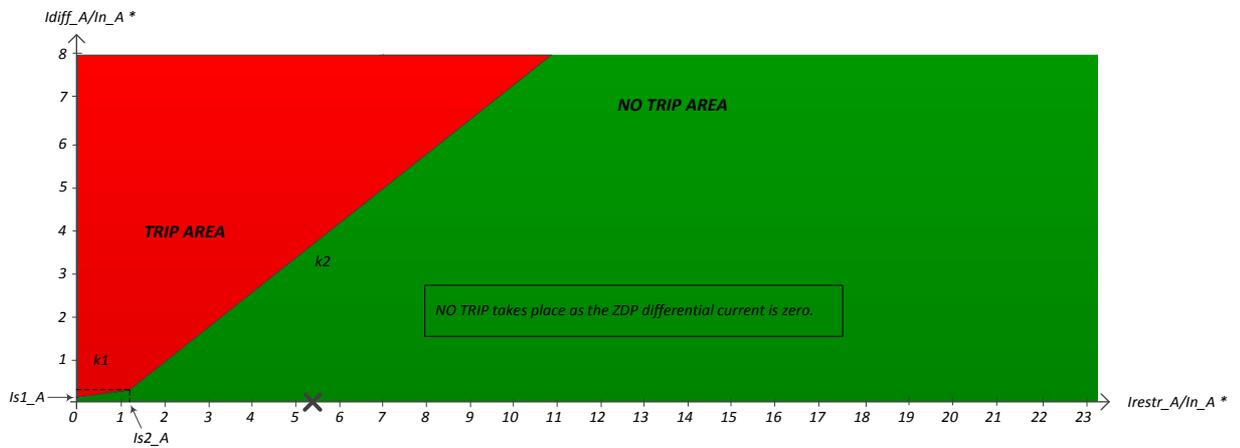
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix B7 – Short-circuit simulation – SP1

[Fault at bus 78 in Zone 4 - Fault on phase = BC – Fault resistance R = 100 ohms]

Zone : 1

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	37.89-85.28j	7.55+20.25j	46.28+86.00j
BR1	267.16-352.97j	-301.39-37.52j	112.46+360.90j
BR2	-165.76+147.38j	173.37+74.45j	-10.09-193.91j
BR3	-63.51+120.28j	135.56-16.71j	-56.11-81.02j



* In_x is the rated current of the phase x of the current zone. x = A or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

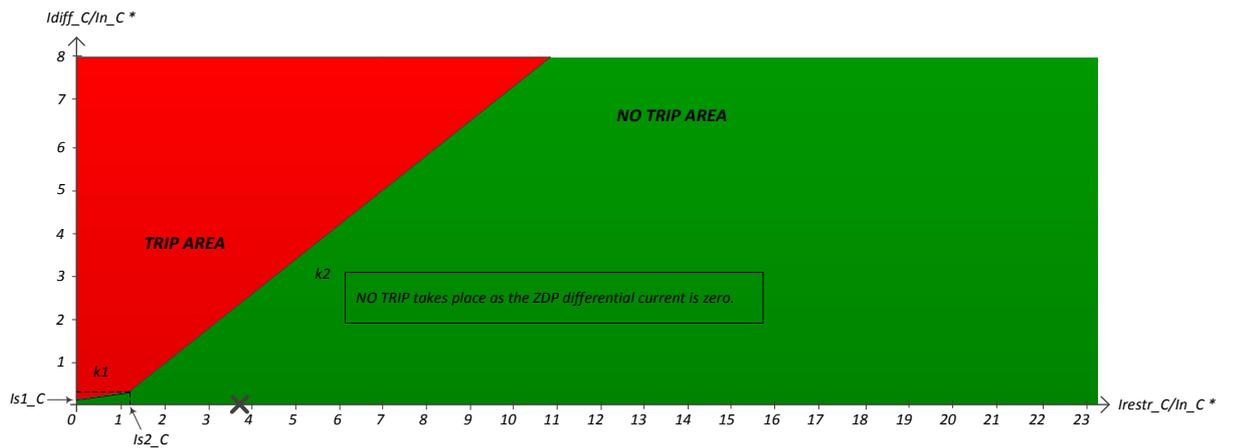
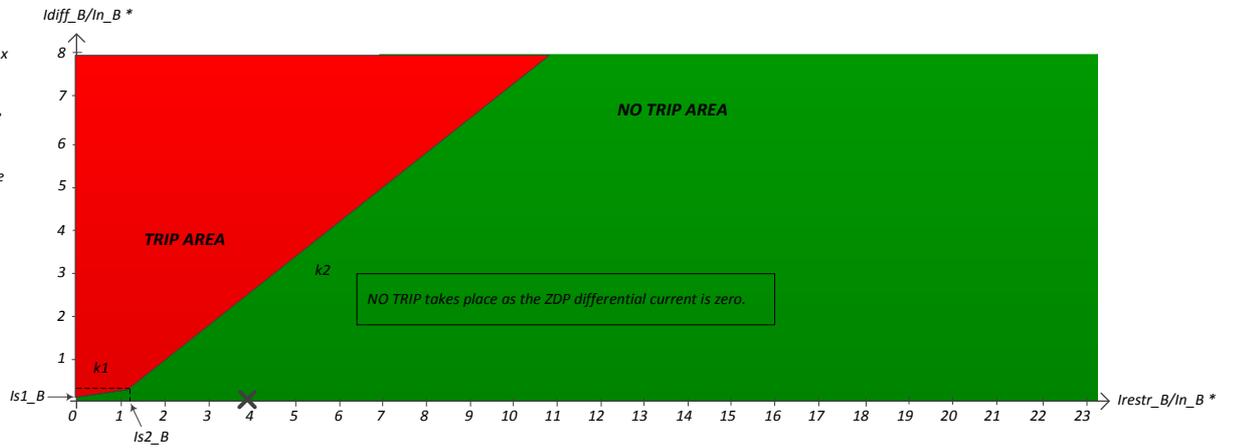
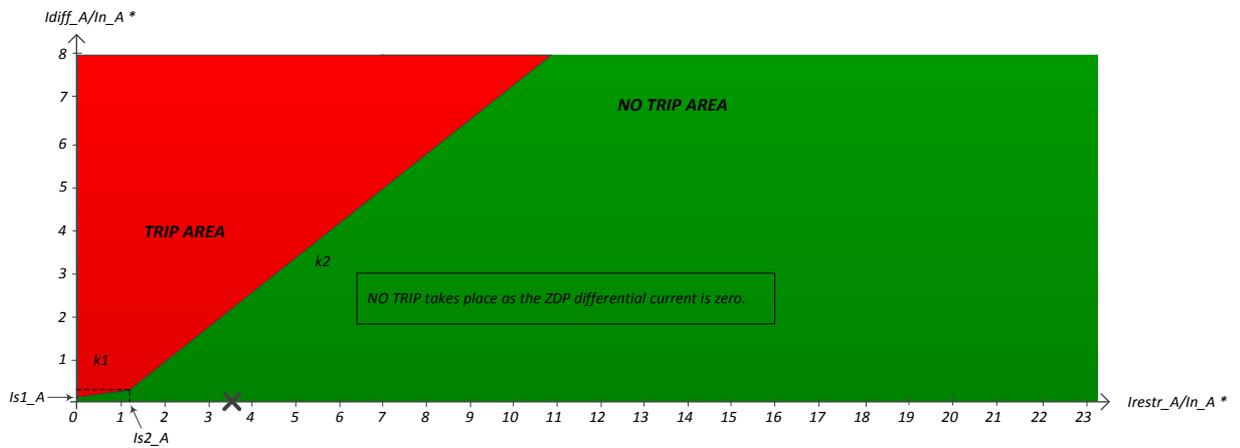
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix B7 – Short-circuit simulation – SP1

[Fault at bus 78 in Zone 4 - Fault on phase = BC – Fault resistance R = 100 ohms]

Zone : 2

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	42.90-92.47j	-79.88+0.62j	38.87+70.28j
BR2	165.76-147.38j	-173.37-74.45j	10.09+193.91j
BR4	-122.84+54.91j	93.52+75.01j	28.73-123.62j
BR6	-0.00-0.00j	-0.00-0.00j	-0.00-0.00j



* In_x is the rated current of the phase x of the current zone. x = A or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

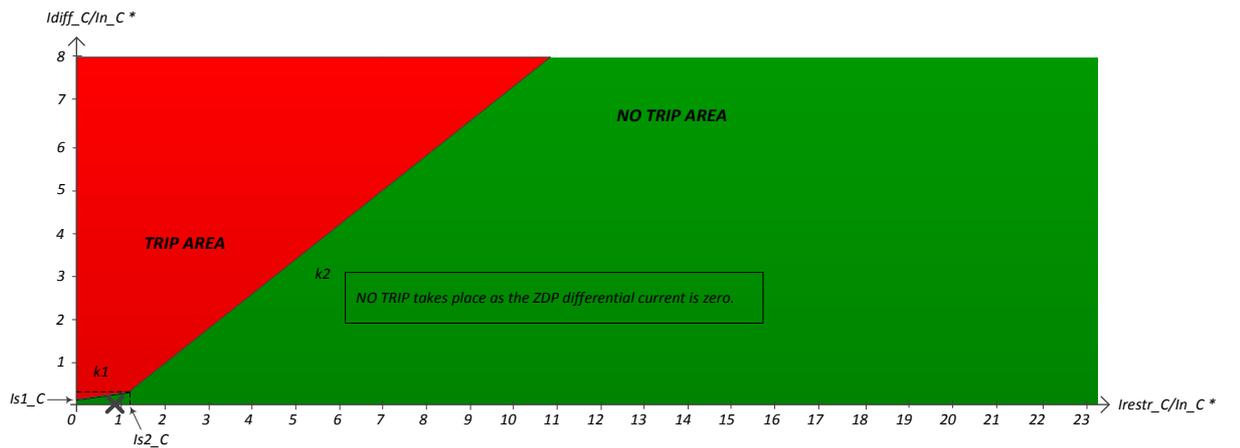
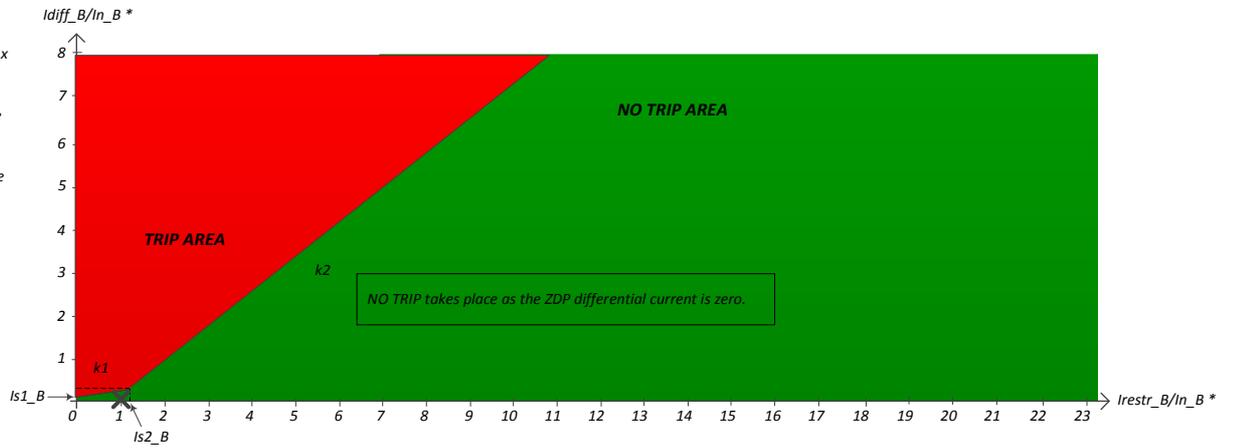
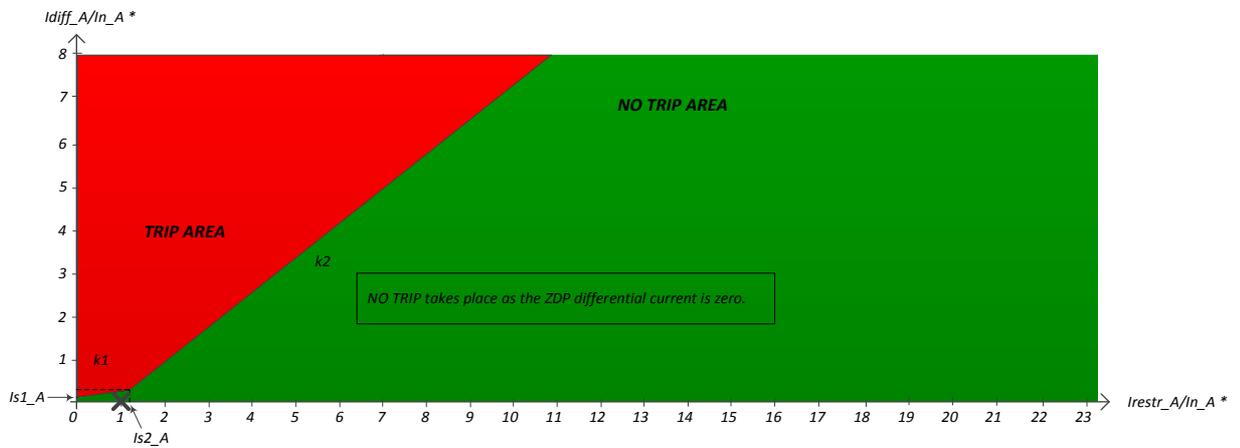
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix B7 – Short-circuit simulation – SP1

[Fault at bus 78 in Zone 4 - Fault on phase = BC – Fault resistance R = 100 ohms]

Zone : 3

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	63.50-120.26j	-135.55+16.74j	56.11+81.01j
BR3	63.51-120.28j	-135.56+16.71j	56.11+81.02j



* In_x is the rated current of the phase x of the current zone. x = A or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

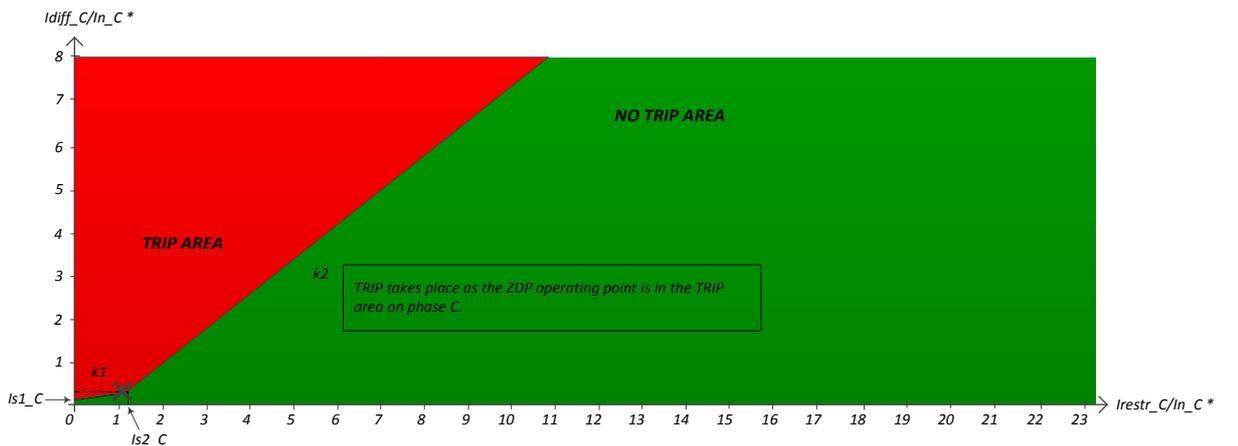
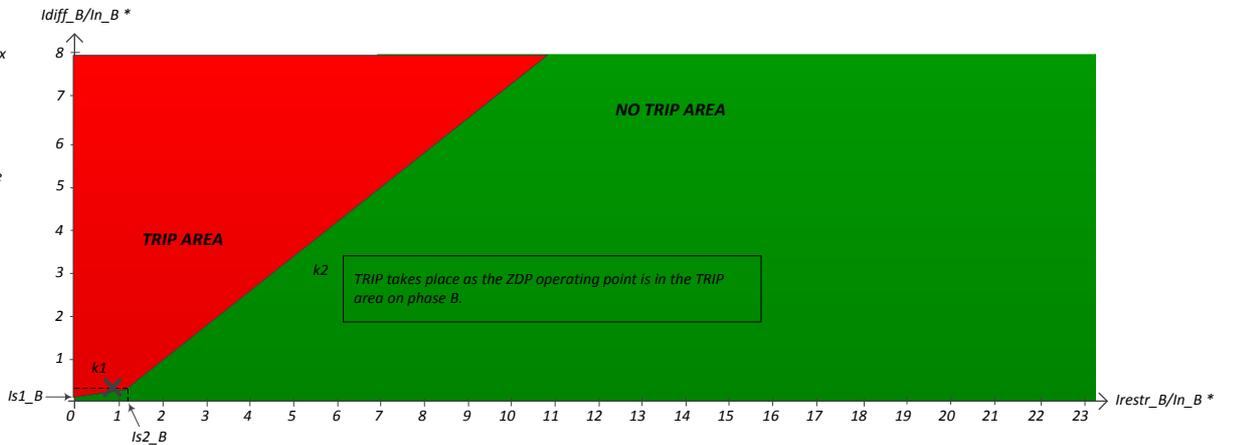
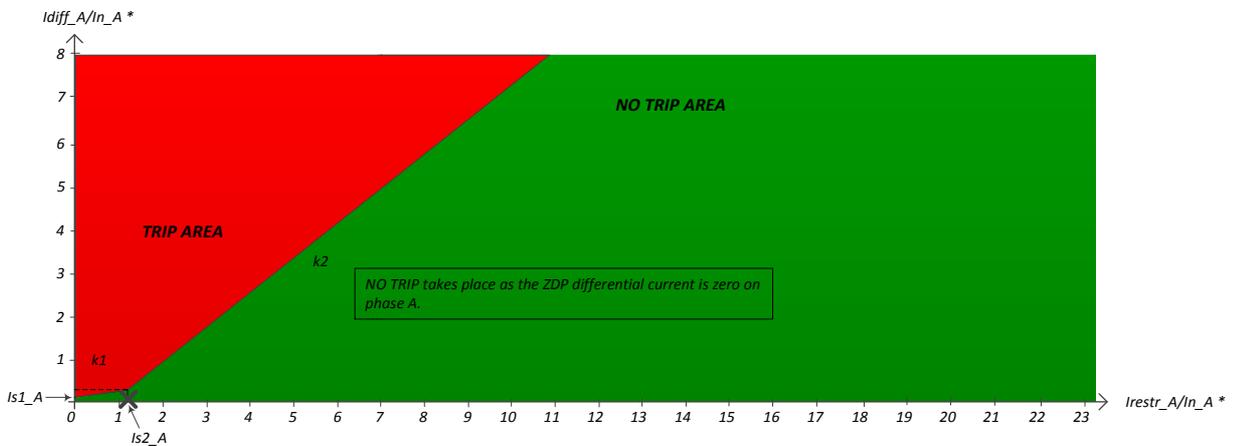
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix B7 – Short-circuit simulation – SP1

[Fault at bus 78 in Zone 4 - Fault on phase = BC – Fault resistance R = 100 ohms]

Zone : 4

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	91.13+2.48j	-34.26-64.08j	-54.78+58.54j
BR4	122.84-54.91j	-93.52-75.01j	-28.73+123.62j
BR5	-31.72+57.35j	38.46+0.28j	-24.47-41.78j



* In_x is the rated current of the phase x of the current zone. x = A or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

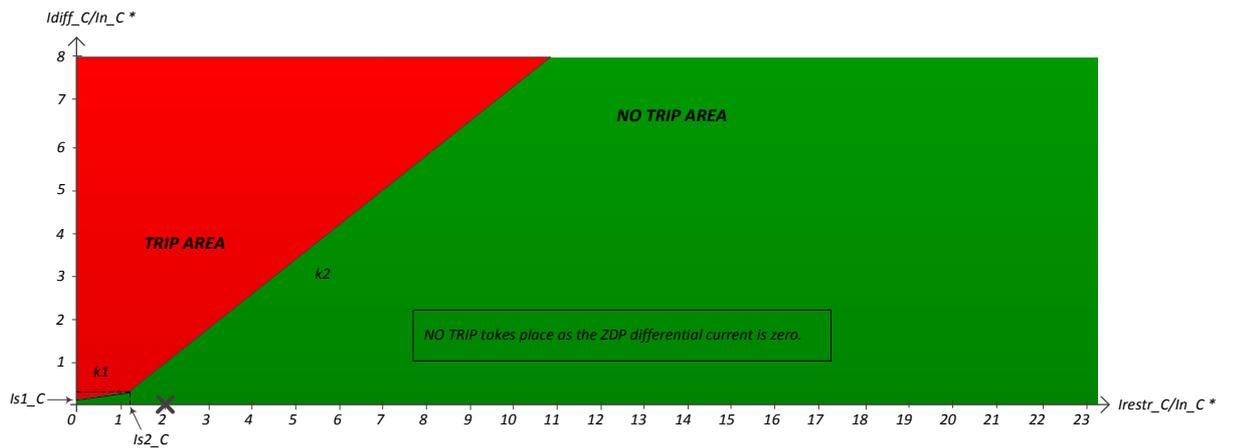
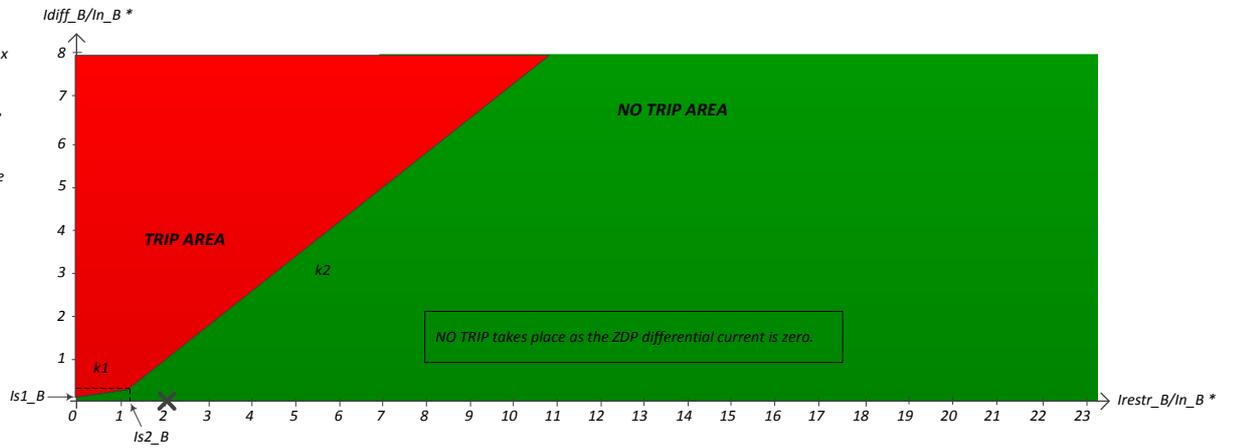
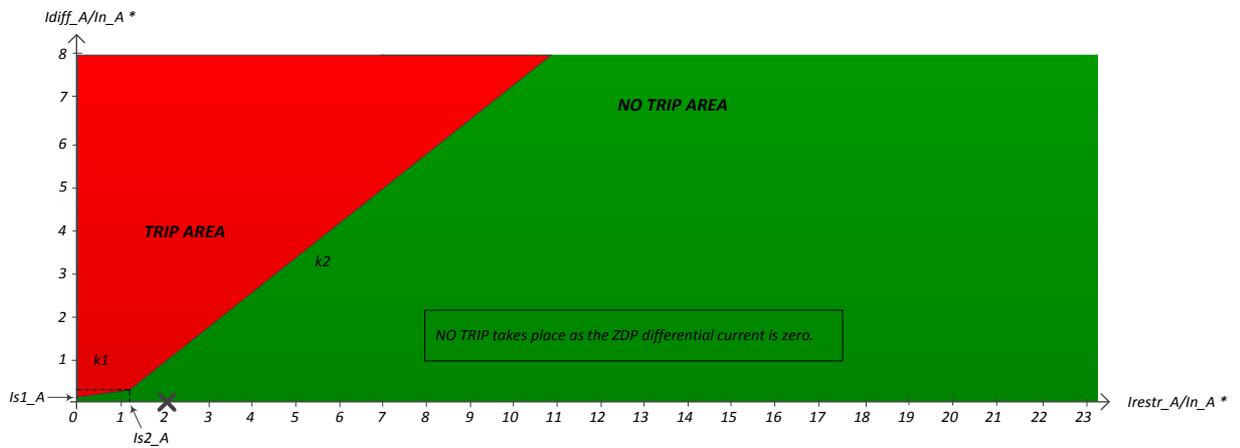
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix B7 – Short-circuit simulation – SP1

[Fault at bus 78 in Zone 4 - Fault on phase = BC – Fault resistance R = 100 ohms]

Zone : 5

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	31.71-57.34j	-38.48-0.26j	24.49+41.78j
BR5	31.72-57.35j	-38.46-0.28j	24.47+41.78j



* In_x is the rated current of the phase x of the current zone. x = A or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

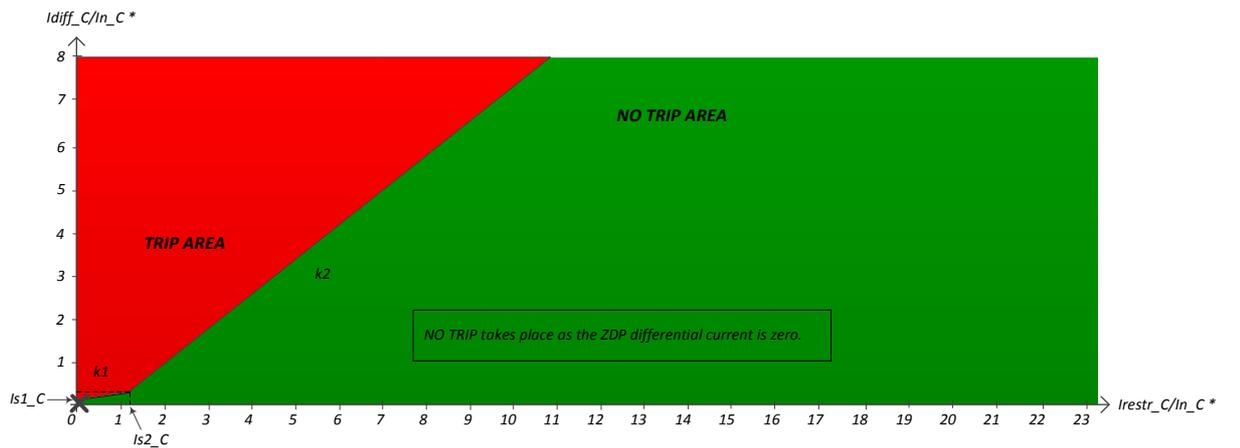
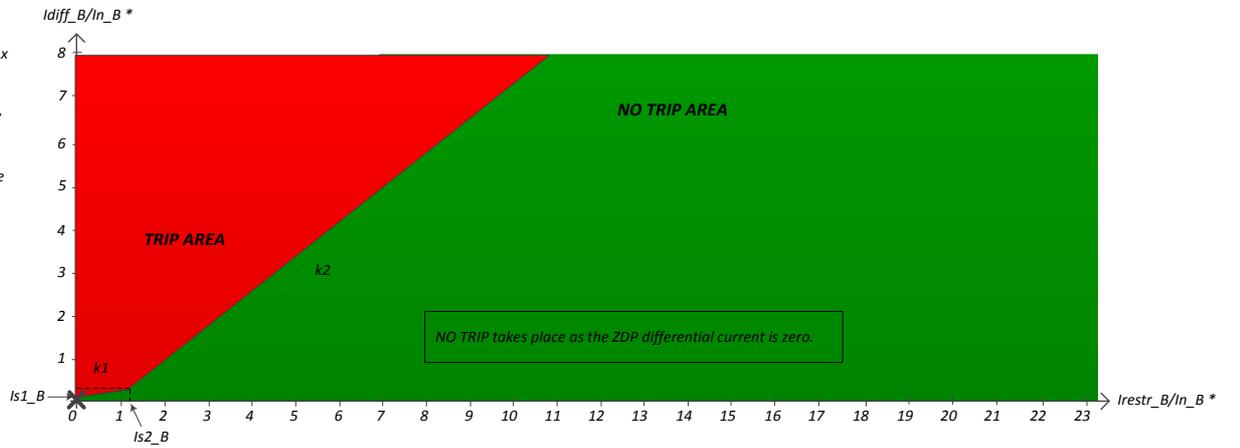
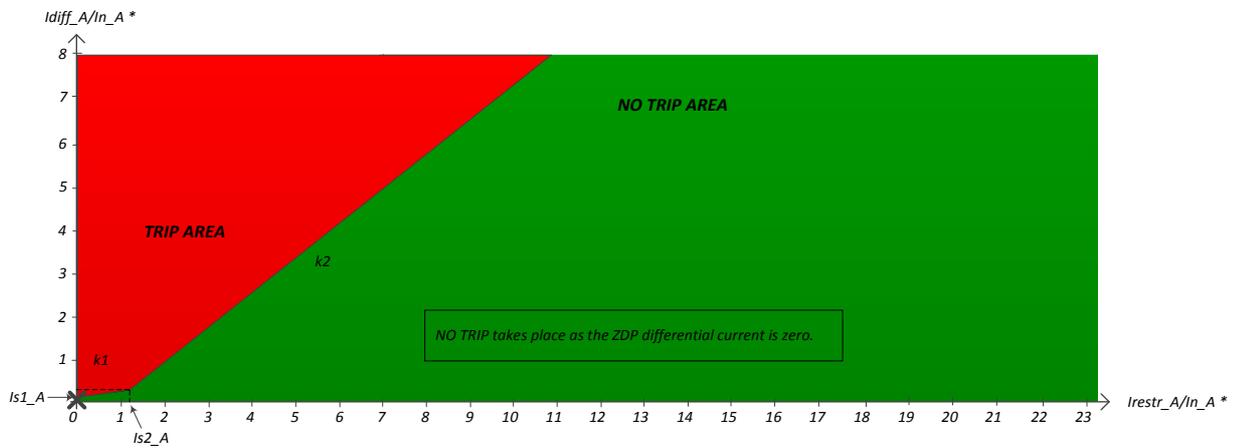
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix B7 – Short-circuit simulation – SP1

[Fault at bus 78 in Zone 4 - Fault on phase = BC – Fault resistance R = 100 ohms]

Zone : 6

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	0.00+0.00j	-0.00+0.00j	0.00+0.00j
BR6	-0.00-0.00j	-0.00-0.00j	-0.00-0.00j



* In_x is the rated current of the phase x of the current zone. x = A or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

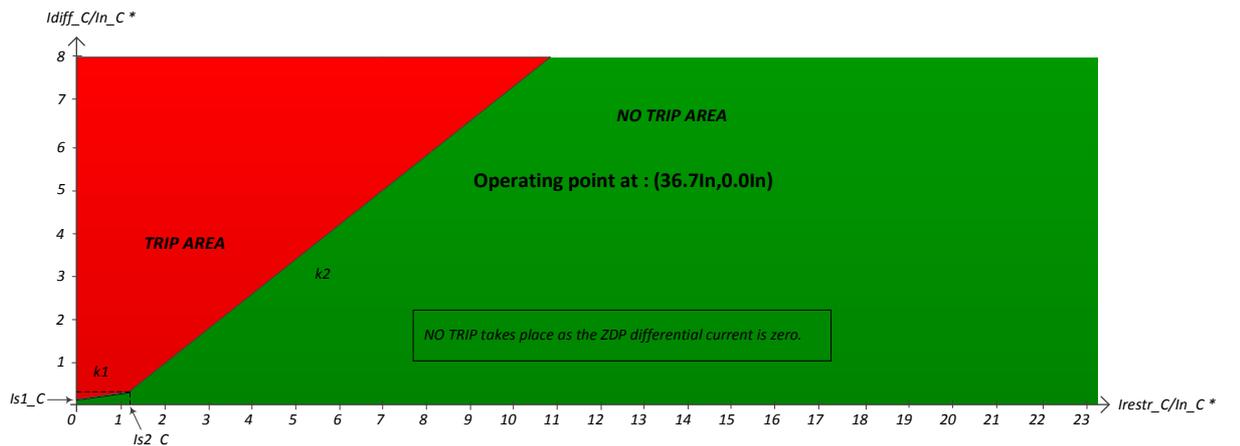
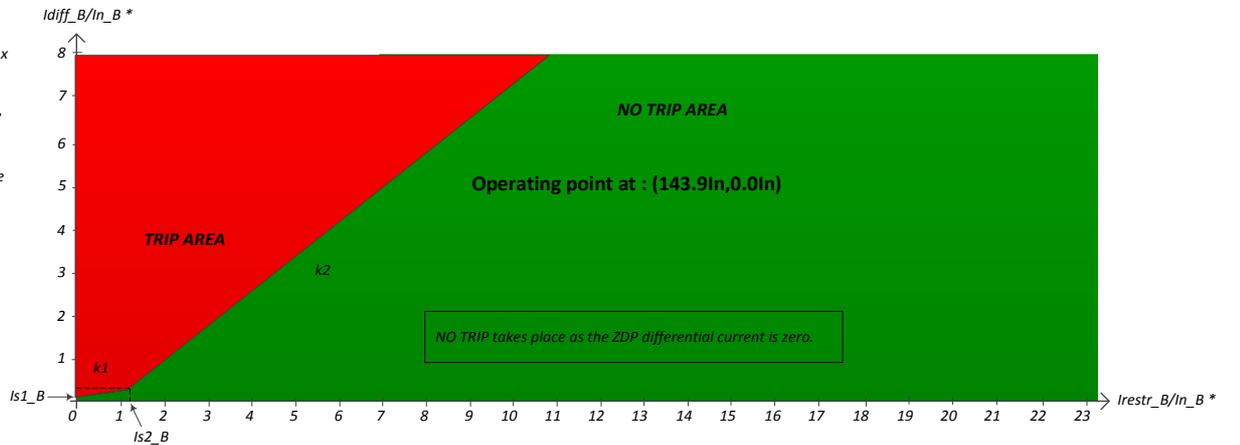
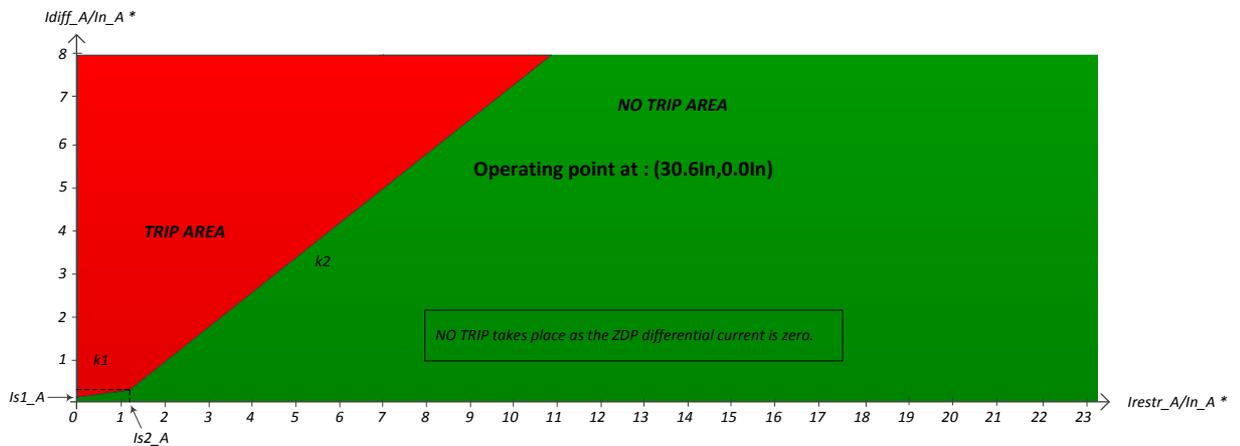
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix B7 – Short-circuit simulation – SP1

[Fault at bus 450 in Zone 4 - Fault on phase = ABC – Fault resistance R = 0 ohms]

Zone : 1

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	57.92+38.49j	93.13-39.46j	-67.12+26.02j
BR1	-273.74-2481.00j	-2109.53+1461.63j	2470.48+990.84j
BR2	373.42+2438.25j	2109.25-1482.22j	-2498.47-914.08j
BR3	-41.75+81.23j	93.42-18.89j	-39.13-50.74j



* In_x is the rated current of the phase x of the current zone. x = A or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

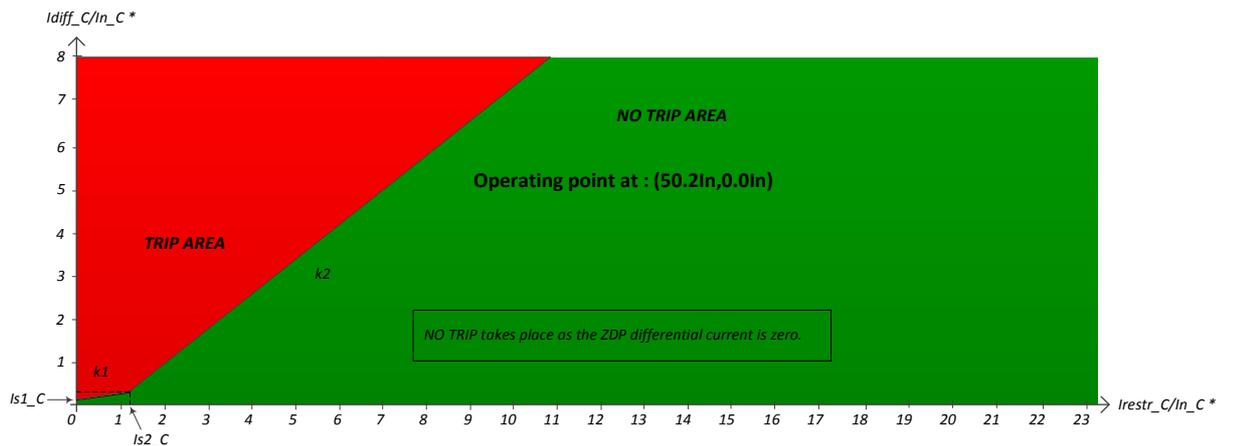
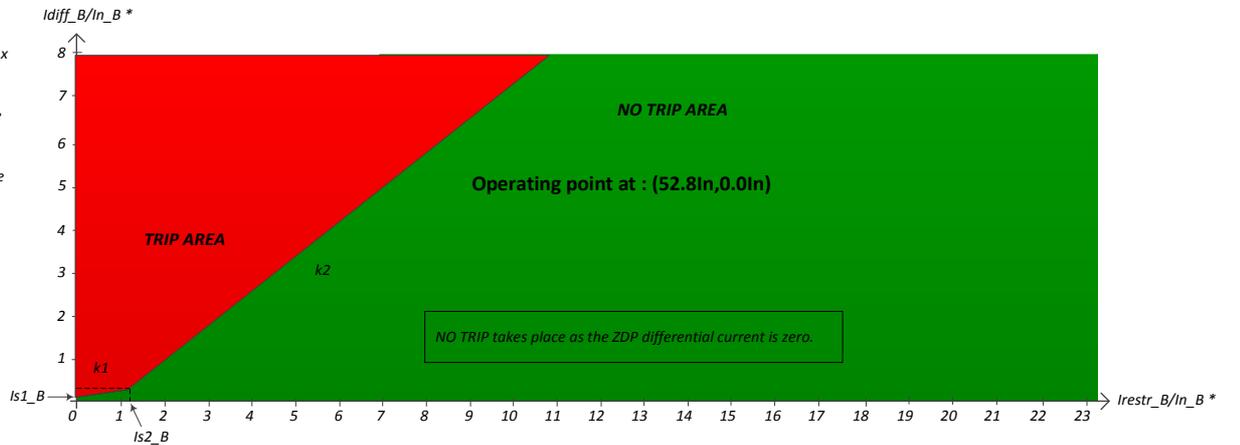
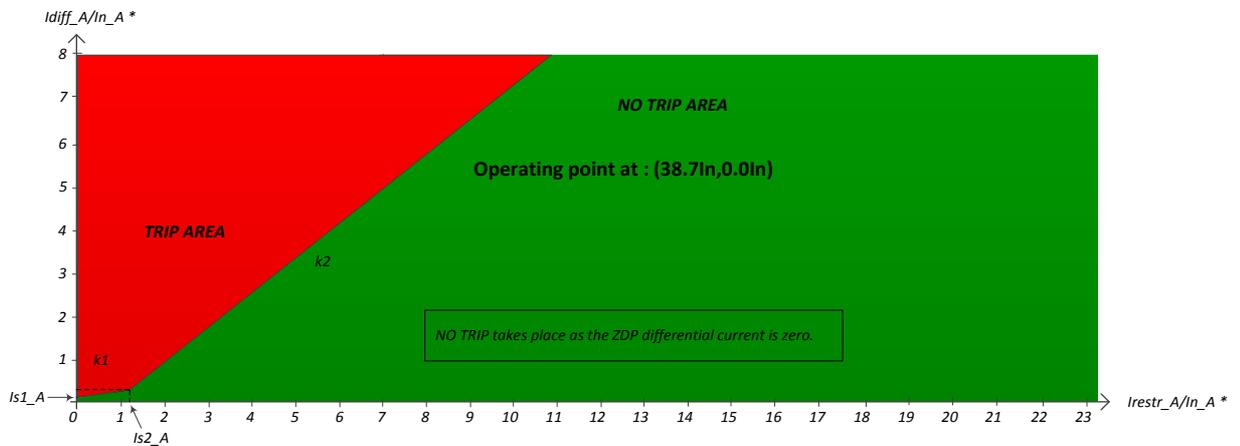
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix B7 – Short-circuit simulation – SP1

[Fault at bus 450 in Zone 4 - Fault on phase = ABC – Fault resistance R = 0 ohms]

Zone : 2

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	22.01-43.39j	-37.50+3.75j	15.94+25.77j
BR2	-373.42-2438.25j	-2109.25+1482.22j	2498.47+914.08j
BR4	395.44+2394.89j	2071.76-1478.49j	-2482.55-888.31j
BR6	-0.00-0.00j	-0.00-0.00j	-0.00-0.00j



* In_x is the rated current of the phase x of the current zone. x = A or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

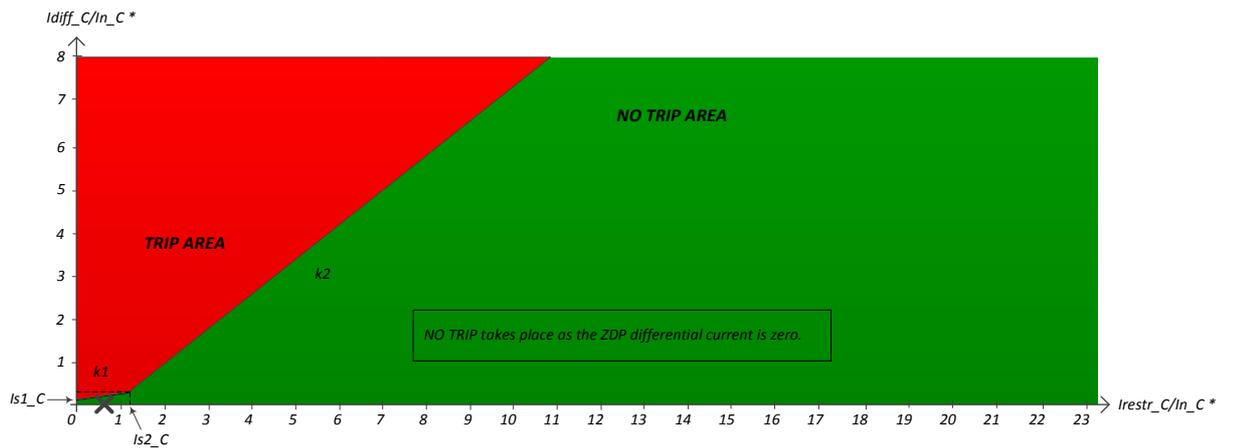
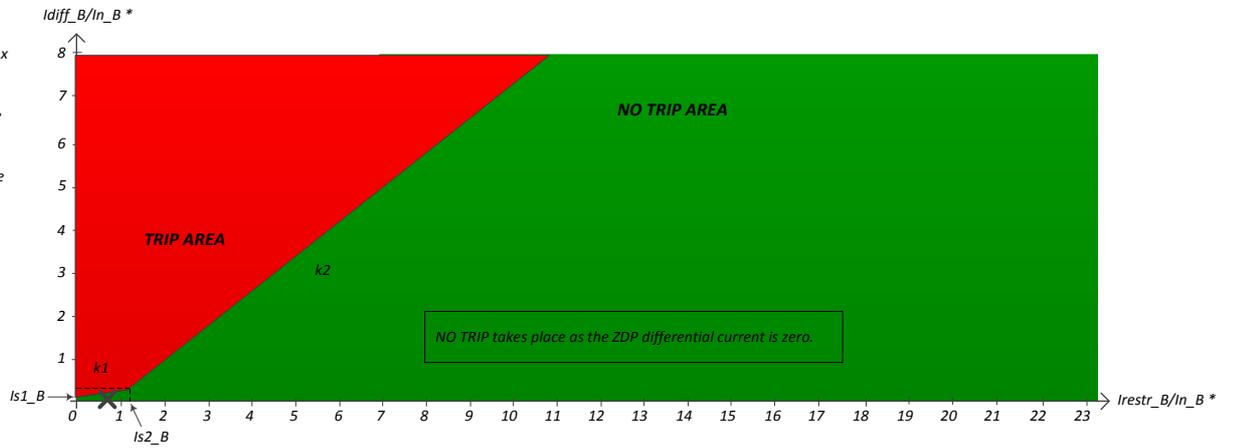
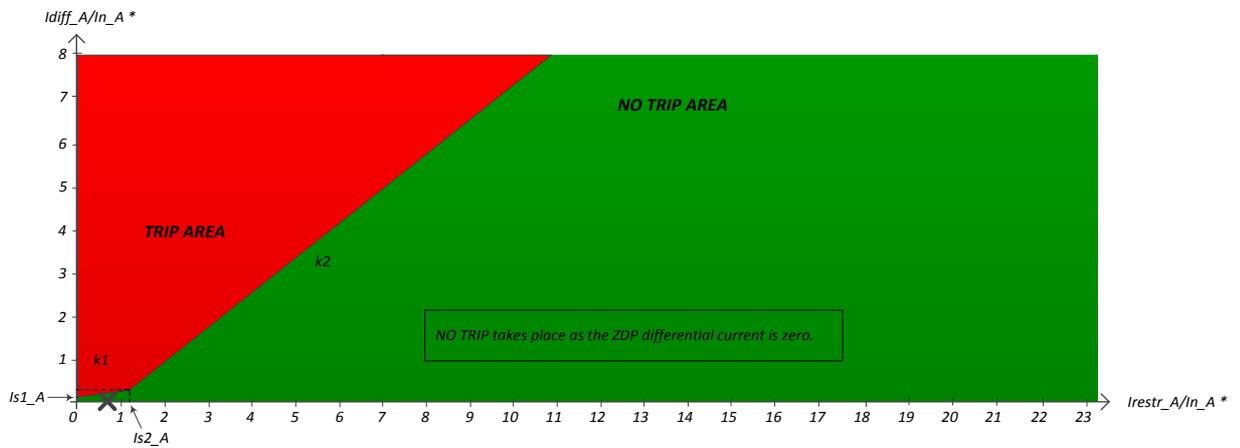
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix B7 – Short-circuit simulation – SP1

[Fault at bus 450 in Zone 4 - Fault on phase = ABC – Fault resistance R = 0 ohms]

Zone : 3

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	41.75-81.21j	-93.44+18.91j	39.14+50.74j
BR3	41.75-81.23j	-93.42+18.89j	39.13+50.74j



* In_x is the rated current of the phase x of the current zone. x = A or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

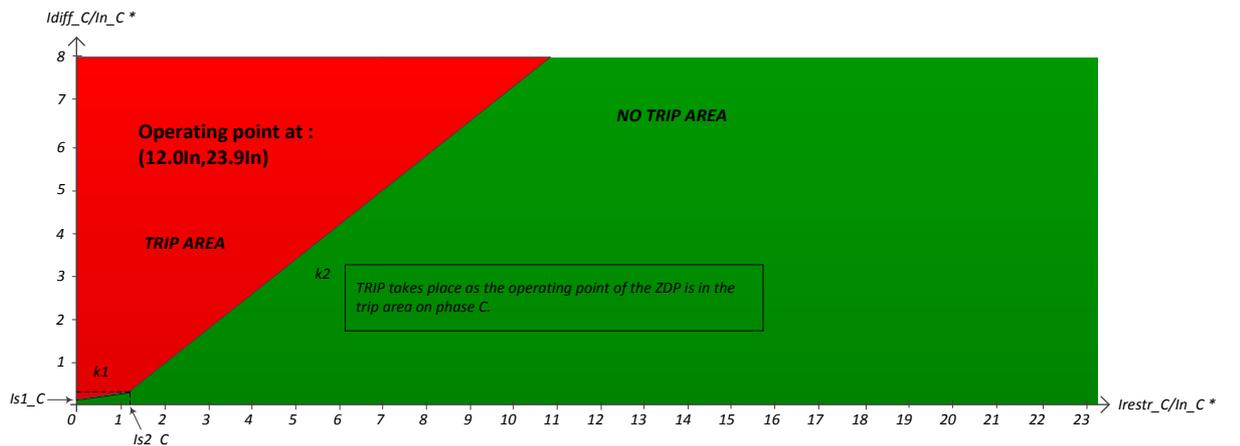
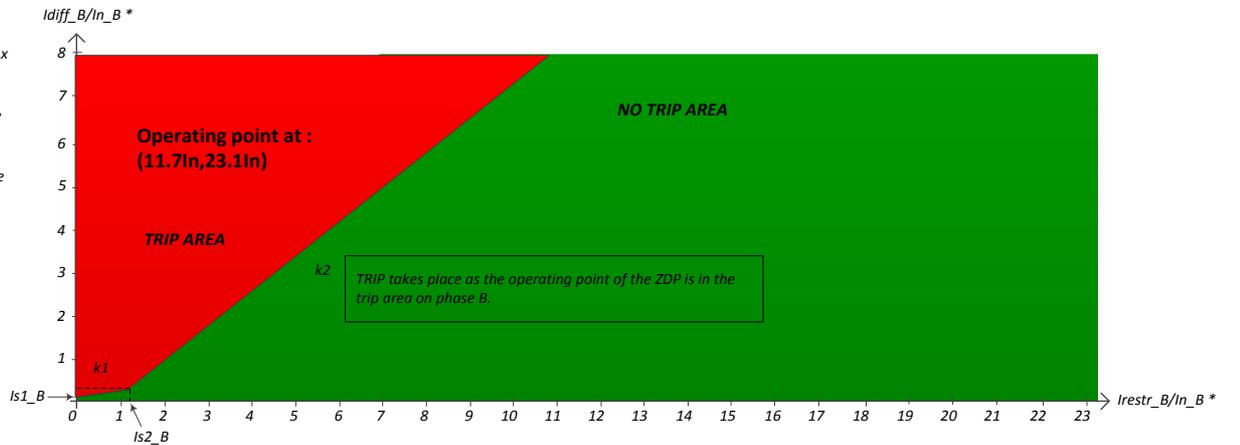
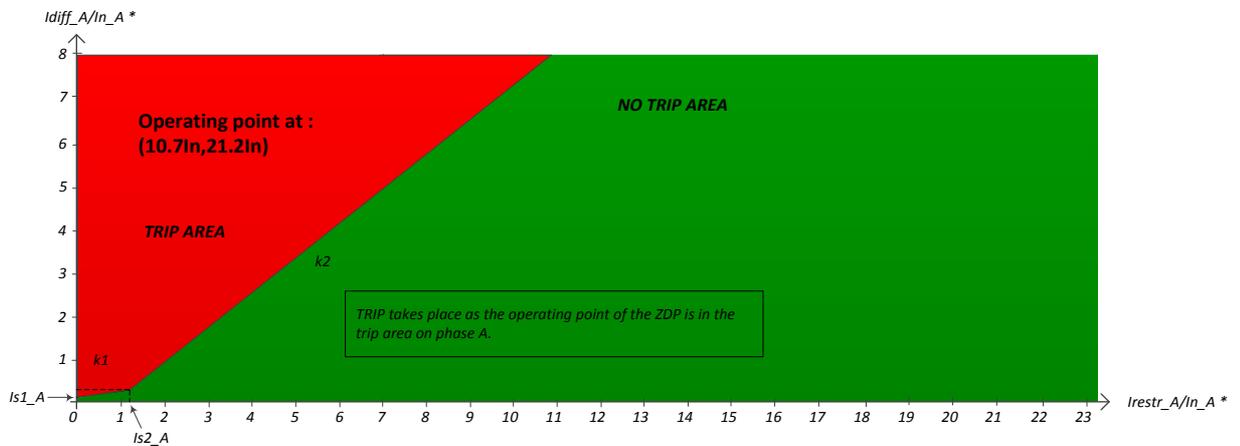
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix B7 – Short-circuit simulation – SP1

[Fault at bus 450 in Zone 4 - Fault on phase = ABC – Fault resistance R = 0 ohms]

Zone : 4

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	36.09+357.43j	309.24-165.47j	-335.10-161.85j
BR4	-395.44-2394.89j	-2071.76+1478.49j	2482.55+888.31j
BR5	-10.43+16.69j	11.94-0.81j	-6.68-11.47j



* In_x is the rated current of the phase x of the current zone. x = A or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

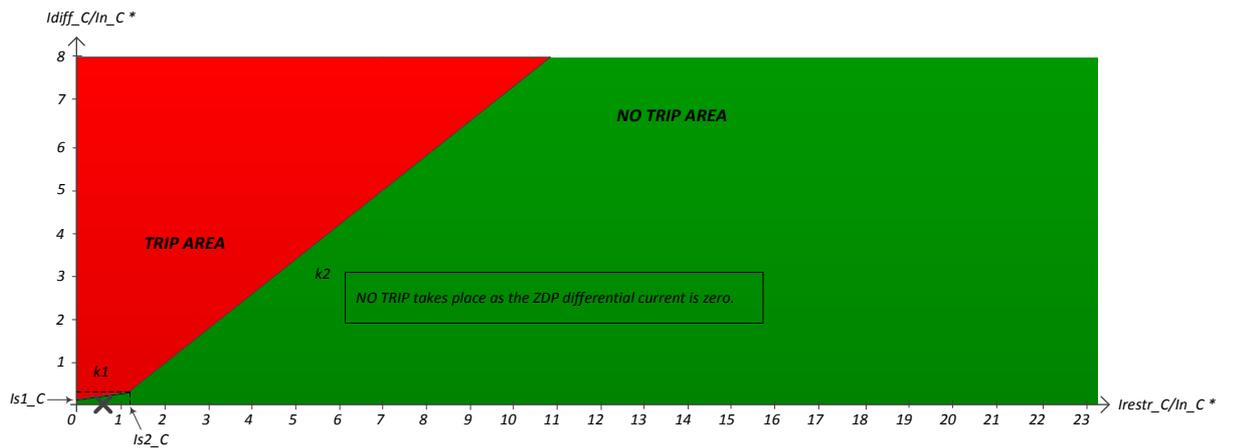
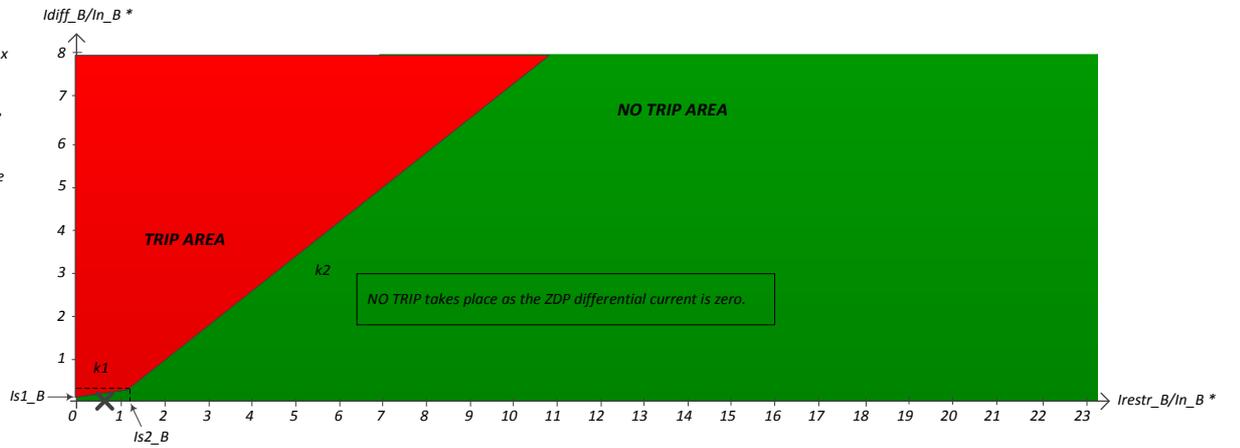
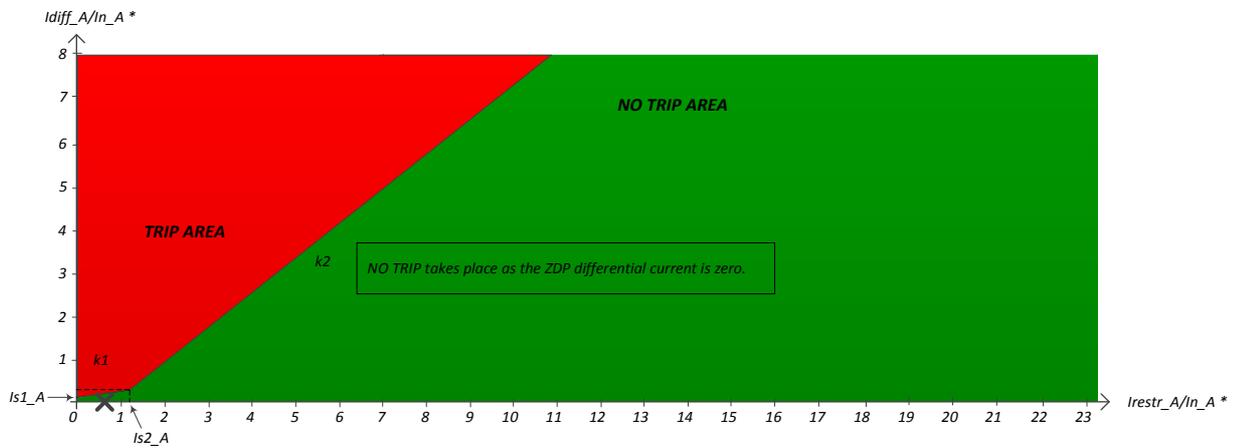
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix B7 – Short-circuit simulation – SP1

[Fault at bus 450 in Zone 4 - Fault on phase = ABC – Fault resistance R = 0 ohms]

Zone : 5

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	10.42-16.69j	-11.95+0.82j	6.68+11.47j
BR5	10.43-16.69j	-11.94+0.81j	6.68+11.47j



* In_x is the rated current of the phase x of the current zone. x = A or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

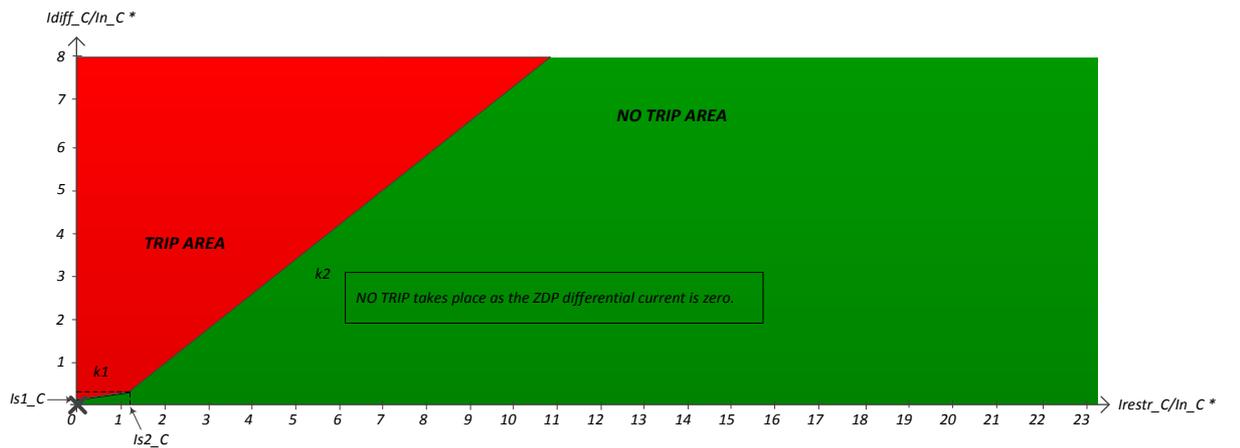
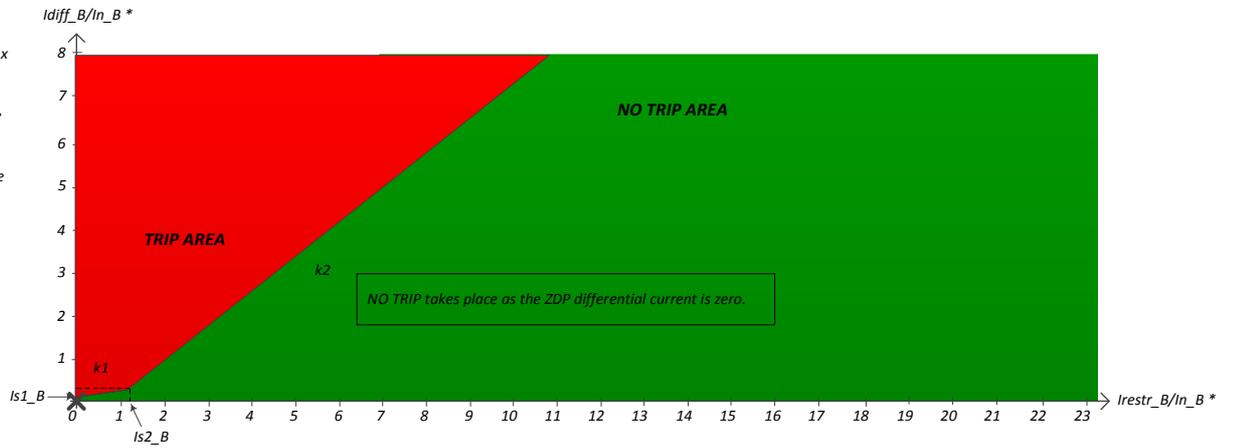
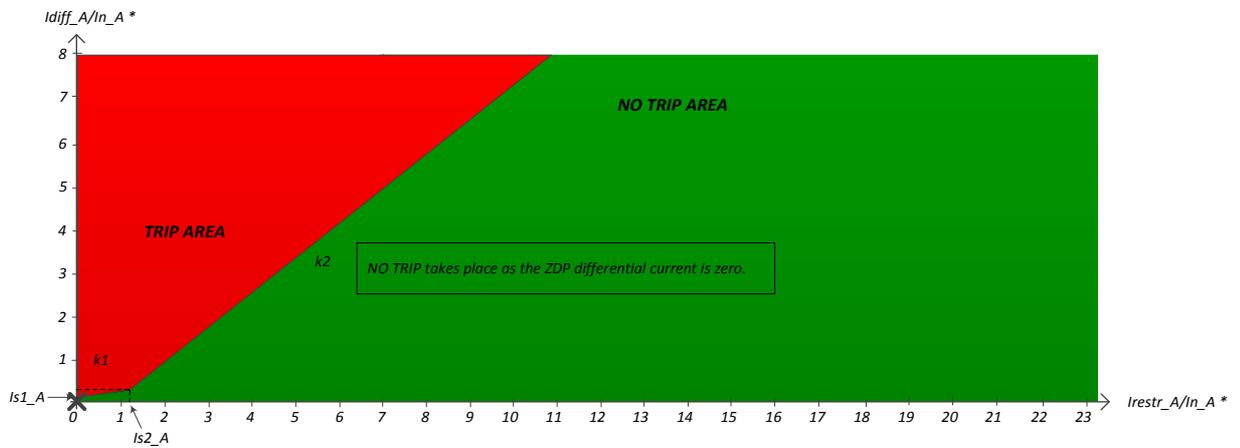
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix B7 – Short-circuit simulation – SP1

[Fault at bus 450 in Zone 4 - Fault on phase = ABC – Fault resistance R = 0 ohms]

Zone : 6

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	0.00+0.00j	-0.00+0.00j	0.00+0.00j
BR6	-0.00-0.00j	-0.00-0.00j	-0.00-0.00j



* I_{n_x} is the rated current of the phase x of the current zone. x = A or B or C

I_{diff_x} is the differential current on the phase x of the current zone.

I_{restr_x} is the restraining current on the phase x of the current zone.

I_{s1_x} is the differential current pick-up setting. It is set to 10% of the phase x rated current.

I_{s2_x} is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

k_1, k_2 : slopes - $k_1=30\%$ & $k_2=80\%$

APPENDIX C1

Extract of the updated reference
network (for SP2) in CIM RDF XML

Appendix C1 – Extract of the new part added to the reference network model in CIM RDF XML

```
.  
<cim:ACLineSegment rdf:ID="_DDCDACD1-04B8-4B60-91D1-106944E0D3DD">  
<cim:IdentifiedObject.mRID>_DDCDACD1-04B8-4B60-91D1-106944E0D3DD</cim:IdentifiedObject.mRID>  
<cim:IdentifiedObject.name>l185</cim:IdentifiedObject.name>  
<cim:Equipment.EquipmentContainer rdf:resource="#_3DF0CE82-665C-4858-B771-CA45A02CEFE1"/>  
<cim:ConductingEquipment.BaseVoltage rdf:resource="#_F96DD9D3-AD7B-4947-8387-E6F851C54296"/>  
<cim:Conductor.length>0.3</cim:Conductor.length>  
<cim:ACLineSegment.PerLengthImpedance rdf:resource="#_195CC8E6-0854-4EF4-A759-F5A73483936C"/>  
<cim:PowerSystemResource.Location rdf:resource="#_DD8E4E4A-57F2-4B1D-8DC4-90728940AEDD"/>  
</cim:ACLineSegment>  
<cim:ACLineSegmentPhase rdf:ID="_DD529BD7-8B52-49B7-9D0D-D8AE8B22E3DD">  
<cim:IdentifiedObject.mRID>_DD529BD7-8B52-49B7-9D0D-D8AE8B22E3DD</cim:IdentifiedObject.mRID>  
<cim:IdentifiedObject.name>l185_B</cim:IdentifiedObject.name>  
<cim:ACLineSegmentPhase.phase rdf:resource="http://iec.ch/TC57/2012/CIM-schema-cim17#SinglePhaseKind.B"/>  
<cim:ACLineSegmentPhase.ACLineSegment rdf:resource="#_DDCDACD1-04B8-4B60-91D1-106944E0D3DD"/>  
<cim:PowerSystemResource.Location rdf:resource="#_DD8E4E4A-57F2-4B1D-8DC4-90728940AEDD"/>  
</cim:ACLineSegmentPhase>  
<cim:Terminal rdf:ID="_DD0DE051-AF37-44CC-9A4A-A89B83BD17DD">  
<cim:IdentifiedObject.mRID>_DD0DE051-AF37-44CC-9A4A-A89B83BD17DD</cim:IdentifiedObject.mRID>  
<cim:IdentifiedObject.name>l185_T1</cim:IdentifiedObject.name>  
<cim:Terminal.ConductingEquipment rdf:resource="#_DDCDACD1-04B8-4B60-91D1-106944E0D3DD"/>  
<cim:Terminal.phases>B</cim:Terminal.phases>  
<cim:ACDCTerminal.sequenceNumber>1</cim:ACDCTerminal.sequenceNumber>  
<cim:Terminal.ConnectivityNode rdf:resource="#_0B65D343-ECEF-4E33-AB5C-965914E6290E"/>  
</cim:Terminal>  
<br>  
<cim:PositionPoint rdf:ID="_DDCCCD87-F813-47AC-A630-BFA7513682DD">  
<cim:PositionPoint.Location rdf:resource="#_DD8E4E4A-57F2-4B1D-8DC4-90728940AEDD"/>  
<cim:PositionPoint.sequenceNumber>1</cim:PositionPoint.sequenceNumber>  
<cim:PositionPoint.xPosition>4700</cim:PositionPoint.xPosition>  
<cim:PositionPoint.yPosition>900</cim:PositionPoint.yPosition>  
</cim:PositionPoint>  
<cim:PositionPoint rdf:ID="_DDA6C901-7A9E-4519-B886-61D6A28024DD">  
<cim:PositionPoint.Location rdf:resource="#_DD8E4E4A-57F2-4B1D-8DC4-90728940AEDD"/>  
<cim:PositionPoint.sequenceNumber>2</cim:PositionPoint.sequenceNumber>  
<cim:PositionPoint.xPosition>4362</cim:PositionPoint.xPosition>  
<cim:PositionPoint.yPosition>900</cim:PositionPoint.yPosition>  
</cim:PositionPoint>  
<br>  
<br>
```

APPENDIX C2

Extract of the updated reference
network (for SP2) in IEC61850

Appendix C2 – Extract of IEC 61850 equivalent file with a new ID attribute

```
.
.
<VoltageLevel Name="M1">
  <Voltage multiplier="k" unit="V" value="4.16"/>
  <ConductingEquipment Desc="Line/Cable segment" ID="_8B5D38A8-3993-4FA5-899B-624F6A7DD88F" Name="I50" Type="LIN" pathName="ieeee123/M1/I50">
    <Terminal ID="_80E66F61-86B4-4861-AF54-A50C7CDAE33C" cNodeName="51" cnID="_B1A89E68-5C0B-4D19-A445-270541356243" connectivityNode="ieeee123/M1/51"
lineName="ieeee123" pathName="ieeee123/M1/I50/T2"/>
    <Terminal ID="_112F745E-32F1-4F64-898E-0C0C1846C5C5" cNodeName="50" cnID="_969CD7EF-E12E-4135-85CB-F527D400B525" connectivityNode="ieeee123/M1/50"
lineName="ieeee123" pathName="ieeee123/M1/I50/T1"/>
  </ConductingEquipment>
.
.
  <ConductingEquipment Desc="Line/Cable segment" ID="_DDCDACD1-04B8-4B60-91D1-106944E0D3DD" Name="I185" Type="LIN" pathName="ieeee123/M1/I185">
    <SubEquipment Name="S" phase="B">
      <LNode IdInst="C1" InClass="ZLIN" InInst="1"/>
    </SubEquipment>
    <Terminal ID="_DD0DE051-AF37-44CC-9A4A-A89B83BD17DD" cNodeName="185" cnID="_0B65D343-ECEF-4E33-AB5C-965914E6290E" connectivityNode="ieeee123/M1/
185" lineName="ieeee123" pathName="ieeee123/M1/I185/T1"/>
    <Terminal ID="_DDB79BA0-FDD3-4F9B-9E14-91C32340C8DD" cNodeName="85" cnID="_BB4A3F9C-98B8-46A1-BAC2-BBF58FF98FBB" connectivityNode="ieeee123/M1/
85" lineName="ieeee123" pathName="ieeee123/M1/I185/T2"/>
  </ConductingEquipment>
.
.
  <ConductingEquipment Desc="Load" ID="_F3DAA273-A8F9-4CB4-BF80-410F9D36233C" Name="s251c" Type="LOD" pathName="ieeee123/M1/s251c">
    <SubEquipment Name="T" phase="C">
      <LNode IdInst="C1" InClass="DLOD" InInst="1"/>
    </SubEquipment>
    <Terminal ID="_F20CB43F-D0A4-42E9-96EF-DB907B7836AB" cNodeName="251" cnID="_CC4A3F9C-98B8-46A1-BAC2-BBF58FF98FCC" connectivityNode="ieeee123/M1/
251" lineName="ieeee123" pathName="ieeee123/M1/s251c/T1"/>
  </ConductingEquipment>
.
.
</VoltageLevel>
<ConnectivityNode ID="_4081276C-7B87-4933-B054-8EB8A5885330" Name="160r" pathName="ieeee123/M1/160r" x="3175" y="1850"/>
<ConnectivityNode ID="_D4C8BDE7-E247-4EE8-8793-A2EA58AE0EF3" Name="160" pathName="ieeee123/M1/160" x="3175" y="1850"/>
.
.
<ConnectivityNode ID="_CC4A3F9C-98B8-46A1-BAC2-BBF58FF98FCC" Name="251" pathName="ieeee123/M1/251" x="2956" y="3928"/>
<ConnectivityNode ID="_BB4A3F9C-98B8-46A1-BAC2-BBF58FF98FBB" Name="185" pathName="ieeee123/M1/185" x="4362" y="900"/>

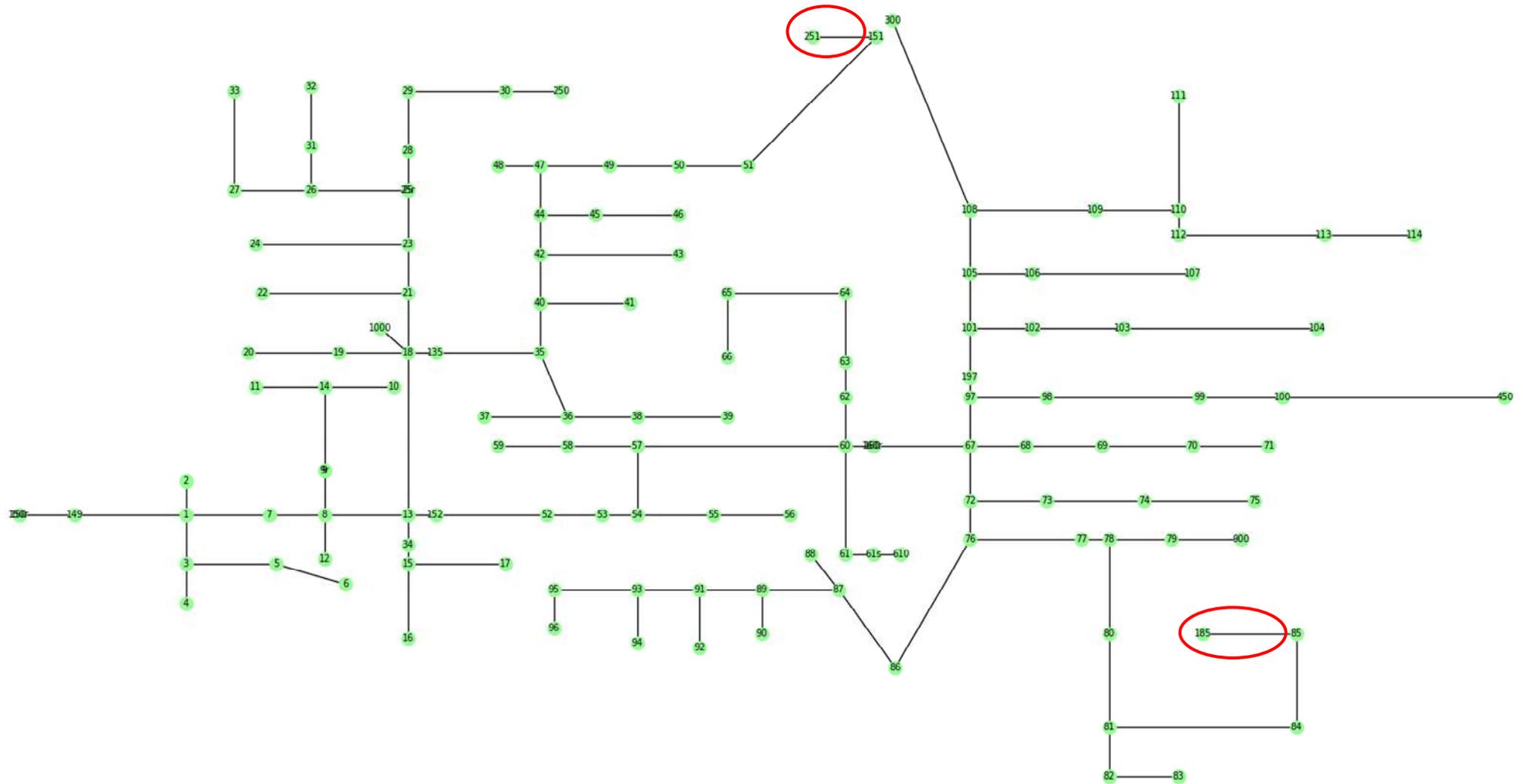
</Line>
.
.</SCL>
```

APPENDIX C3

Graph of the updated reference network
for simulations in SP2

Appendix C3 – Graph of the updated reference network – SP2

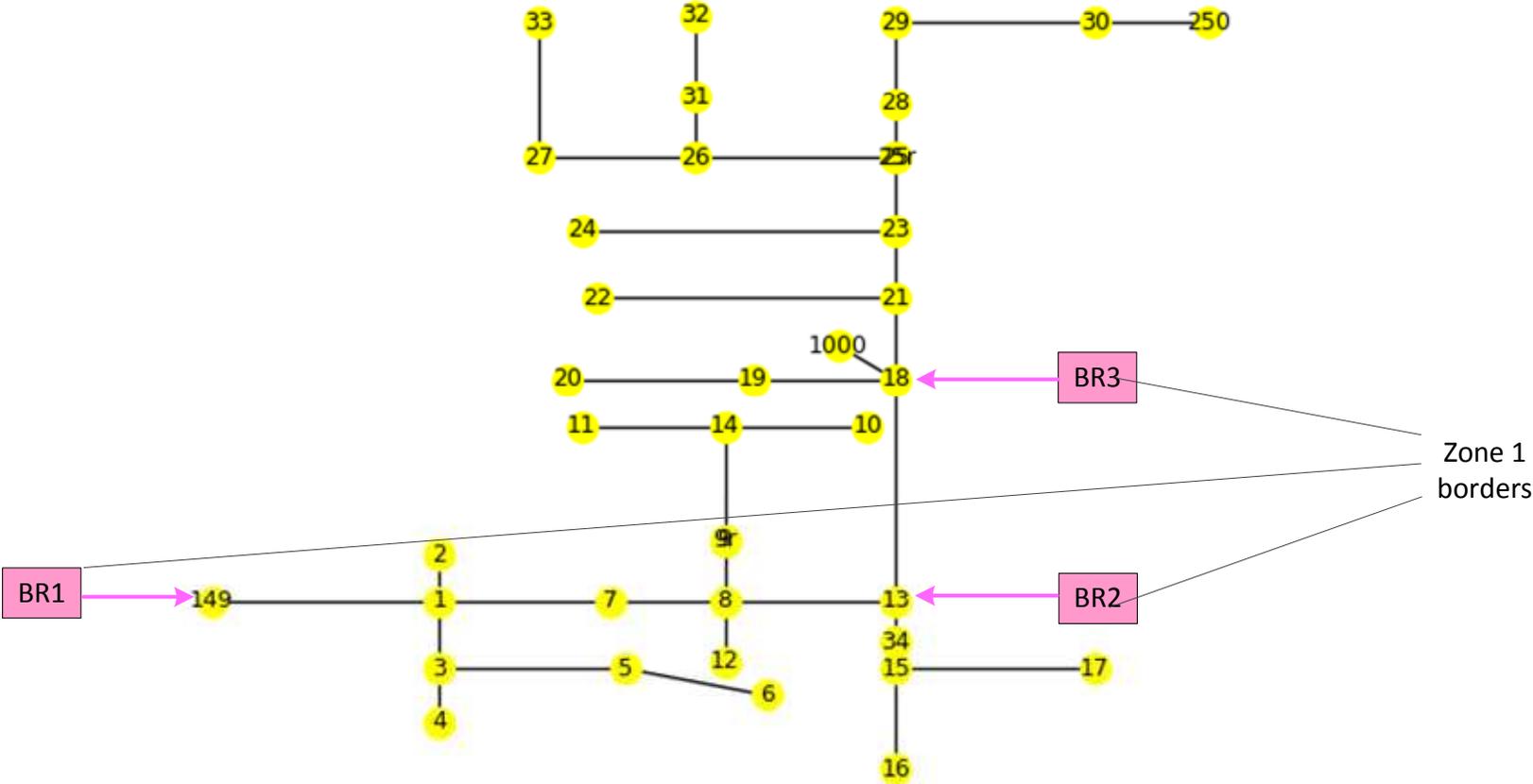
The graph below represents the connectivity of the reference network where 02 single phase loads and 02 overhead line segments have been added as highlighted below in red.



APPENDIX C4

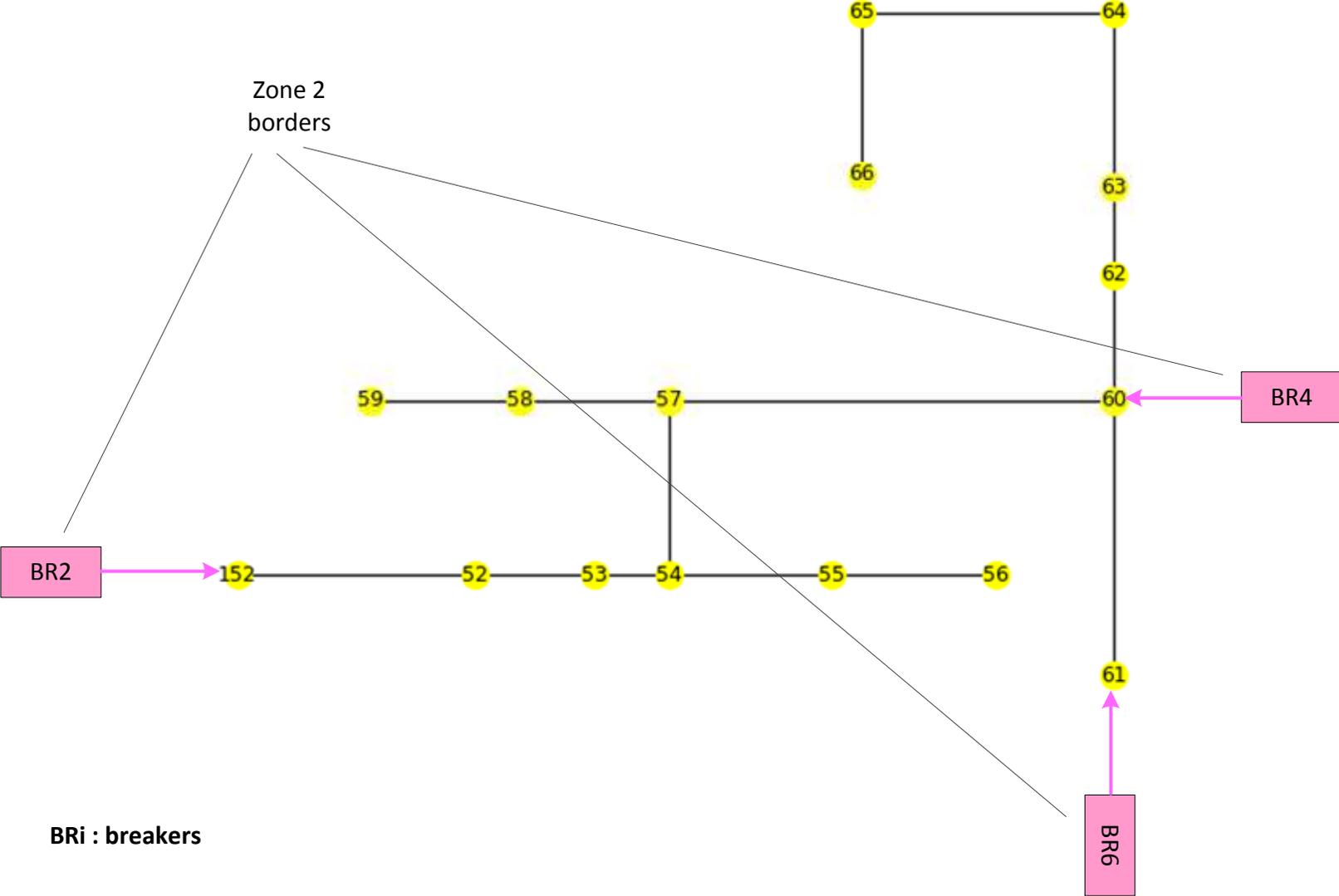
Zones creation with the updated reference
network – SP2

Appendix C4 – Zones creation – SP2

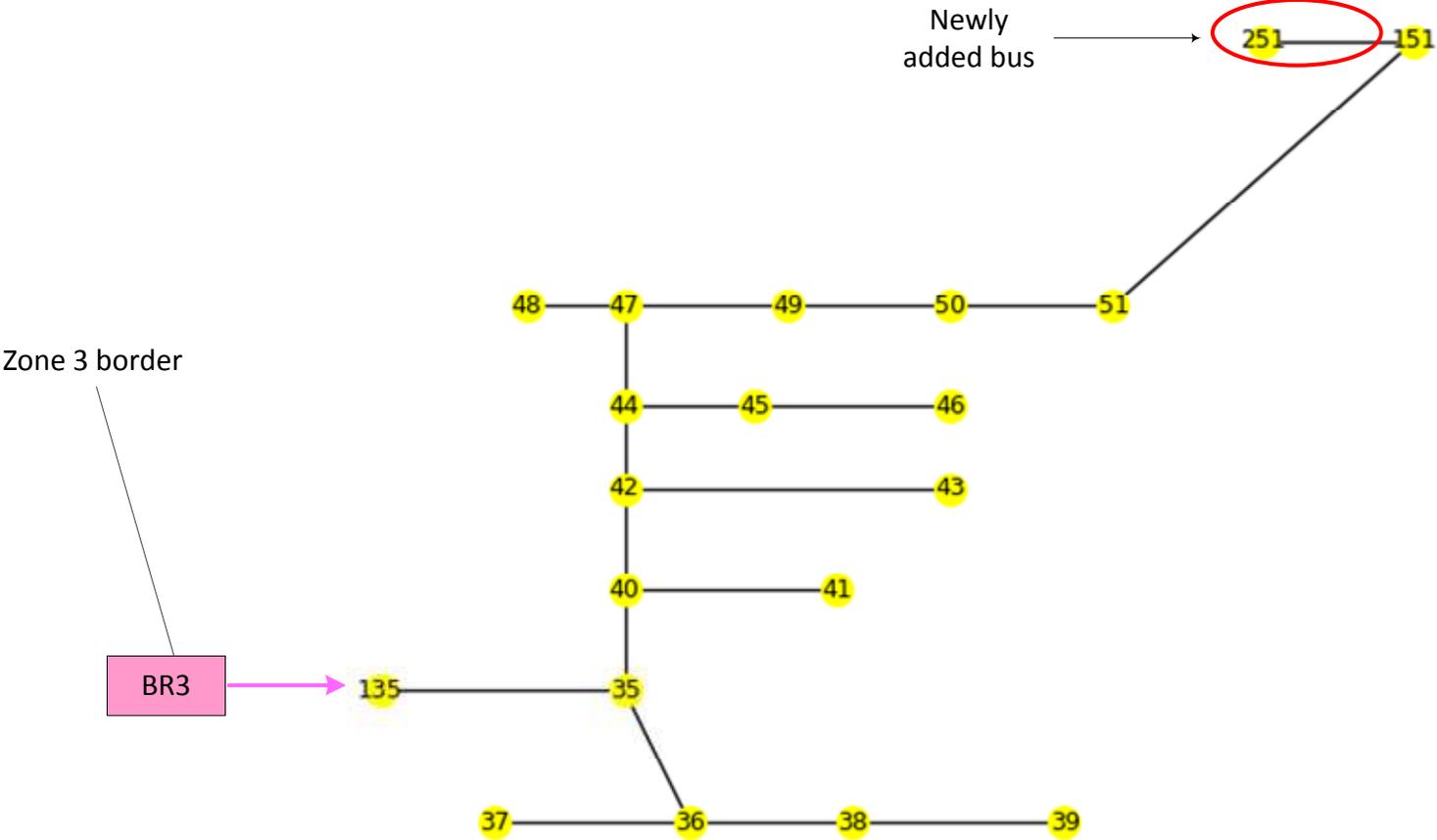


BRi : breakers

Appendix C4 – Zones creation – SP2 - continued



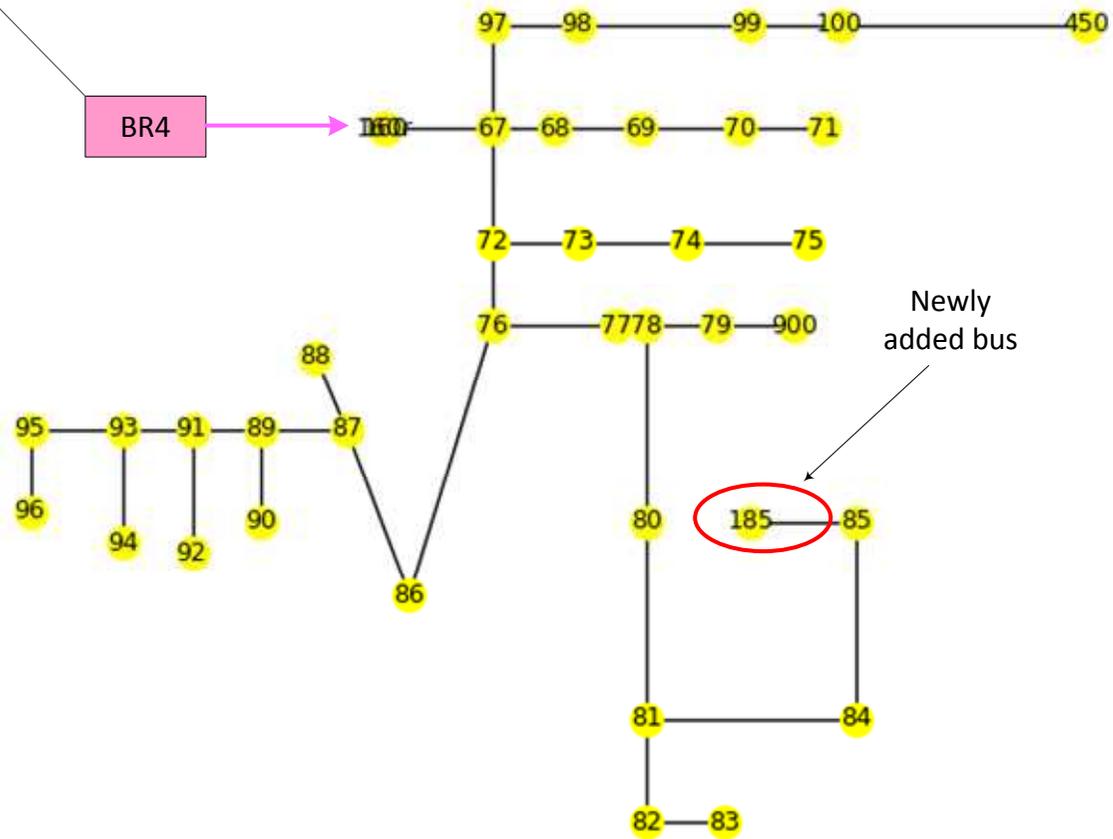
Appendix C4 – Zones creation – SP2 - continued



BRi : breakers

Appendix C4 – Zones creation – SP2 - continued

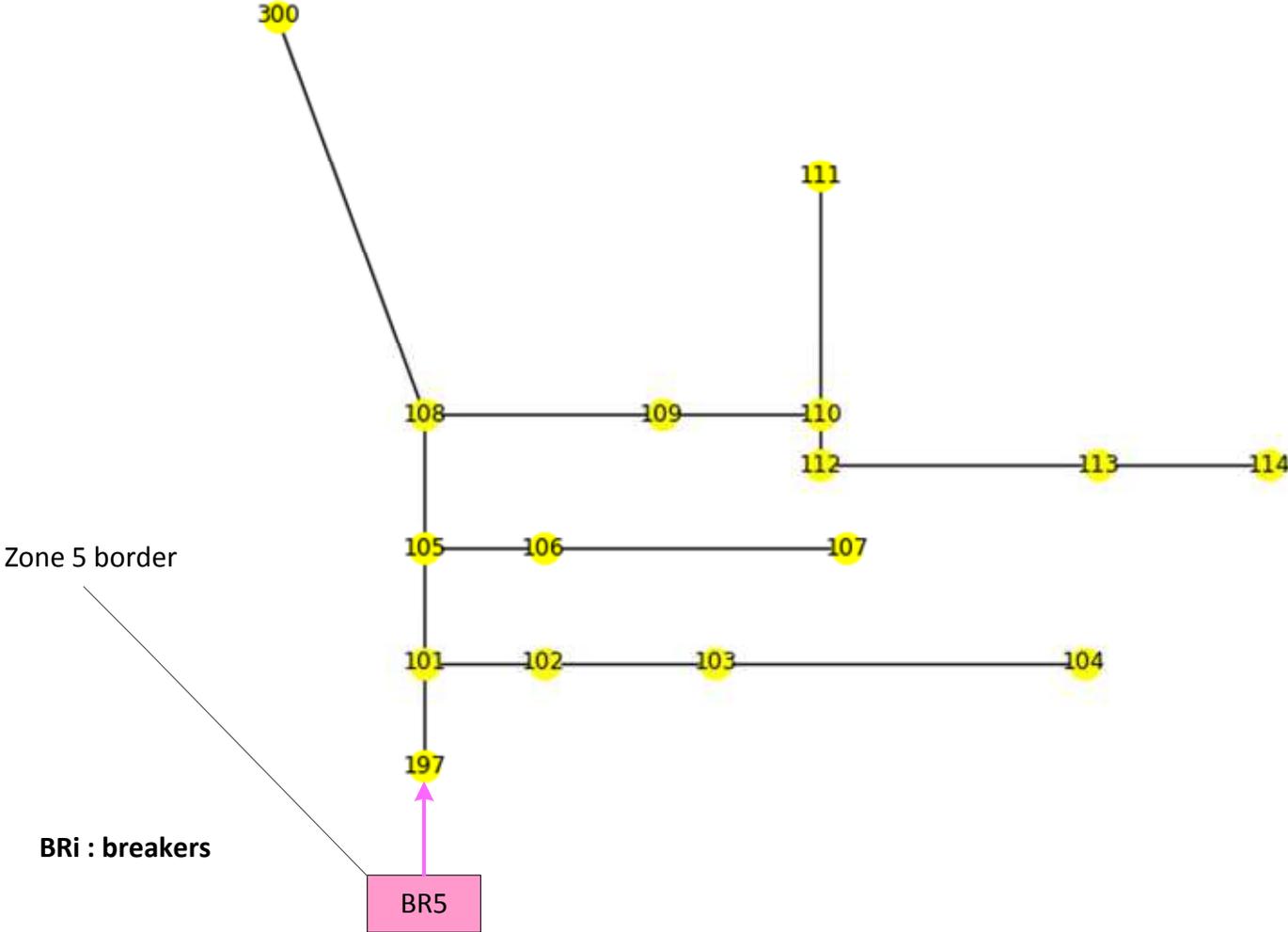
Zone 4
border



Newly
added bus

BRi : breakers

Appendix C4 – Zones creation – SP2 - continued



Appendix C4 – Zones creation – SP2 - continued

Zone 6 border



BRi : breakers

APPENDIX C5

OpenDSS netlist of the reference network in SP2

Note : in the newly generated netlist, only the files that have been modified are shown (lines and loads files as per the change introduced in SP2). The other files remain unchanged.

Appendix C5 – OpenDSS netlist of the reference network – SP2 - continued

C5-4- Lines

!LINE DEFINITION

New Line.l251 Phases=1 Bus1=151.2 Bus2=251.2 Linecode=10 Length=0.5

New Line.l81 Phases=3 Bus1=80.1.2.3 Bus2=81.1.2.3 Linecode=6 Length=0.175

New Line.l91 Phases=1 Bus1=91.3 Bus2=92.3 Linecode=11 Length=0.3

New Line.l98 Phases=3 Bus1=99.1.2.3 Bus2=100.1.2.3 Linecode=3 Length=0.3

New Line.l55 Phases=3 Bus1=54.1.2.3 Bus2=57.1.2.3 Linecode=3 Length=0.35

New Line.l2 Phases=1 Bus1=1.3 Bus2=3.3 Linecode=11 Length=0.25

New Line.l3 Phases=3 Bus1=1.1.2.3 Bus2=7.1.2.3 Linecode=1 Length=0.3

New Line.l28 Phases=1 Bus1=26.3 Bus2=31.3 Linecode=11 Length=0.225

New Line.l111 Phases=1 Bus1=110.1 Bus2=112.1 Linecode=9 Length=0.125

New Line.l85 Phases=1 Bus1=84.3 Bus2=85.3 Linecode=11 Length=0.475

New Line.l13 Phases=3 Bus1=13.1.2.3 Bus2=18.1.2.3 Linecode=2 Length=0.825

New Line.l71 Phases=1 Bus1=70.1 Bus2=71.1 Linecode=9 Length=0.275

New Line.l102 Phases=1 Bus1=102.3 Bus2=103.3 Linecode=11 Length=0.325

New Line.l67 Phases=3 Bus1=67.1.2.3 Bus2=72.1.2.3 Linecode=3 Length=0.275

New Line.l35 Phases=2 Bus1=35.2.1 Bus2=36.2.1 Linecode=8 Length=0.65

New Line.l7 Phases=3 Bus1=7.1.2.3 Bus2=8.1.2.3 Linecode=1 Length=0.2

New Line.l19 Phases=3 Bus1=18.1.2.3 Bus2=21.1.2.3 Linecode=2 Length=0.3

New Line.l15 Phases=1 Bus1=14.1 Bus2=10.1 Linecode=9 Length=0.25

New Line.l32 Phases=3 Bus1=30.1.2.3 Bus2=250.1.2.3 Linecode=2 Length=0.2

New Line.l69 Phases=1 Bus1=68.1 Bus2=69.1 Linecode=9 Length=0.275

New Line.l33 Phases=1 Bus1=31.3 Bus2=32.3 Linecode=11 Length=0.3

New Line.l10 Phases=3 Bus1=8.1.2.3 Bus2=13.1.2.3 Linecode=1 Length=0.3

New Line.l27 Phases=2 Bus1=26.3.1 Bus2=27.3.1 Linecode=7 Length=0.275

New Line.l21 Phases=1 Bus1=21.2 Bus2=22.2 Linecode=10 Length=0.525

New Line.l22 Phases=3 Bus1=21.1.2.3 Bus2=23.1.2.3 Linecode=2 Length=0.25

New Line.l100 Phases=1 Bus1=101.3 Bus2=102.3 Linecode=11 Length=0.225

New Line.l96 Phases=3 Bus1=97.1.2.3 Bus2=98.1.2.3 Linecode=3 Length=0.275

New Line.l60 Phases=3 Bus1=60.1.2.3 Bus2=61.1.2.3 Linecode=5 Length=0.55

New Line.l38 Phases=1 Bus1=36.2 Bus2=38.2 Linecode=10 Length=0.25

New Line.l20 Phases=1 Bus1=19.1 Bus2=20.1 Linecode=9 Length=0.325

Note : new lines generated from the network model in SP2 are highlighted in red

Appendix C5 – OpenDSS netlist of the reference network – SP2 - continued

C5-4- Lines - continued

New Line.l68 Phases=3 Bus1=67.1.2.3 Bus2=97.1.2.3 Linecode=3 Length=0.25
New Line.l90 Phases=3 Bus1=89.1.2.3 Bus2=91.1.2.3 Linecode=6 Length=0.225
New Line.l82 Phases=3 Bus1=81.1.2.3 Bus2=82.1.2.3 Linecode=6 Length=0.25
New Line.l83 Phases=1 Bus1=81.3 Bus2=84.3 Linecode=11 Length=0.675
New Line.l41 Phases=3 Bus1=40.1.2.3 Bus2=42.1.2.3 Linecode=1 Length=0.25
New Line.l89 Phases=1 Bus1=89.2 Bus2=90.2 Linecode=10 Length=0.25
New Line.l93 Phases=1 Bus1=93.1 Bus2=94.1 Linecode=9 Length=0.275
New Line.l47 Phases=3 Bus1=47.1.2.3 Bus2=48.1.2.3 Linecode=4 Length=0.15
New Line.l61 Phases=3 Bus1=60.1.2.3 Bus2=62.1.2.3 Linecode=12 Length=0.25
New Line.l75 Phases=1 Bus1=74.3 Bus2=75.3 Linecode=11 Length=0.4
New Line.l92 Phases=3 Bus1=91.1.2.3 Bus2=93.1.2.3 Linecode=6 Length=0.225
New Line.l110 Phases=1 Bus1=110.1 Bus2=111.1 Linecode=9 Length=0.575
New Line.l26 Phases=3 Bus1=25.1.2.3 Bus2=28.1.2.3 Linecode=2 Length=0.2
New Line.l76 Phases=3 Bus1=76.1.2.3 Bus2=77.1.2.3 Linecode=6 Length=0.4
New Line.l72 Phases=1 Bus1=72.3 Bus2=73.3 Linecode=11 Length=0.275
New Line.l29 Phases=1 Bus1=27.1 Bus2=33.1 Linecode=9 Length=0.5
New Line.l4 Phases=1 Bus1=3.3 Bus2=4.3 Linecode=11 Length=0.2
New Line.l114 Phases=3 Bus1=135.1.2.3 Bus2=35.1.2.3 Linecode=4 Length=0.375
New Line.l115 Phases=3 Bus1=149.1.2.3 Bus2=1.1.2.3 Linecode=1 Length=0.4
New Line.l44 Phases=1 Bus1=44.1 Bus2=45.1 Linecode=9 Length=0.2
New Line.l11 Phases=1 Bus1=9r.1 Bus2=14.1 Linecode=9 Length=0.425
New Line.l8 Phases=1 Bus1=8.2 Bus2=12.2 Linecode=10 Length=0.225
New Line.l1 Phases=1 Bus1=1.2 Bus2=2.2 Linecode=10 Length=0.175
New Line.l17 Phases=1 Bus1=15.3 Bus2=17.3 Linecode=11 Length=0.35
New Line.l116 Phases=3 Bus1=152.1.2.3 Bus2=52.1.2.3 Linecode=1 Length=0.4
New Line.l53 Phases=3 Bus1=53.1.2.3 Bus2=54.1.2.3 Linecode=1 Length=0.125
New Line.l24 Phases=3 Bus1=23.1.2.3 Bus2=25.1.2.3 Linecode=2 Length=0.275
New Line.l50 Phases=3 Bus1=50.1.2.3 Bus2=51.1.2.3 Linecode=4 Length=0.25
New Line.l9 Phases=1 Bus1=8.1 Bus2=9.1 Linecode=9 Length=0.225
New Line.l77 Phases=3 Bus1=76.1.2.3 Bus2=86.1.2.3 Linecode=3 Length=0.7
New Line.l36 Phases=3 Bus1=35.1.2.3 Bus2=40.1.2.3 Linecode=1 Length=0.25
New Line.l113 Phases=1 Bus1=113.1 Bus2=114.1 Linecode=9 Length=0.325

Appendix C5 – OpenDSS netlist of the reference network – SP2 - continued

C5-4- Lines - continued

New Line.l64 Phases=3 Bus1=64.1.2.3 Bus2=65.1.2.3 Linecode=12 Length=0.425
New Line.l87 Phases=1 Bus1=87.1 Bus2=88.1 Linecode=9 Length=0.175
New Line.l63 Phases=3 Bus1=63.1.2.3 Bus2=64.1.2.3 Linecode=12 Length=0.35
New Line.l97 Phases=3 Bus1=98.1.2.3 Bus2=99.1.2.3 Linecode=3 Length=0.55
New Line.l84 Phases=3 Bus1=82.1.2.3 Bus2=83.1.2.3 Linecode=6 Length=0.25
New Line.l31 Phases=3 Bus1=29.1.2.3 Bus2=30.1.2.3 Linecode=2 Length=0.35
New Line.l117 Phases=3 Bus1=160r.1.2.3 Bus2=67.1.2.3 Linecode=6 Length=0.35
New Line.l37 Phases=1 Bus1=36.1 Bus2=37.1 Linecode=9 Length=0.3
New Line.l49 Phases=3 Bus1=49.1.2.3 Bus2=50.1.2.3 Linecode=4 Length=0.25
New Line.l78 Phases=3 Bus1=77.1.2.3 Bus2=78.1.2.3 Linecode=6 Length=0.1
New Line.l105 Phases=3 Bus1=105.1.2.3 Bus2=108.1.2.3 Linecode=3 Length=0.325
New Line.l99 Phases=3 Bus1=100.1.2.3 Bus2=450.1.2.3 Linecode=3 Length=0.8
New Line.l101 Phases=3 Bus1=101.1.2.3 Bus2=105.1.2.3 Linecode=3 Length=0.275
New Line.l106 Phases=1 Bus1=106.2 Bus2=107.2 Linecode=10 Length=0.575
New Line.l48 Phases=3 Bus1=47.1.2.3 Bus2=49.1.2.3 Linecode=4 Length=0.25
New Line.l43 Phases=3 Bus1=42.1.2.3 Bus2=44.1.2.3 Linecode=1 Length=0.2
New Line.l118 Phases=3 Bus1=197.1.2.3 Bus2=101.1.2.3 Linecode=3 Length=0.25
New Line.l74 Phases=1 Bus1=73.3 Bus2=74.3 Linecode=11 Length=0.35
New Line.l51 Phases=3 Bus1=51.1.2.3 Bus2=151.1.2.3 Linecode=4 Length=0.5
New Line.l14 Phases=1 Bus1=14.1 Bus2=11.1 Linecode=9 Length=0.25
New Line.l59 Phases=1 Bus1=58.2 Bus2=59.2 Linecode=10 Length=0.25
New Line.l86 Phases=3 Bus1=86.1.2.3 Bus2=87.1.2.3 Linecode=6 Length=0.45
New Line.l5 Phases=1 Bus1=3.3 Bus2=5.3 Linecode=11 Length=0.325
New Line.l45 Phases=3 Bus1=44.1.2.3 Bus2=47.1.2.3 Linecode=1 Length=0.25
New Line.l6 Phases=1 Bus1=5.3 Bus2=6.3 Linecode=11 Length=0.25
New Line.l109 Phases=1 Bus1=109.1 Bus2=110.1 Linecode=9 Length=0.3
New Line.l103 Phases=1 Bus1=103.3 Bus2=104.3 Linecode=11 Length=0.7
New Line.l95 Phases=1 Bus1=95.2 Bus2=96.2 Linecode=10 Length=0.2
New Line.l23 Phases=1 Bus1=23.3 Bus2=24.3 Linecode=11 Length=0.55
New Line.l58 Phases=3 Bus1=57.1.2.3 Bus2=60.1.2.3 Linecode=3 Length=0.75
New Line.l108 Phases=3 Bus1=108.1.2.3 Bus2=300.1.2.3 Linecode=3 Length=1.0
New Line.l88 Phases=3 Bus1=87.1.2.3 Bus2=89.1.2.3 Linecode=6 Length=0.275

Appendix C5 – OpenDSS netlist of the reference network – SP2 - continued

C5-4- Lines - continued

New Line.l25 Phases=2 Bus1=25r.3.1 Bus2=26.3.1 Linecode=7 Length=0.35
New Line.l185 Phases=1 Bus1=85.3 Bus2=185.3 Linecode=10 Length=0.3
New Line.l57 Phases=1 Bus1=57.2 Bus2=58.2 Linecode=10 Length=0.25
New Line.l107 Phases=1 Bus1=108.1 Bus2=109.1 Linecode=9 Length=0.45
New Line.l112 Phases=1 Bus1=112.1 Bus2=113.1 Linecode=9 Length=0.525
New Line.l66 Phases=1 Bus1=67.1 Bus2=68.1 Linecode=9 Length=0.2
New Line.l80 Phases=3 Bus1=78.1.2.3 Bus2=80.1.2.3 Linecode=6 Length=0.475
New Line.l18 Phases=1 Bus1=18.1 Bus2=19.1 Linecode=9 Length=0.25
New Line.l73 Phases=3 Bus1=72.1.2.3 Bus2=76.1.2.3 Linecode=3 Length=0.2
New Line.l70 Phases=1 Bus1=69.1 Bus2=70.1 Linecode=9 Length=0.325
New Line.l94 Phases=3 Bus1=93.1.2.3 Bus2=95.1.2.3 Linecode=6 Length=0.3
New Line.l79 Phases=3 Bus1=78.1.2.3 Bus2=79.1.2.3 Linecode=6 Length=0.225
New Line.l34 Phases=1 Bus1=34.3 Bus2=15.3 Linecode=11 Length=0.1
New Line.l42 Phases=1 Bus1=42.2 Bus2=43.2 Linecode=10 Length=0.5
New Line.l46 Phases=1 Bus1=45.1 Bus2=46.1 Linecode=9 Length=0.3
New Line.l104 Phases=1 Bus1=105.2 Bus2=106.2 Linecode=10 Length=0.225
New Line.l62 Phases=3 Bus1=62.1.2.3 Bus2=63.1.2.3 Linecode=12 Length=0.175
New Line.l65 Phases=3 Bus1=65.1.2.3 Bus2=66.1.2.3 Linecode=12 Length=0.325
New Line.l12 Phases=1 Bus1=13.3 Bus2=34.3 Linecode=11 Length=0.15
New Line.l16 Phases=1 Bus1=15.3 Bus2=16.3 Linecode=11 Length=0.375
New Line.l30 Phases=3 Bus1=28.1.2.3 Bus2=29.1.2.3 Linecode=2 Length=0.3
New Line.l56 Phases=3 Bus1=55.1.2.3 Bus2=56.1.2.3 Linecode=1 Length=0.275
New Line.l40 Phases=1 Bus1=40.3 Bus2=41.3 Linecode=11 Length=0.325
New Line.l54 Phases=3 Bus1=54.1.2.3 Bus2=55.1.2.3 Linecode=1 Length=0.275
New Line.l39 Phases=1 Bus1=38.2 Bus2=39.2 Linecode=10 Length=0.325
New Line.l52 Phases=3 Bus1=52.1.2.3 Bus2=53.1.2.3 Linecode=1 Length=0.2

Note : new lines generated from the network model in SP2 are highlighted in red

Appendix C5 – OpenDSS netlist of the reference network – SP2 - continued

C5-6- Loads

The loads are defined in a file called : Test_Loads.DSS. As already explained, the load models have been changed to ‘Constant power’ to be able to run a time series power flow. The content is given below:

!LOADSHAPES DEFINITION

```
New LoadShape.loadcurve_s92c npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s92c.txt action=normalize
New LoadShape.loadcurve_s76c npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s76c.txt action=normalize
New LoadShape.loadcurve_s4c npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s4c.txt action=normalize
New LoadShape.loadcurve_s42a npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s42a.txt action=normalize
New LoadShape.loadcurve_s9a npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s9a.txt action=normalize
New LoadShape.loadcurve_s103c npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s103c.txt action=normalize
New LoadShape.loadcurve_s35a npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s35a.txt action=normalize
New LoadShape.loadcurve_s45a npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s45a.txt action=normalize
New LoadShape.loadcurve_s51a npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s51a.txt action=normalize
New LoadShape.loadcurve_s55a npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s55a.txt action=normalize
New LoadShape.loadcurve_s65b npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s65b.txt action=normalize
New LoadShape.loadcurve_s58b npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s58b.txt action=normalize
New LoadShape.loadcurve_s83c npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s83c.txt action=normalize
New LoadShape.loadcurve_s77b npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s77b.txt action=normalize
New LoadShape.loadcurve_s49c npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s49c.txt action=normalize
New LoadShape.loadcurve_s5c npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s5c.txt action=normalize
New LoadShape.loadcurve_s60a npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s60a.txt action=normalize
New LoadShape.loadcurve_s33a npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s33a.txt action=normalize
New LoadShape.loadcurve_s96b npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s96b.txt action=normalize
New LoadShape.loadcurve_s99b npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s99b.txt action=normalize
New LoadShape.loadcurve_s10a npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s10a.txt action=normalize
New LoadShape.loadcurve_s43b npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s43b.txt action=normalize
New LoadShape.loadcurve_s95b npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s95b.txt action=normalize
New LoadShape.loadcurve_s68a npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s68a.txt action=normalize
New LoadShape.loadcurve_s106b npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s106b.txt action=normalize
New LoadShape.loadcurve_s30c npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s30c.txt action=normalize
New LoadShape.loadcurve_s24c npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s24c.txt action=normalize
New LoadShape.loadcurve_s38b npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s38b.txt action=normalize
```

Appendix C5 – OpenDSS netlist of the reference network – SP2 - continued

C5-6- Loads - continued

New LoadShape.loadcurve_s17c npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s17c.txt action=normalize
New LoadShape.loadcurve_s94a npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s94a.txt action=normalize
New LoadShape.loadcurve_s46a npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s46a.txt action=normalize
New LoadShape.loadcurve_s65c npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s65c.txt action=normalize
New LoadShape.loadcurve_s107b npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s107b.txt action=normalize
New LoadShape.loadcurve_s111a npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s111a.txt action=normalize
New LoadShape.loadcurve_s70a npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s70a.txt action=normalize
New LoadShape.loadcurve_s104c npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s104c.txt action=normalize
New LoadShape.loadcurve_s86b npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s86b.txt action=normalize
New LoadShape.loadcurve_s39b npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s39b.txt action=normalize
New LoadShape.loadcurve_s12b npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s12b.txt action=normalize
New LoadShape.loadcurve_s49a npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s49a.txt action=normalize
New LoadShape.loadcurve_s62c npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s62c.txt action=normalize
New LoadShape.loadcurve_s20a npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s20a.txt action=normalize
New LoadShape.loadcurve_s28a npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s28a.txt action=normalize
New LoadShape.loadcurve_s113a npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s113a.txt action=normalize
New LoadShape.loadcurve_s6c npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s6c.txt action=normalize
New LoadShape.loadcurve_s29a npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s29a.txt action=normalize
New LoadShape.loadcurve_s32c npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s32c.txt action=normalize
New LoadShape.loadcurve_s11a npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s11a.txt action=normalize
New LoadShape.loadcurve_s41c npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s41c.txt action=normalize
New LoadShape.loadcurve_s71a npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s71a.txt action=normalize
New LoadShape.loadcurve_s59b npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s59b.txt action=normalize
New LoadShape.loadcurve_s79a npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s79a.txt action=normalize
New LoadShape.loadcurve_s31c npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s31c.txt action=normalize
New LoadShape.loadcurve_s69a npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s69a.txt action=normalize
New LoadShape.loadcurve_s74c npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s74c.txt action=normalize
New LoadShape.loadcurve_s114a npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s114a.txt action=normalize
New LoadShape.loadcurve_s112a npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s112a.txt action=normalize
New LoadShape.loadcurve_s73c npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s73c.txt action=normalize
New LoadShape.loadcurve_s65a npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s65a.txt action=normalize
New LoadShape.loadcurve_s50c npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s50c.txt action=normalize

Appendix C5 – OpenDSS netlist of the reference network – SP2 - continued

C5-6- Loads - continued

Note : new loads generated from the network model in SP2 are highlighted in red

New LoadShape.loadcurve_s66c npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s66c.txt action=normalize
New LoadShape.loadcurve_s56b npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s56b.txt action=normalize
New LoadShape.loadcurve_s84c npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s84c.txt action=normalize
New LoadShape.loadcurve_s90b npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s90b.txt action=normalize
New LoadShape.loadcurve_s2b npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s2b.txt action=normalize
New LoadShape.loadcurve_s34c npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s34c.txt action=normalize
New LoadShape.loadcurve_s251c npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s251c.txt action=normalize
New LoadShape.loadcurve_s49b npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s49b.txt action=normalize
New LoadShape.loadcurve_s7a npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s7a.txt action=normalize
New LoadShape.loadcurve_s48 npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s48.txt action=normalize
New LoadShape.loadcurve_s16c npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s16c.txt action=normalize
New LoadShape.loadcurve_s185b npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s185b.txt action=normalize
New LoadShape.loadcurve_s22b npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s22b.txt action=normalize
New LoadShape.loadcurve_s1a npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s1a.txt action=normalize
New LoadShape.loadcurve_s88a npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s88a.txt action=normalize
New LoadShape.loadcurve_s82a npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s82a.txt action=normalize
New LoadShape.loadcurve_s53a npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s53a.txt action=normalize
New LoadShape.loadcurve_s98a npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s98a.txt action=normalize
New LoadShape.loadcurve_s87b npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s87b.txt action=normalize
New LoadShape.loadcurve_s52a npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s52a.txt action=normalize
New LoadShape.loadcurve_s63a npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s63a.txt action=normalize
New LoadShape.loadcurve_s19a npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s19a.txt action=normalize
New LoadShape.loadcurve_s47 npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s47.txt action=normalize
New LoadShape.loadcurve_s76b npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s76b.txt action=normalize
New LoadShape.loadcurve_s85c npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s85c.txt action=normalize
New LoadShape.loadcurve_s100c npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s100c.txt action=normalize
New LoadShape.loadcurve_s109a npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s109a.txt action=normalize
New LoadShape.loadcurve_s102c npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s102c.txt action=normalize
New LoadShape.loadcurve_s64b npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s64b.txt action=normalize
New LoadShape.loadcurve_s76a npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s76a.txt action=normalize
New LoadShape.loadcurve_s37a npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s37a.txt action=normalize
New LoadShape.loadcurve_s80b npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s80b.txt action=normalize
New LoadShape.loadcurve_s75c npts=24 interval=1 csvfile=C:/Users/SESA160732/Documents/test/loadcurve_s75c.txt action=normalize

Appendix C5 – OpenDSS netlist of the reference network – SP2 - continued

C5-6- Loads - continued

!LOAD DEFINITION

New Load.s92c Bus1=92.3 Phases=1 Conn=Wye Model=1 kV=2.4 kW=40.0 kvar=20.0 daily=loadcurve_s92c status=variable
New Load.s76c Bus1=76.3.1 Phases=1 Conn=Delta Model=5 kV=4.16 kW=70.0 kvar=50.0 daily=loadcurve_s76c status=variable
New Load.s4c Bus1=4.3 Phases=1 Conn=Wye Model=1 kV=2.4 kW=40.0 kvar=20.0 daily=loadcurve_s4c status=variable
New Load.s42a Bus1=42.1 Phases=1 Conn=Wye Model=1 kV=2.4 kW=20.0 kvar=10.0 daily=loadcurve_s42a status=variable
New Load.s9a Bus1=9.1 Phases=1 Conn=Wye Model=1 kV=2.4 kW=40.0 kvar=20.0 daily=loadcurve_s9a status=variable
New Load.s103c Bus1=103.3 Phases=1 Conn=Wye Model=1 kV=2.4 kW=40.0 kvar=20.0 daily=loadcurve_s103c status=variable
New Load.s35a Bus1=35.1.2 Phases=1 Conn=Delta Model=1 kV=4.16 kW=40.0 kvar=20.0 daily=loadcurve_s35a status=variable
New Load.s45a Bus1=45.1 Phases=1 Conn=Wye Model=5 kV=2.4 kW=20.0 kvar=10.0 daily=loadcurve_s45a status=variable
New Load.s51a Bus1=51.1 Phases=1 Conn=Wye Model=1 kV=2.4 kW=20.0 kvar=10.0 daily=loadcurve_s51a status=variable
New Load.s55a Bus1=55.1 Phases=1 Conn=Wye Model=2 kV=2.4 kW=20.0 kvar=10.0 daily=loadcurve_s55a status=variable
New Load.s65b Bus1=65.2.3 Phases=1 Conn=Delta Model=2 kV=4.16 kW=35.0 kvar=25.0 daily=loadcurve_s65b status=variable
New Load.s58b Bus1=58.2 Phases=1 Conn=Wye Model=5 kV=2.4 kW=20.0 kvar=10.0 daily=loadcurve_s58b status=variable
New Load.s83c Bus1=83.3 Phases=1 Conn=Wye Model=1 kV=2.4 kW=20.0 kvar=10.0 daily=loadcurve_s83c status=variable
New Load.s77b Bus1=77.2 Phases=1 Conn=Wye Model=1 kV=2.4 kW=40.0 kvar=20.0 daily=loadcurve_s77b status=variable
New Load.s49c Bus1=49.3 Phases=1 Conn=Wye Model=1 kV=2.4 kW=35.0 kvar=20.0 daily=loadcurve_s49c status=variable
New Load.s5c Bus1=5.3 Phases=1 Conn=Wye Model=5 kV=2.4 kW=20.0 kvar=10.0 daily=loadcurve_s5c status=variable
New Load.s60a Bus1=60.1 Phases=1 Conn=Wye Model=1 kV=2.4 kW=20.0 kvar=10.0 daily=loadcurve_s60a status=variable
New Load.s33a Bus1=33.1 Phases=1 Conn=Wye Model=5 kV=2.4 kW=40.0 kvar=20.0 daily=loadcurve_s33a status=variable
New Load.s96b Bus1=96.2 Phases=1 Conn=Wye Model=1 kV=2.4 kW=20.0 kvar=10.0 daily=loadcurve_s96b status=variable
New Load.s99b Bus1=99.2 Phases=1 Conn=Wye Model=1 kV=2.4 kW=40.0 kvar=20.0 daily=loadcurve_s99b status=variable
New Load.s10a Bus1=10.1 Phases=1 Conn=Wye Model=5 kV=2.4 kW=20.0 kvar=10.0 daily=loadcurve_s10a status=variable
New Load.s43b Bus1=43.2 Phases=1 Conn=Wye Model=2 kV=2.4 kW=40.0 kvar=20.0 daily=loadcurve_s43b status=variable
New Load.s95b Bus1=95.2 Phases=1 Conn=Wye Model=1 kV=2.4 kW=20.0 kvar=10.0 daily=loadcurve_s95b status=variable
New Load.s68a Bus1=68.1 Phases=1 Conn=Wye Model=1 kV=2.4 kW=20.0 kvar=10.0 daily=loadcurve_s68a status=variable
New Load.s106b Bus1=106.2 Phases=1 Conn=Wye Model=1 kV=2.4 kW=40.0 kvar=20.0 daily=loadcurve_s106b status=variable
New Load.s30c Bus1=30.3 Phases=1 Conn=Wye Model=1 kV=2.4 kW=40.0 kvar=20.0 daily=loadcurve_s30c status=variable
New Load.s24c Bus1=24.3 Phases=1 Conn=Wye Model=1 kV=2.4 kW=40.0 kvar=20.0 daily=loadcurve_s24c status=variable
New Load.s38b Bus1=38.2 Phases=1 Conn=Wye Model=5 kV=2.4 kW=20.0 kvar=10.0 daily=loadcurve_s38b status=variable
New Load.s17c Bus1=17.3 Phases=1 Conn=Wye Model=1 kV=2.4 kW=20.0 kvar=10.0 daily=loadcurve_s17c status=variable
New Load.s94a Bus1=94.1 Phases=1 Conn=Wye Model=1 kV=2.4 kW=40.0 kvar=20.0 daily=loadcurve_s94a status=variable

Appendix C5 – OpenDSS netlist of the reference network – SP2 - continued

C5-6- Loads - continued

New Load.s46a Bus1=46.1 Phases=1 Conn=Wye Model=1 kV=2.4 kW=20.0 kvar=10.0 daily=loadcurve_s46a status=variable
New Load.s65c Bus1=65.3.1 Phases=1 Conn=Delta Model=2 kV=4.16 kW=70.0 kvar=50.0 daily=loadcurve_s65c status=variable
New Load.s107b Bus1=107.2 Phases=1 Conn=Wye Model=1 kV=2.4 kW=40.0 kvar=20.0 daily=loadcurve_s107b status=variable
New Load.s111a Bus1=111.1 Phases=1 Conn=Wye Model=1 kV=2.4 kW=20.0 kvar=10.0 daily=loadcurve_s111a status=variable
New Load.s70a Bus1=70.1 Phases=1 Conn=Wye Model=1 kV=2.4 kW=20.0 kvar=10.0 daily=loadcurve_s70a status=variable
New Load.s104c Bus1=104.3 Phases=1 Conn=Wye Model=1 kV=2.4 kW=40.0 kvar=20.0 daily=loadcurve_s104c status=variable
New Load.s86b Bus1=86.2 Phases=1 Conn=Wye Model=1 kV=2.4 kW=20.0 kvar=10.0 daily=loadcurve_s86b status=variable
New Load.s39b Bus1=39.2 Phases=1 Conn=Wye Model=1 kV=2.4 kW=20.0 kvar=10.0 daily=loadcurve_s39b status=variable
New Load.s12b Bus1=12.2 Phases=1 Conn=Wye Model=1 kV=2.4 kW=20.0 kvar=10.0 daily=loadcurve_s12b status=variable
New Load.s49a Bus1=49.1 Phases=1 Conn=Wye Model=1 kV=2.4 kW=35.0 kvar=25.0 daily=loadcurve_s49a status=variable
New Load.s62c Bus1=62.3 Phases=1 Conn=Wye Model=2 kV=2.4 kW=40.0 kvar=20.0 daily=loadcurve_s62c status=variable
New Load.s20a Bus1=20.1 Phases=1 Conn=Wye Model=5 kV=2.4 kW=40.0 kvar=20.0 daily=loadcurve_s20a status=variable
New Load.s28a Bus1=28.1 Phases=1 Conn=Wye Model=5 kV=2.4 kW=40.0 kvar=20.0 daily=loadcurve_s28a status=variable
New Load.s113a Bus1=113.1 Phases=1 Conn=Wye Model=2 kV=2.4 kW=40.0 kvar=20.0 daily=loadcurve_s113a status=variable
New Load.s6c Bus1=6.3 Phases=1 Conn=Wye Model=2 kV=2.4 kW=40.0 kvar=20.0 daily=loadcurve_s6c status=variable
New Load.s29a Bus1=29.1 Phases=1 Conn=Wye Model=2 kV=2.4 kW=40.0 kvar=20.0 daily=loadcurve_s29a status=variable
New Load.s32c Bus1=32.3 Phases=1 Conn=Wye Model=1 kV=2.4 kW=20.0 kvar=10.0 daily=loadcurve_s32c status=variable
New Load.s11a Bus1=11.1 Phases=1 Conn=Wye Model=2 kV=2.4 kW=40.0 kvar=20.0 daily=loadcurve_s11a status=variable
New Load.s41c Bus1=41.3 Phases=1 Conn=Wye Model=1 kV=2.4 kW=20.0 kvar=10.0 daily=loadcurve_s41c status=variable
New Load.s71a Bus1=71.1 Phases=1 Conn=Wye Model=1 kV=2.4 kW=40.0 kvar=20.0 daily=loadcurve_s71a status=variable
New Load.s59b Bus1=59.2 Phases=1 Conn=Wye Model=1 kV=2.4 kW=20.0 kvar=10.0 daily=loadcurve_s59b status=variable
New Load.s79a Bus1=79.1 Phases=1 Conn=Wye Model=2 kV=2.4 kW=40.0 kvar=20.0 daily=loadcurve_s79a status=variable
New Load.s31c Bus1=31.3 Phases=1 Conn=Wye Model=1 kV=2.4 kW=20.0 kvar=10.0 daily=loadcurve_s31c status=variable
New Load.s69a Bus1=69.1 Phases=1 Conn=Wye Model=1 kV=2.4 kW=40.0 kvar=20.0 daily=loadcurve_s69a status=variable
New Load.s74c Bus1=74.3 Phases=1 Conn=Wye Model=2 kV=2.4 kW=40.0 kvar=20.0 daily=loadcurve_s74c status=variable
New Load.s114a Bus1=114.1 Phases=1 Conn=Wye Model=1 kV=2.4 kW=20.0 kvar=10.0 daily=loadcurve_s114a status=variable
New Load.s112a Bus1=112.1 Phases=1 Conn=Wye Model=5 kV=2.4 kW=20.0 kvar=10.0 daily=loadcurve_s112a status=variable
New Load.s73c Bus1=73.3 Phases=1 Conn=Wye Model=1 kV=2.4 kW=40.0 kvar=20.0 daily=loadcurve_s73c status=variable
New Load.s65a Bus1=65.1.2 Phases=1 Conn=Delta Model=2 kV=4.16 kW=35.0 kvar=25.0 daily=loadcurve_s65a status=variable
New Load.s50c Bus1=50.3 Phases=1 Conn=Wye Model=1 kV=2.4 kW=40.0 kvar=20.0 daily=loadcurve_s50c status=variable
New Load.s66c Bus1=66.3 Phases=1 Conn=Wye Model=1 kV=2.4 kW=75.0 kvar=35.0 daily=loadcurve_s66c status=variable
New Load.s56b Bus1=56.2 Phases=1 Conn=Wye Model=1 kV=2.4 kW=20.0 kvar=10.0 daily=loadcurve_s56b status=variable

Appendix C5 – OpenDSS netlist of the reference network – SP2 - continued

C5-6- Loads - continued

Note : new loads generated from the network model in SP2 are highlighted in red

New Load.s84c Bus1=84.3 Phases=1 Conn=Wye Model=1 kV=2.4 kW=20.0 kvar=10.0 daily=loadcurve_s84c status=variable
New Load.s90b Bus1=90.2 Phases=1 Conn=Wye Model=5 kV=2.4 kW=40.0 kvar=20.0 daily=loadcurve_s90b status=variable
New Load.s2b Bus1=2.2 Phases=1 Conn=Wye Model=1 kV=2.4 kW=20.0 kvar=10.0 daily=loadcurve_s2b status=variable
New Load.s34c Bus1=34.3 Phases=1 Conn=Wye Model=2 kV=2.4 kW=40.0 kvar=20.0 daily=loadcurve_s34c status=variable
New Load.s251c Bus1=251.3 Phases=1 Conn=Wye Model=1 kV=2.4 kW=10.0 kvar=5.0 daily=loadcurve_s251c status=variable
New Load.s49b Bus1=49.2 Phases=1 Conn=Wye Model=1 kV=2.4 kW=70.0 kvar=50.0 daily=loadcurve_s49b status=variable
New Load.s7a Bus1=7.1 Phases=1 Conn=Wye Model=1 kV=2.4 kW=20.0 kvar=10.0 daily=loadcurve_s7a status=variable
New Load.s48 Bus1=48 Phases=3 Conn=Wye Model=2 kV=4.16 kW=210.0 kvar=150.0 daily=loadcurve_s48 status=variable
New Load.s16c Bus1=16.3 Phases=1 Conn=Wye Model=1 kV=2.4 kW=40.0 kvar=20.0 daily=loadcurve_s16c status=variable
New Load.s185b Bus1=185.2 Phases=1 Conn=Wye Model=1 kV=2.4 kW=10.0 kvar=5.0 daily=loadcurve_s185b status=variable
New Load.s22b Bus1=22.2 Phases=1 Conn=Wye Model=2 kV=2.4 kW=40.0 kvar=20.0 daily=loadcurve_s22b status=variable
New Load.s1a Bus1=1.1 Phases=1 Conn=Wye Model=1 kV=2.4 kW=40.0 kvar=20.0 daily=loadcurve_s1a status=variable
New Load.s88a Bus1=88.1 Phases=1 Conn=Wye Model=1 kV=2.4 kW=40.0 kvar=20.0 daily=loadcurve_s88a status=variable
New Load.s82a Bus1=82.1 Phases=1 Conn=Wye Model=1 kV=2.4 kW=40.0 kvar=20.0 daily=loadcurve_s82a status=variable
New Load.s53a Bus1=53.1 Phases=1 Conn=Wye Model=1 kV=2.4 kW=40.0 kvar=20.0 daily=loadcurve_s53a status=variable
New Load.s98a Bus1=98.1 Phases=1 Conn=Wye Model=1 kV=2.4 kW=40.0 kvar=20.0 daily=loadcurve_s98a status=variable
New Load.s87b Bus1=87.2 Phases=1 Conn=Wye Model=1 kV=2.4 kW=40.0 kvar=20.0 daily=loadcurve_s87b status=variable
New Load.s52a Bus1=52.1 Phases=1 Conn=Wye Model=1 kV=2.4 kW=40.0 kvar=20.0 daily=loadcurve_s52a status=variable
New Load.s63a Bus1=63.1 Phases=1 Conn=Wye Model=1 kV=2.4 kW=40.0 kvar=20.0 daily=loadcurve_s63a status=variable
New Load.s19a Bus1=19.1 Phases=1 Conn=Wye Model=1 kV=2.4 kW=40.0 kvar=20.0 daily=loadcurve_s19a status=variable
New Load.s47 Bus1=47 Phases=3 Conn=Wye Model=5 kV=4.16 kW=105.0 kvar=75.0 daily=loadcurve_s47 status=variable
New Load.s76b Bus1=76.2.3 Phases=1 Conn=Delta Model=5 kV=4.16 kW=70.0 kvar=50.0 daily=loadcurve_s76b status=variable
New Load.s85c Bus1=85.3 Phases=1 Conn=Wye Model=1 kV=2.4 kW=40.0 kvar=20.0 daily=loadcurve_s85c status=variable
New Load.s100c Bus1=100.3 Phases=1 Conn=Wye Model=2 kV=2.4 kW=40.0 kvar=20.0 daily=loadcurve_s100c status=variable
New Load.s109a Bus1=109.1 Phases=1 Conn=Wye Model=1 kV=2.4 kW=40.0 kvar=20.0 daily=loadcurve_s109a status=variable
New Load.s102c Bus1=102.3 Phases=1 Conn=Wye Model=1 kV=2.4 kW=20.0 kvar=10.0 daily=loadcurve_s102c status=variable
New Load.s64b Bus1=64.2 Phases=1 Conn=Wye Model=5 kV=2.4 kW=75.0 kvar=35.0 daily=loadcurve_s64b status=variable
New Load.s76a Bus1=76.1.2 Phases=1 Conn=Delta Model=5 kV=4.16 kW=105.0 kvar=80.0 daily=loadcurve_s76a status=variable
New Load.s37a Bus1=37.1 Phases=1 Conn=Wye Model=2 kV=2.4 kW=40.0 kvar=20.0 daily=loadcurve_s37a status=variable
New Load.s80b Bus1=80.2 Phases=1 Conn=Wye Model=1 kV=2.4 kW=40.0 kvar=20.0 daily=loadcurve_s80b status=variable
New Load.s75c Bus1=75.3 Phases=1 Conn=Wye Model=1 kV=2.4 kW=40.0 kvar=20.0 daily=loadcurve_s75c status=variable

Appendix C5 – OpenDSS netlist of the reference network – SP2 - continued

B5-11- Bus coordinates

The bus coordinates of the network are defined in a file called : *Test_Buscoords.DSS*. The content is given below in five blocks. For each block, the first column represents the bus name, the second and third being the corresponding (x,y) coordinates.

!BUS
COORDINATES
DEFINITION

Note : new buses generated from the network model in SP2 are highlighted in red

25r 1500 3150	26 1150 3150	25 1500 3150	59 1825 1850	20 925 2325
68 3725 1850	150 100 1500	36 2075 2000	18 1500 2325	900 4500 1375
77 3925 1375	78 4025 1375	63 3075 2275	17 1850 1250	84 4700 425
23 1500 2875	610 3275 1300	150r 100 1500	21 1500 2625	52 2000 1500
92 2550 825	103 4075 2450	64 3075 2625	94 2325 850	50 2475 3275
73 3800 1575	35 1975 2325	79 4250 1375	9r 1200 1725	85 4700 900
108 3525 3050	69 4000 1850	100 4650 2100	197 3525 2200	450 5450 2100
93 2325 1125	99 4350 2100	10 1450 2150	152 1600 1500	91 2550 1125
80 4025 900	47 1975 3275	43 2475 2825	46 2475 3025	1 700 1500
76 3525 1375	14 1200 2150	95 2025 1125	98 3800 2100	8 1200 1500
62 3075 2100	48 1825 3275	66 2650 2300	32 1150 3675	149 300 1500
74 4150 1575	45 2175 3025	31 1150 3375	107 4325 2725	89 2775 1125
27 875 3150	51 2725 3275	7 1000 1500	111 4275 3625	1000 1400 2450
44 1975 3025	55 2600 1500	28 1500 3350	70 4325 1850	15 1500 1250
57 2325 1850	65 2650 2625	29 1500 3650	104 4775 2450	22 975 2625
4 700 1050	58 2075 1850	105 3525 2725	13 1500 1500	34 1500 1350
96 2025 925	83 4275 175	106 3750 2725	72 3525 1575	71 4600 1850
61s 3175 1300	49 2225 3275	16 1500 875	102 3750 2450	101 3525 2450
40 1975 2575	3 700 1250	30 1850 3650	87 3050 1125	37 1775 2000
41 2300 2575	113 4800 2925	97 3525 2100	82 4025 175	114 5125 2925
67 3525 1850	88 2950 1300	109 3975 3050	39 2650 2000	81 4025 425
160r 3175 1850	60 3075 1850	86 3255 725	12 1200 1275	56 2875 1500
42 1975 2825	19 1250 2325	24 950 2875	53 2200 1500	135 1600 2325
185 4362 900	33 875 3650	6 1275 1150	11 950 2150	90 2775 900
5 1025 1250	160 3175 1850	38 2325 2000	151 3187 3928	110 4275 3050
9 1200 1725	112 4275 2925	61 3075 1300	2 700 1675	54 2325 1500

APPENDIX C6

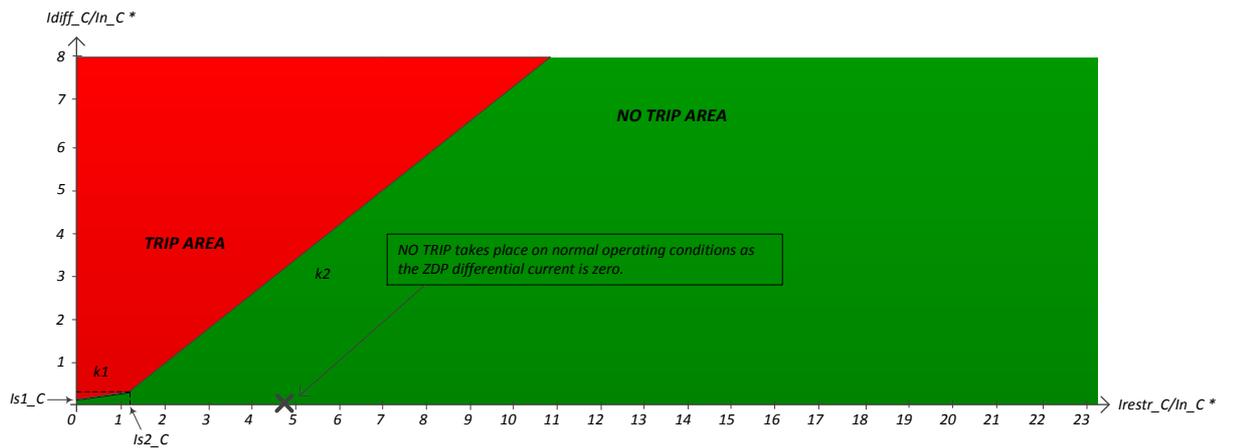
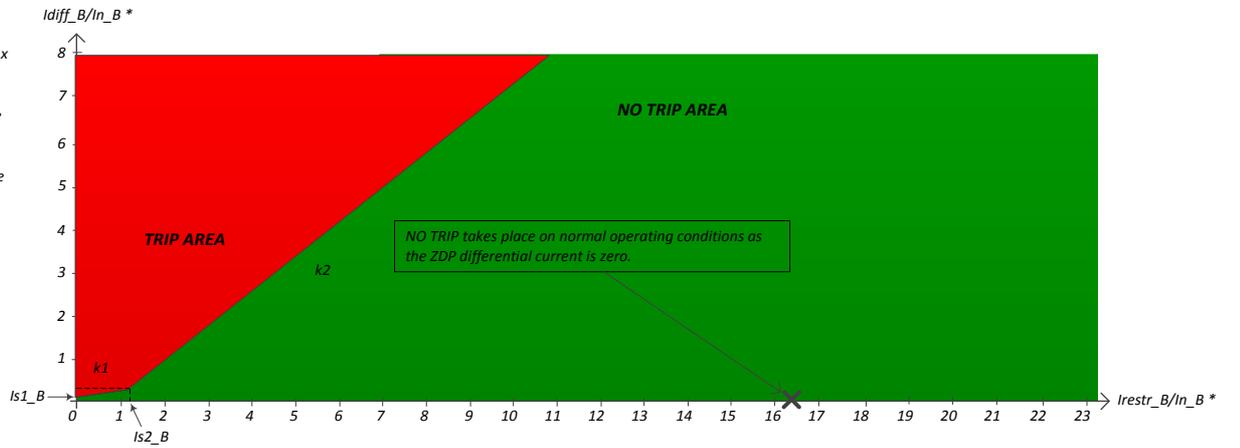
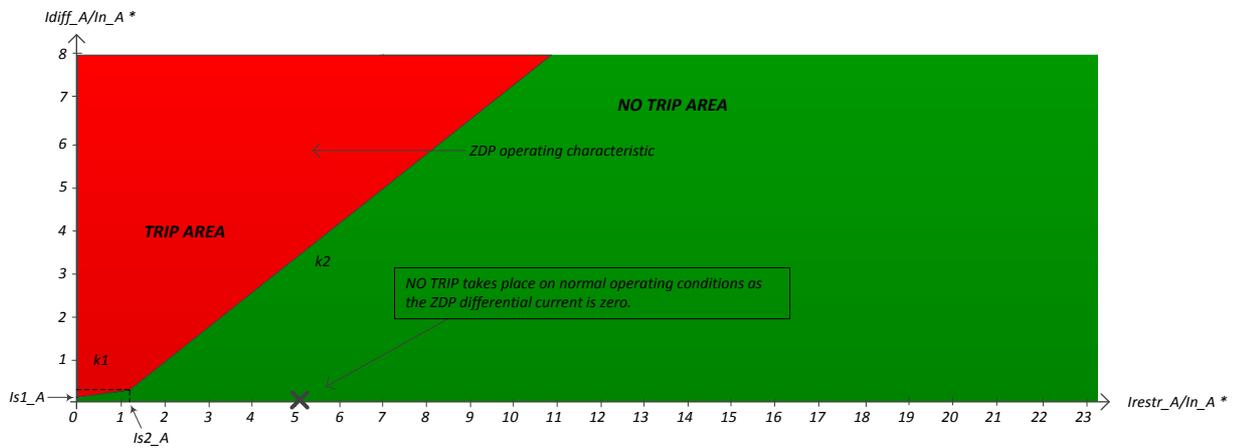
Power flow simulation results in SP2-
Extract (10 first simulation steps over 24)

Appendix C6 – Power flow simulation – SP2 - continued

Simulation step 1/24

Zone : 1

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	25.18-72.13j	14.83+15.24j	40.55+77.35j
BR1	174.40-381.96j	-282.58+46.30j	186.55+310.24j
BR2	-96.76+211.99j	188.47-18.92j	-98.79-162.76j
BR3	-52.42+97.83j	108.92-12.17j	-47.21-70.14j



* In_x is the rated current of the phase x of the current zone. x = A or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

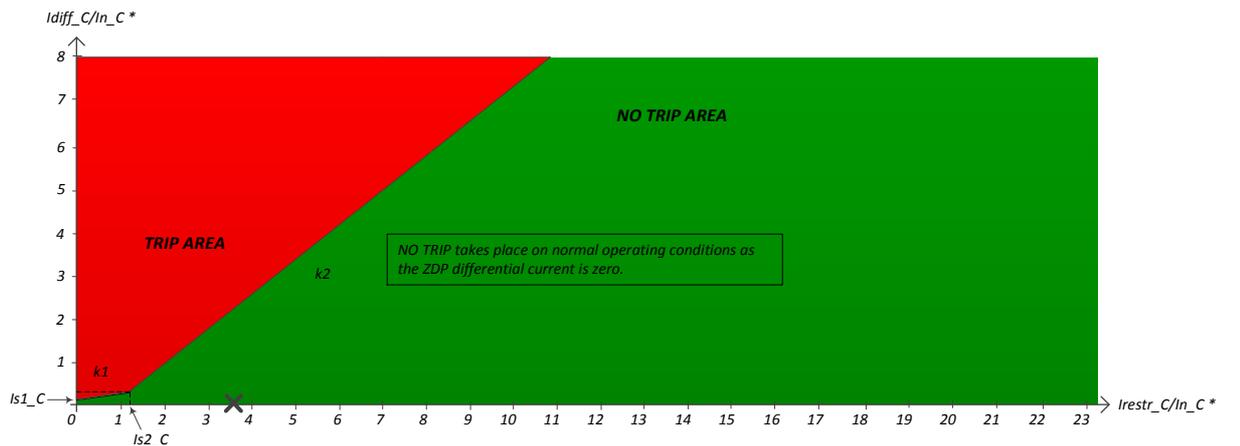
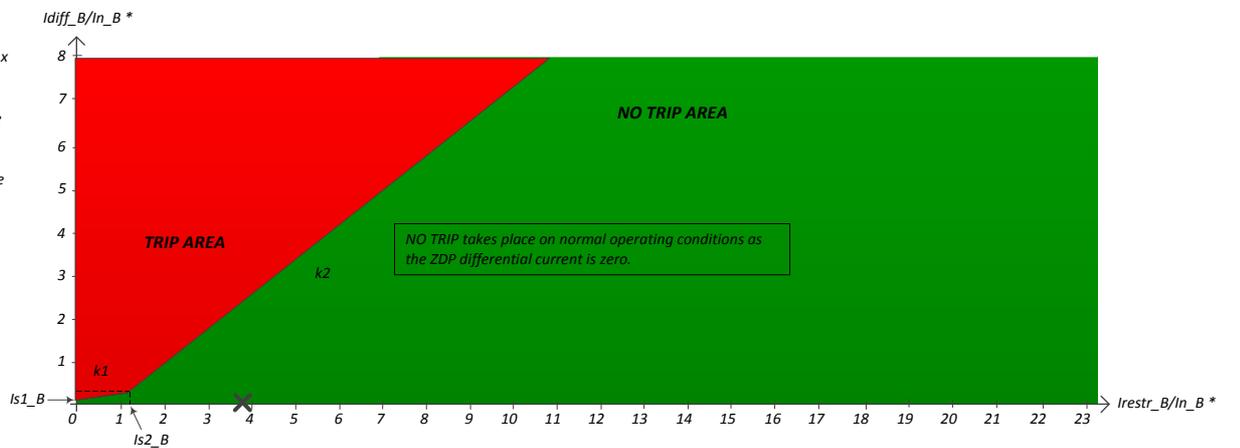
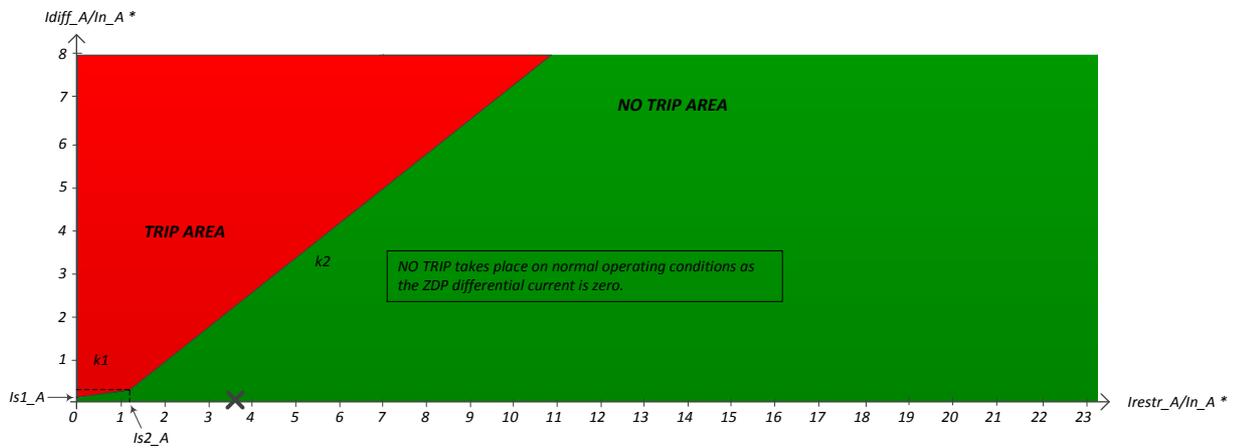
k1, k2 : slopes - k1=30% & k2=80%

Appendix C6 – Power flow simulation – SP2 - continued

Simulation step 1/24

Zone : 2

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	37.26-74.22j	-63.88+0.42j	29.86+55.90j
BR2	96.76-211.99j	-188.47+18.92j	98.79+162.76j
BR4	-59.47+137.77j	124.60-18.57j	-68.97-106.85j
BR6	-0.00-0.00j	-0.00-0.00j	-0.00-0.00j



* In_x is the rated current of the phase x of the current zone. $x = A$ or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

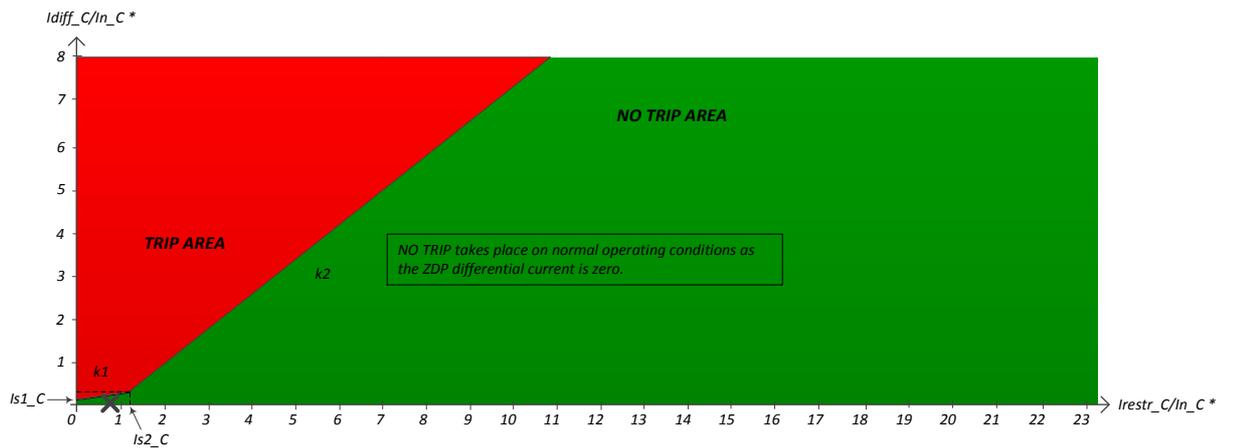
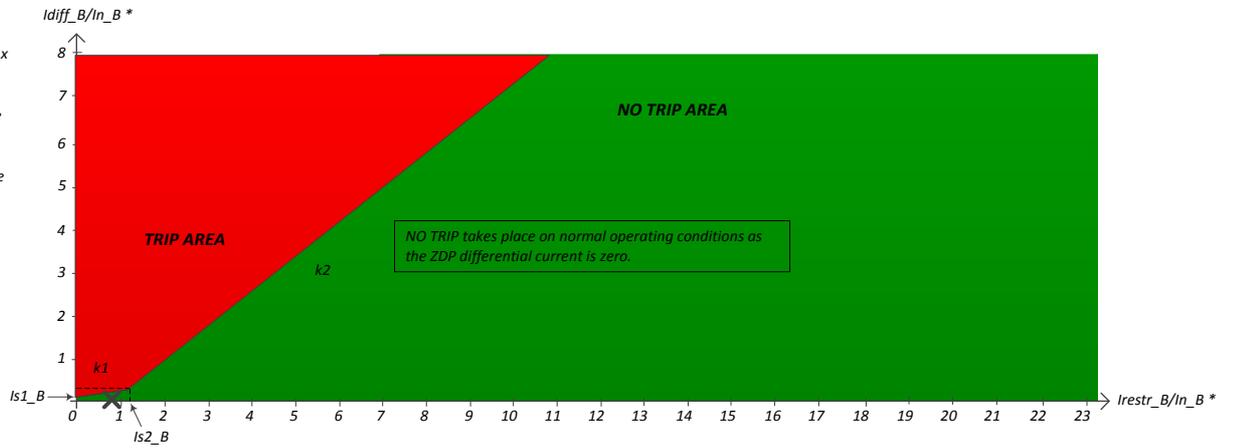
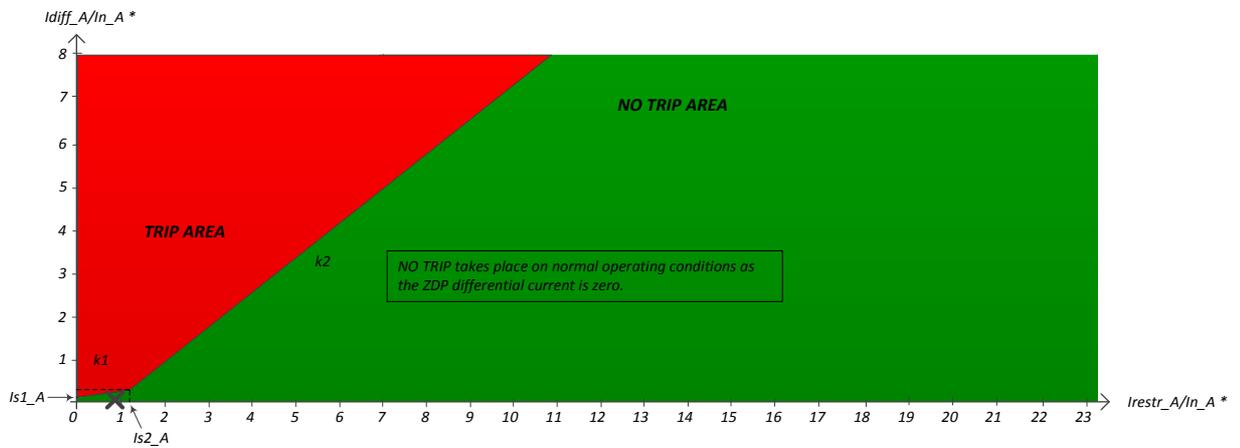
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix C6 – Power flow simulation – SP2

Simulation step 1/24

Zone : 3

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	52.40-97.81j	-108.91+12.20j	47.22+70.14j
BR3	52.42-97.83j	-108.92+12.17j	47.21+70.14j



* In_x is the rated current of the phase x of the current zone. $x = A$ or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

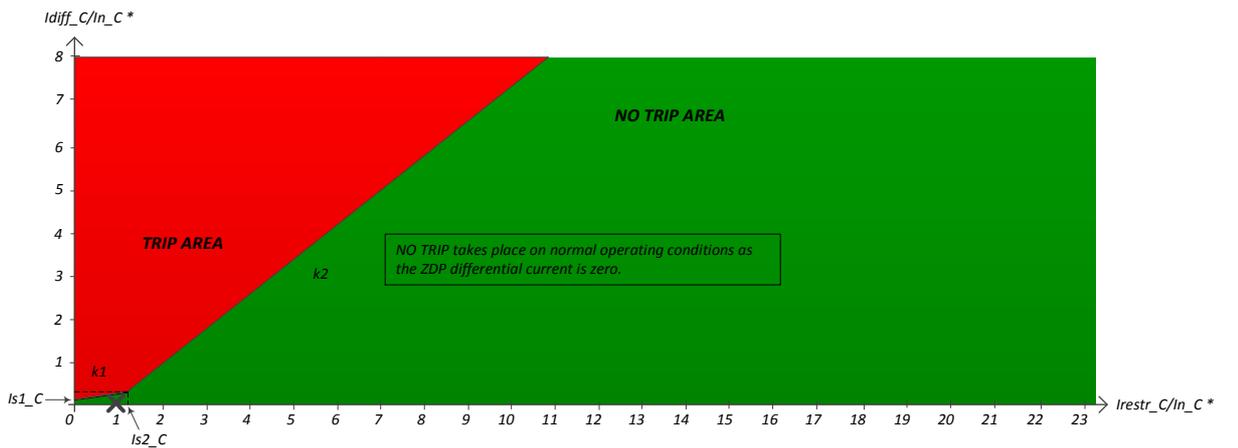
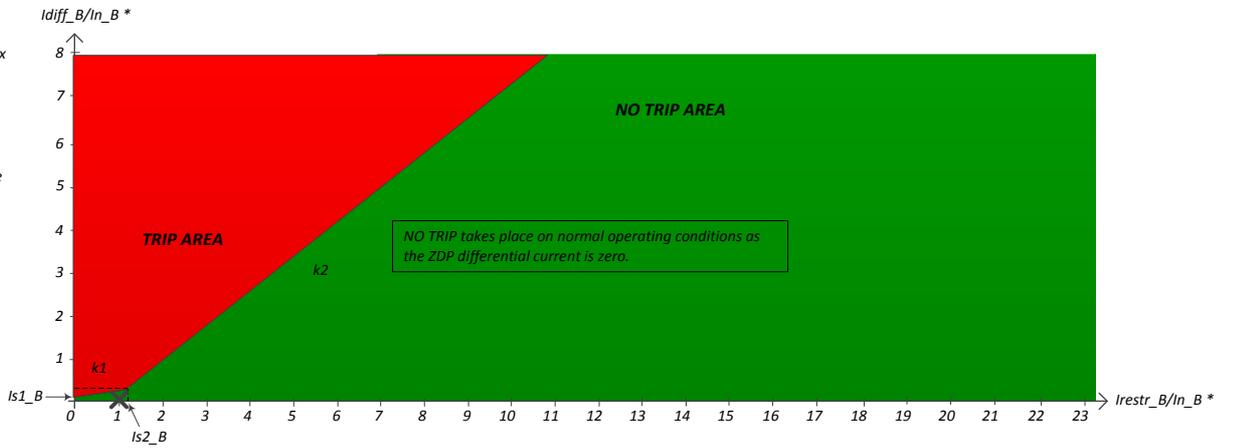
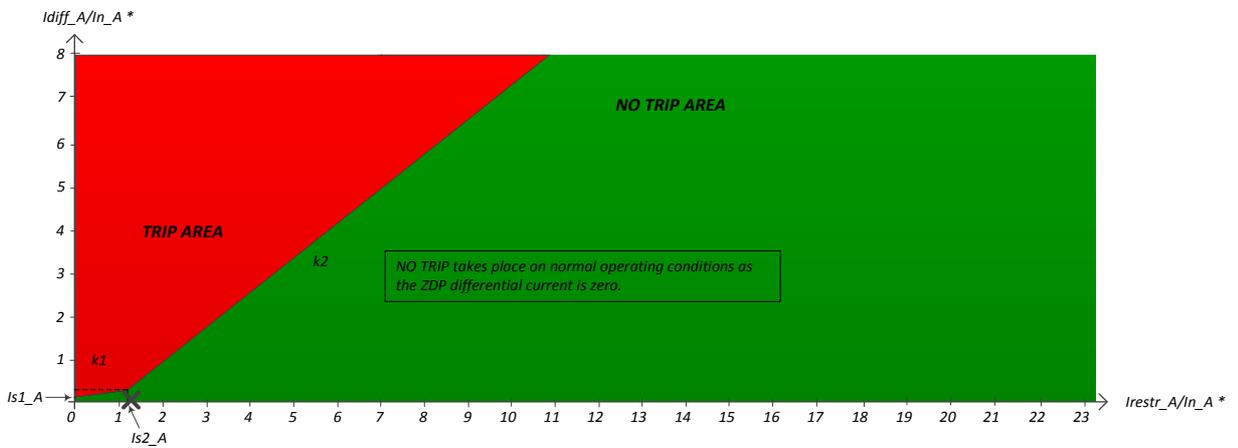
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix C6 – Power flow simulation – SP2 - continued

Simulation step 1/24

Zone : 4

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	33.02-92.21j	-92.26+19.45j	50.62+74.18j
BR5	-26.41+45.54j	32.36+0.82j	-18.38-32.67j
BR4	59.47-137.77j	-124.60+18.57j	68.97+106.85j



* In_x is the rated current of the phase x of the current zone. $x = A$ or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

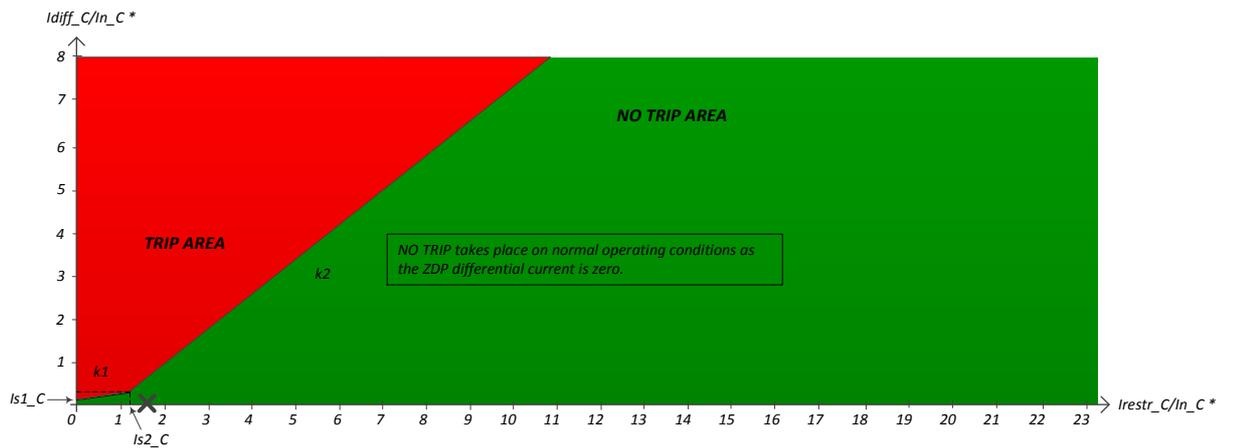
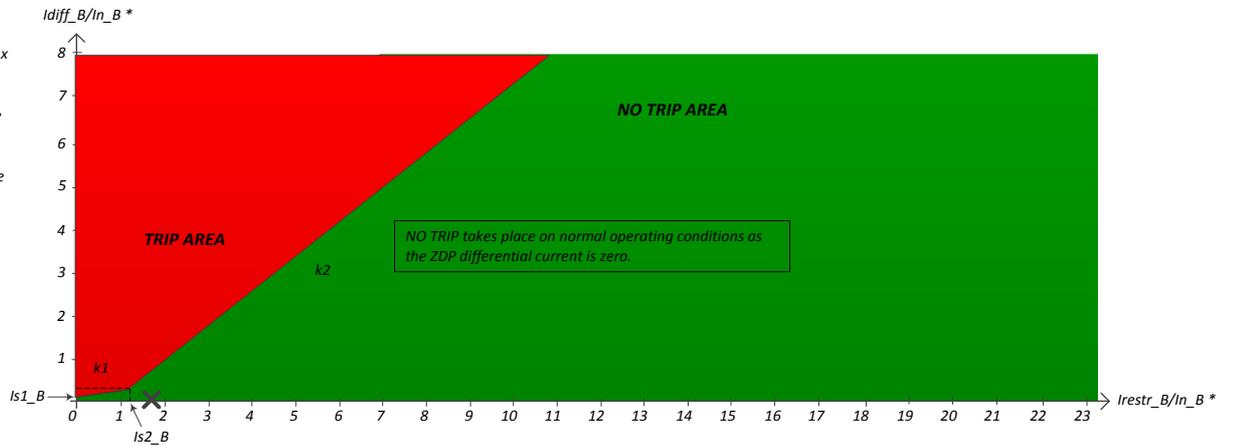
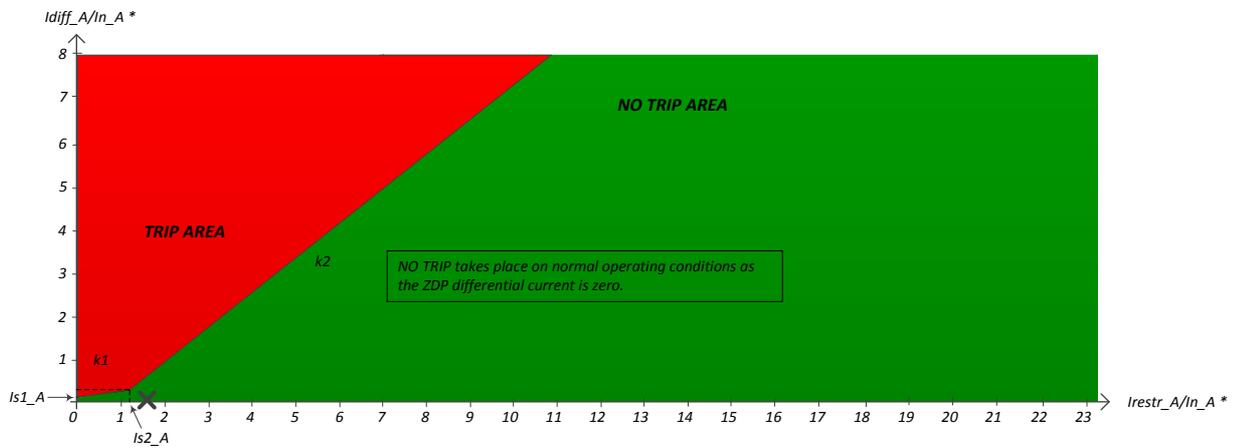
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix C6 – Power flow simulation – SP2 - continued

Simulation step 1/24

Zone : 5

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	26.39-45.53j	-32.36-0.81j	18.39+32.67j
BR5	26.41-45.54j	-32.36-0.82j	18.38+32.67j



* In_x is the rated current of the phase x of the current zone. $x = A$ or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

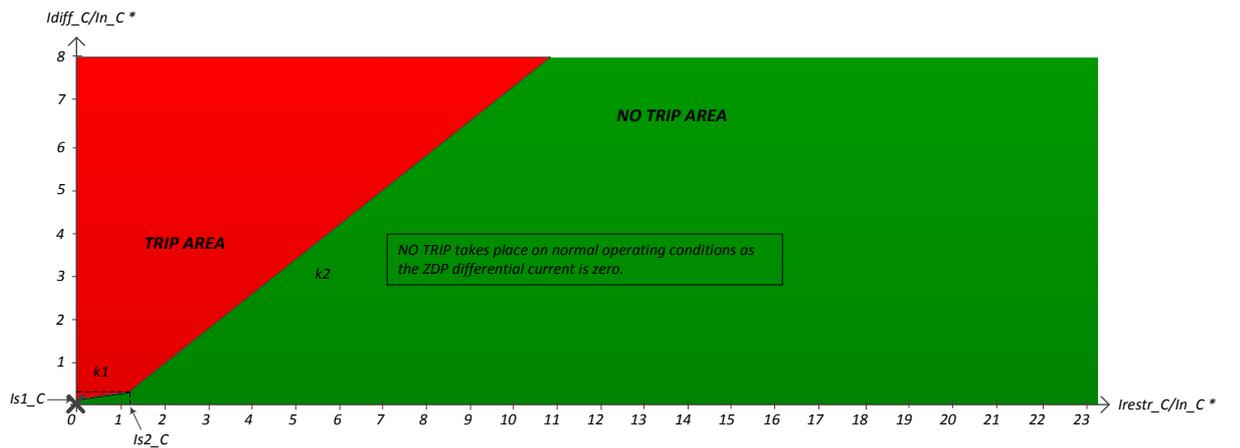
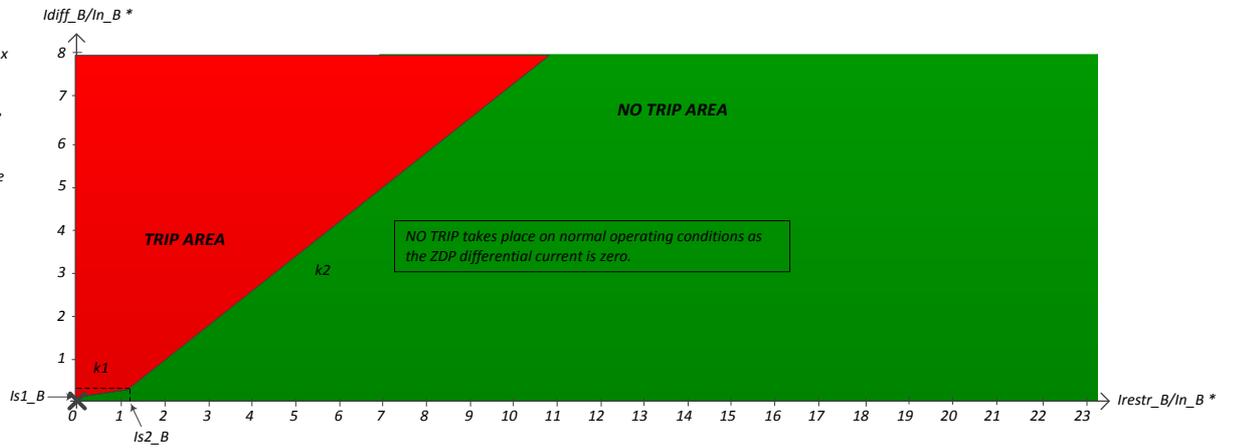
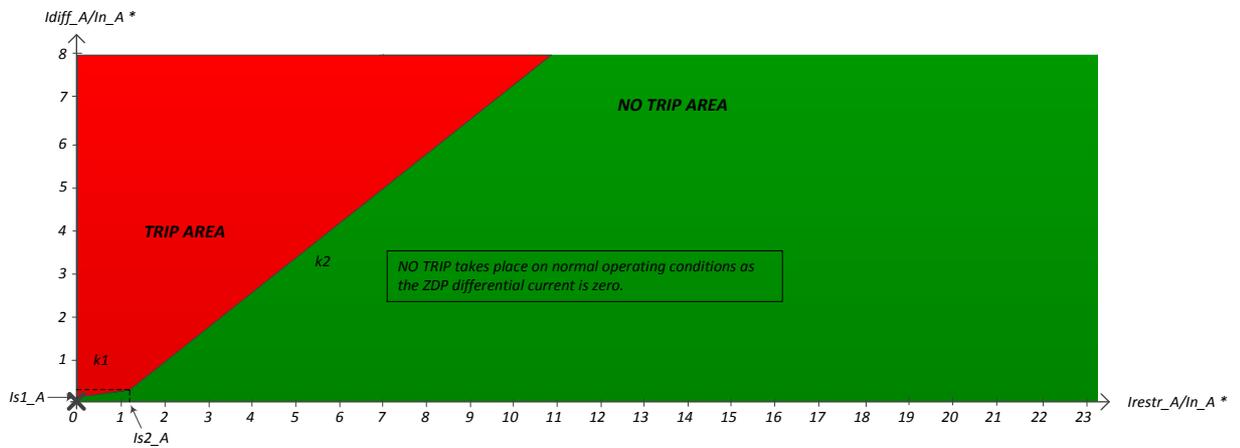
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix C6 – Power flow simulation – SP2 - continued

Simulation step 1/24

Zone : 6

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	0.00+0.00j	0.00+0.00j	0.00+0.00j
BR6	0.00+0.00j	0.00+0.00j	0.00+0.00j



* In_x is the rated current of the phase x of the current zone. $x = A$ or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

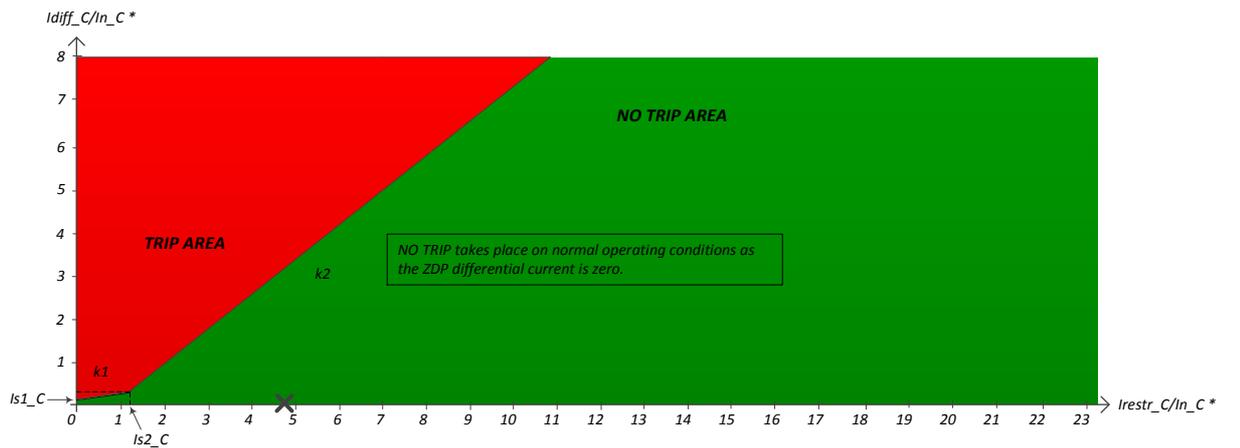
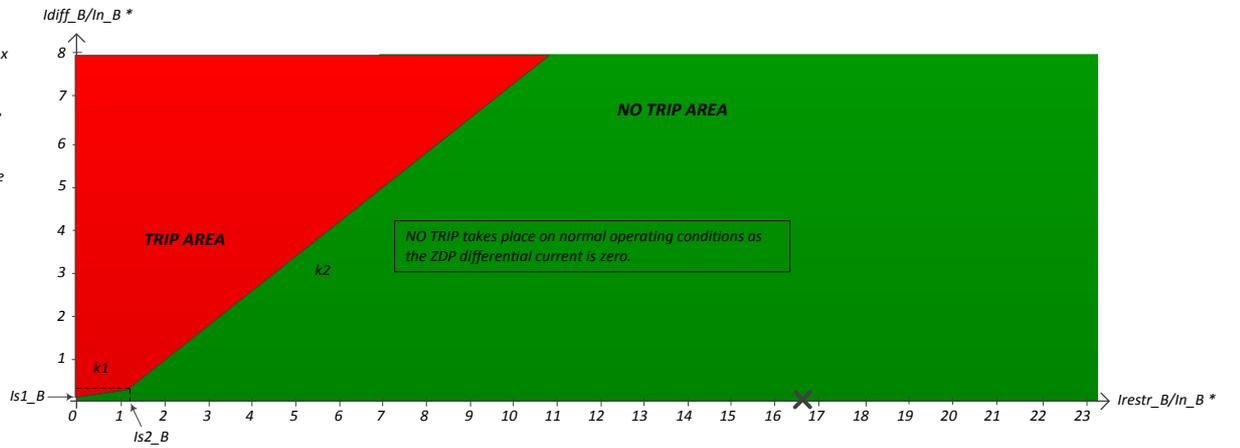
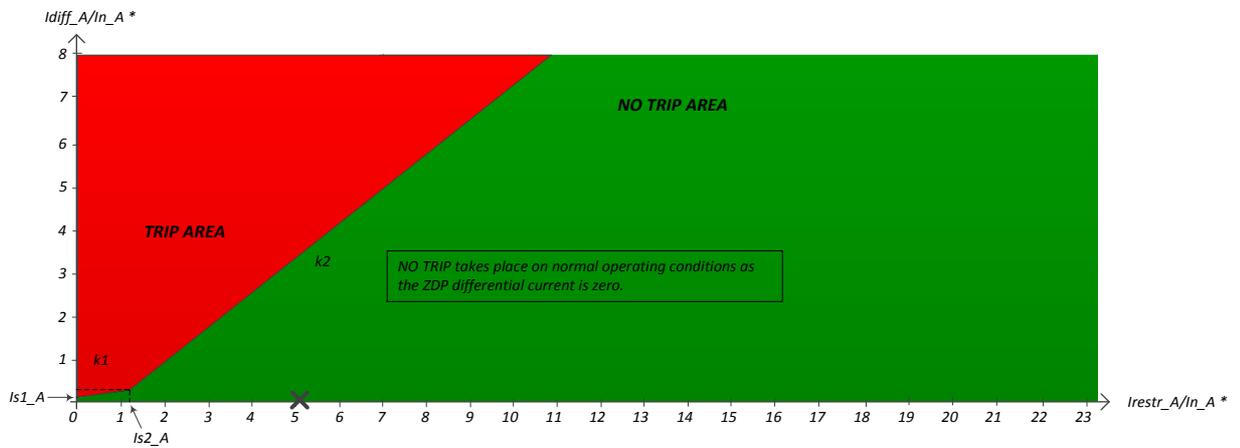
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix C6 – Power flow simulation – SP2 - continued

Simulation step 2/24

Zone : 1

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	25.38-69.20j	8.57+13.78j	36.13+69.66j
BR1	179.52-384.30j	-294.55+44.62j	186.13+309.79j
BR2	-101.64+217.70j	194.45-18.54j	-106.01-174.98j
BR3	-52.48+97.38j	108.66-12.34j	-44.01-65.14j



* In_x is the rated current of the phase x of the current zone. $x = A$ or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

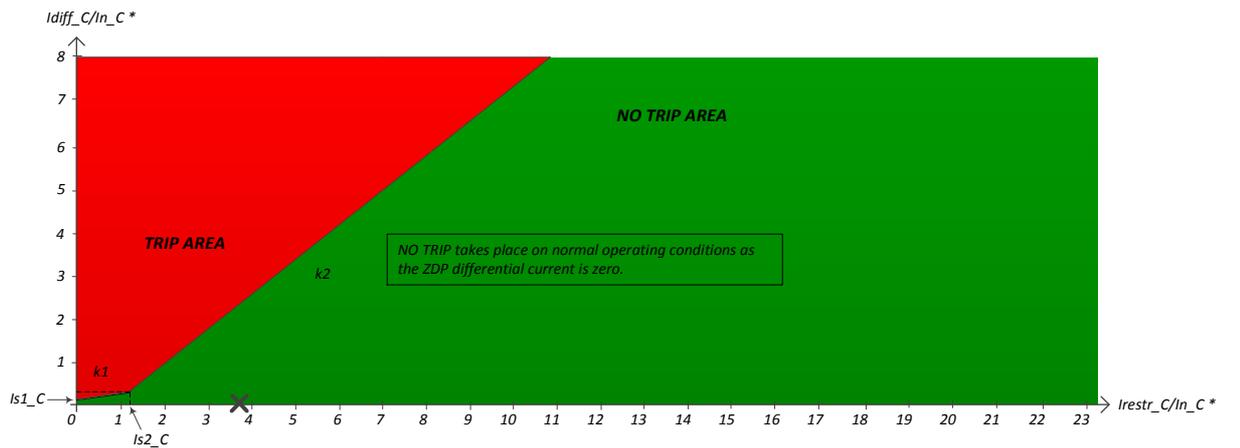
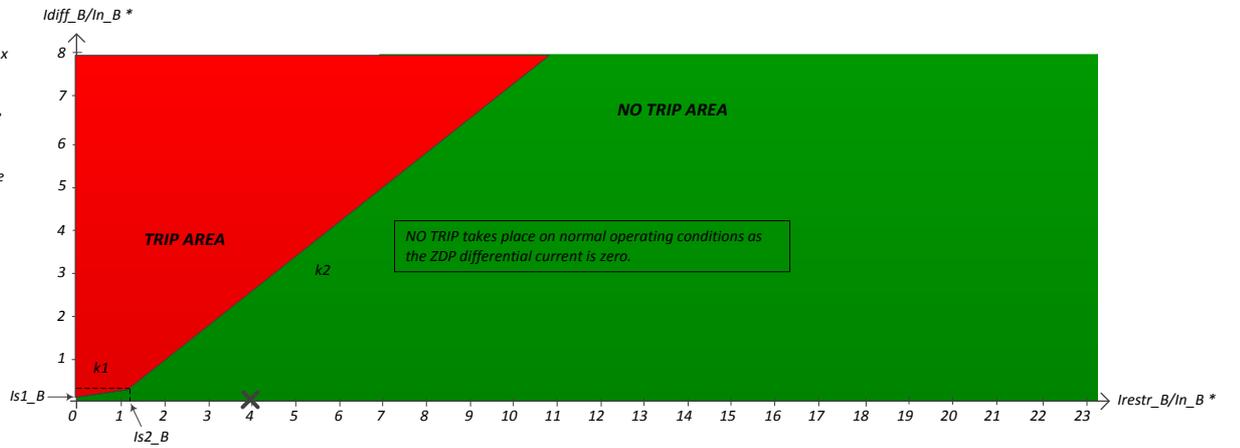
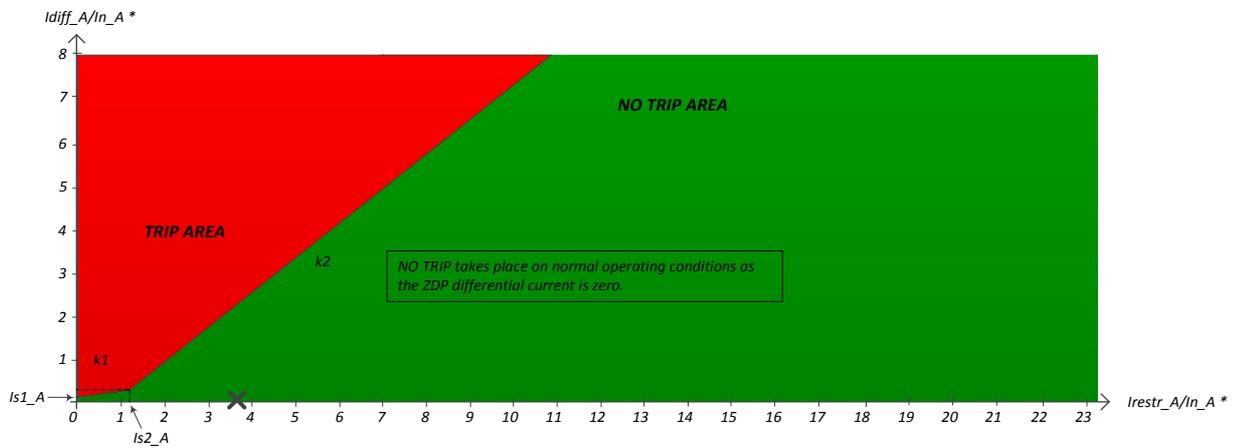
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix C6 – Power flow simulation – SP2 - continued

Simulation step 2/24

Zone : 2

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	39.19-79.67j	-63.02-0.01j	32.98+61.27j
BR2	101.64-217.70j	-194.45+18.54j	106.01+174.98j
BR4	-62.41+138.04j	131.45-18.62j	-73.08-113.71j
BR6	-0.00-0.00j	-0.00-0.00j	-0.00-0.00j



* In_x is the rated current of the phase x of the current zone. $x = A$ or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

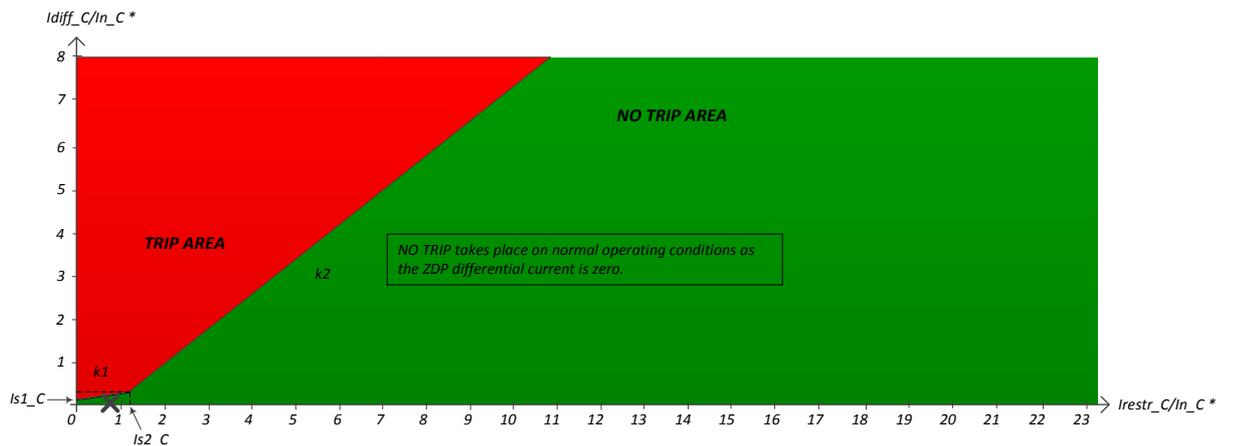
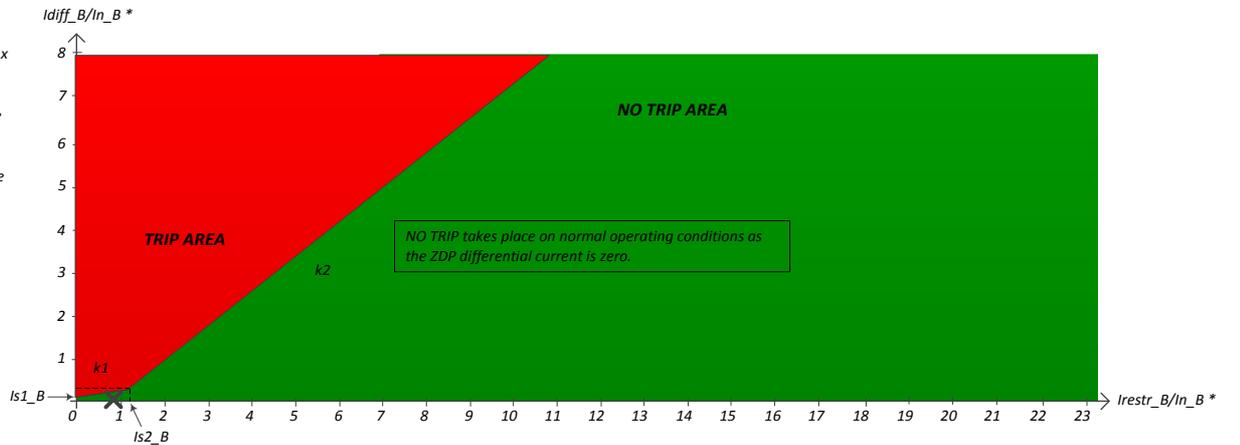
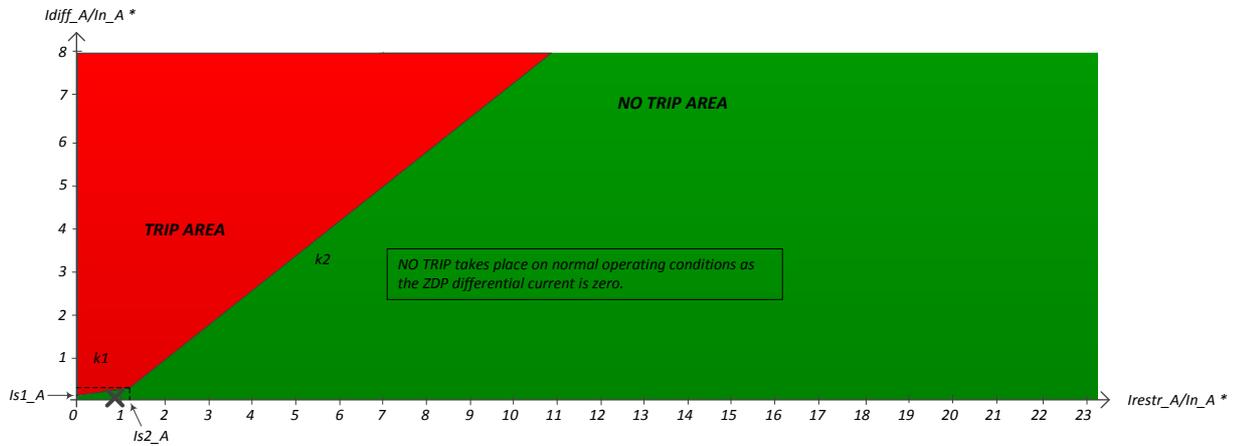
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix C6 – Power flow simulation – SP2

Simulation step 2/24

Zone : 3

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	52.46-97.38j	-108.65+12.38j	44.03+65.14j
BR3	52.48-97.38j	-108.66+12.34j	44.01+65.14j



* In_x is the rated current of the phase x of the current zone. $x = A$ or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

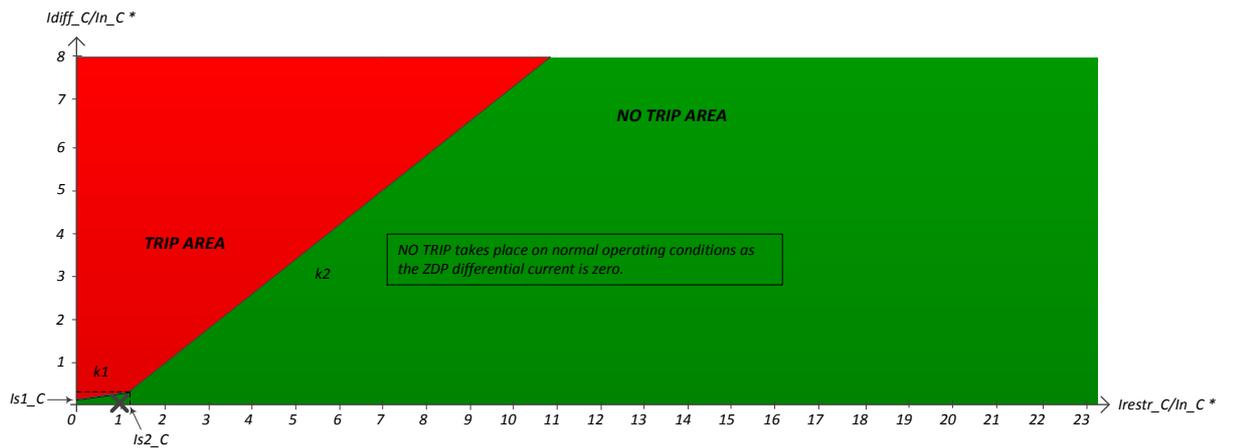
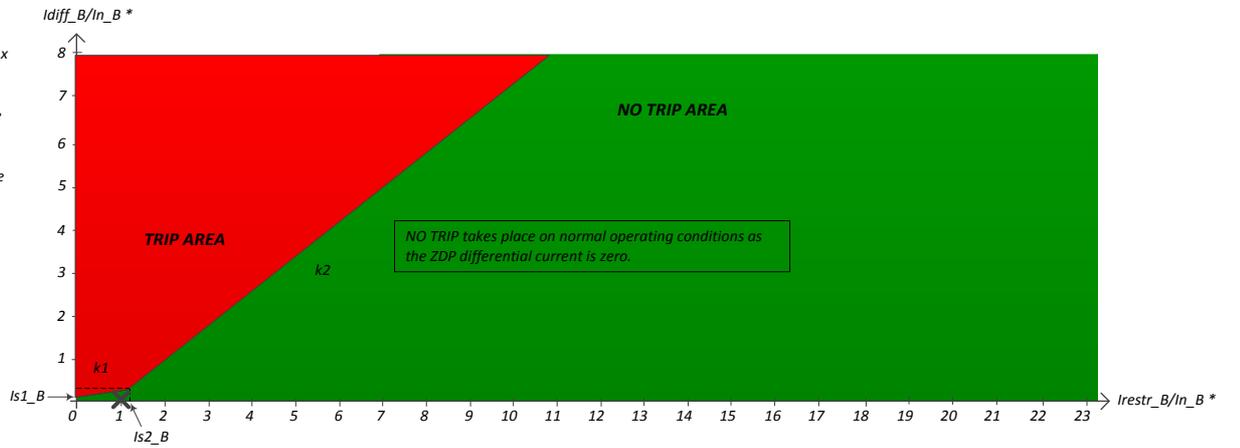
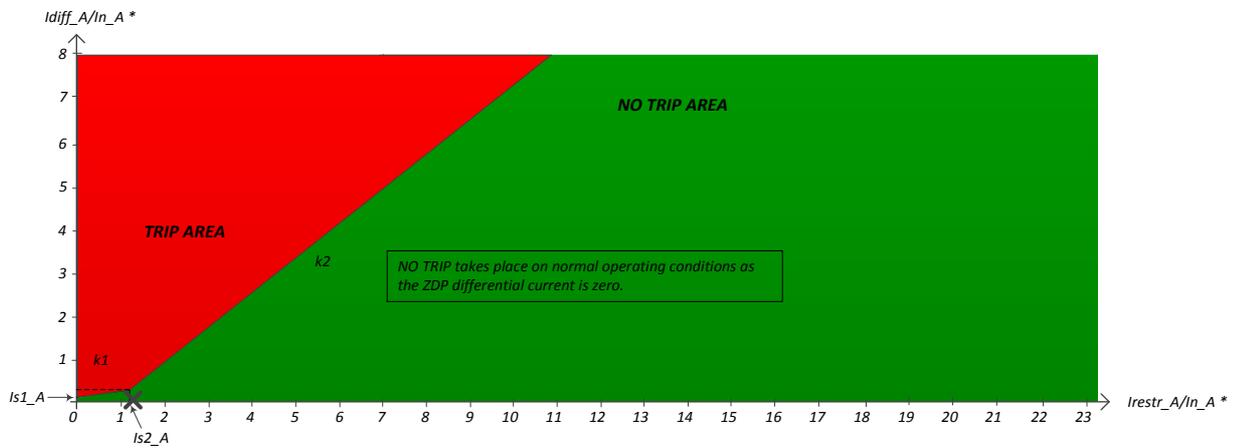
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix C6 – Power flow simulation – SP2 - continued

Simulation step 2/24

Zone : 4

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	35.86-92.19j	-97.08+19.51j	52.11+76.60j
BR5	-26.49+45.83j	34.39+0.84j	-20.99-37.13j
BR4	62.41-138.04j	-131.45+18.62j	73.08+113.71j



* I_{n_x} is the rated current of the phase x of the current zone. x = A or B or C

I_{diff_x} is the differential current on the phase x of the current zone.

I_{restr_x} is the restraining current on the phase x of the current zone.

I_{s1_x} is the differential current pick-up setting. It is set to 10% of the phase x rated current.

I_{s2_x} is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

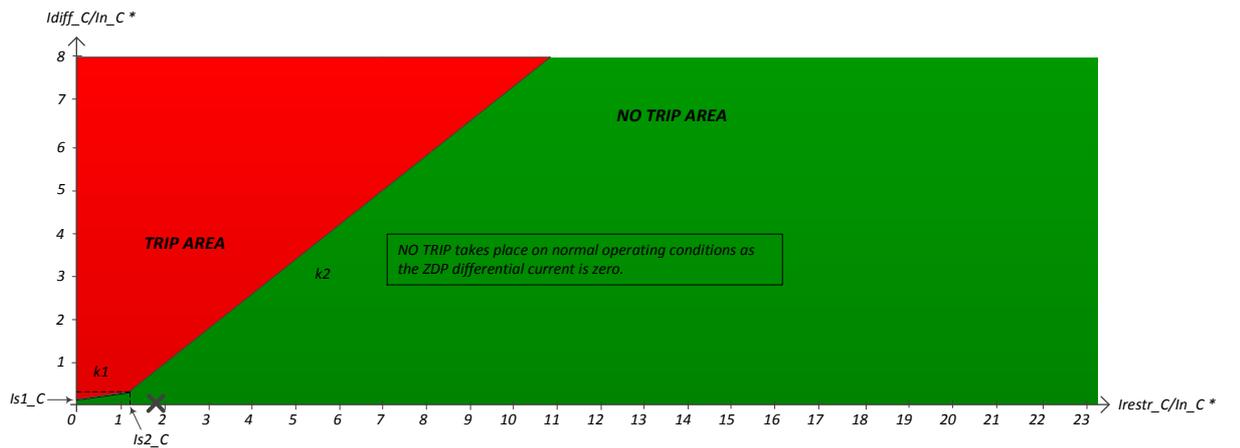
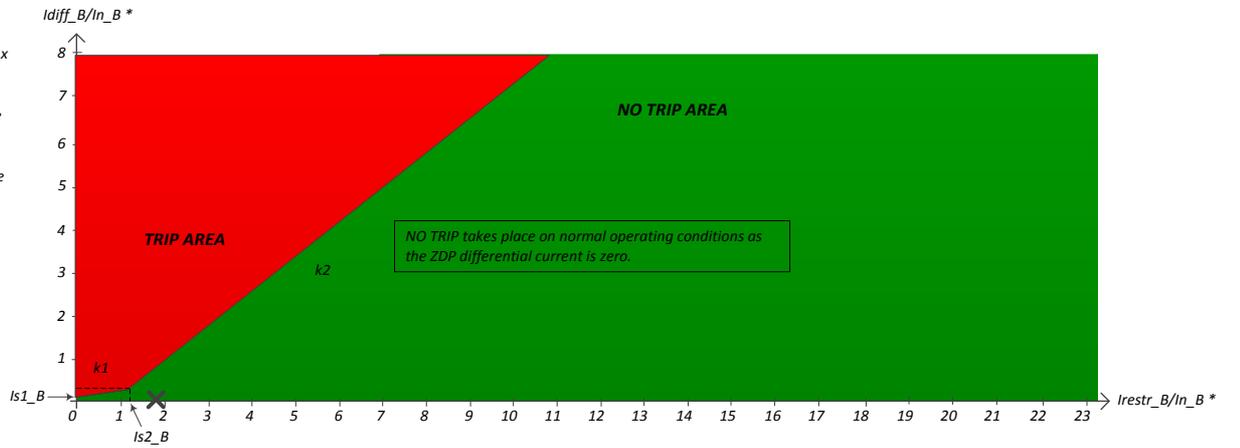
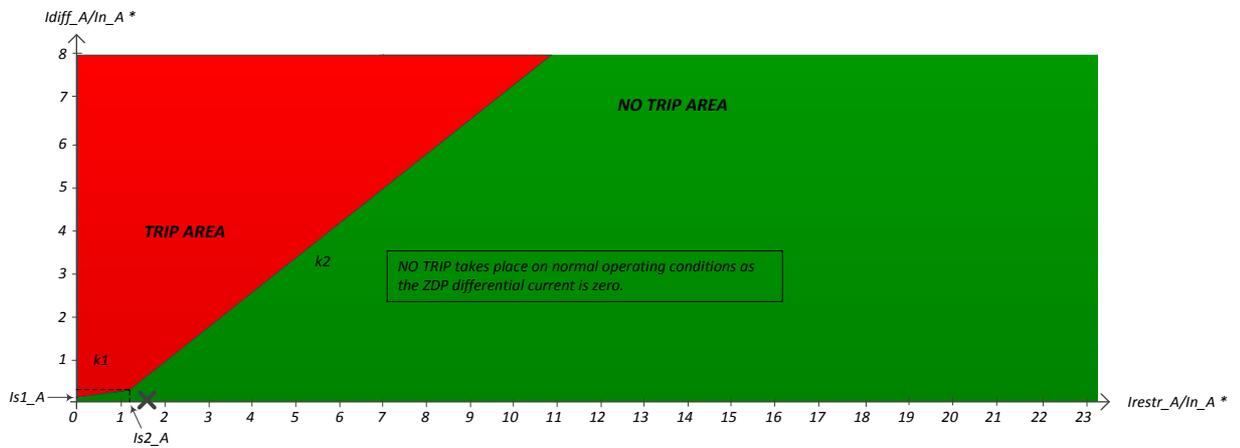
k_1, k_2 : slopes - $k_1=30\%$ & $k_2=80\%$

Appendix C6 – Power flow simulation – SP2 - continued

Simulation step 2/24

Zone : 5

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	26.48-45.81j	-34.40-0.82j	21.00+37.13j
BR5	26.49-45.83j	-34.39-0.84j	20.99+37.13j



* In_x is the rated current of the phase x of the current zone. $x = A$ or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

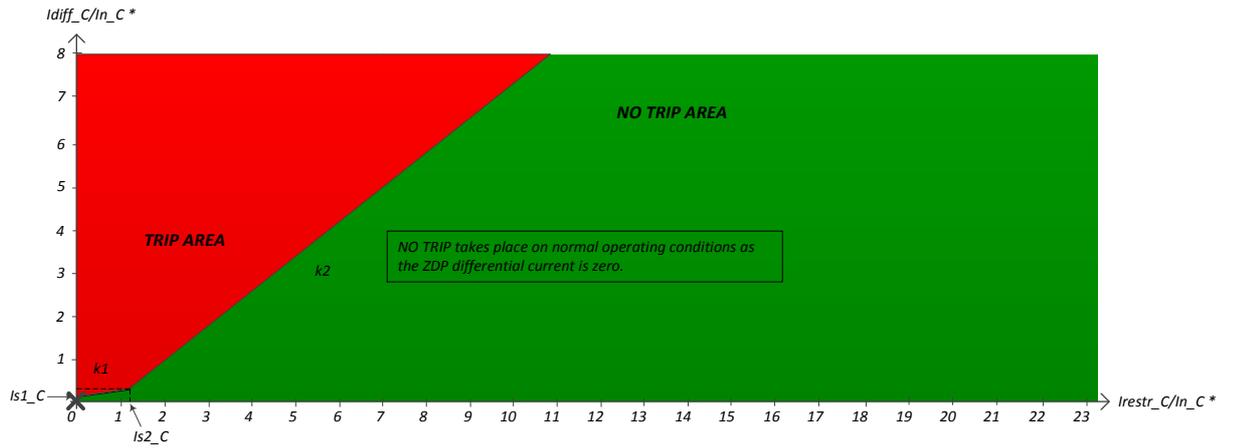
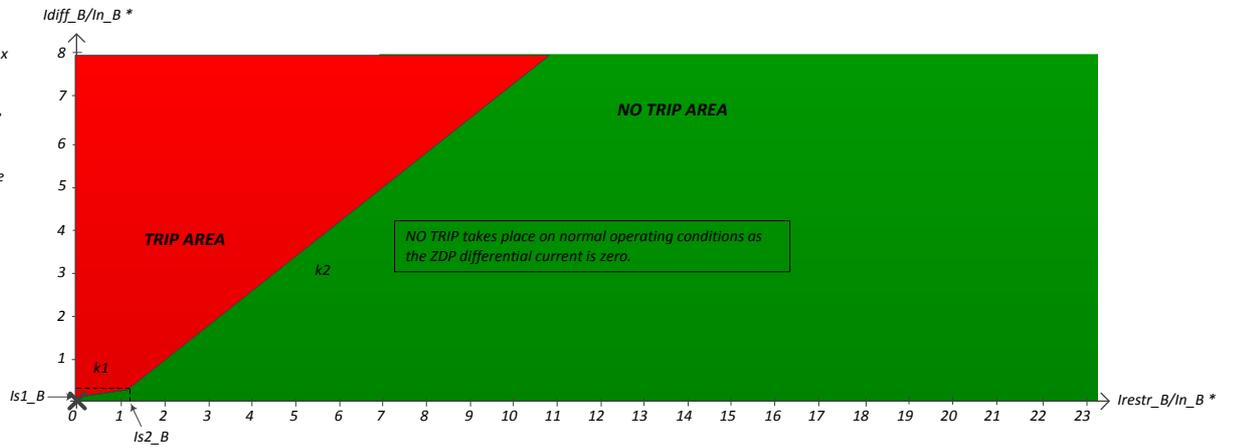
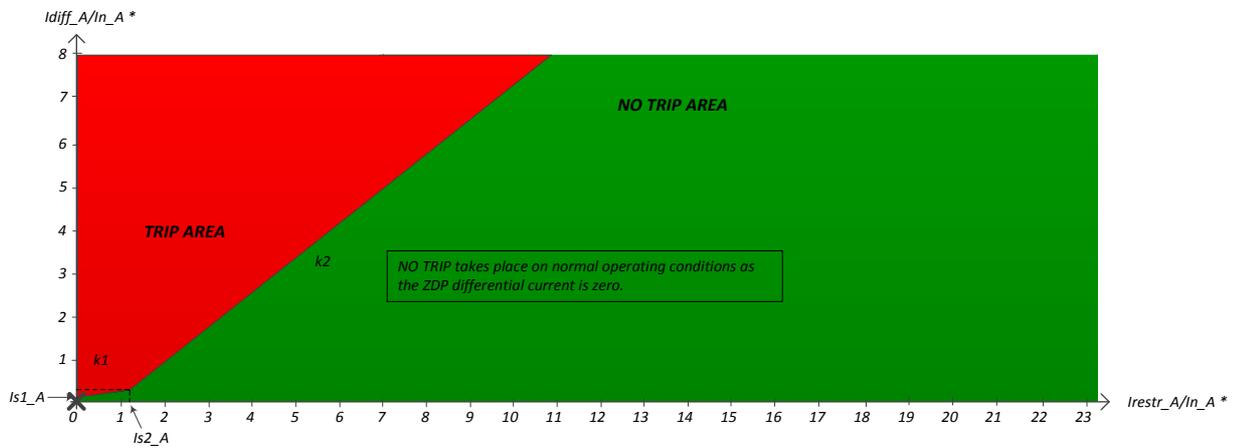
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix C6 – Power flow simulation – SP2 - continued

Simulation step 2/24

Zone : 6

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	0.00+0.00j	0.00+0.00j	0.00+0.00j
BR6	0.00+0.00j	0.00+0.00j	0.00+0.00j



* I_{n_x} is the rated current of the phase x of the current zone. x = A or B or C

I_{diff_x} is the differential current on the phase x of the current zone.

I_{restr_x} is the restraining current on the phase x of the current zone.

I_{s1_x} is the differential current pick-up setting. It is set to 10% of the phase x rated current.

I_{s2_x} is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

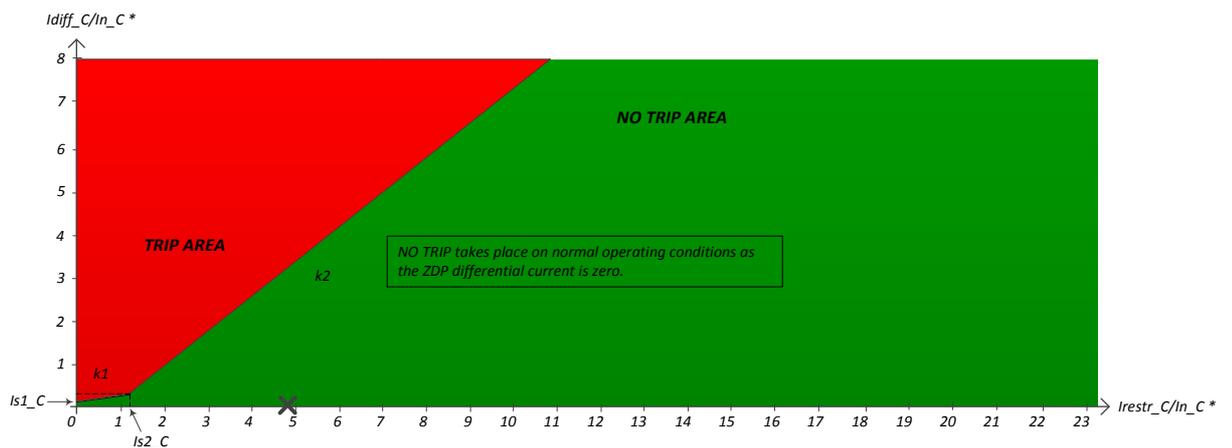
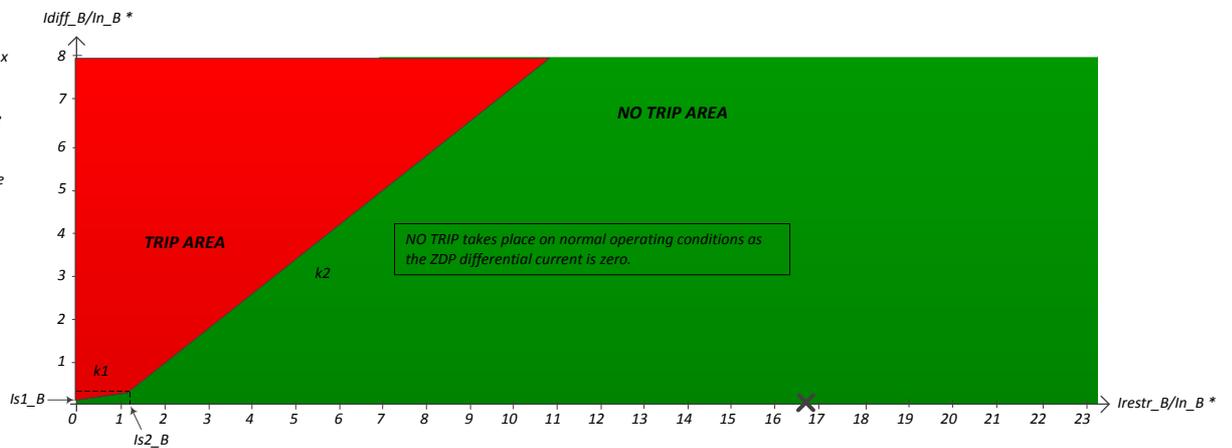
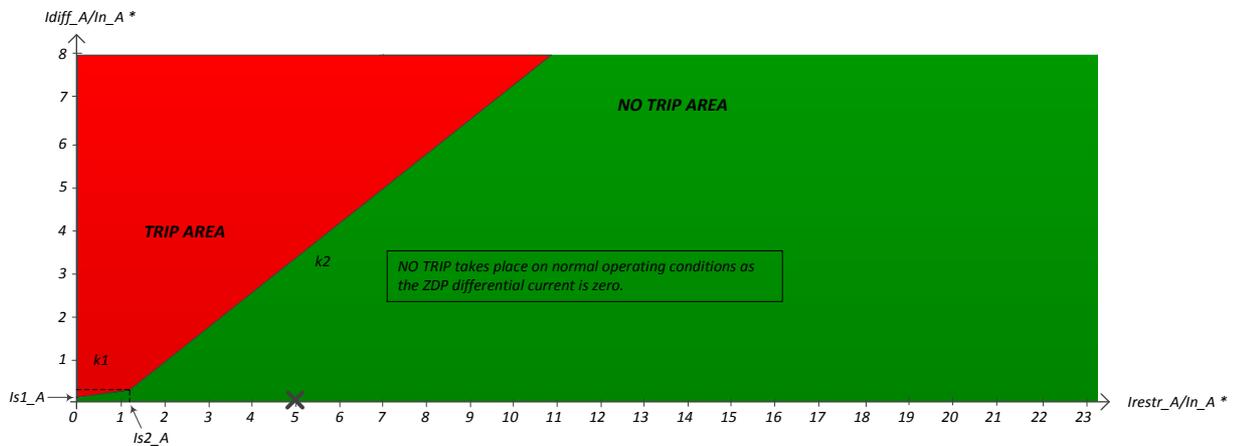
k_1, k_2 : slopes - $k_1=30\%$ & $k_2=80\%$

Appendix C6 – Power flow simulation – SP2 - continued

Simulation step 3/24

Zone : 1

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	24.84-68.78j	11.09+13.28j	36.88+70.22j
BR1	174.38-381.22j	-294.02+40.72j	188.52+312.91j
BR2	-98.60+218.05j	193.96-14.88j	-106.00-174.99j
BR3	-50.92+94.36j	111.13-12.59j	-45.63-67.70j



* In_x is the rated current of the phase x of the current zone. $x = A$ or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

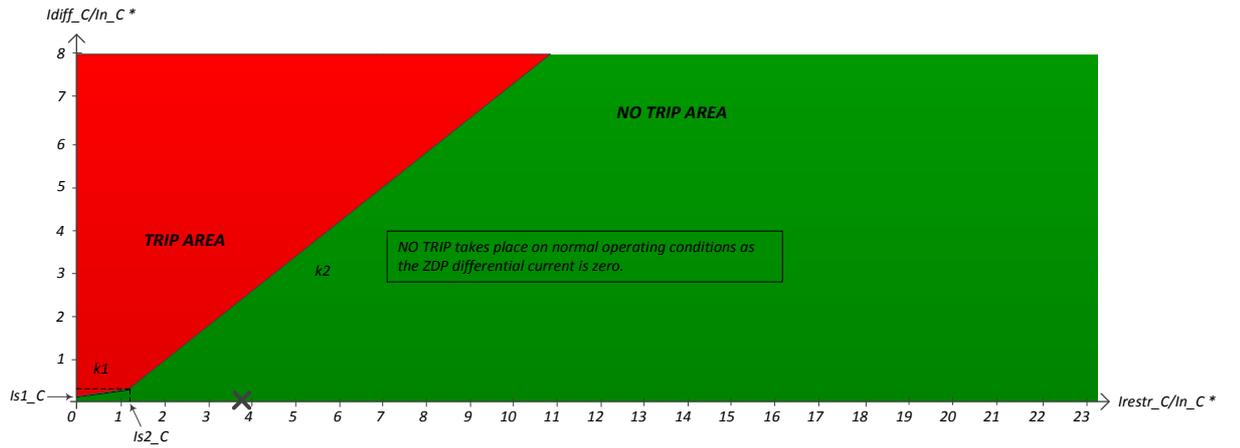
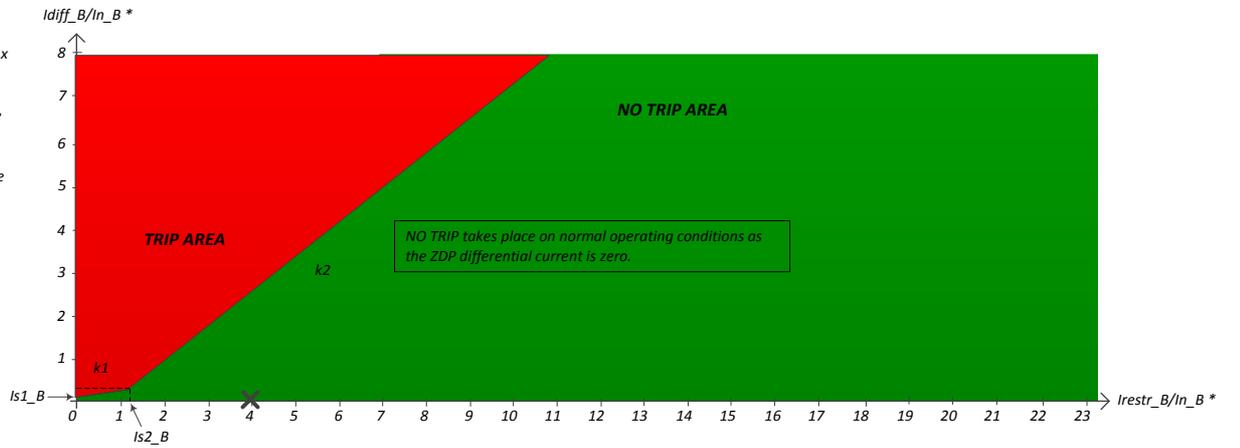
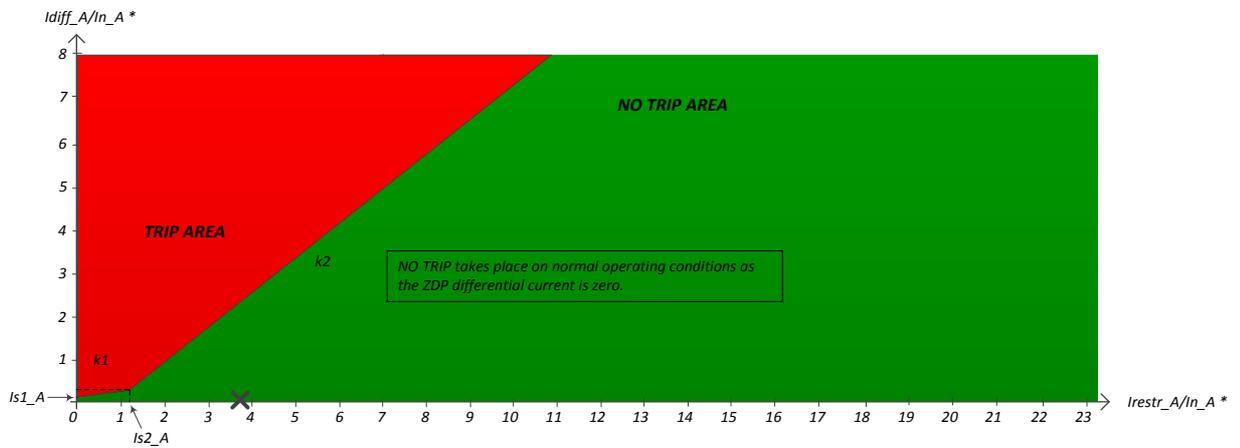
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix C6 – Power flow simulation – SP2 - continued

Simulation step 3/24

Zone : 2

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	36.18-77.13j	-66.08-0.32j	29.80+57.58j
BR2	98.60-218.05j	-193.96+14.88j	106.00+174.99j
BR4	-62.37+140.93j	127.88-15.26j	-76.25-117.40j
BR6	-0.00-0.00j	-0.00-0.00j	-0.00-0.00j



* I_{n_x} is the rated current of the phase x of the current zone. x = A or B or C

I_{diff_x} is the differential current on the phase x of the current zone.

I_{restr_x} is the restraining current on the phase x of the current zone.

I_{s1_x} is the differential current pick-up setting. It is set to 10% of the phase x rated current.

I_{s2_x} is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

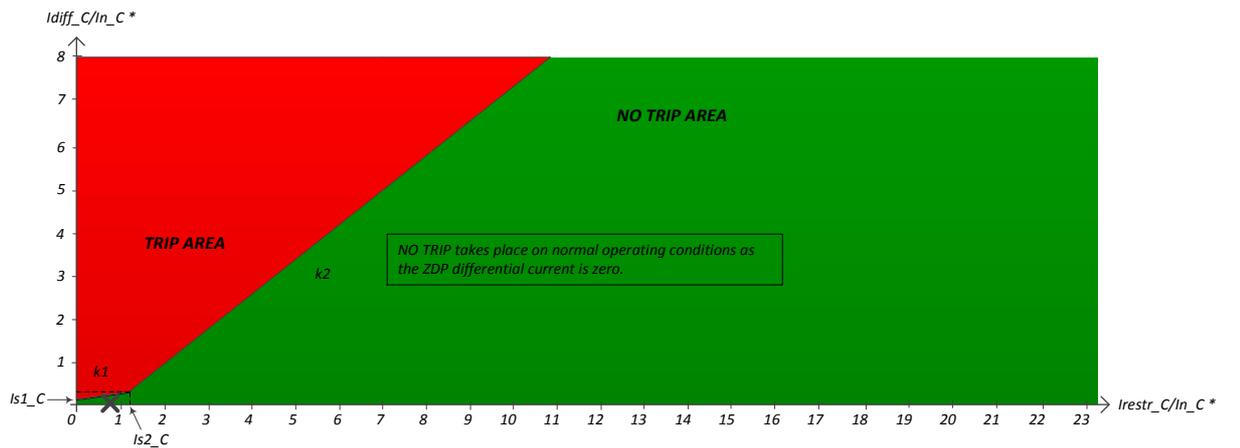
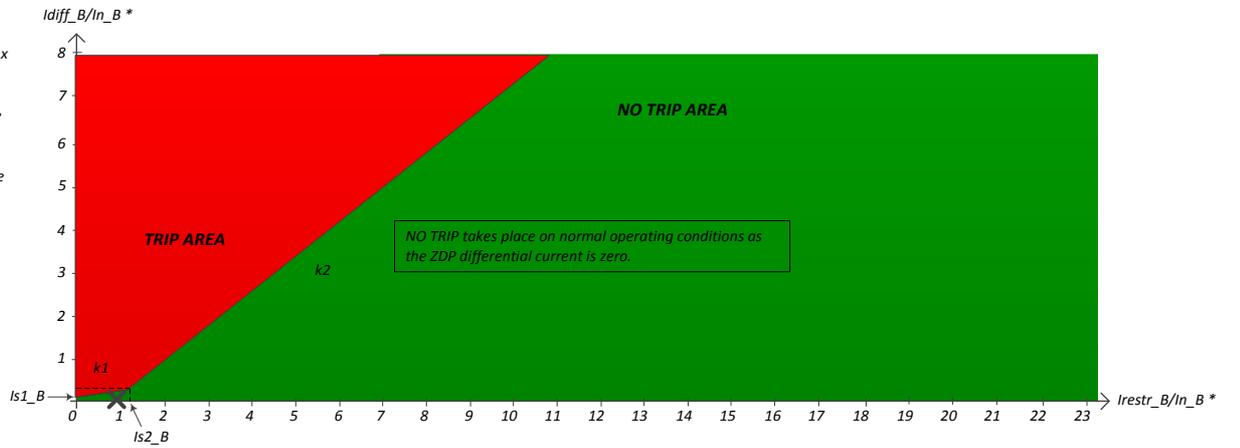
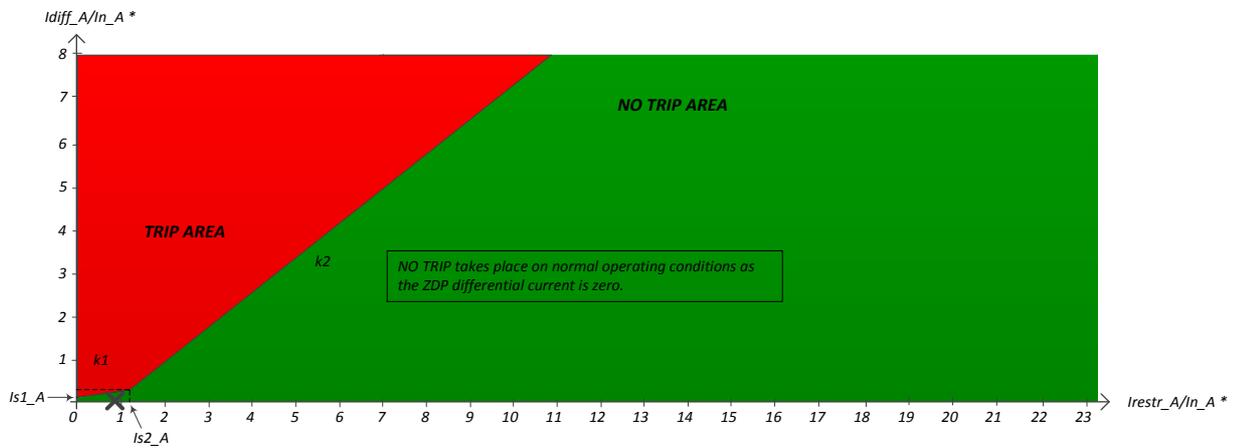
k_1, k_2 : slopes - $k_1=30\%$ & $k_2=80\%$

Appendix C6 – Power flow simulation – SP2

Simulation step 3/24

Zone : 3

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	50.89-94.35j	-111.12+12.62j	45.65+67.70j
BR3	50.92-94.36j	-111.13+12.59j	45.63+67.70j



* In_x is the rated current of the phase x of the current zone. $x = A$ or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

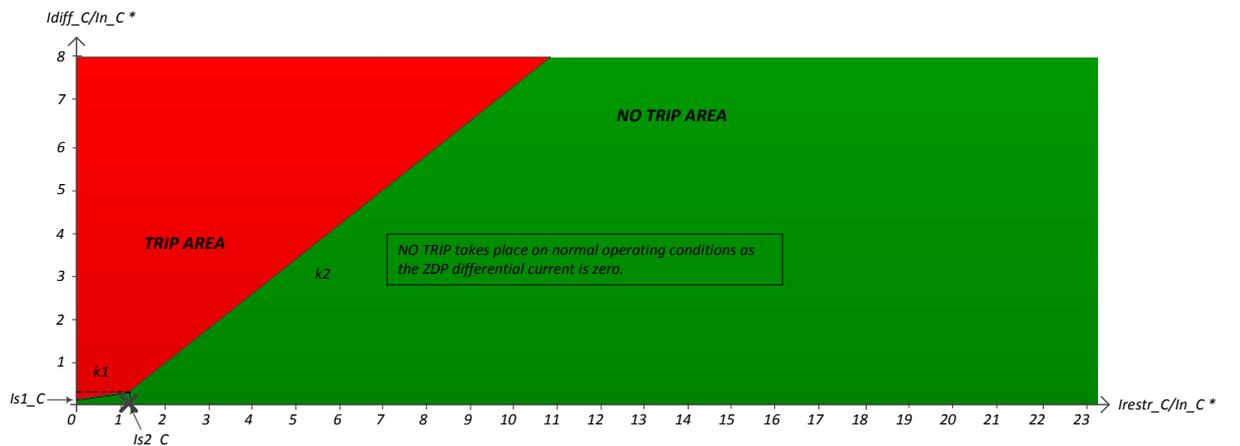
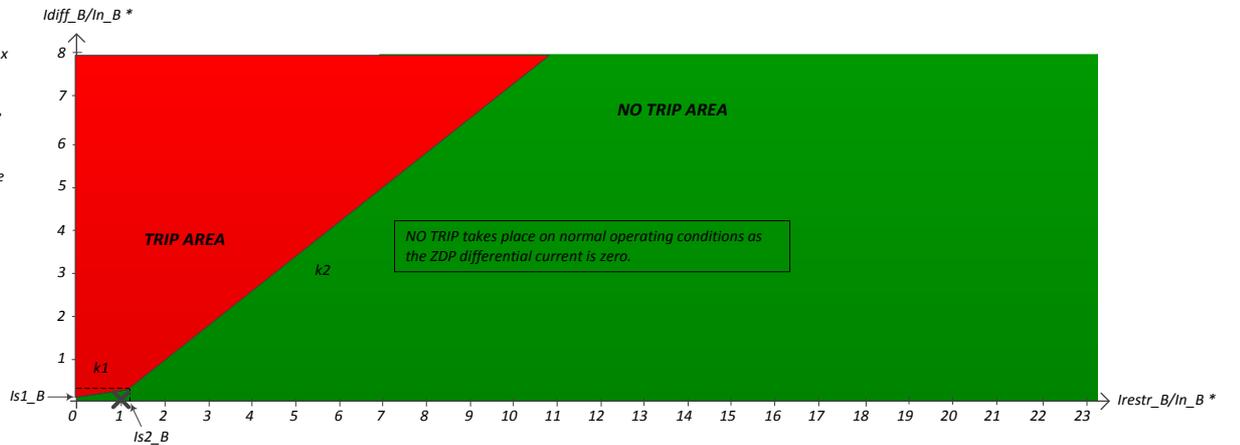
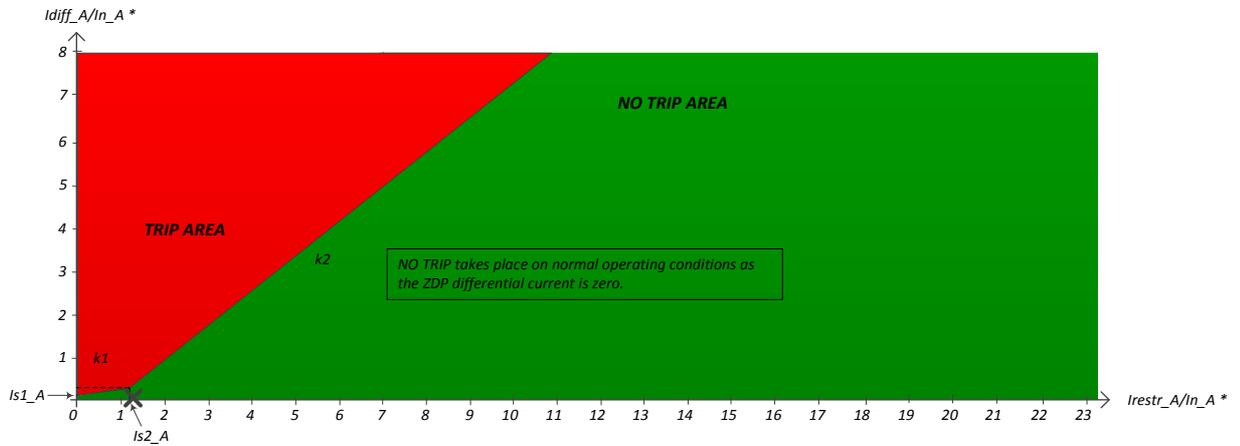
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix C6 – Power flow simulation – SP2 - continued

Simulation step 3/24

Zone : 4

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	37.06-97.25j	-95.55+16.07j	56.46+82.36j
BR5	-25.29+43.65j	32.36+0.76j	-19.80-35.04j
BR4	62.37-140.93j	-127.88+15.26j	76.25+117.40j



* In_x is the rated current of the phase x of the current zone. $x = A$ or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

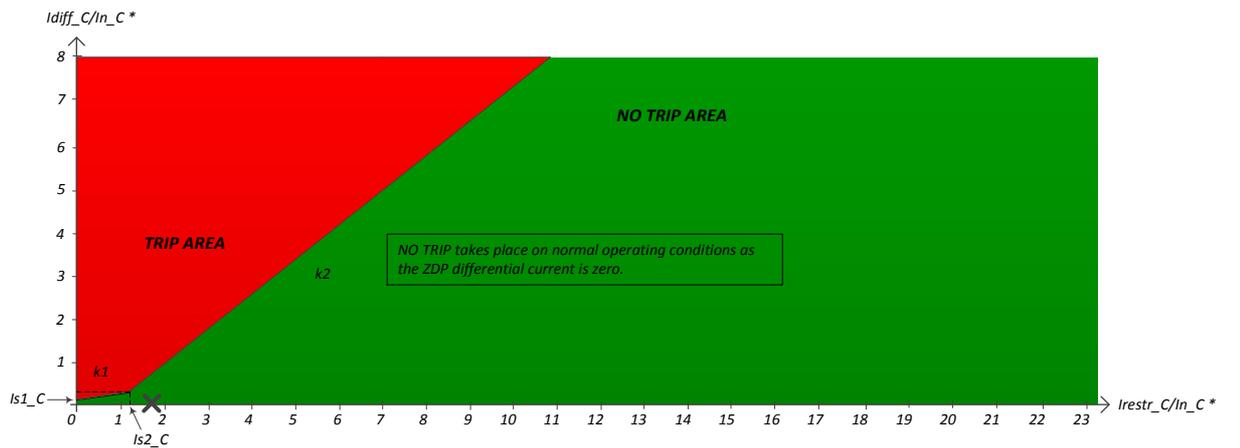
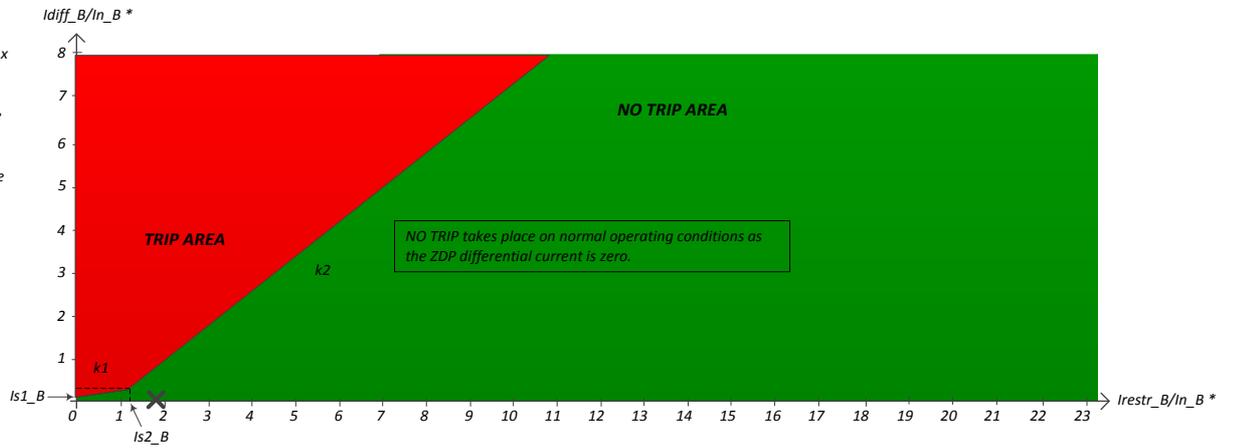
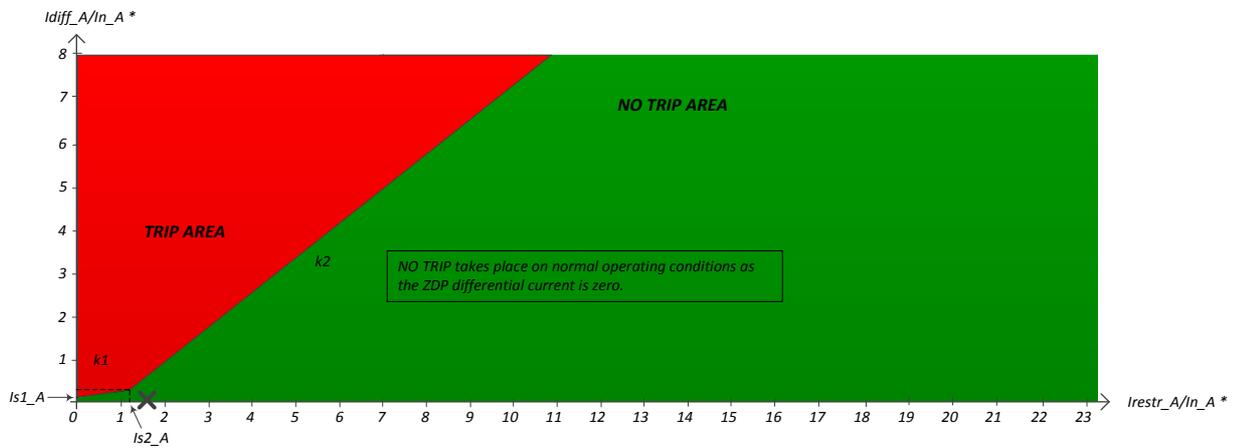
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix C6 – Power flow simulation – SP2 - continued

Simulation step 3/24

Zone : 5

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	25.27-43.64j	-32.36-0.75j	19.81+35.04j
BR5	25.29-43.65j	-32.36-0.76j	19.80+35.04j



* In_x is the rated current of the phase x of the current zone. $x = A$ or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

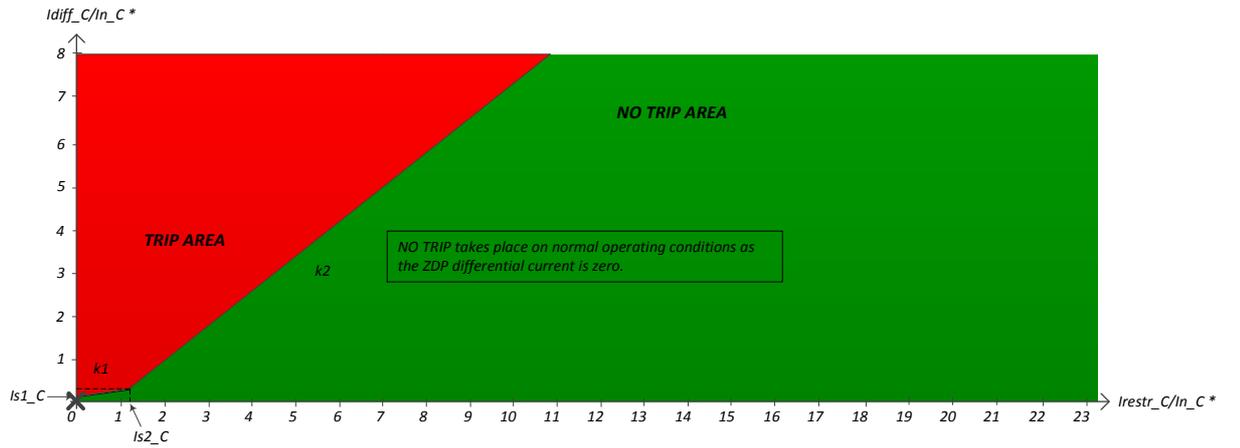
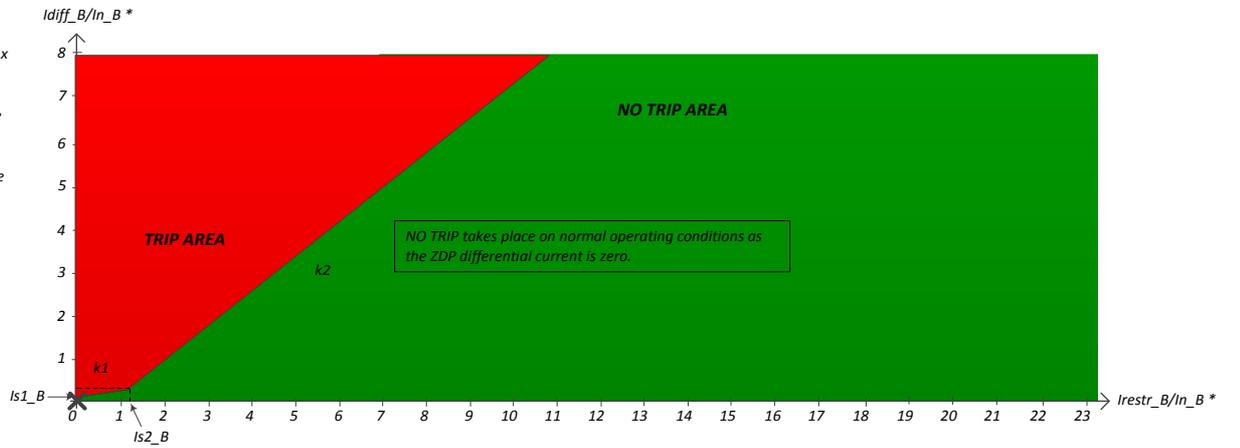
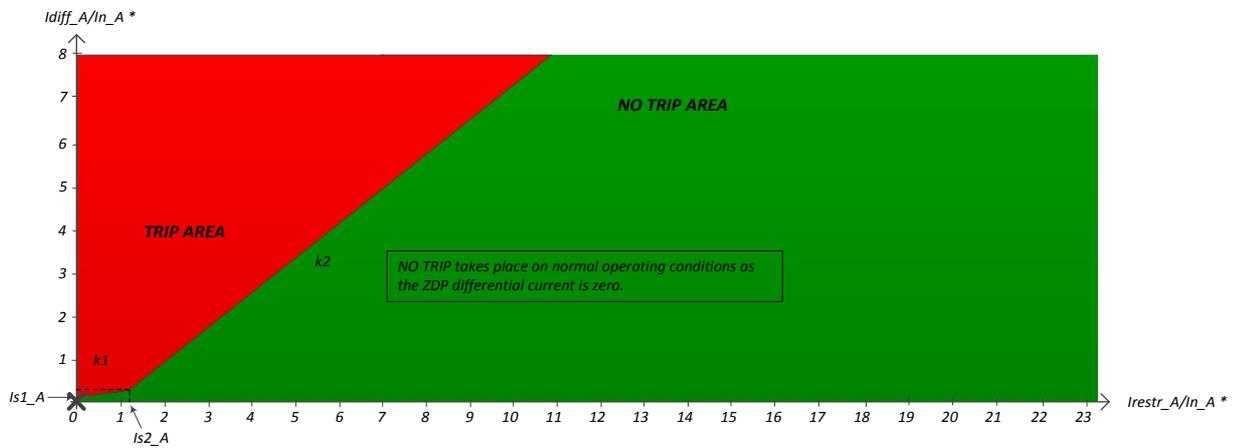
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix C6 – Power flow simulation – SP2 - continued

Simulation step 3/24

Zone : 6

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	0.00+0.00j	0.00+0.00j	0.00+0.00j
BR6	0.00+0.00j	0.00+0.00j	0.00+0.00j



* In_x is the rated current of the phase x of the current zone. $x = A$ or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

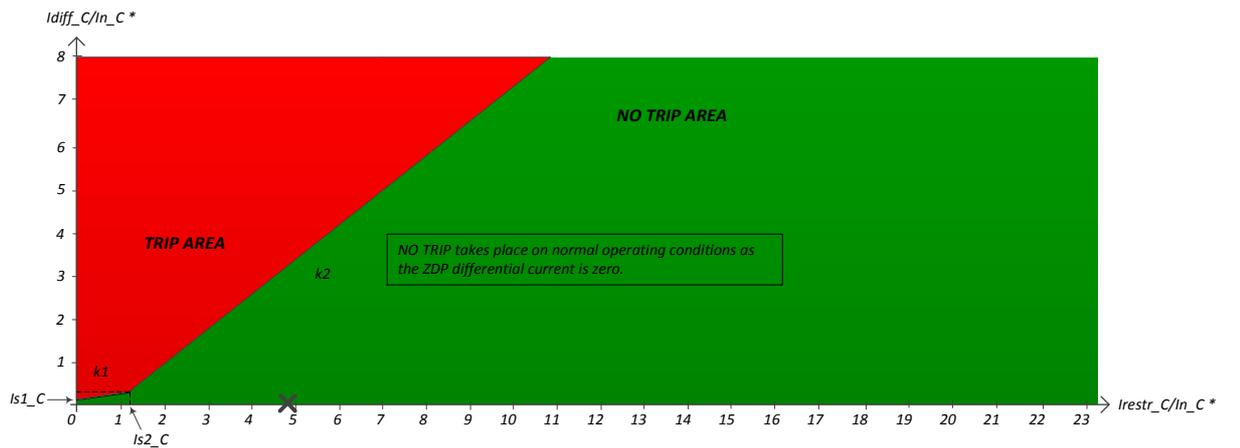
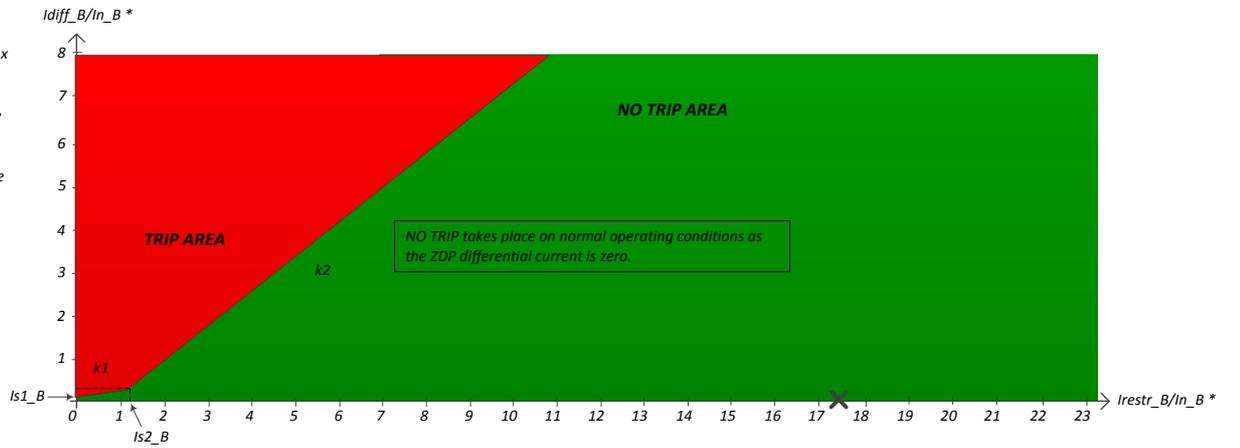
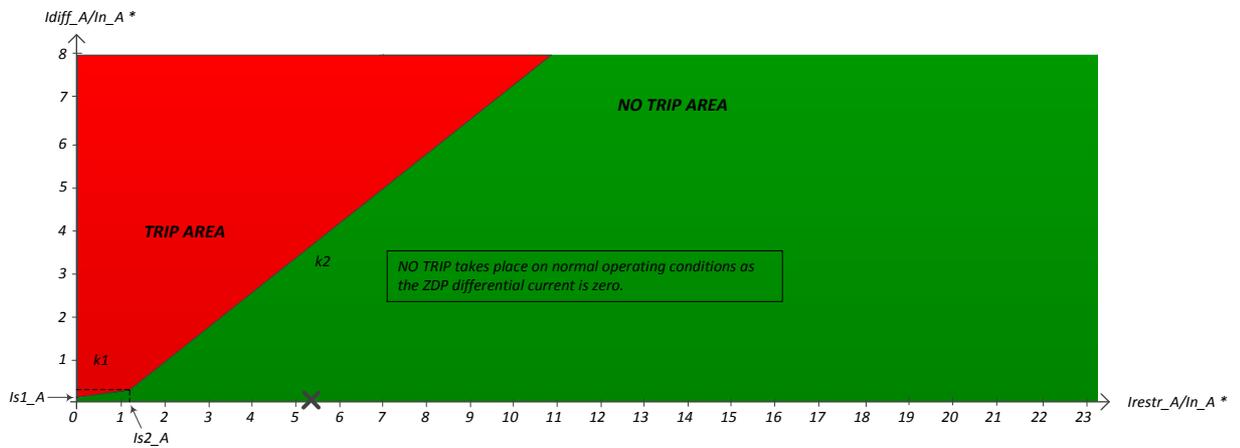
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix C6 – Power flow simulation – SP2 - continued

Simulation step 4/24

Zone : 1

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	28.77-71.49j	4.21+14.06j	38.17+74.90j
BR1	189.82-385.62j	-312.28+48.25j	185.07+306.52j
BR2	-108.94+218.62j	209.06-21.70j	-102.01-165.07j
BR3	-52.10+95.51j	107.42-12.53j	-44.90-66.54j



* In_x is the rated current of the phase x of the current zone. $x = A$ or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

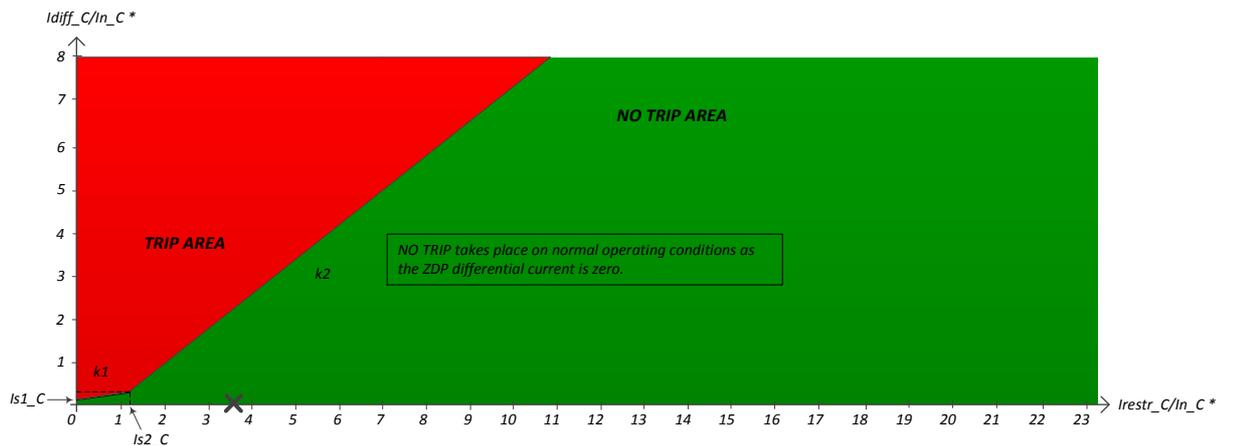
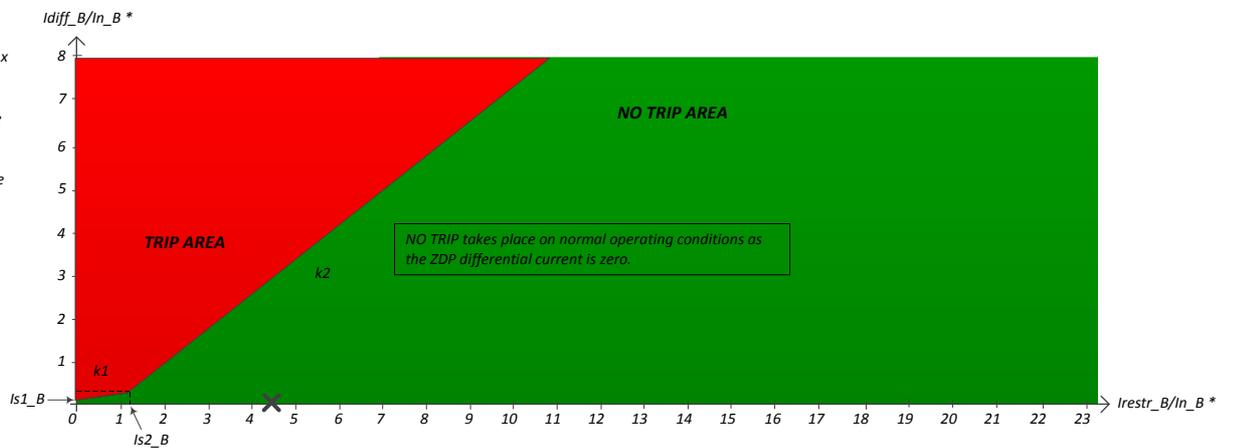
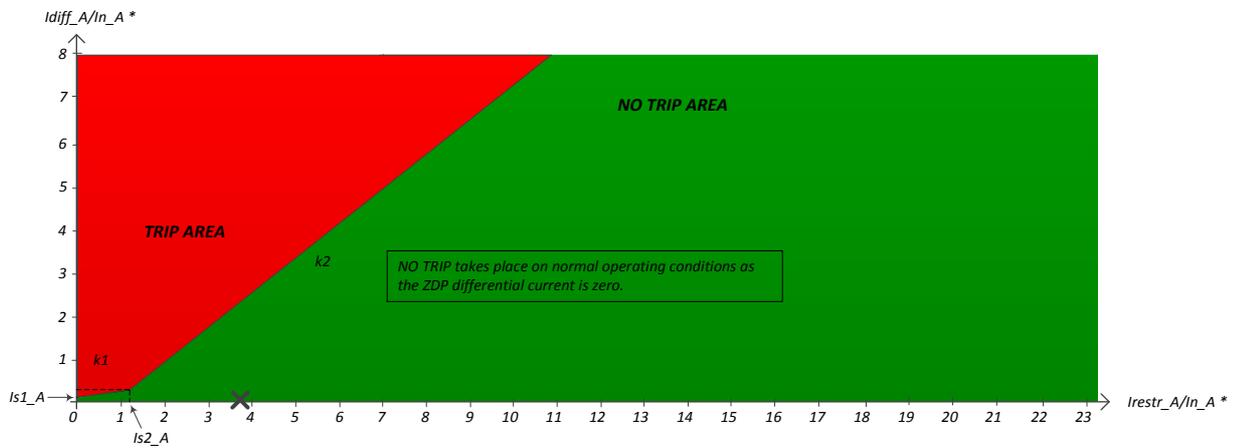
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix C6 – Power flow simulation – SP2 - continued

Simulation step 4/24

Zone : 2

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	36.31-76.01j	-68.37-0.83j	30.57+57.18j
BR2	108.94-218.62j	-209.06+21.70j	102.01+165.07j
BR4	-72.60+142.64j	140.71-22.59j	-71.49-107.89j
BR6	-0.00-0.00j	-0.00-0.00j	-0.00-0.00j



* In_x is the rated current of the phase x of the current zone. $x = A$ or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

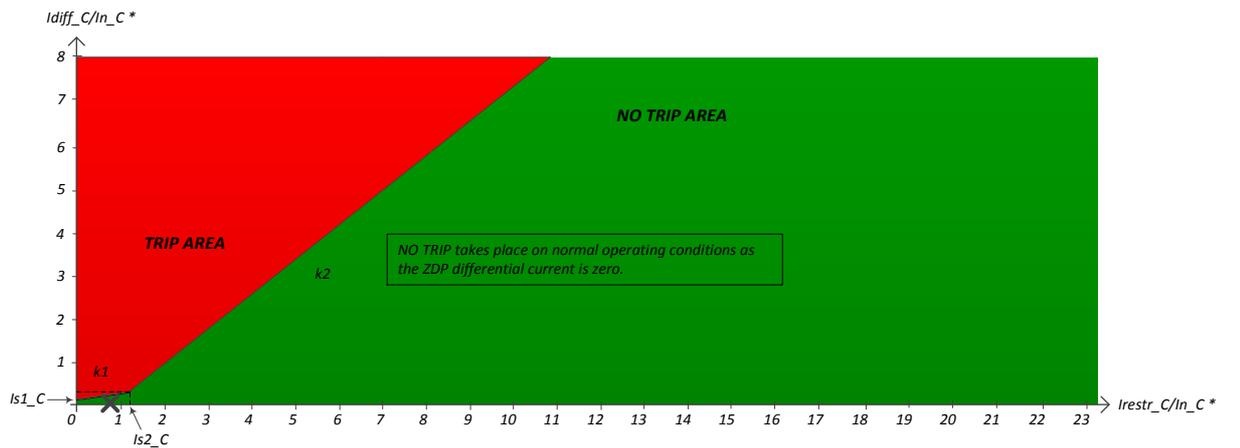
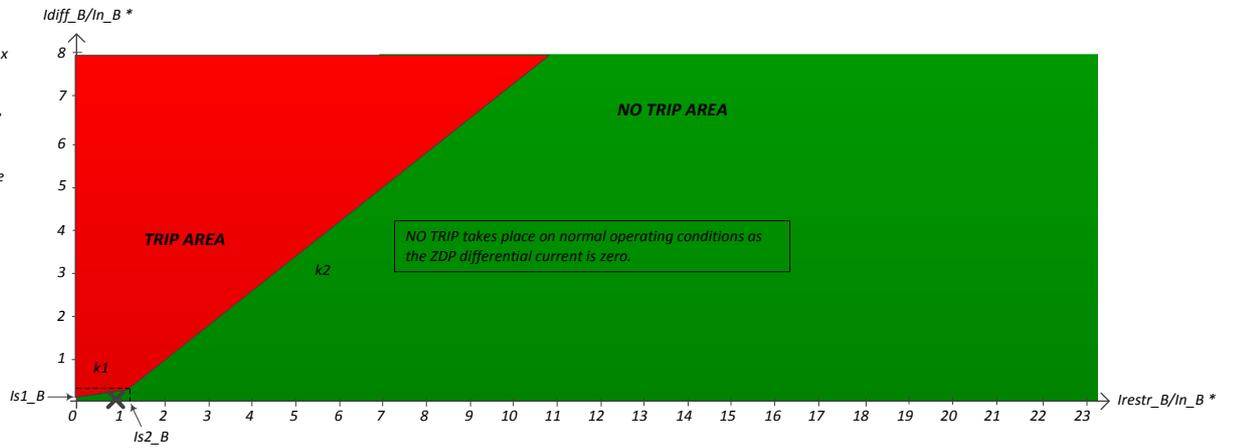
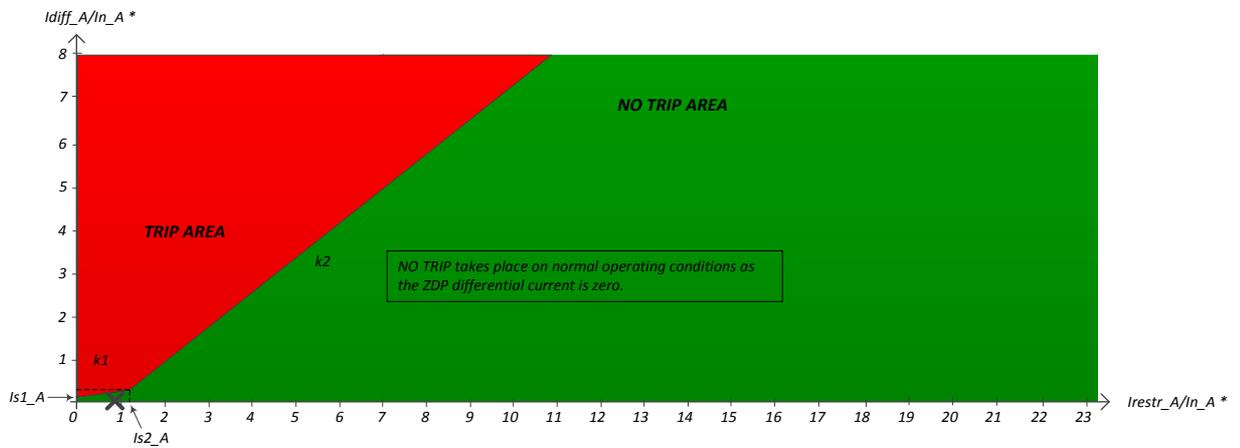
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix C6 – Power flow simulation – SP2

Simulation step 4/24

Zone : 3

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	52.08-95.51j	-107.43+12.57j	44.91+66.54j
BR3	52.10-95.51j	-107.42+12.53j	44.90+66.54j



* In_x is the rated current of the phase x of the current zone. $x = A$ or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

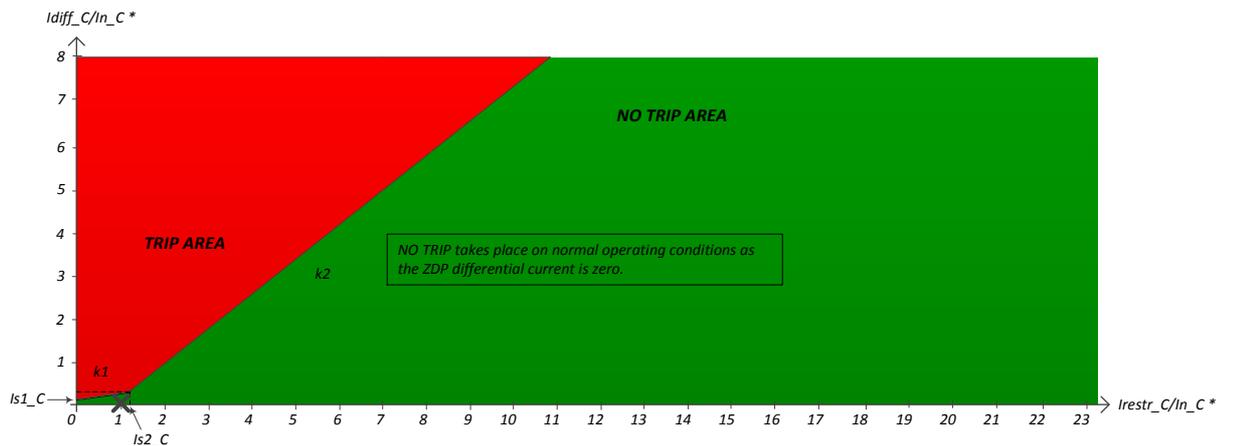
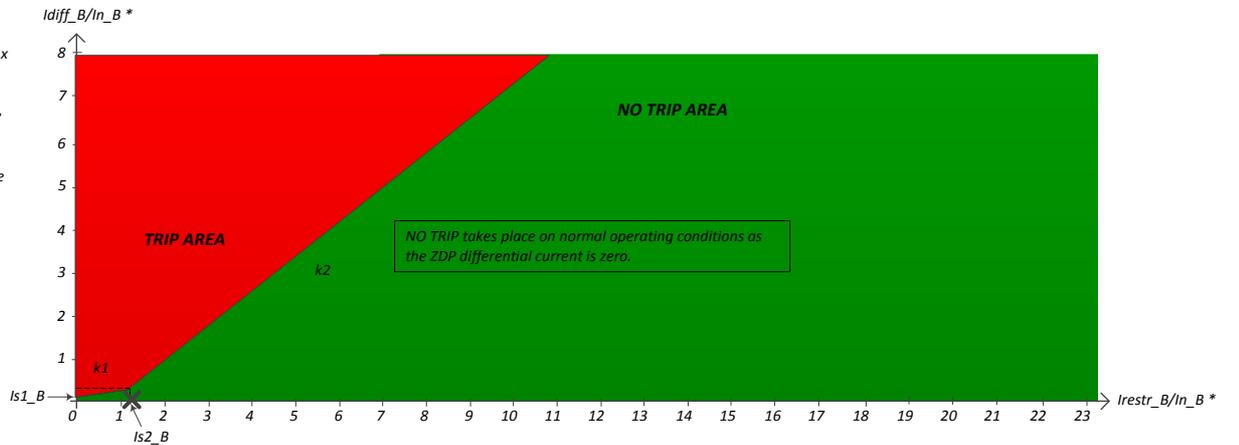
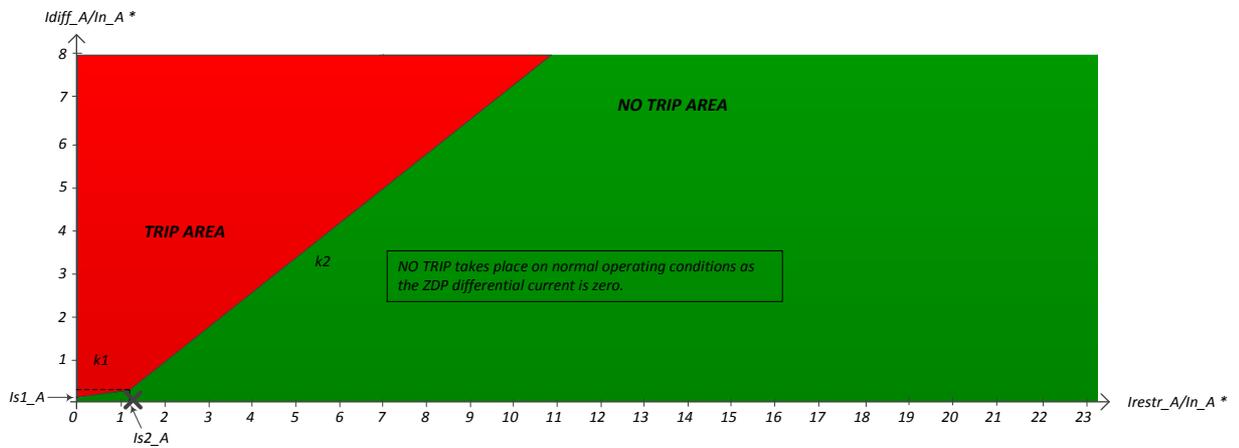
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix C6 – Power flow simulation – SP2 - continued

Simulation step 4/24

Zone : 4

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	44.84-94.44j	-105.57+23.40j	52.50+74.07j
BR5	-27.71+48.19j	35.16+0.74j	-19.02-33.82j
BR4	72.60-142.64j	-140.71+22.59j	71.49+107.89j



* In_x is the rated current of the phase x of the current zone. $x = A$ or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

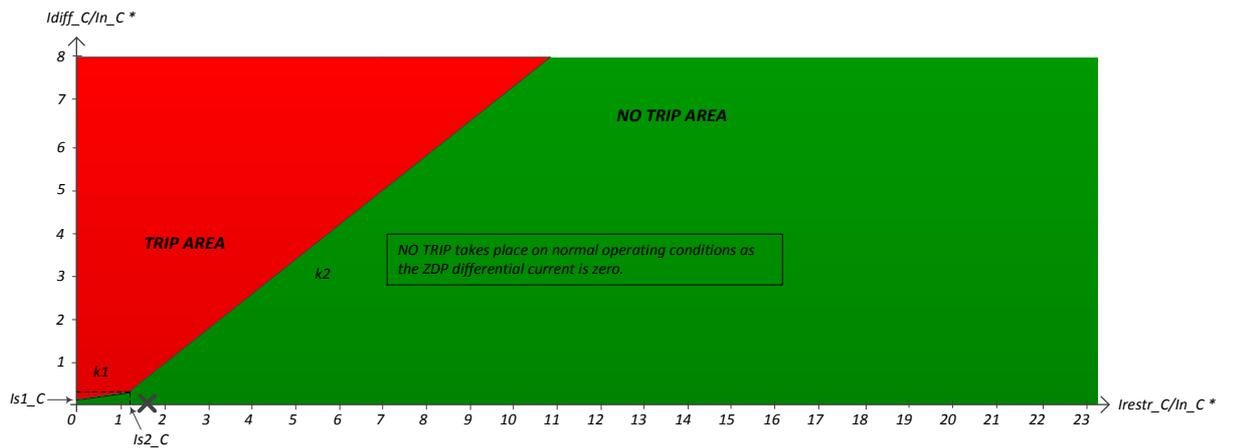
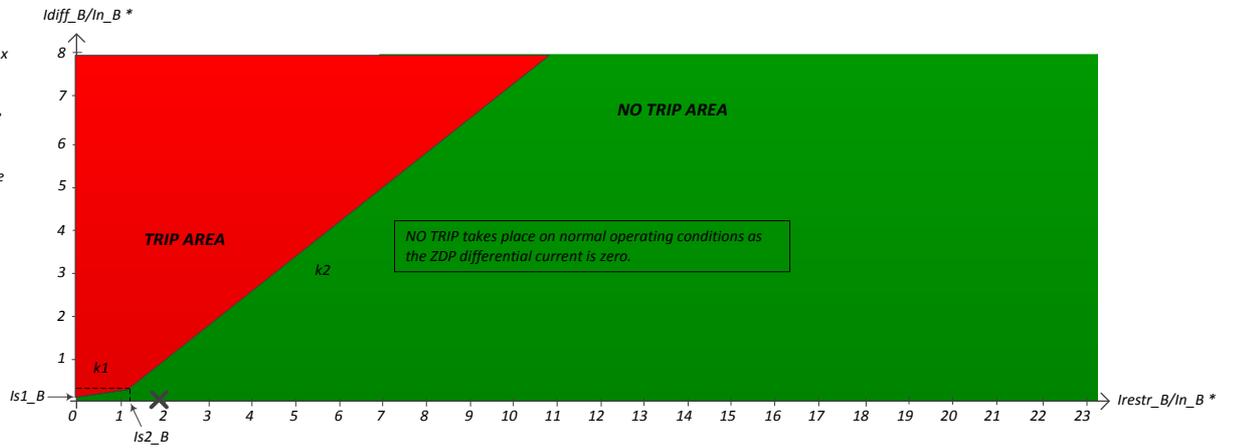
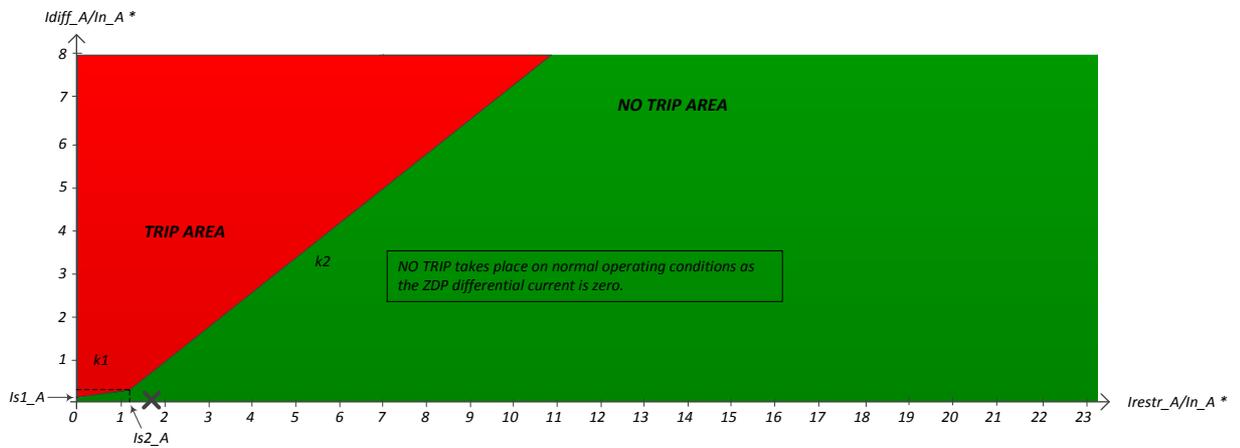
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix C6 – Power flow simulation – SP2 - continued

Simulation step 4/24

Zone : 5

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	27.70-48.18j	-35.17-0.72j	19.02+33.82j
BR5	27.71-48.19j	-35.16-0.74j	19.02+33.82j



* In_x is the rated current of the phase x of the current zone. $x = A$ or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

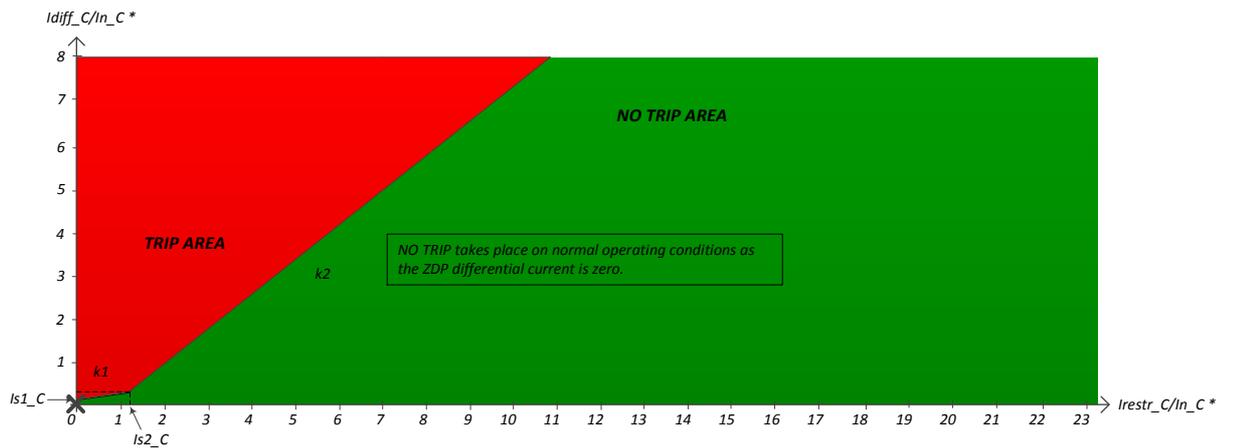
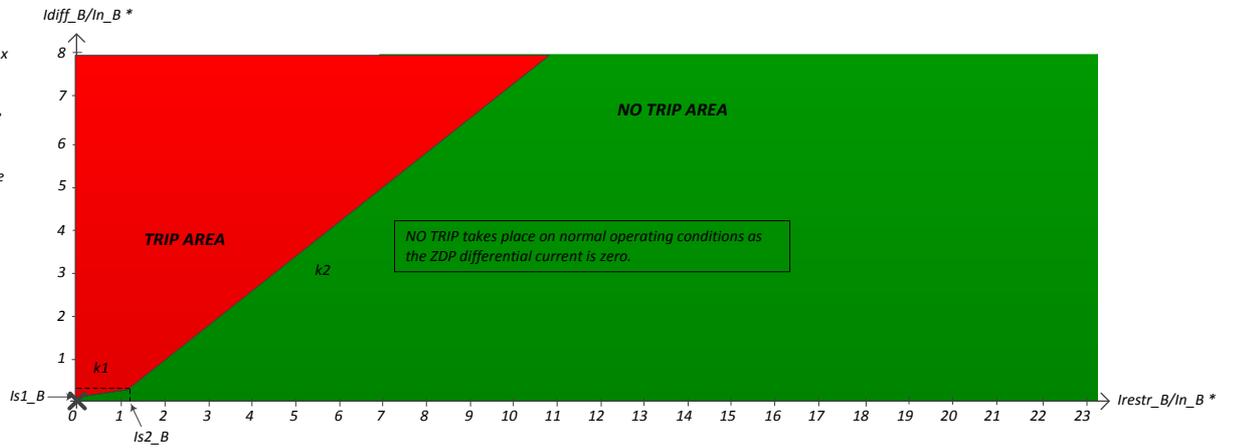
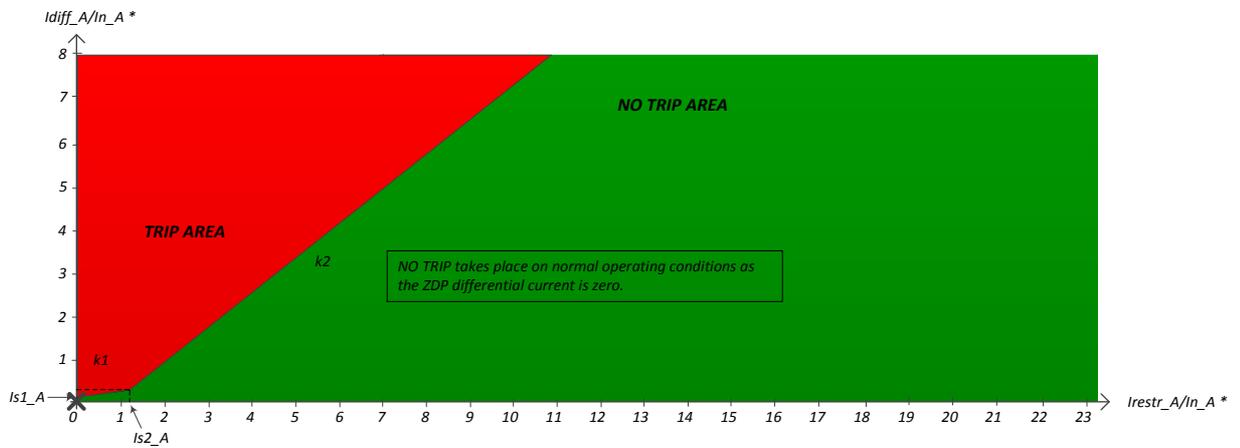
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix C6 – Power flow simulation – SP2 - continued

Simulation step 4/24

Zone : 6

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	0.00+0.00j	0.00+0.00j	0.00+0.00j
BR6	0.00+0.00j	0.00+0.00j	0.00+0.00j



* In_x is the rated current of the phase x of the current zone. $x = A$ or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

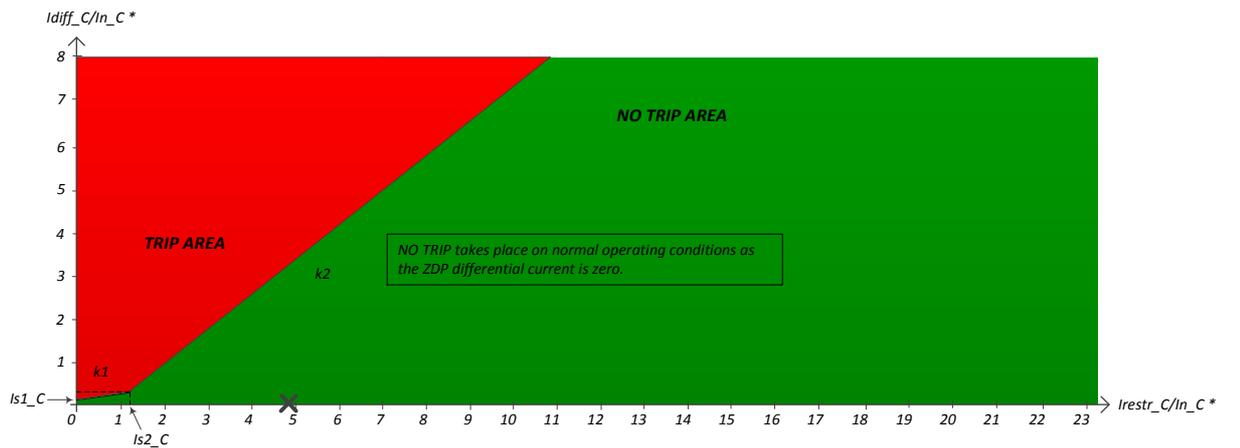
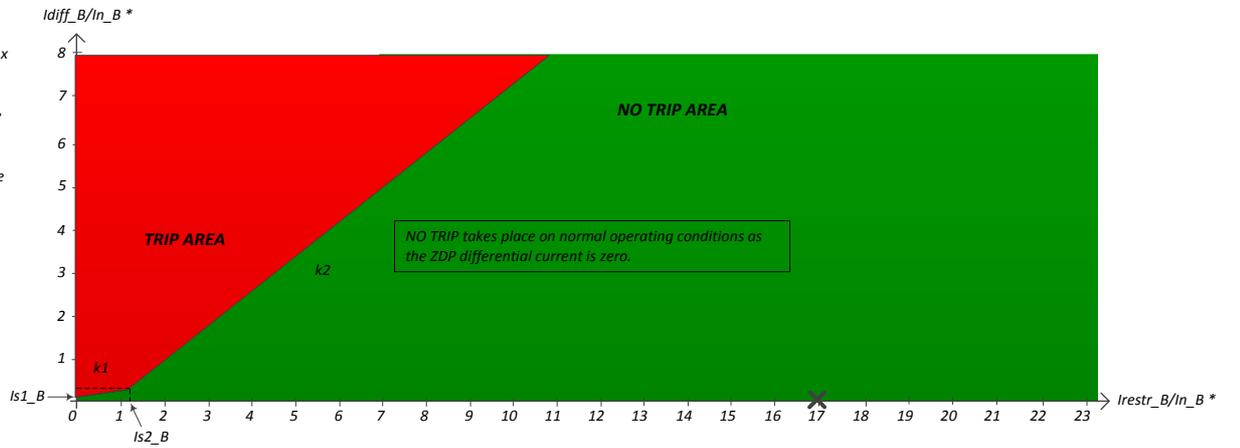
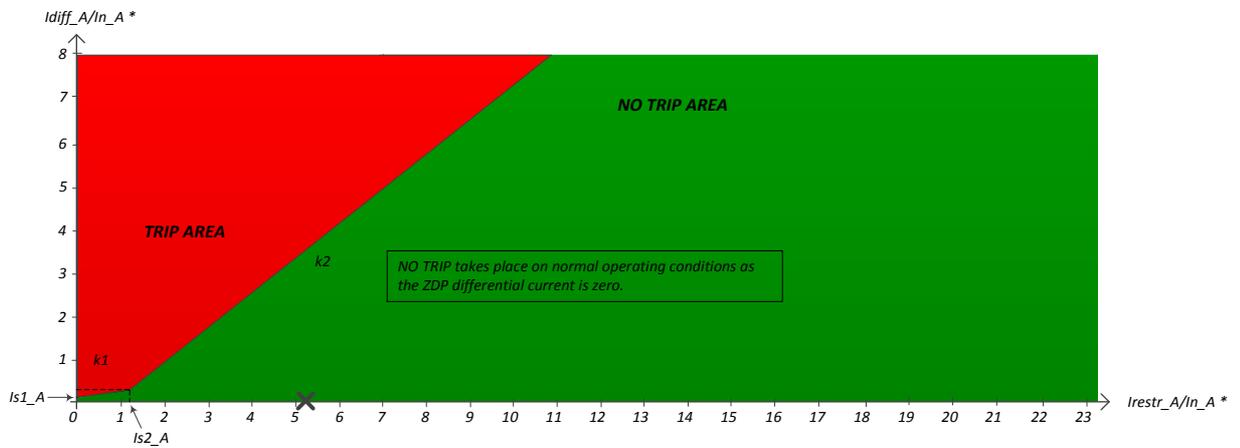
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix C6 – Power flow simulation – SP2 - continued

Simulation step 5/24

Zone : 1

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	29.88-74.57j	6.83+15.12j	40.37+80.64j
BR1	187.46-388.43j	-300.32+48.12j	183.34+309.05j
BR2	-104.95+216.69j	195.90-20.34j	-97.33-160.75j
BR3	-52.59+97.16j	111.22-12.69j	-45.66-67.65j



* In_x is the rated current of the phase x of the current zone. $x = A$ or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

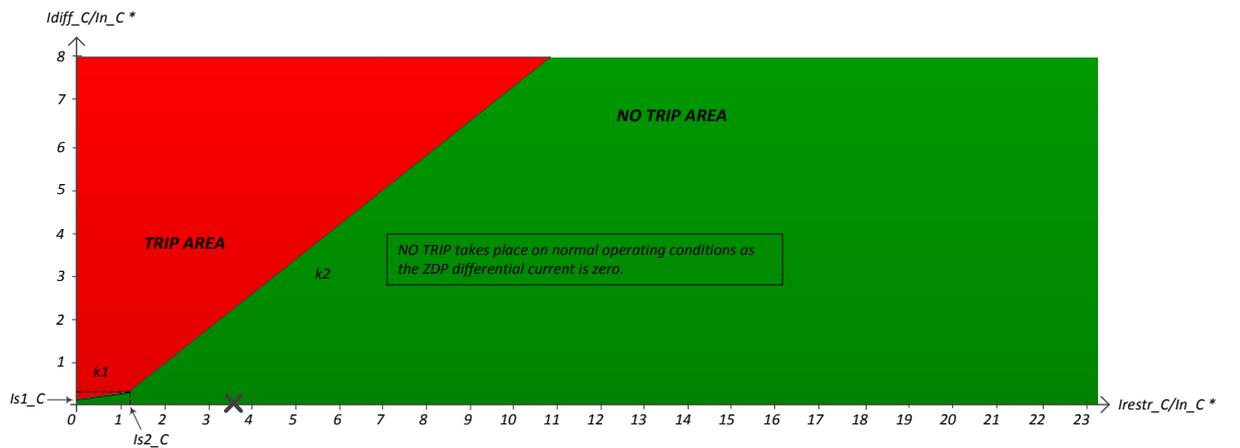
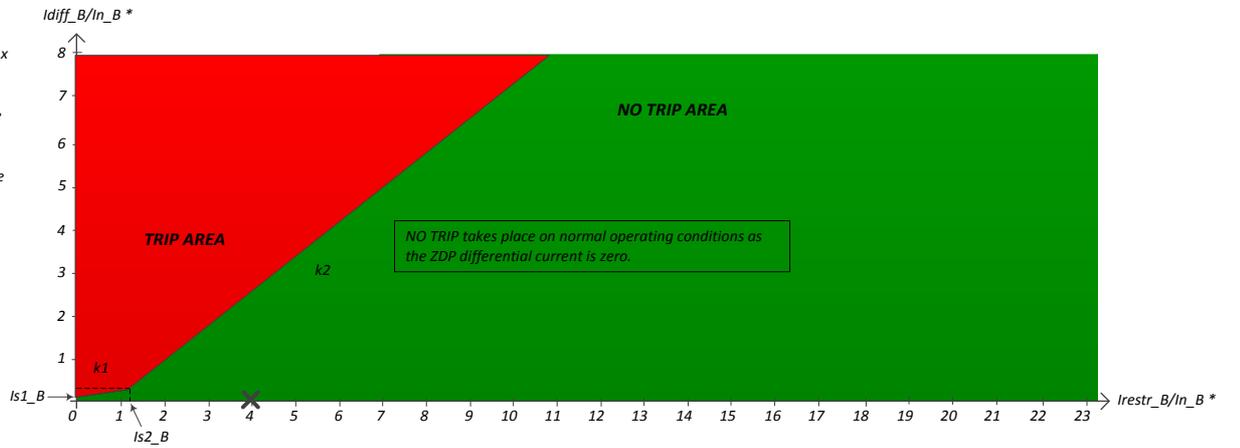
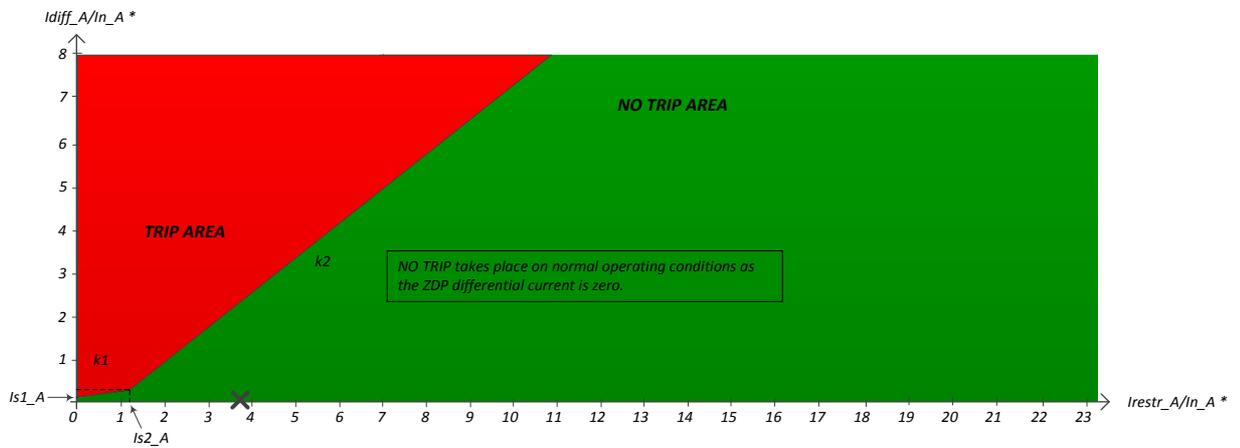
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix C6 – Power flow simulation – SP2 - continued

Simulation step 5/24

Zone : 2

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	38.37-80.00j	-64.48-0.73j	30.31+56.29j
BR2	104.95-216.69j	-195.90+20.34j	97.33+160.75j
BR4	-66.54+136.71j	131.44-21.15j	-67.07-104.46j
BR6	-0.00-0.00j	-0.00-0.00j	-0.00-0.00j



* In_x is the rated current of the phase x of the current zone. $x = A$ or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

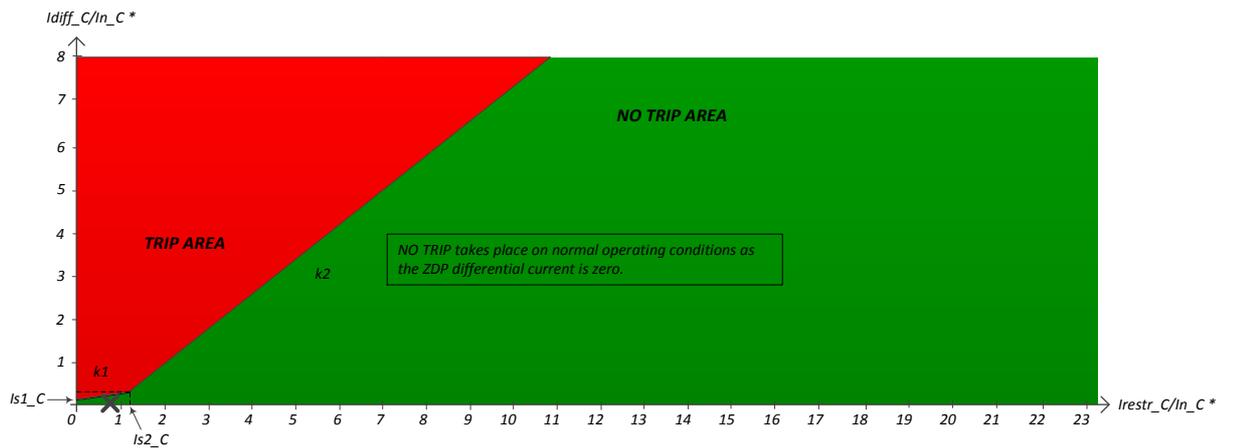
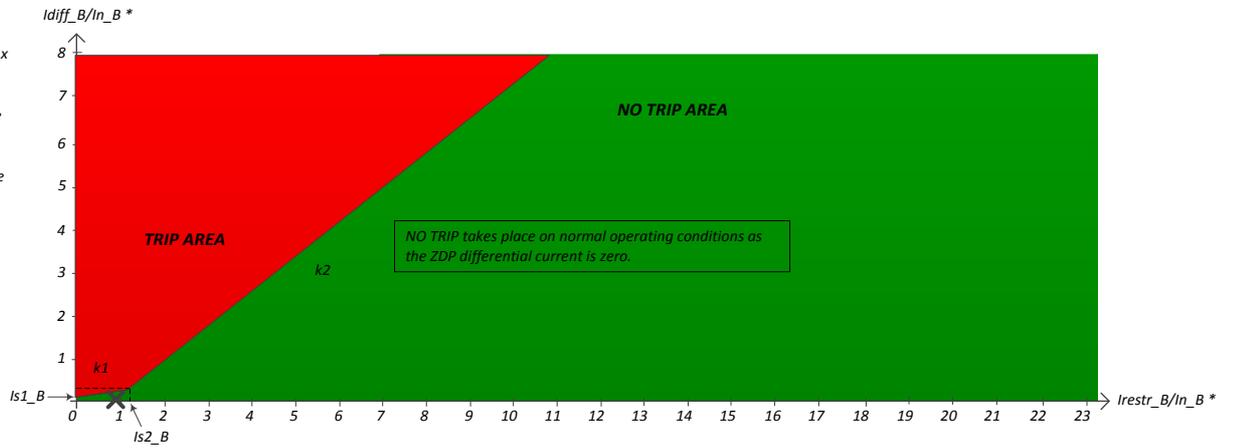
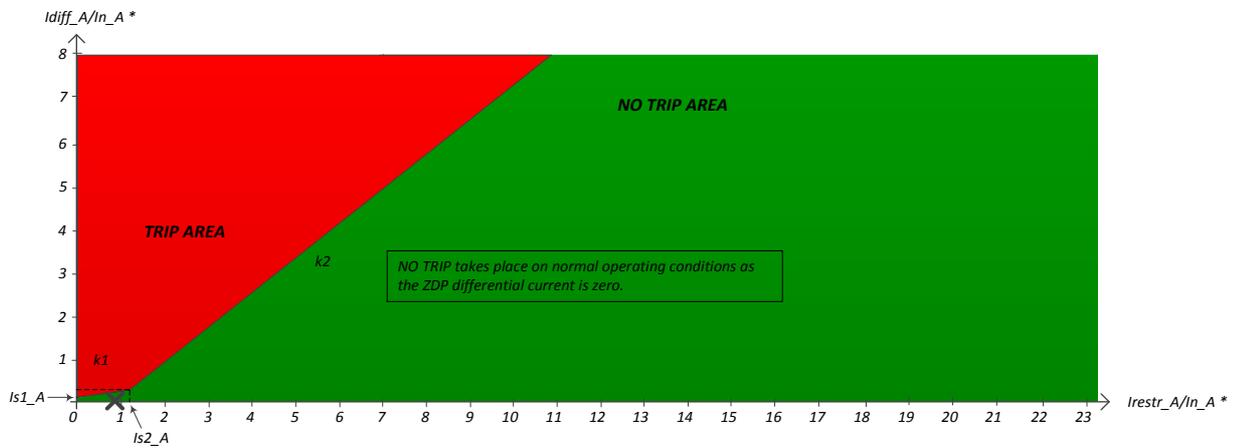
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix C6 – Power flow simulation – SP2

Simulation step 5/24

Zone : 3

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	52.56-97.14j	-111.23+12.73j	45.67+67.64j
BR3	52.59-97.16j	-111.22+12.69j	45.66+67.65j



* In_x is the rated current of the phase x of the current zone. $x = A$ or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

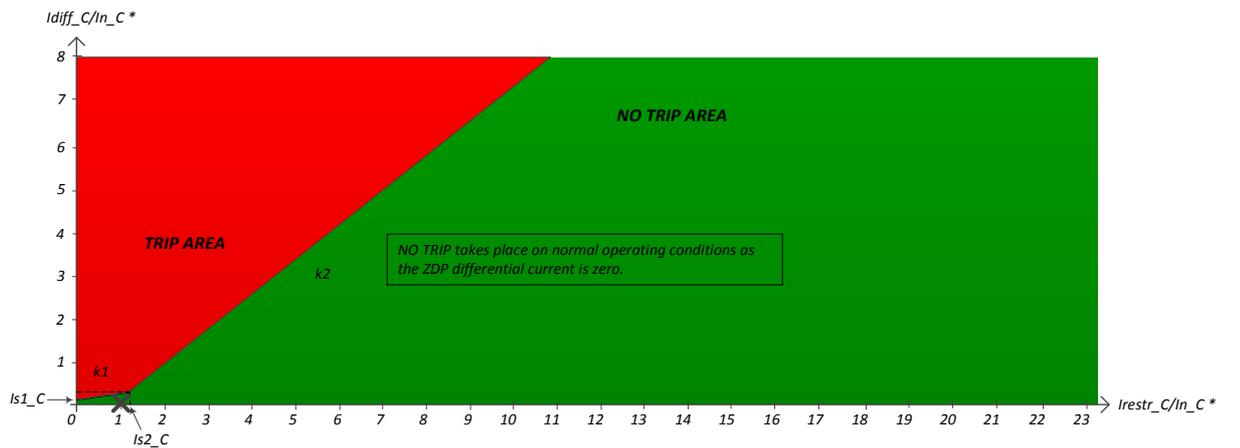
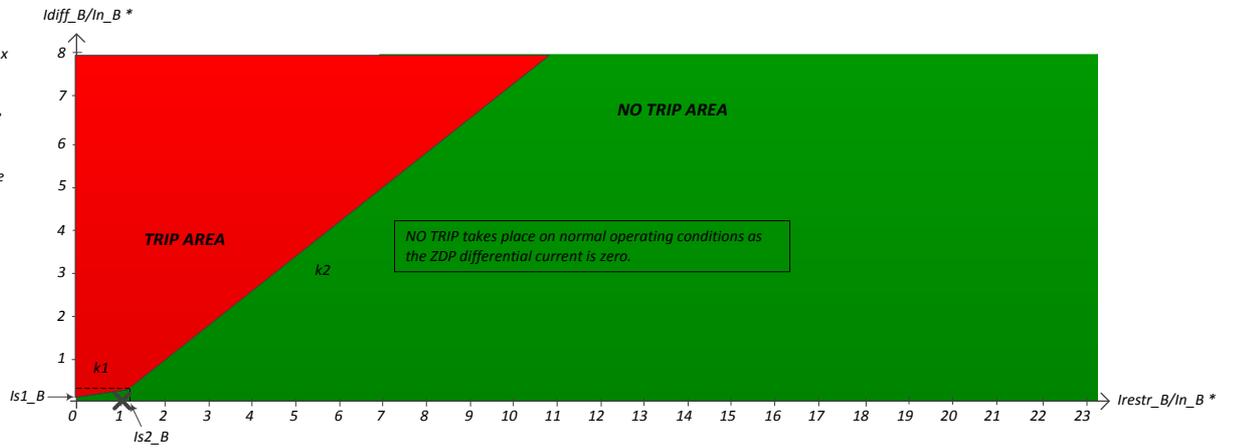
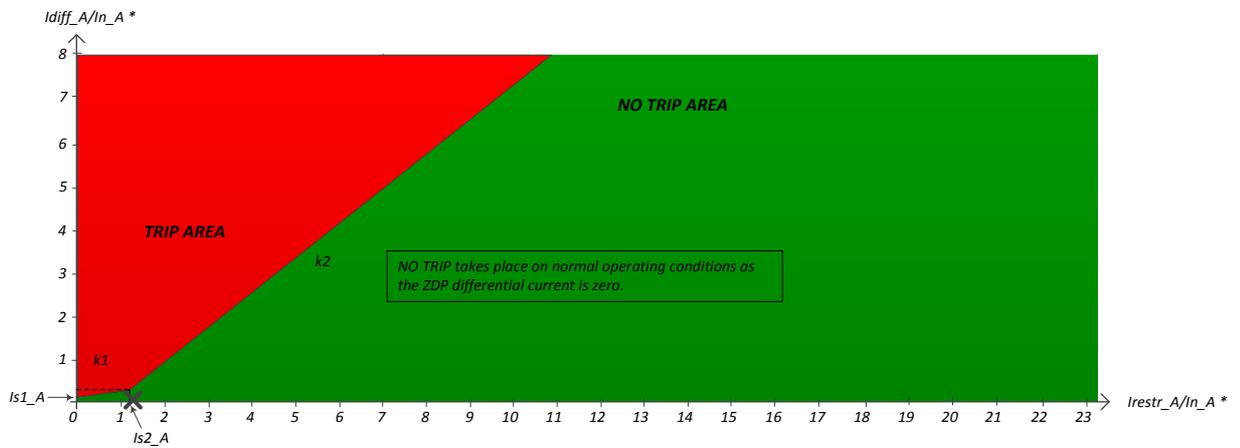
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix C6 – Power flow simulation – SP2 - continued

Simulation step 5/24

Zone : 4

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	40.41-91.37j	-99.56+21.96j	48.33+71.07j
BR5	-26.09+45.32j	+31.90+0.74j	-18.76-33.38j
BR4	66.54-136.71j	-131.44+21.15j	67.07+104.46j



* In_x is the rated current of the phase x of the current zone. $x = A$ or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

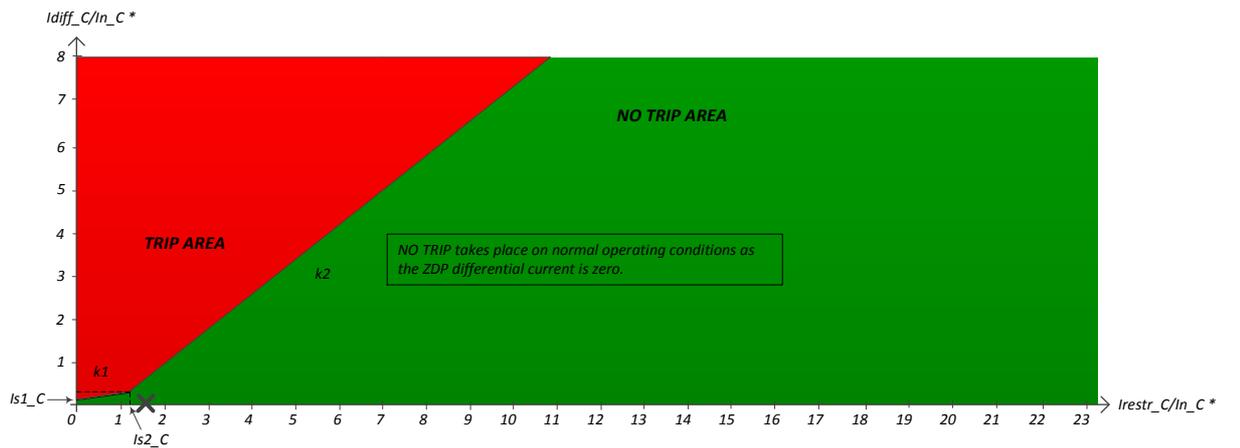
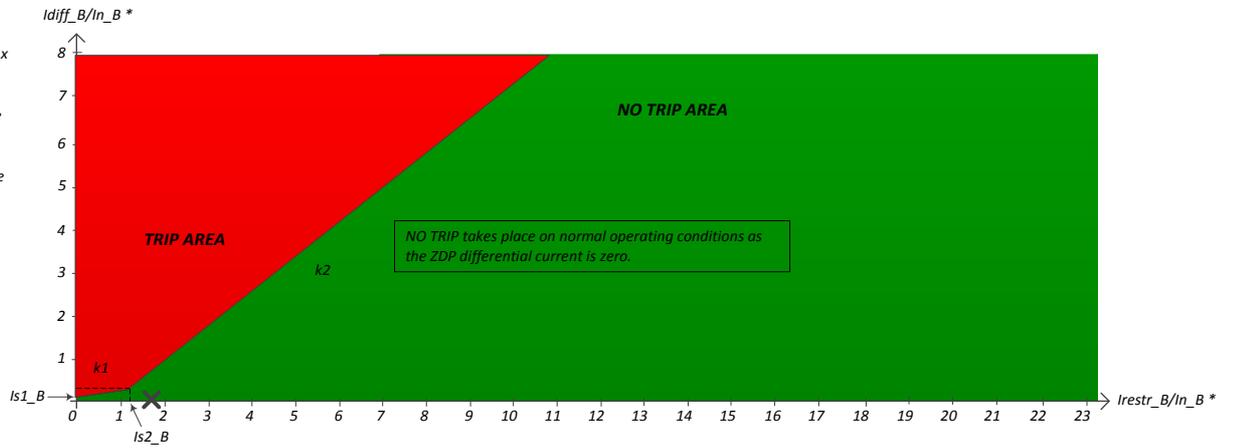
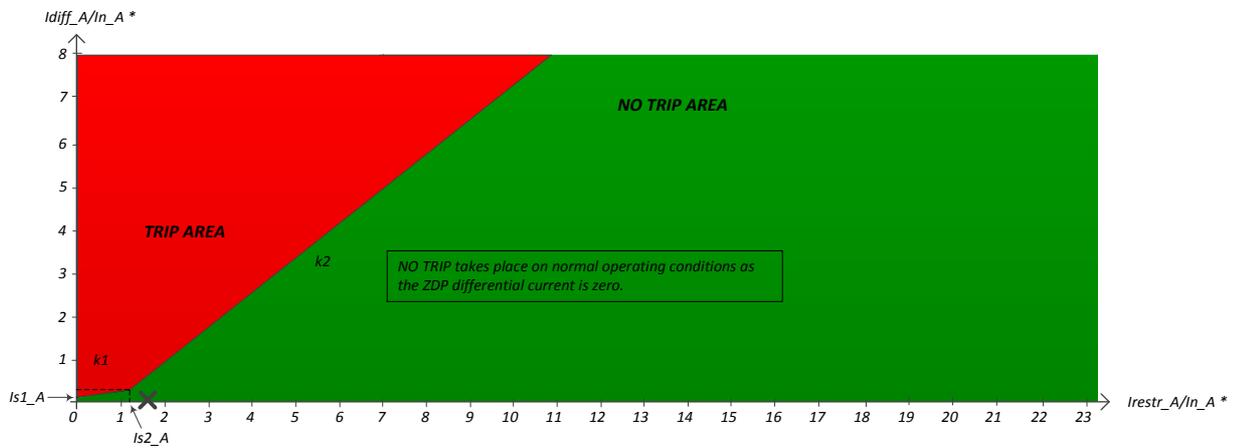
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix C6 – Power flow simulation – SP2 - continued

Simulation step 5/24

Zone : 5

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	26.07-45.30j	-31.90-0.72j	18.76+33.38j
BR5	26.09-45.32j	-31.90-0.74j	18.76+33.38j



* In_x is the rated current of the phase x of the current zone. $x = A$ or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

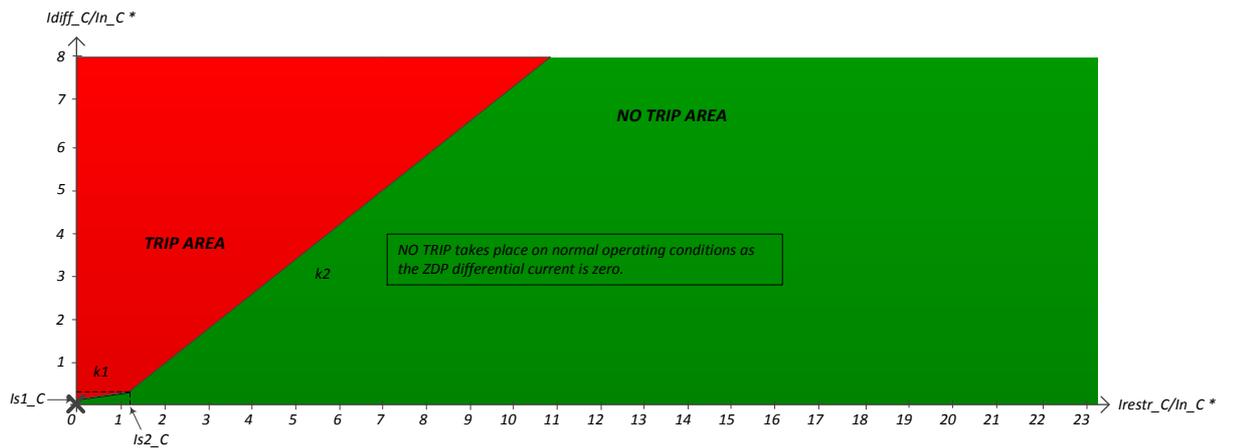
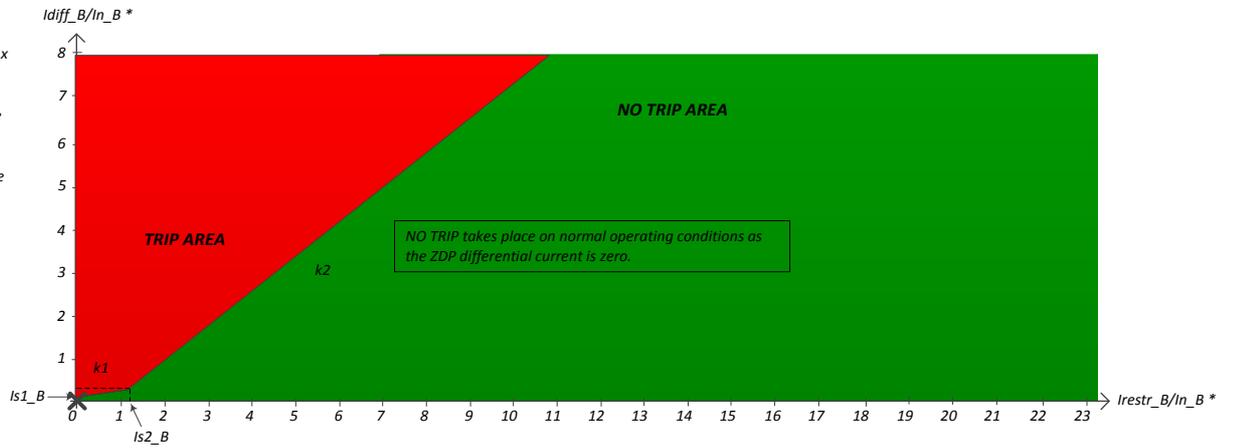
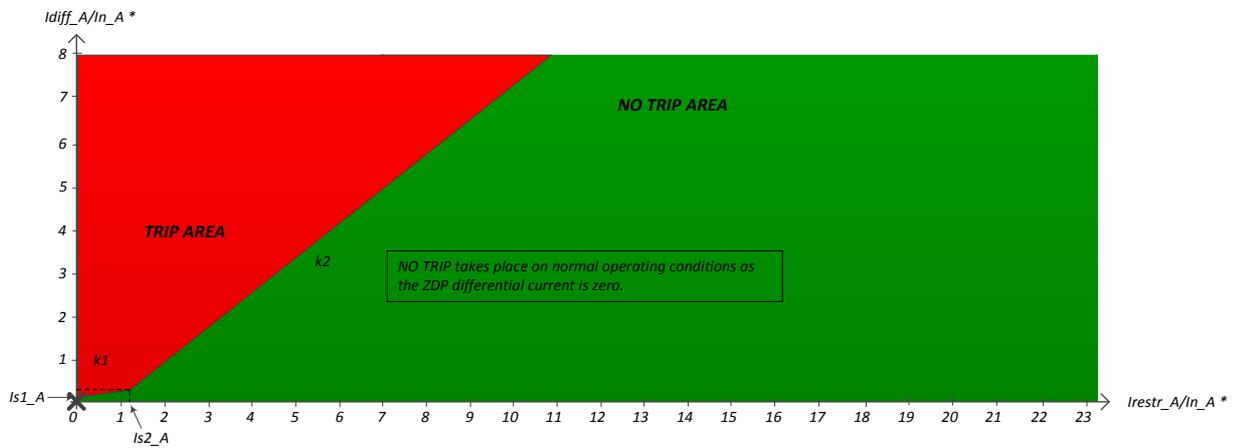
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix C6 – Power flow simulation – SP2 - continued

Simulation step 5/24

Zone : 6

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	0.00+0.00j	0.00+0.00j	0.00+0.00j
BR6	0.00+0.00j	0.00+0.00j	0.00+0.00j



* I_{n_x} is the rated current of the phase x of the current zone. x = A or B or C

I_{diff_x} is the differential current on the phase x of the current zone.

I_{restr_x} is the restraining current on the phase x of the current zone.

I_{s1_x} is the differential current pick-up setting. It is set to 10% of the phase x rated current.

I_{s2_x} is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

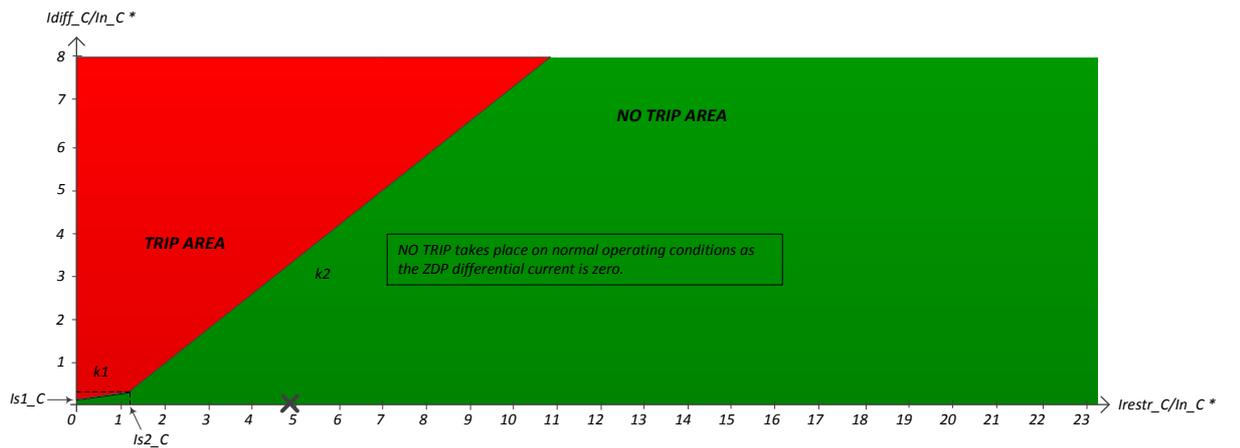
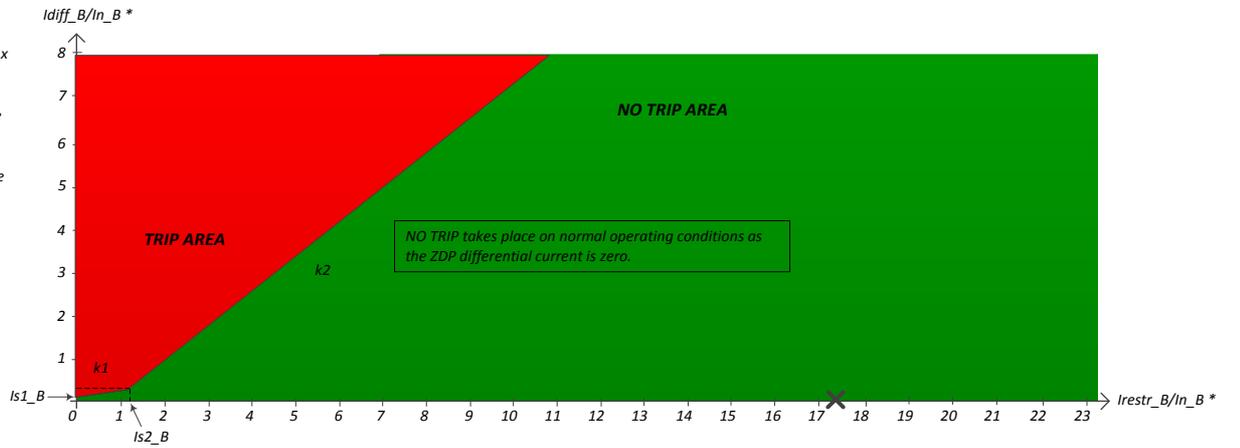
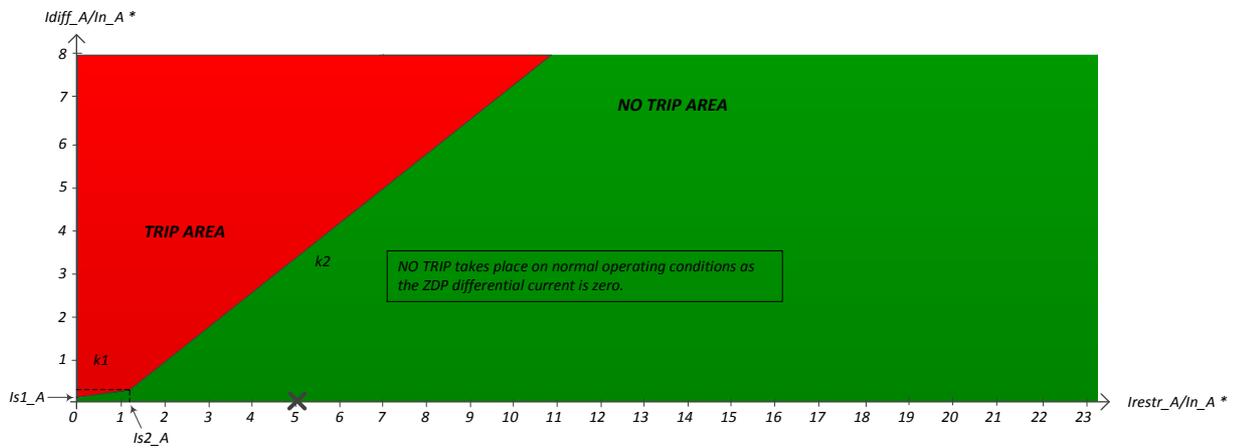
k_1, k_2 : slopes - $k_1=30\%$ & $k_2=80\%$

Appendix C6 – Power flow simulation – SP2 - continued

Simulation step 6/24

Zone : 1

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	29.84-74.93j	5.45+13.68j	39.59+76.84j
BR1	183.42-379.98j	-309.68+40.65j	192.14+313.66j
BR2	-104.92+215.01j	211.25-15.09j	-108.62-171.03j
BR3	-48.65+90.03j	103.87-11.93j	-43.95-65.79j



* In_x is the rated current of the phase x of the current zone. $x = A$ or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

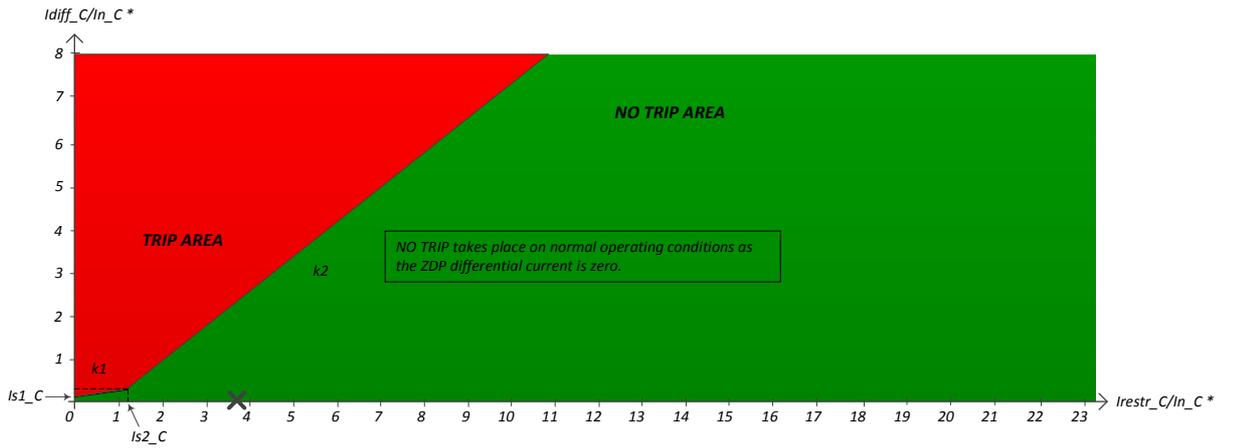
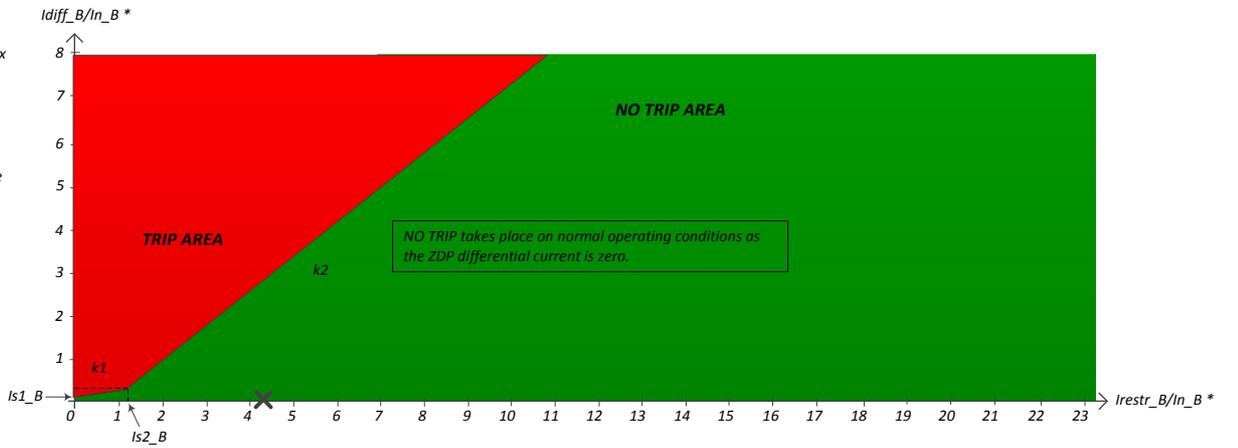
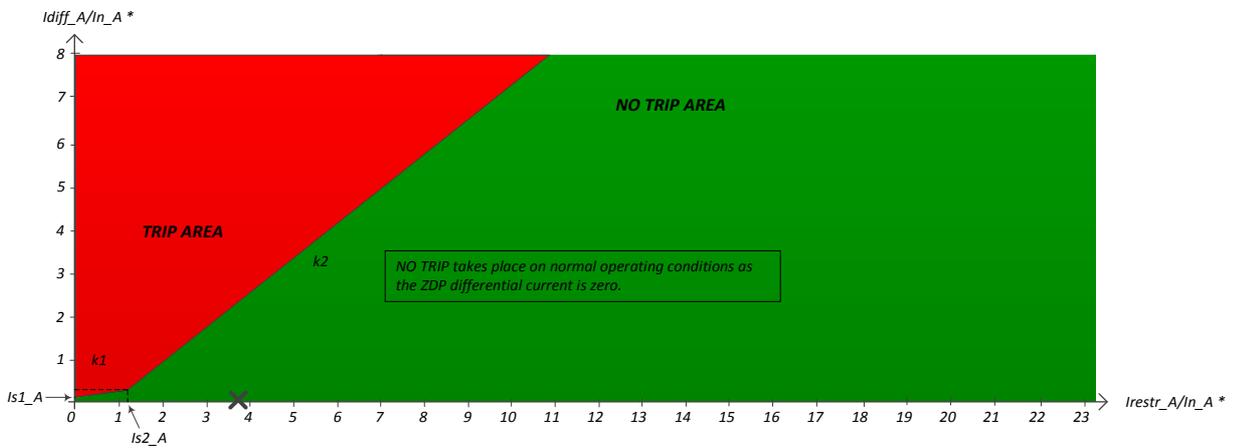
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix C6 – Power flow simulation – SP2 - continued

Simulation step 6/24

Zone : 2

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	40.01-79.18j	-72.78-1.17j	32.49+58.48j
BR2	104.92-215.01j	-211.25+15.09j	108.62+171.03j
BR4	-64.85+135.85j	138.49-16.33j	-76.17-112.55j
BR6	-0.00-0.00j	-0.00-0.00j	-0.00-0.00j



* In_x is the rated current of the phase x of the current zone. $x = A$ or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

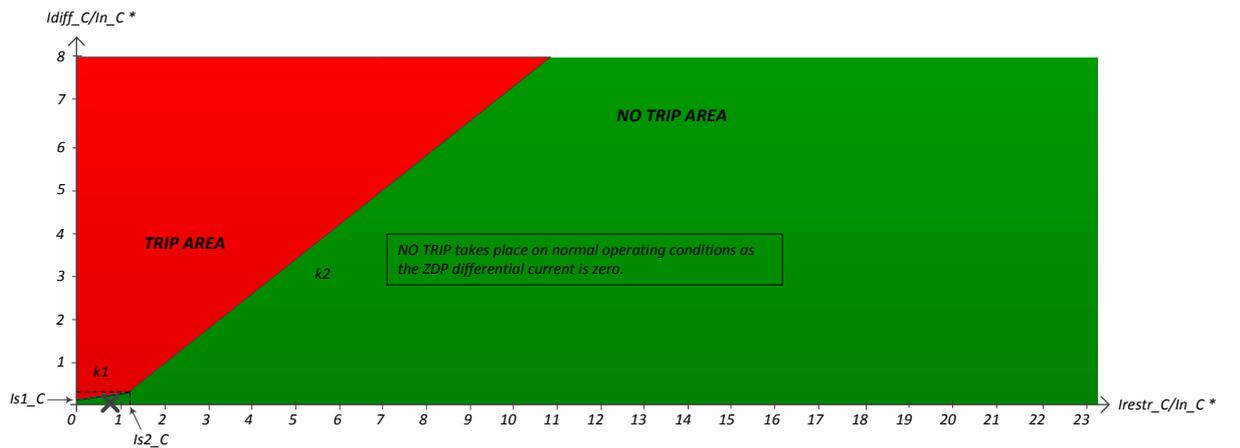
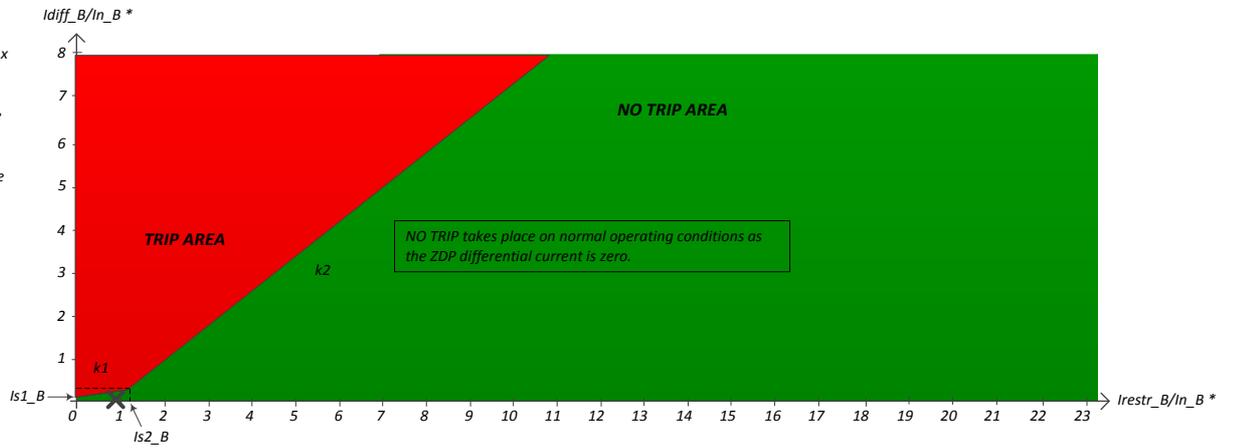
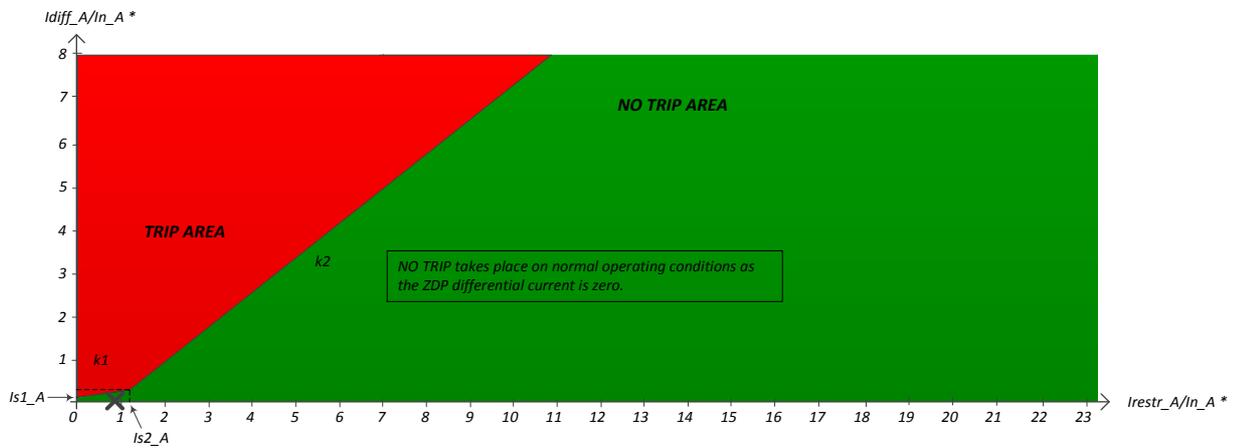
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix C6 – Power flow simulation – SP2

Simulation step 6/24

Zone : 3

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	48.62-90.02j	-103.86+11.97j	43.95+65.80j
BR3	48.65-90.03j	-103.87+11.93j	43.95+65.79j



* In_x is the rated current of the phase x of the current zone. x = A or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

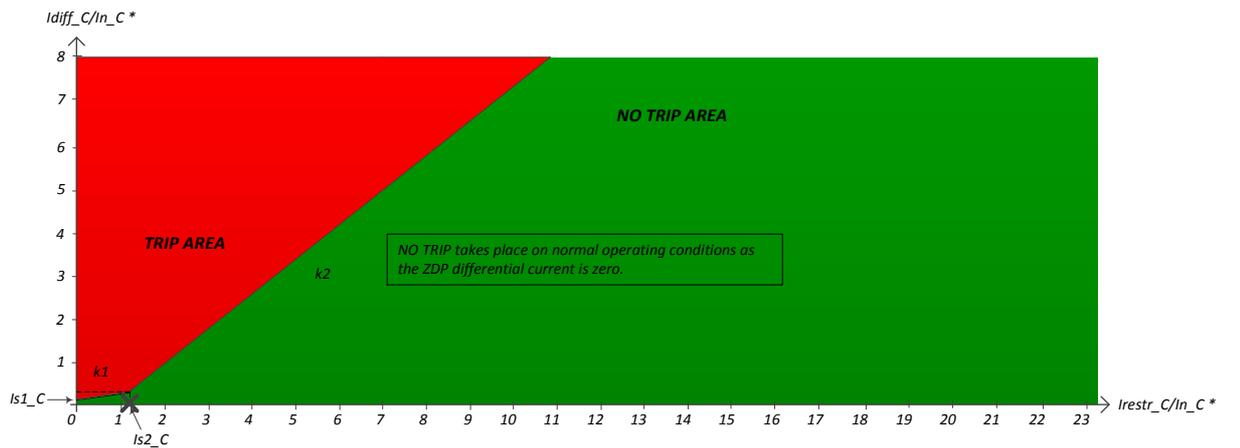
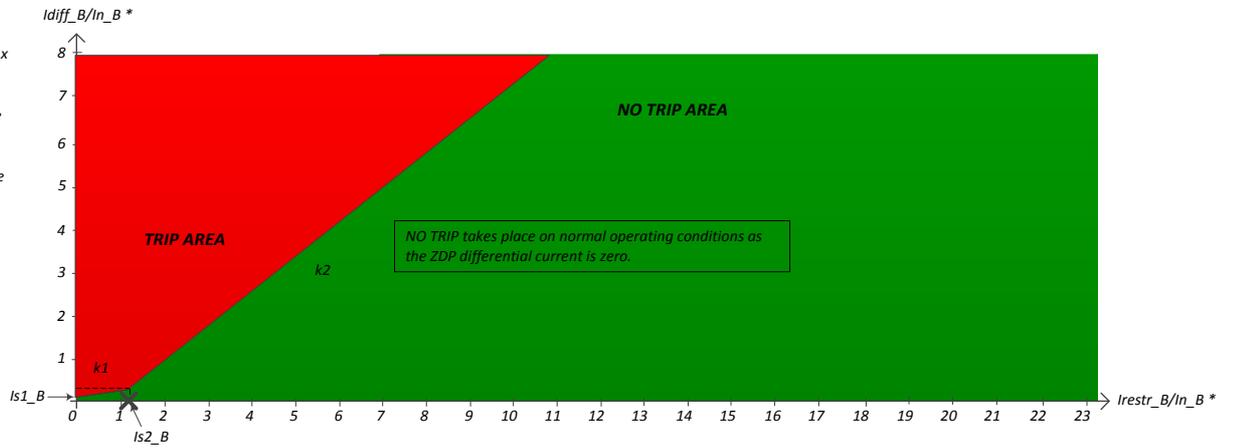
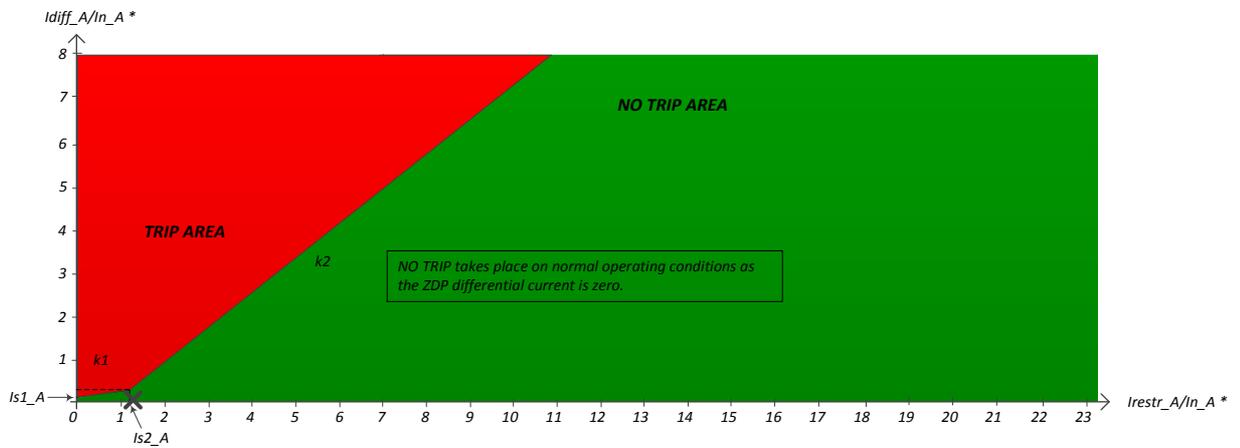
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix C6 – Power flow simulation – SP2 - continued

Simulation step 6/24

Zone : 4

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	37.73-89.01j	-104.80+17.07j	56.66+77.94j
BR5	-27.08+46.82j	33.72+0.68j	-19.53-34.60j
BR4	64.85-135.85j	-138.49+16.33j	76.17+112.55j



* In_x is the rated current of the phase x of the current zone. $x = A$ or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

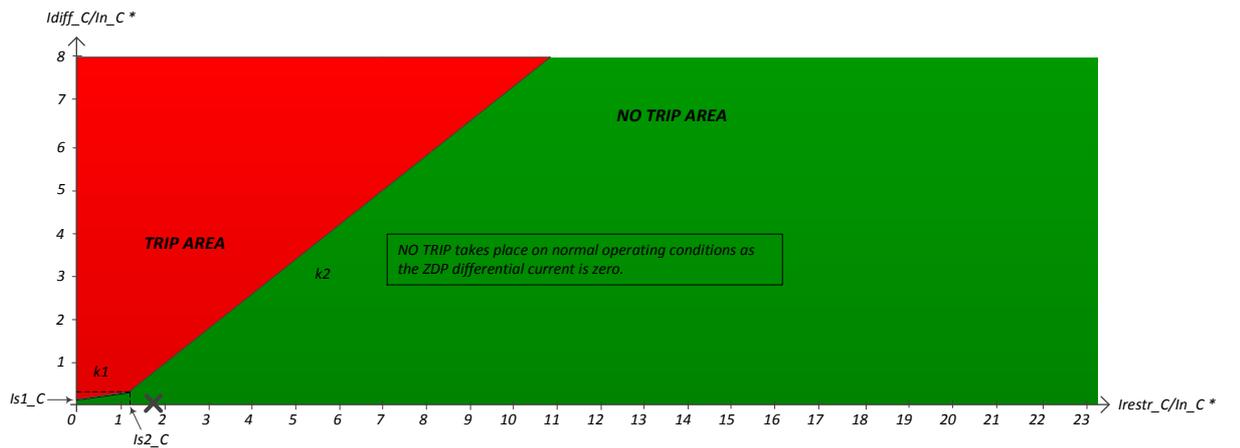
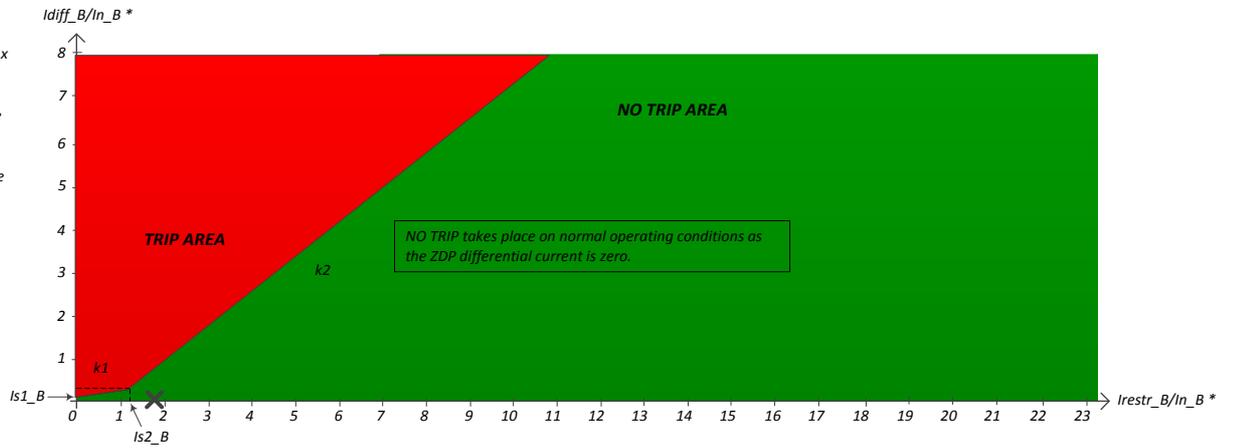
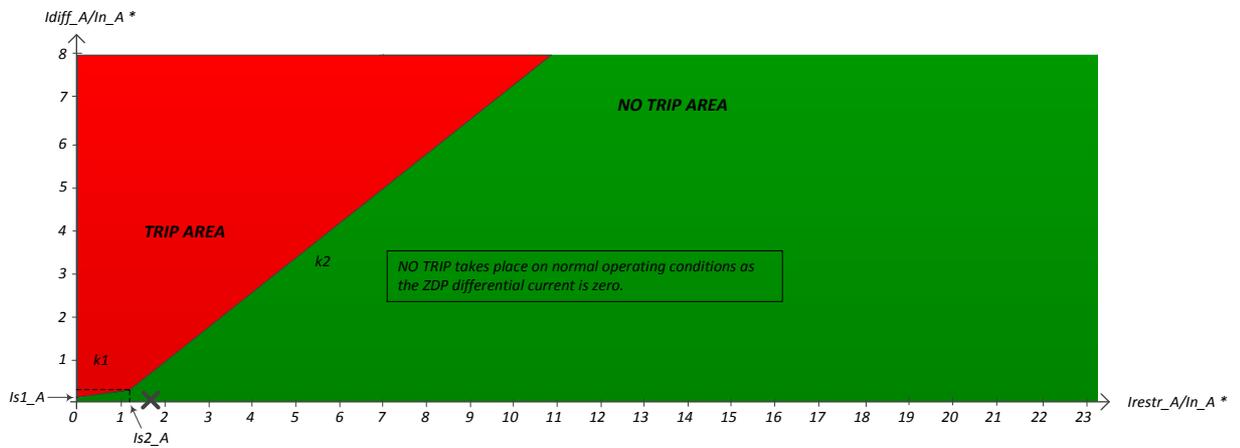
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix C6 – Power flow simulation – SP2 - continued

Simulation step 6/24

Zone : 5

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	27.06-46.80j	-33.72-0.66j	19.53+34.59j
BR5	27.08-46.82j	-33.72-0.68j	19.53+34.60j



* In_x is the rated current of the phase x of the current zone. $x = A$ or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

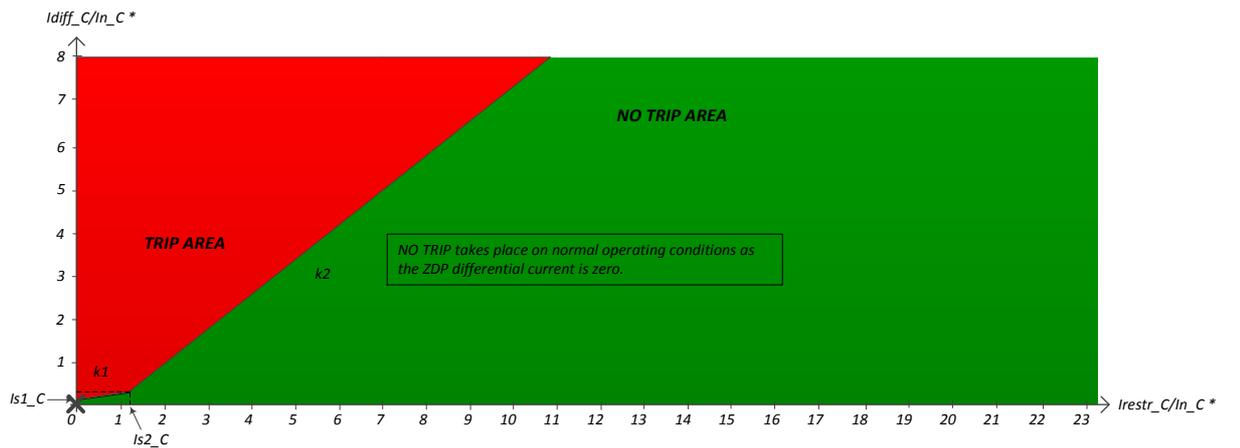
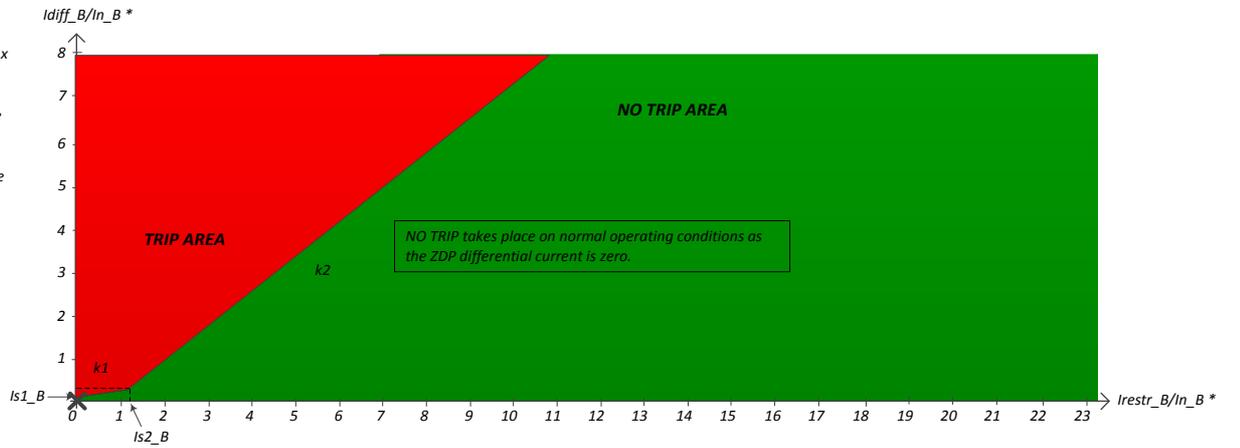
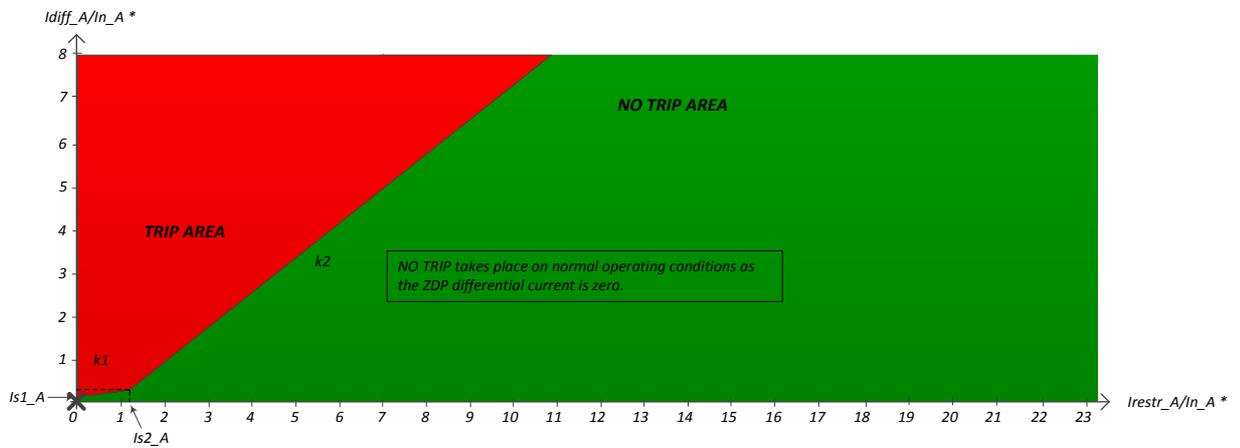
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix C6 – Power flow simulation – SP2 - continued

Simulation step 6/24

Zone : 6

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	0.00+0.00j	0.00+0.00j	0.00+0.00j
BR6	0.00+0.00j	0.00+0.00j	0.00+0.00j



* I_{n_x} is the rated current of the phase x of the current zone. x = A or B or C

I_{diff_x} is the differential current on the phase x of the current zone.

I_{restr_x} is the restraining current on the phase x of the current zone.

I_{s1_x} is the differential current pick-up setting. It is set to 10% of the phase x rated current.

I_{s2_x} is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

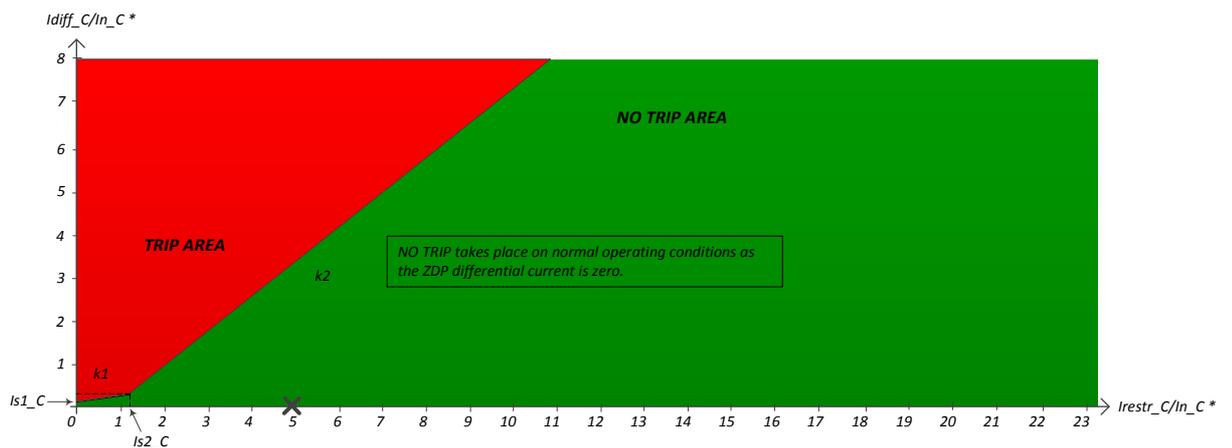
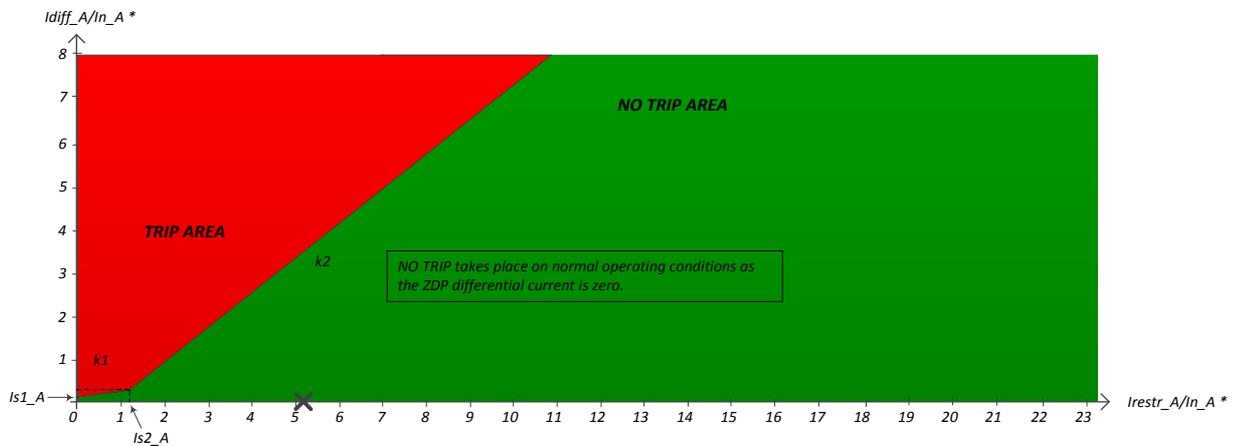
k_1, k_2 : slopes - $k_1=30\%$ & $k_2=80\%$

Appendix C6 – Power flow simulation – SP2 - continued

Simulation step 7/24

Zone : 1

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	30.20-75.78j	7.25+15.64j	37.69+77.34j
BR1	188.93-396.07j	-301.09+47.58j	187.67+314.96j
BR2	-105.30+218.81j	198.38-19.52j	-101.57-167.37j
BR3	-53.41+101.45j	109.95-12.46j	-48.42-70.26j



* In_x is the rated current of the phase x of the current zone. $x = A$ or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

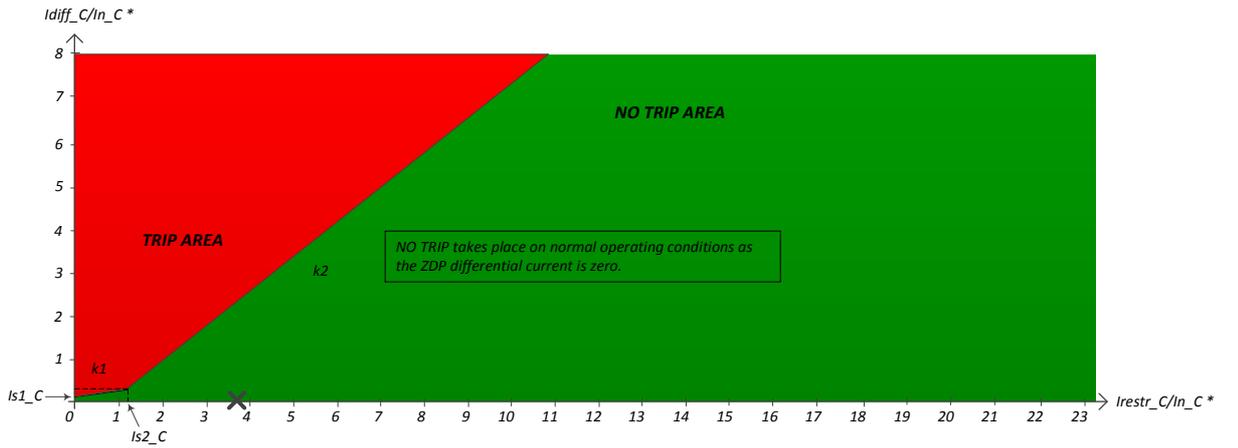
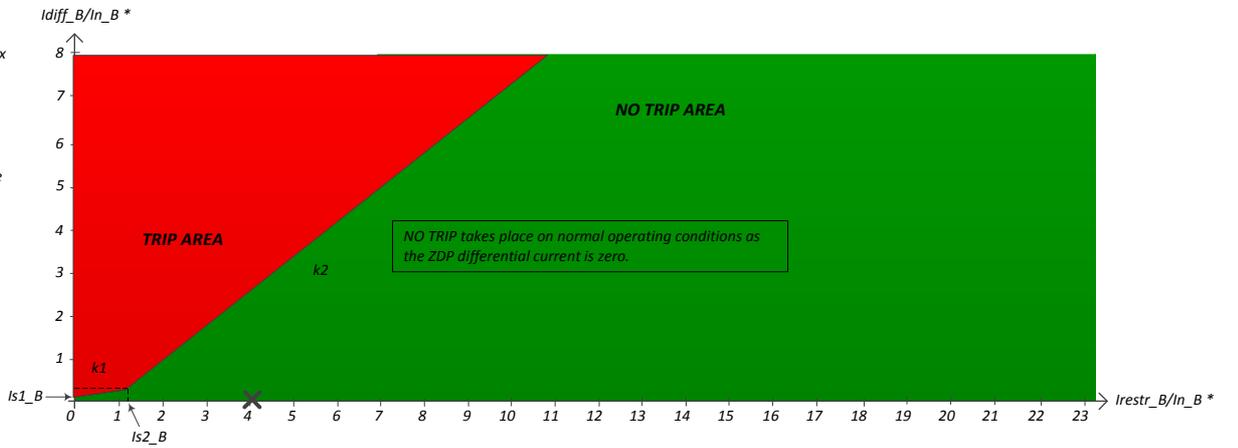
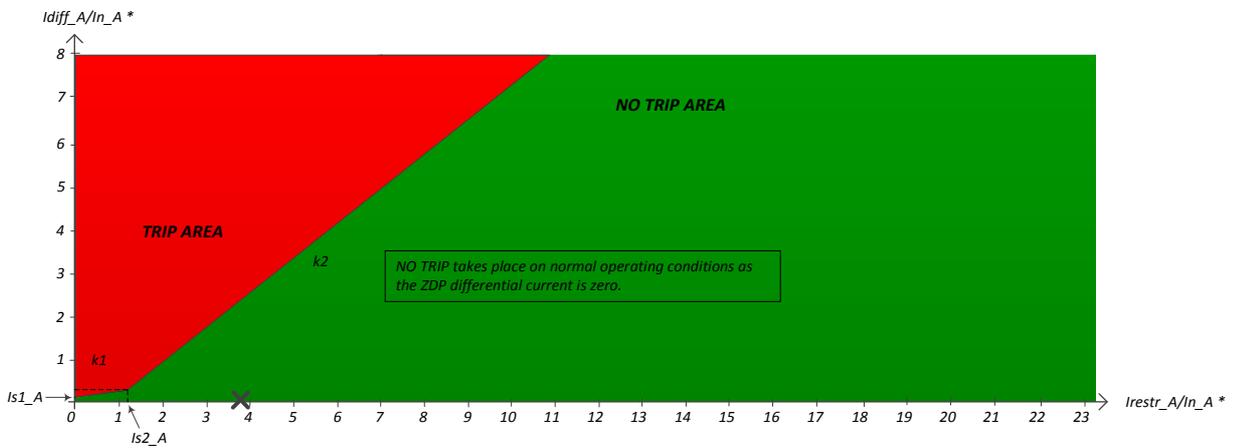
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix C6 – Power flow simulation – SP2 - continued

Simulation step 7/24

Zone : 2

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	35.19-76.12j	-65.92-0.50j	29.51+57.08j
BR2	105.30-218.81j	-198.38+19.52j	101.57+167.37j
BR4	-70.09+142.70j	132.47-20.08j	-72.11-110.29j
BR6	-0.00-0.00j	-0.00-0.00j	-0.00-0.00j



* In_x is the rated current of the phase x of the current zone. $x = A$ or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

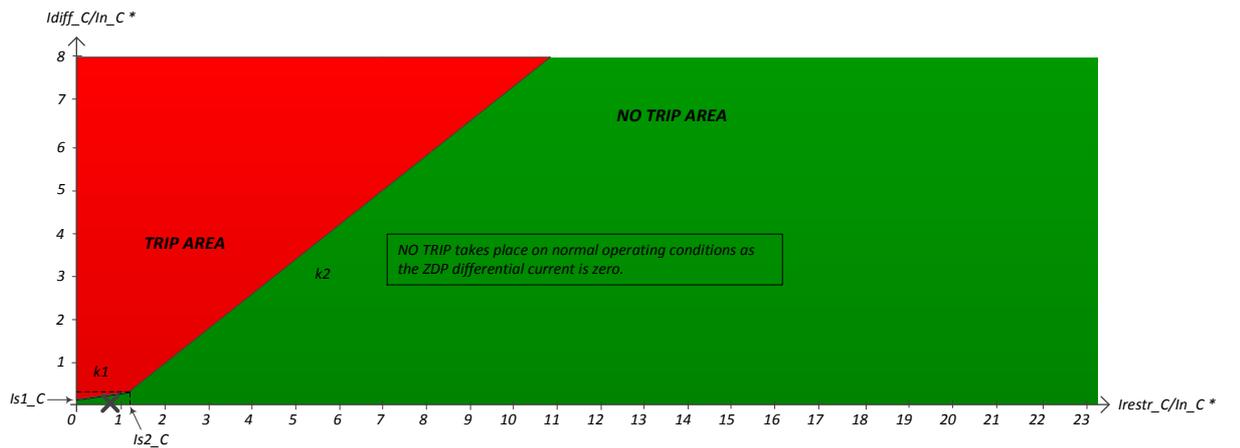
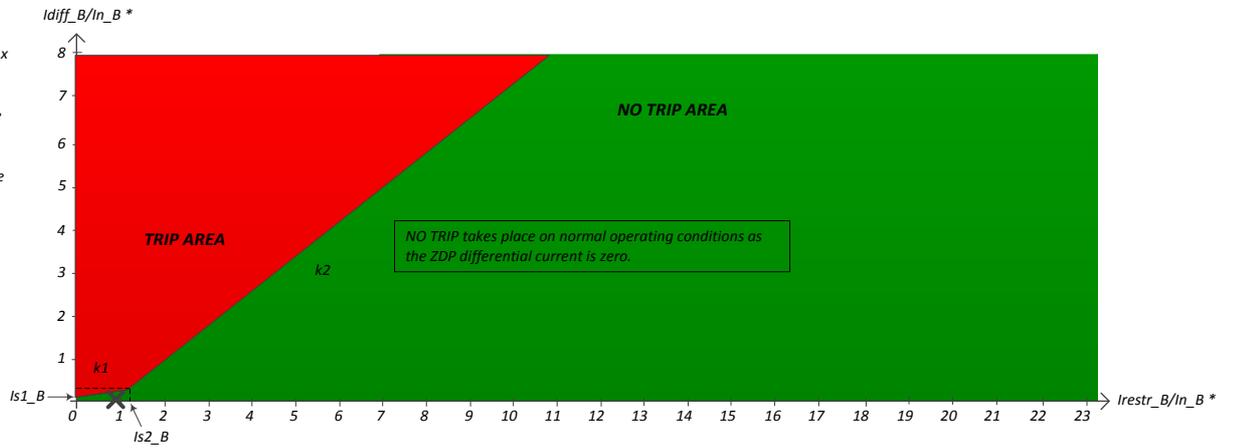
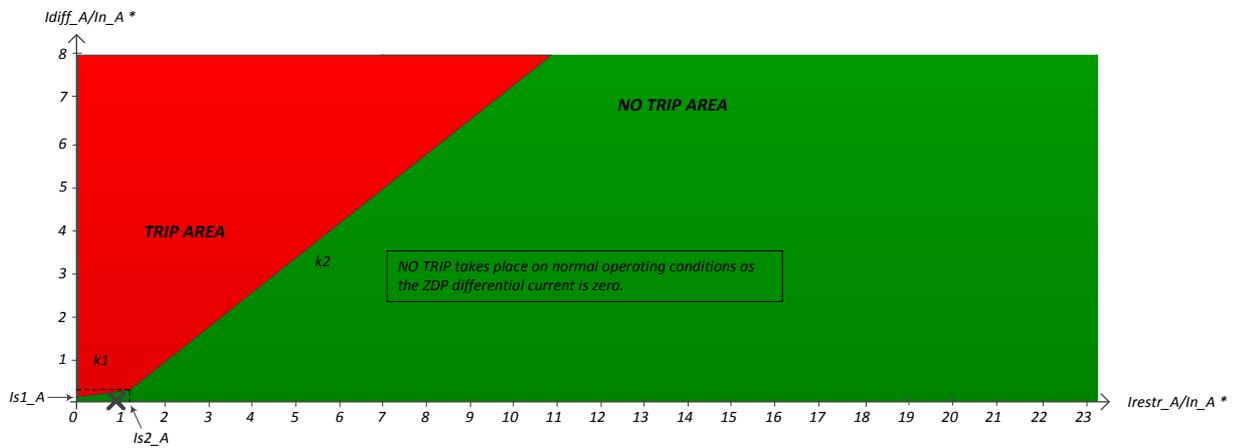
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix C6 – Power flow simulation – SP2

Simulation step 7/24

Zone : 3

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	53.38-101.44j	-109.94+12.50j	48.43+70.27j
BR3	53.41-101.45j	-109.95+12.46j	48.42+70.26j



* In_x is the rated current of the phase x of the current zone. $x = A$ or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

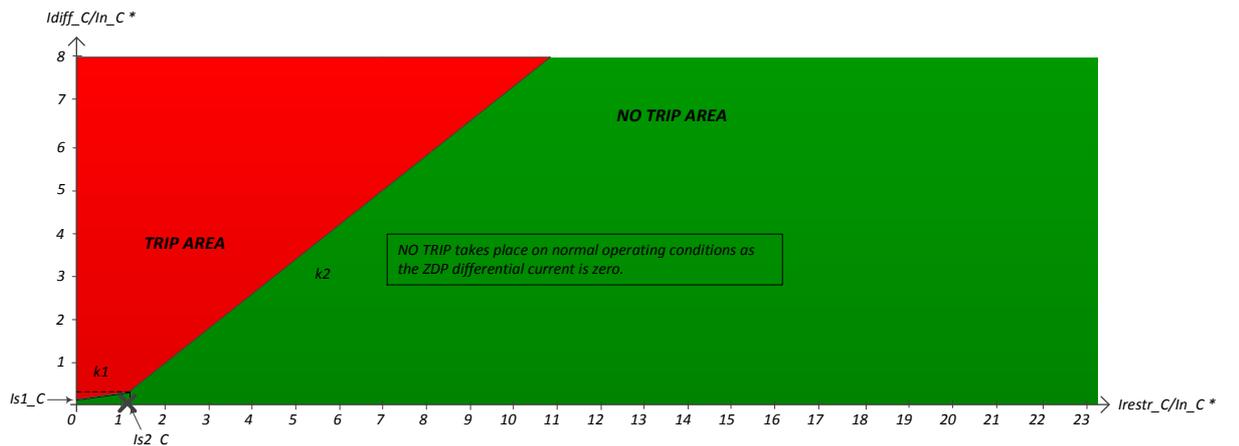
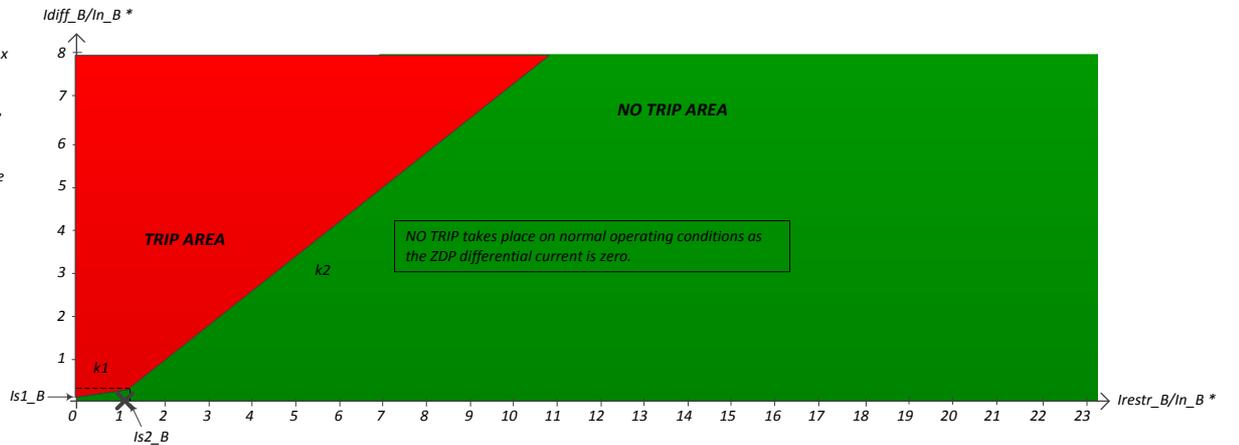
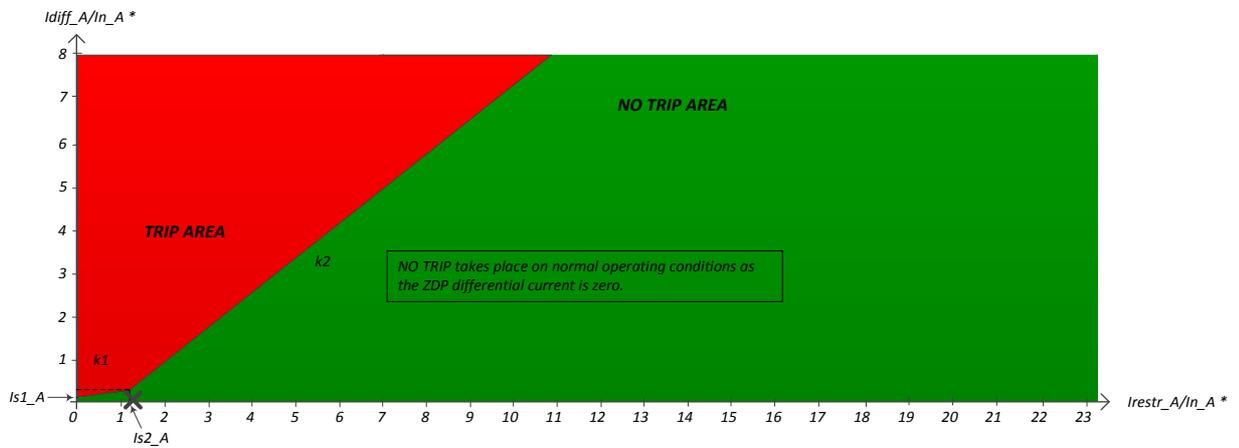
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix C6 – Power flow simulation – SP2 - continued

Simulation step 7/24

Zone : 4

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	43.05-95.65j	-104.80+20.80j	52.95+76.22j
BR5	-26.99+47.04j	27.69+0.65j	-19.19-34.06j
BR4	70.09-142.70j	-132.47+20.08j	72.11+110.29j



* In_x is the rated current of the phase x of the current zone. $x = A$ or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

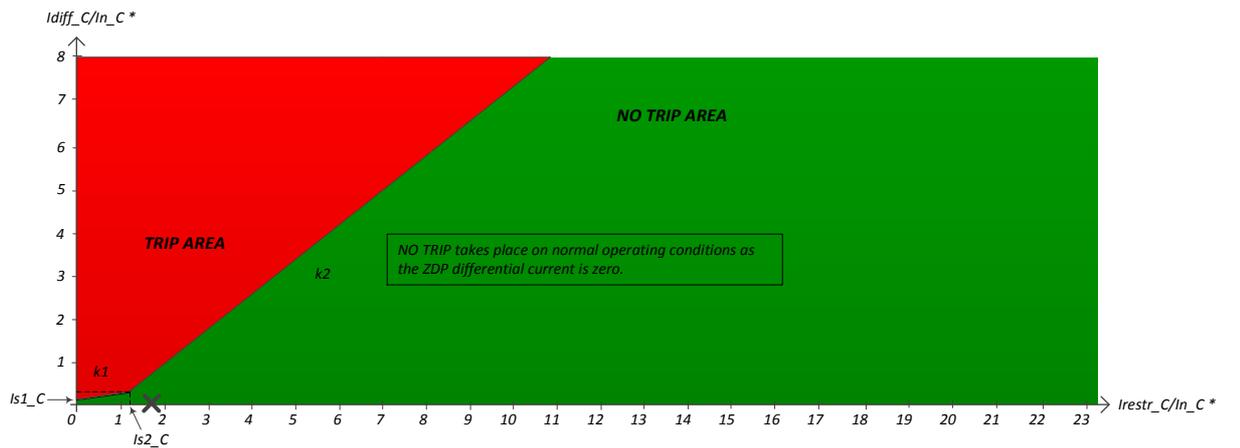
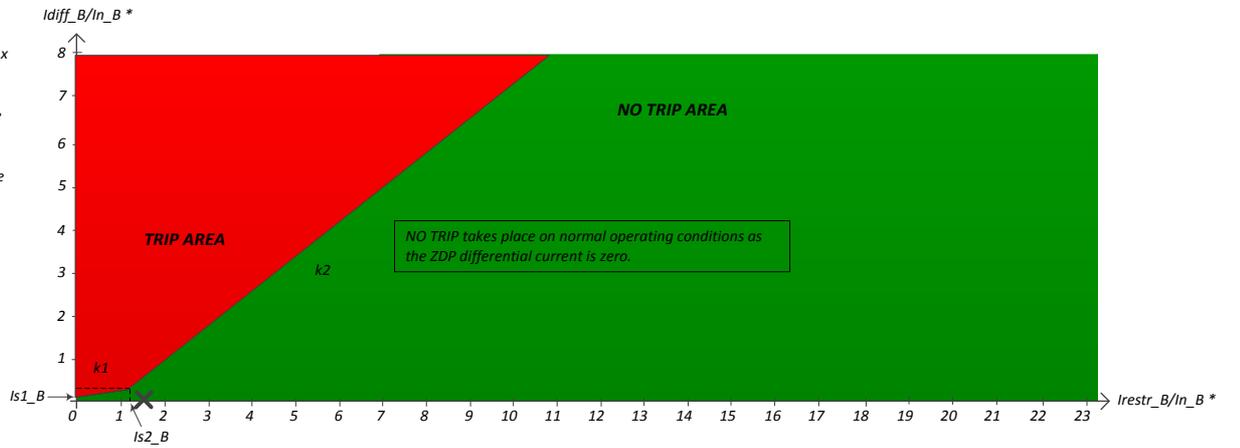
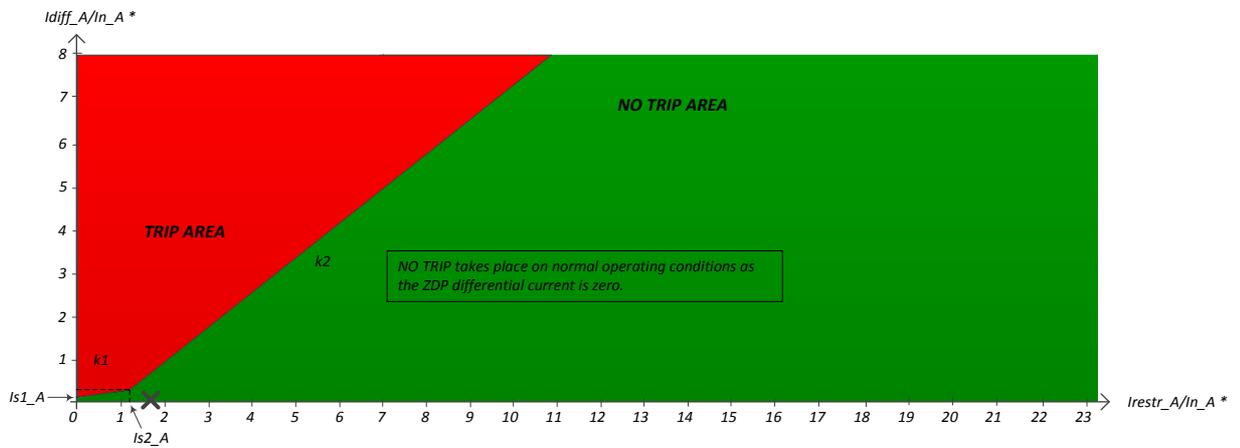
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix C6 – Power flow simulation – SP2 - continued

Simulation step 7/24

Zone : 5

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	26.99-47.02j	-27.69-0.64j	19.20+34.07j
BR5	26.99-47.04j	-27.69-0.65j	19.19+34.06j



* In_x is the rated current of the phase x of the current zone. $x = A$ or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

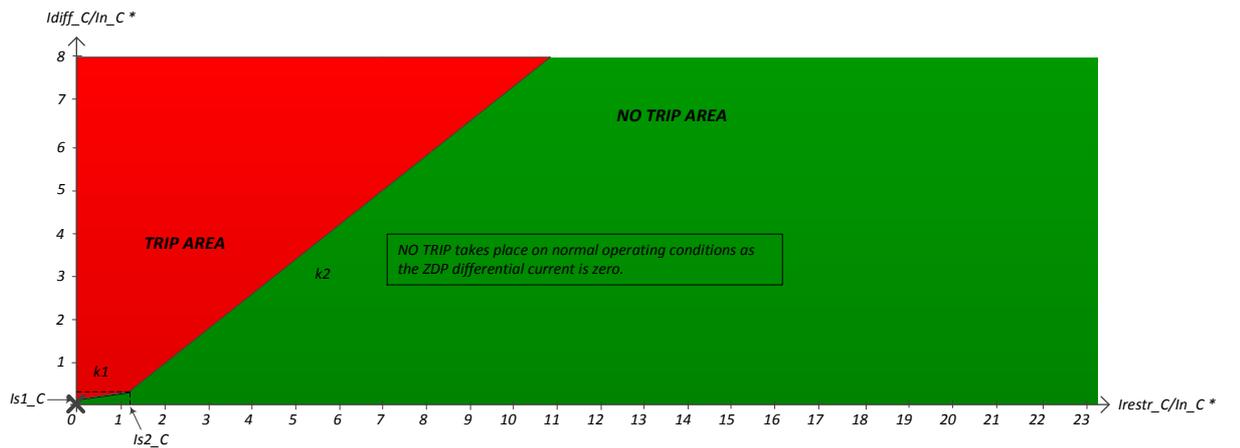
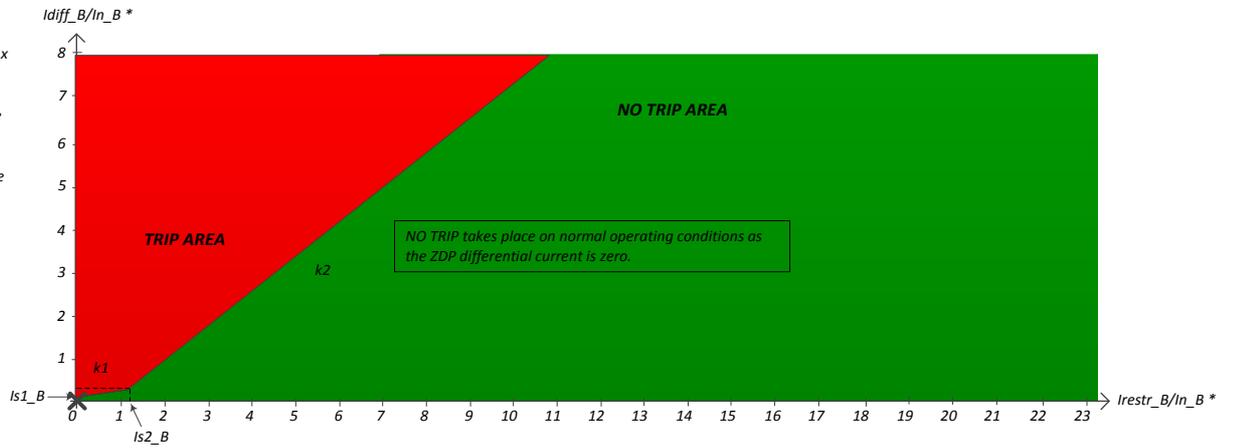
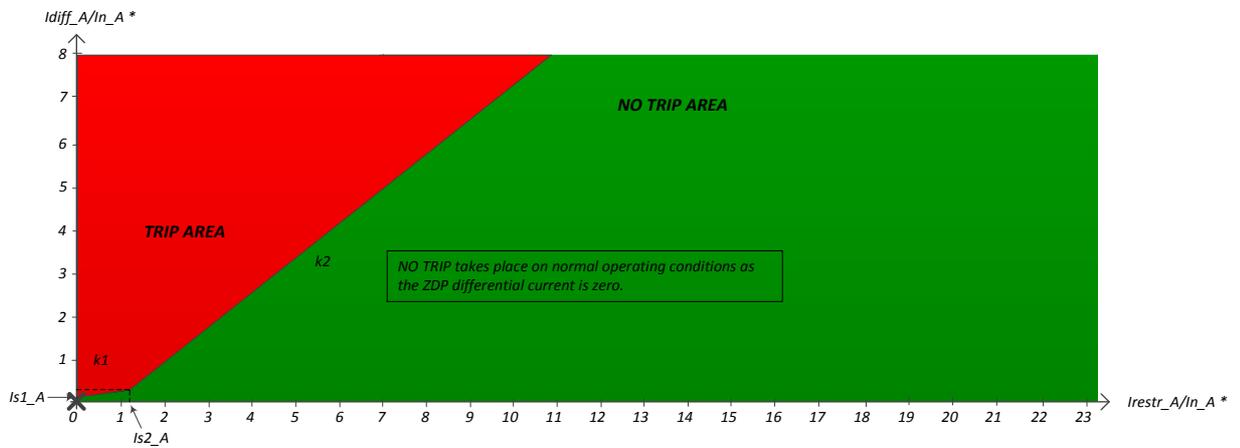
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix C6 – Power flow simulation – SP2 - continued

Simulation step 7/24

Zone : 6

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	0.00+0.00j	0.00+0.00j	0.00+0.00j
BR6	0.00+0.00j	0.00+0.00j	0.00+0.00j



* I_{n_x} is the rated current of the phase x of the current zone. x = A or B or C

I_{diff_x} is the differential current on the phase x of the current zone.

I_{restr_x} is the restraining current on the phase x of the current zone.

I_{s1_x} is the differential current pick-up setting. It is set to 10% of the phase x rated current.

I_{s2_x} is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

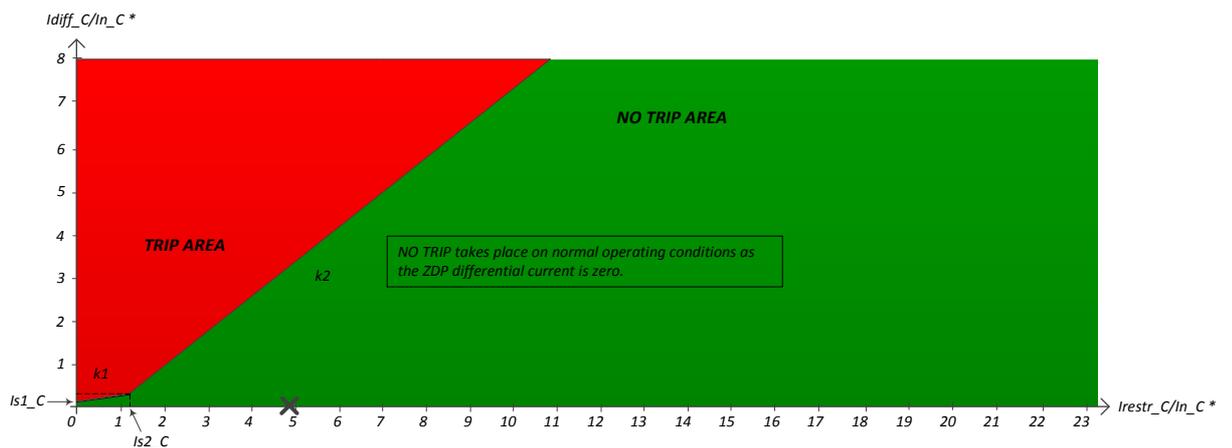
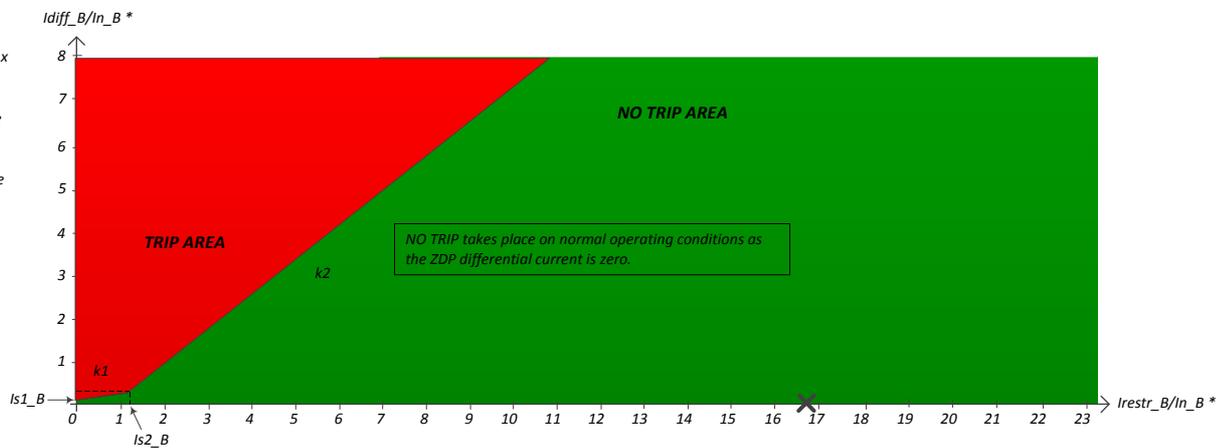
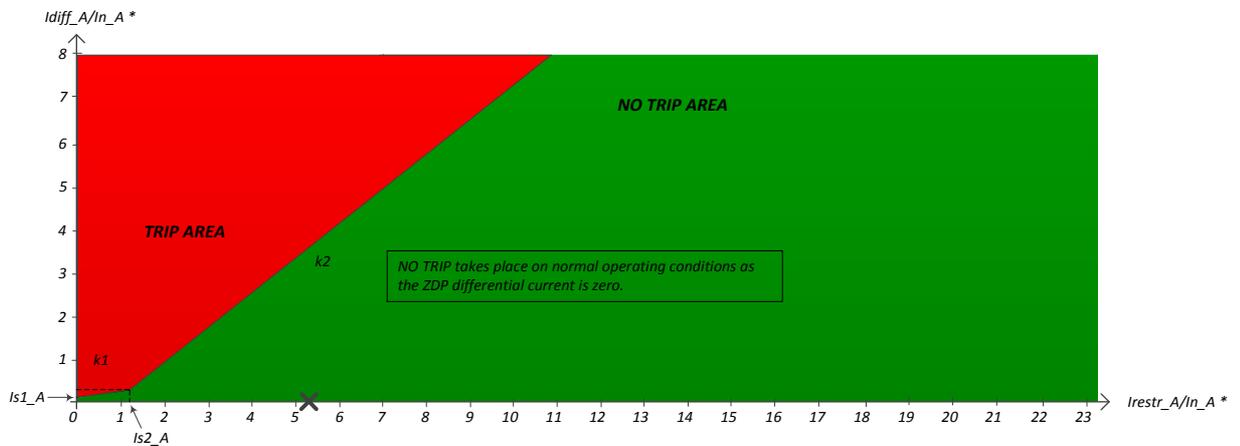
k_1, k_2 : slopes - $k_1=30\%$ & $k_2=80\%$

Appendix C6 – Power flow simulation – SP2 - continued

Simulation step 8/24

Zone : 1

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	28.48-74.67j	11.02+15.06j	40.73+80.40j
BR1	186.35-394.74j	-295.21+47.05j	186.89+314.65j
BR2	-105.13+224.99j	190.28-18.38j	-102.63-169.75j
BR3	-52.72+95.08j	115.94-13.63j	-43.56-64.49j



* In_x is the rated current of the phase x of the current zone. $x = A$ or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

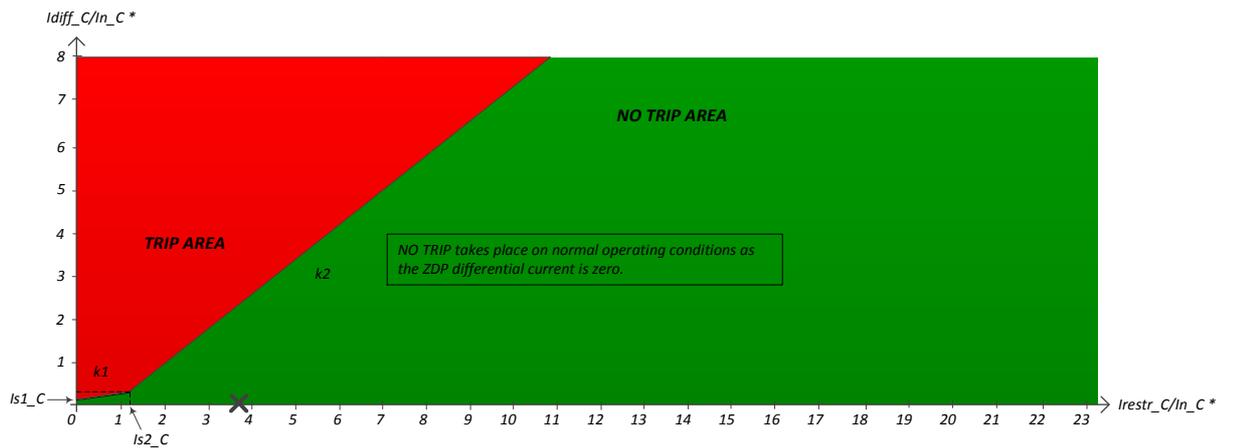
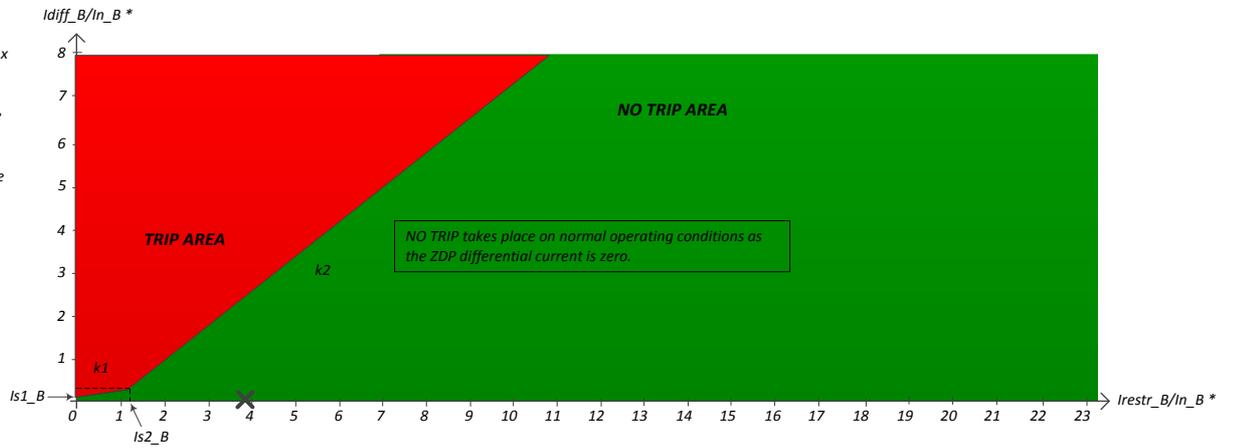
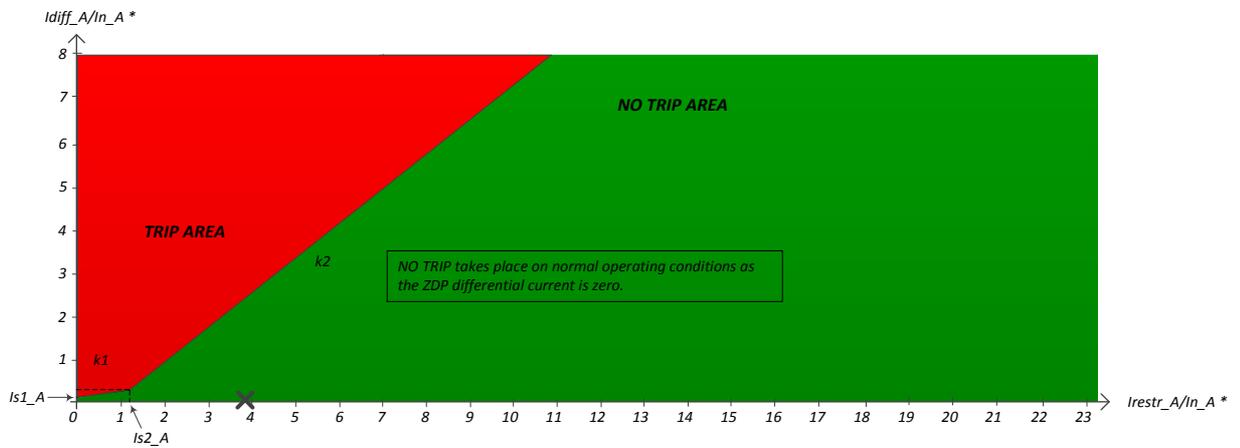
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix C6 – Power flow simulation – SP2 - continued

Simulation step 8/24

Zone : 2

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	40.33-82.76j	-62.84-0.11j	26.21+49.01j
BR2	105.13-224.99j	-190.28+18.38j	102.63+169.75j
BR4	-64.75+142.25j	127.45-18.56j	-76.47-120.75j
BR6	-0.00-0.00j	-0.00-0.00j	-0.00-0.00j



* In_x is the rated current of the phase x of the current zone. $x = A$ or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

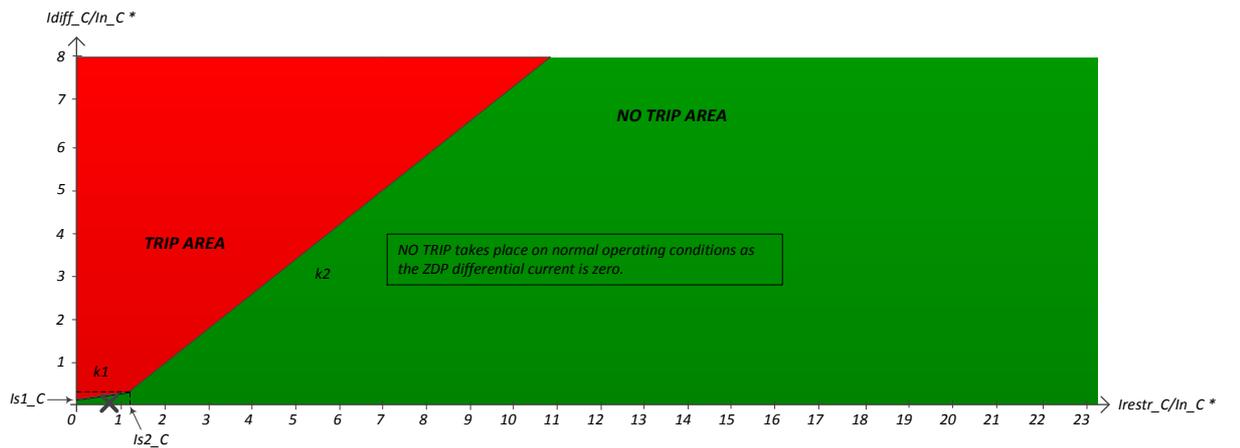
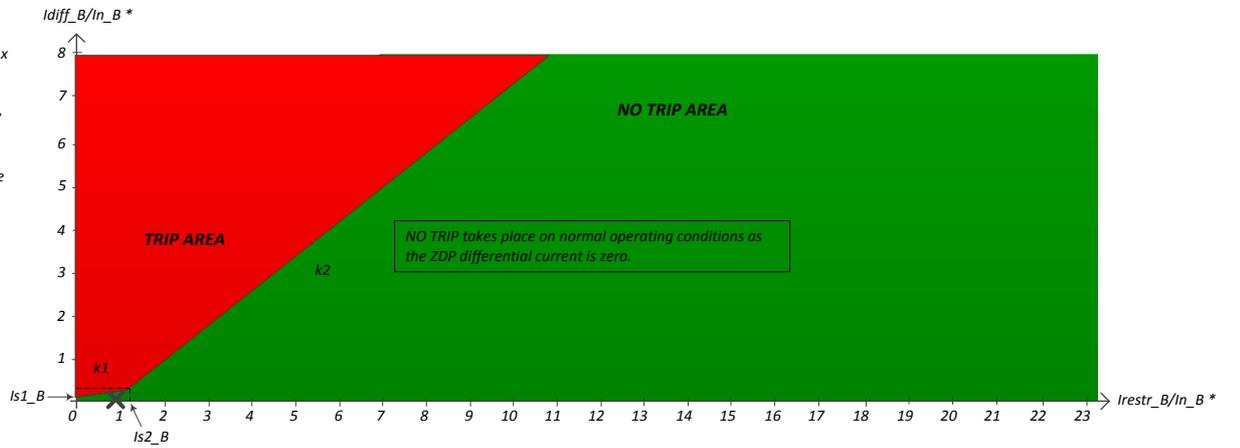
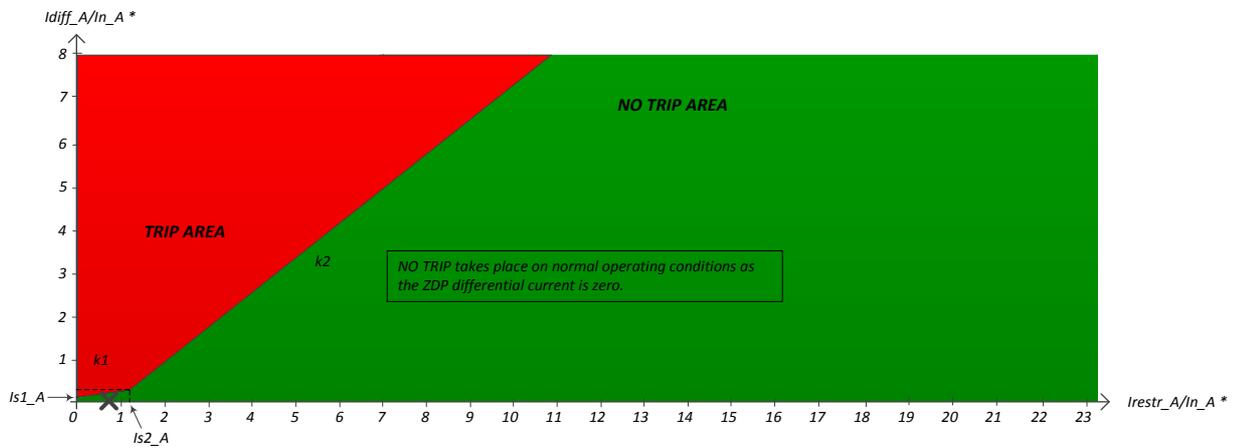
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix C6 – Power flow simulation – SP2

Simulation step 8/24

Zone : 3

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	52.70-95.05j	-115.94+13.66j	43.56+64.50j
BR3	52.72-95.08j	-115.94+13.63j	43.56+64.49j



* In_x is the rated current of the phase x of the current zone. $x = A$ or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

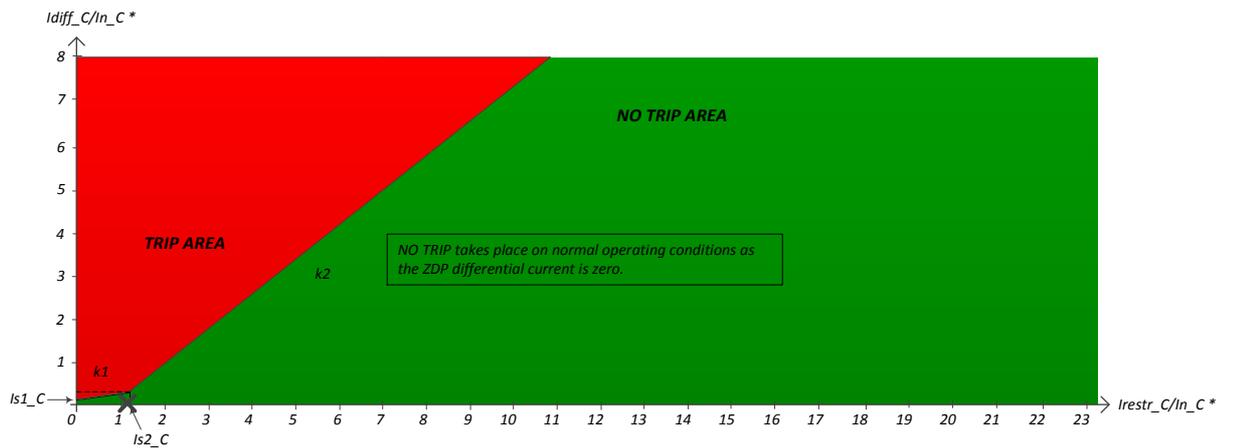
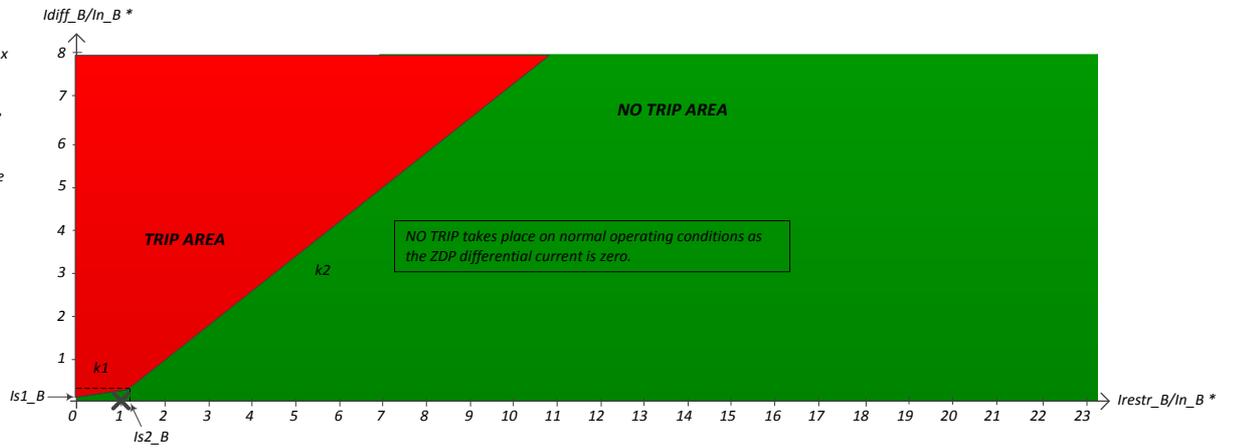
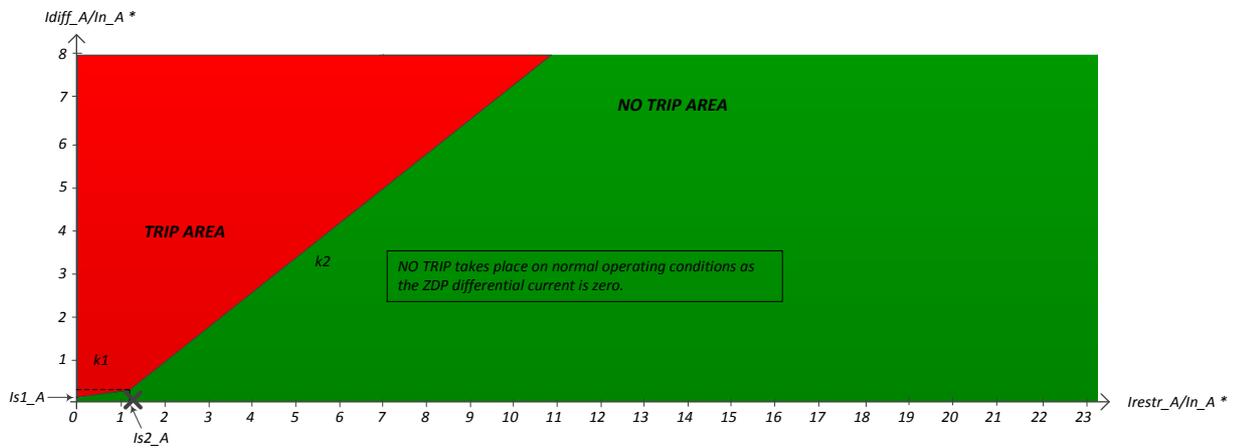
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix C6 – Power flow simulation – SP2 - continued

Simulation step 8/24

Zone : 4

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	37.24-94.35j	-94.66+19.42j	52.66+78.56j
BR5	-27.48+47.89j	32.81+0.81j	-23.81-42.19j
BR4	64.75-142.25j	-127.45+18.56j	76.47+120.75j



* In_x is the rated current of the phase x of the current zone. $x = A$ or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

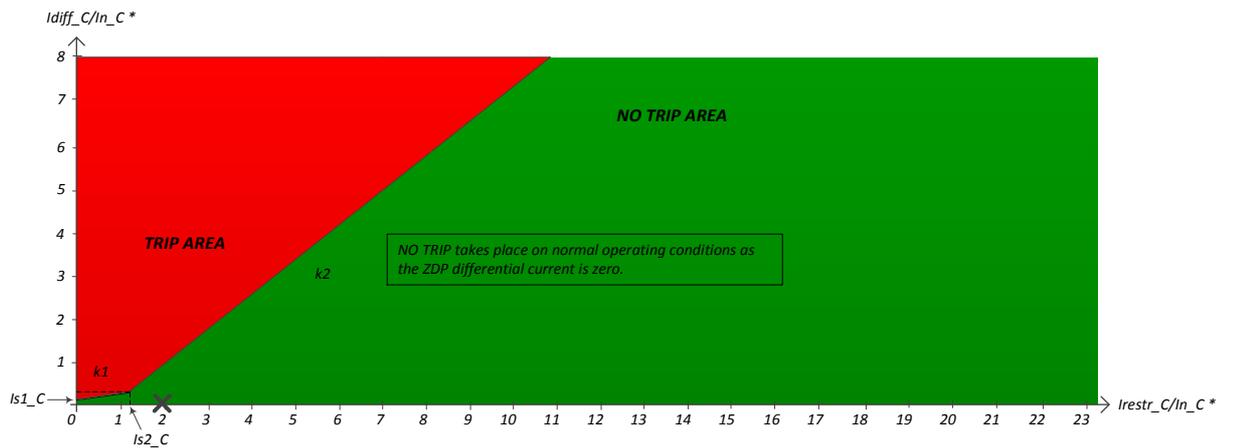
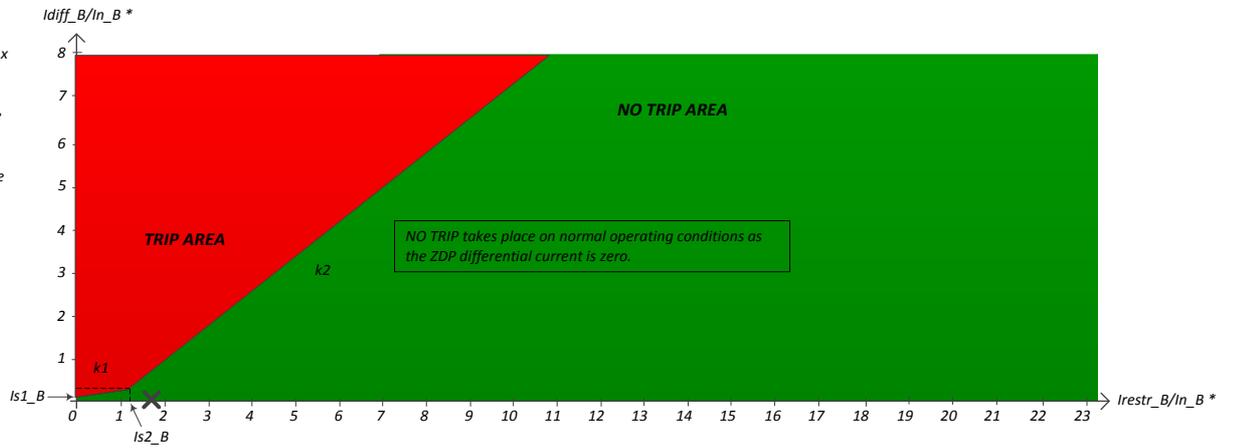
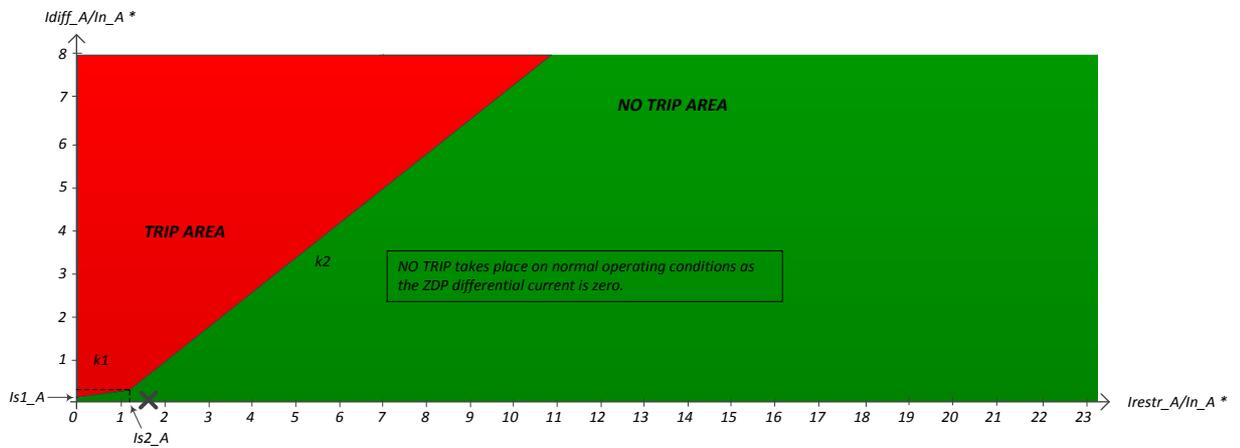
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix C6 – Power flow simulation – SP2 - continued

Simulation step 8/24

Zone : 5

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	27.46-47.88j	-32.82-0.80j	23.81+42.20j
BR5	27.48-47.89j	-32.81-0.81j	23.81+42.19j



* In_x is the rated current of the phase x of the current zone. $x = A$ or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

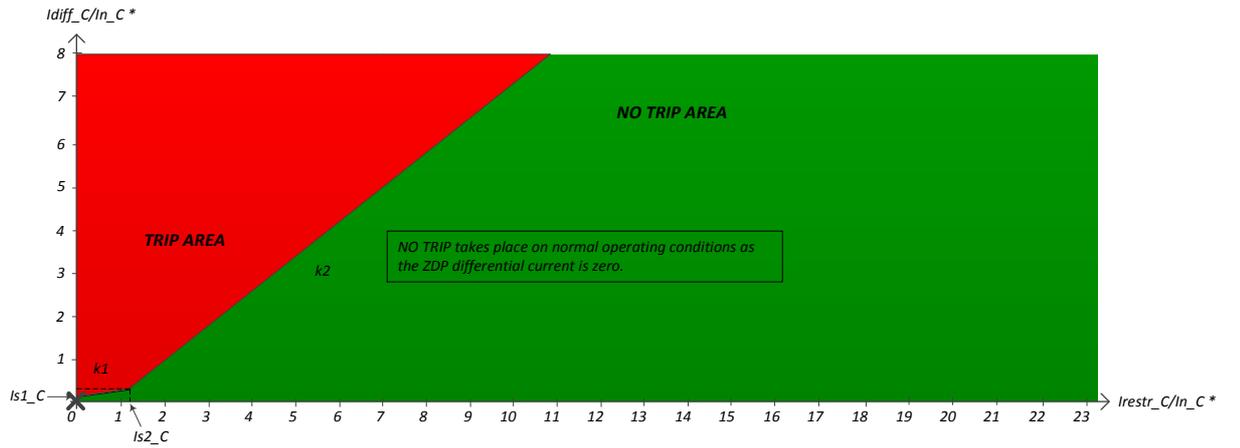
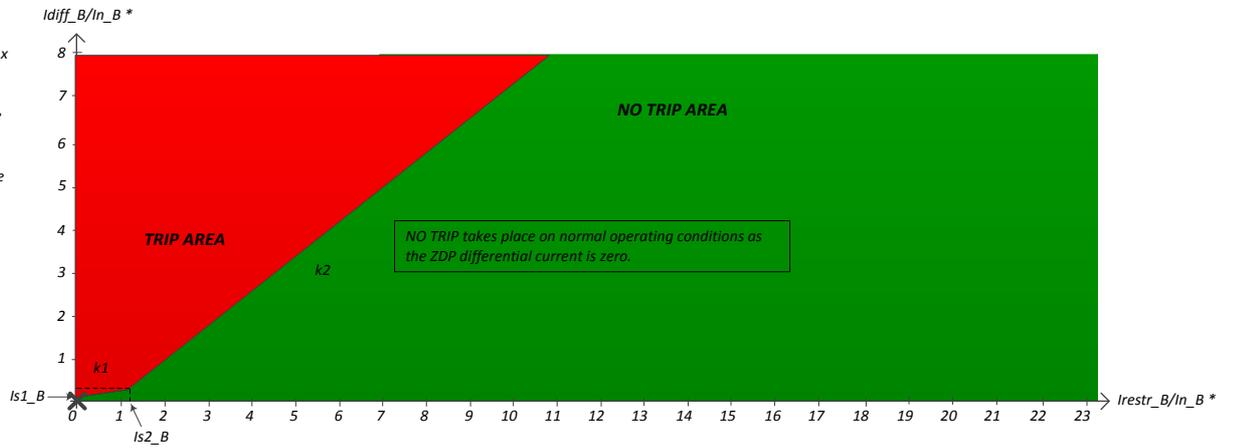
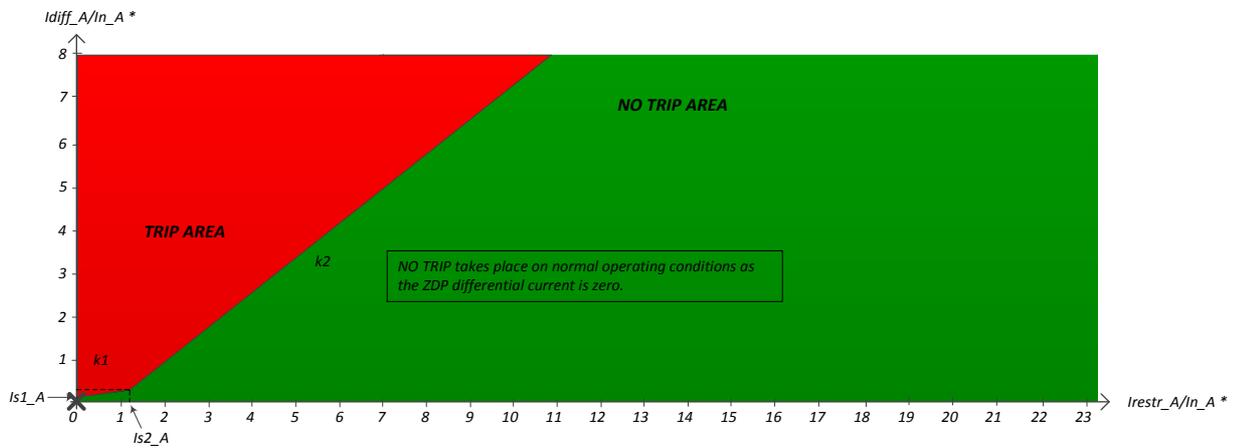
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix C6 – Power flow simulation – SP2 - continued

Simulation step 8/24

Zone : 6

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	0.00+0.00j	0.00+0.00j	0.00+0.00j
BR6	0.00+0.00j	0.00+0.00j	0.00+0.00j



* In_x is the rated current of the phase x of the current zone. $x = A$ or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

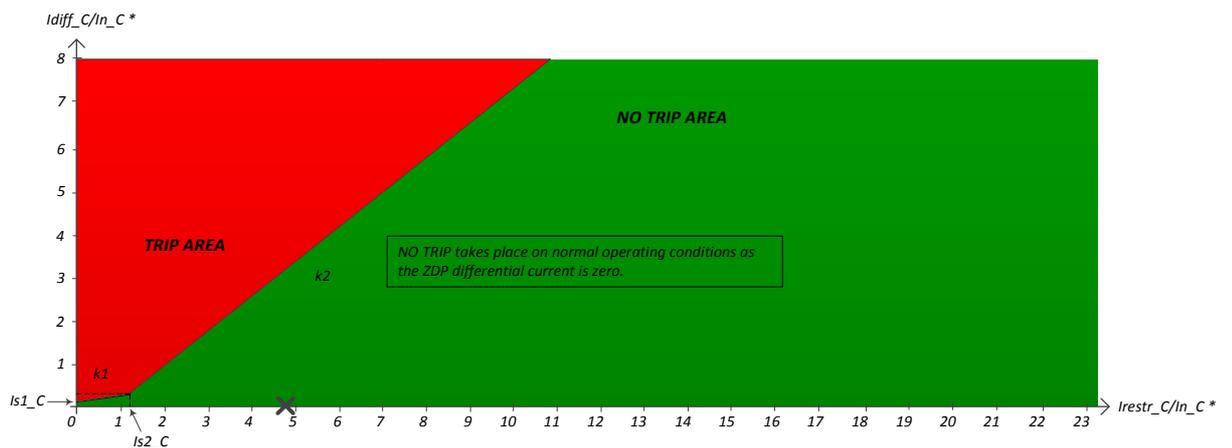
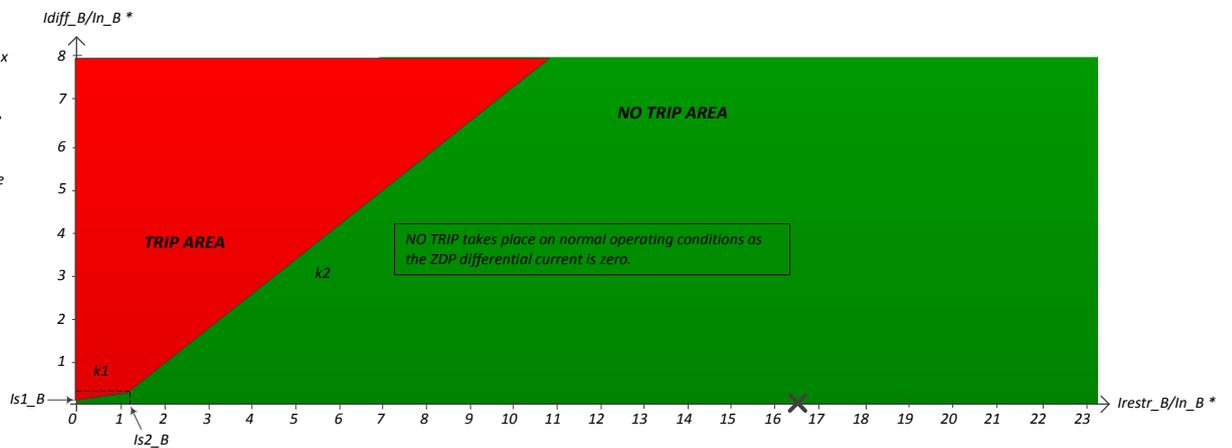
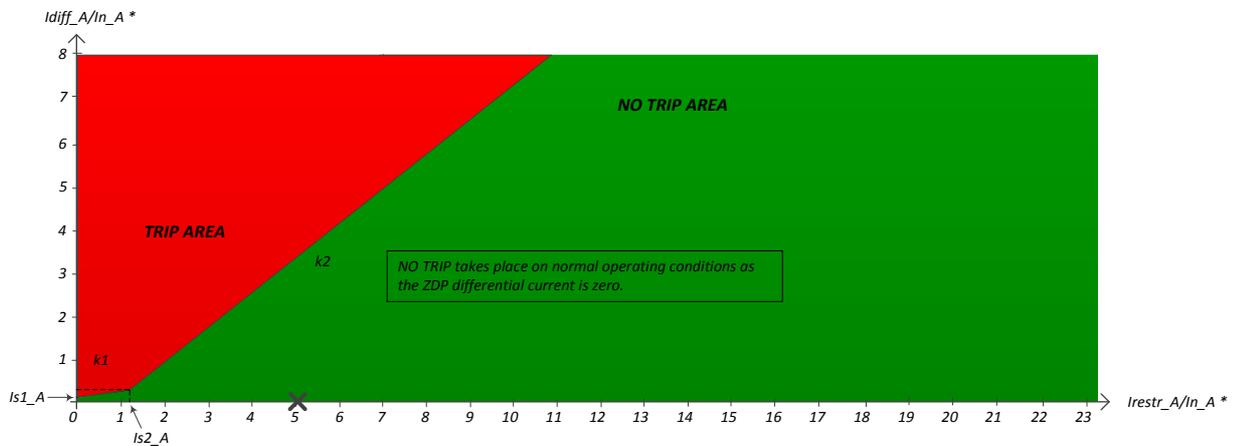
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix C6 – Power flow simulation – SP2 - continued

Simulation step 9/24

Zone : 1

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	24.19-68.94j	16.58+16.40j	36.59+71.41j
BR1	178.63-380.82j	-284.63+47.49j	181.82+299.34j
BR2	-100.76+212.55j	187.97-18.63j	-99.62-160.72j
BR3	-53.63+99.32j	113.22-12.48j	-45.61-67.19j



* In_x is the rated current of the phase x of the current zone. $x = A$ or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

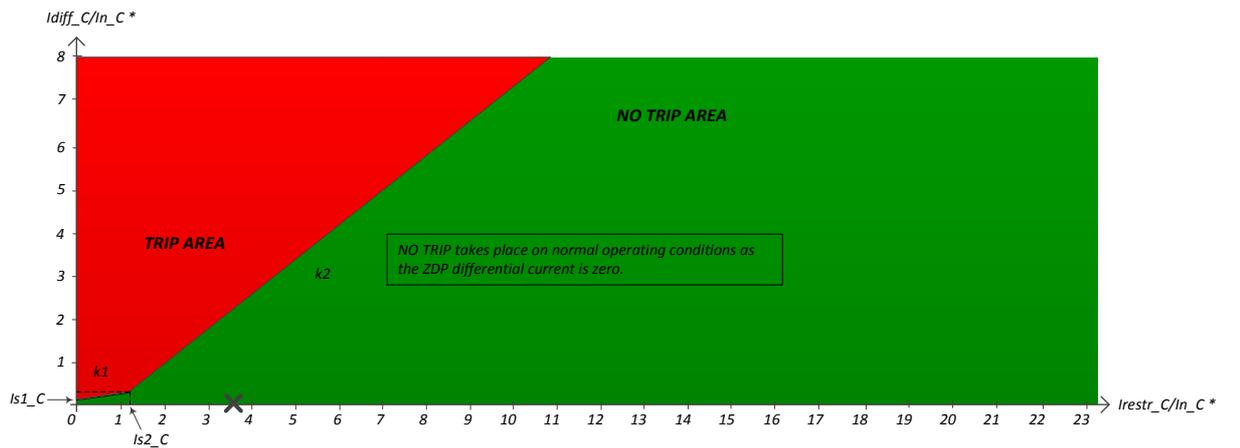
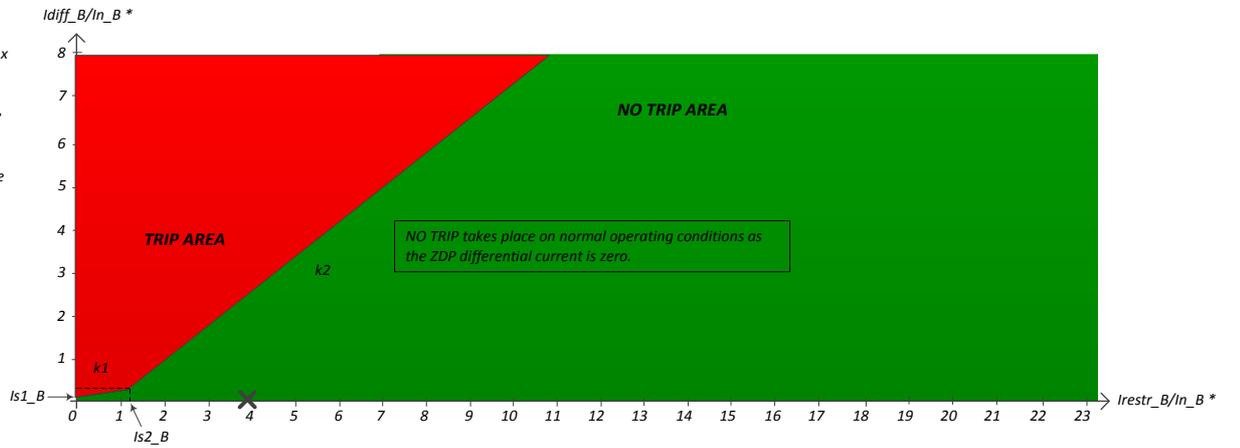
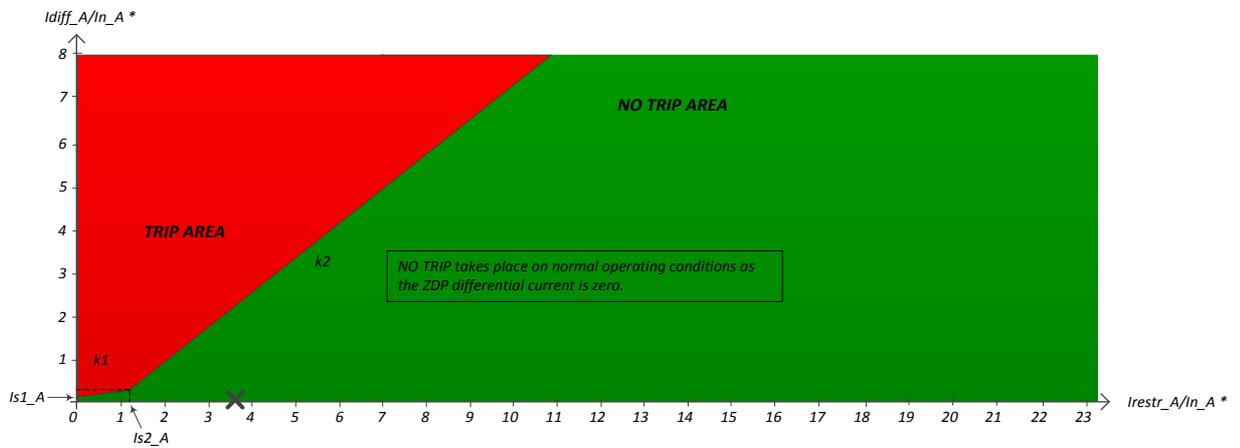
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix C6 – Power flow simulation – SP2 - continued

Simulation step 9/24

Zone : 2

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	39.40-79.82j	-66.28+0.26j	31.90+61.18j
BR2	100.76-212.55j	-187.97+18.63j	99.62+160.72j
BR4	-61.31+132.75j	121.70-18.45j	-67.78-99.54j
BR6	-0.00-0.00j	-0.00-0.00j	-0.00-0.00j



* In_x is the rated current of the phase x of the current zone. $x = A$ or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

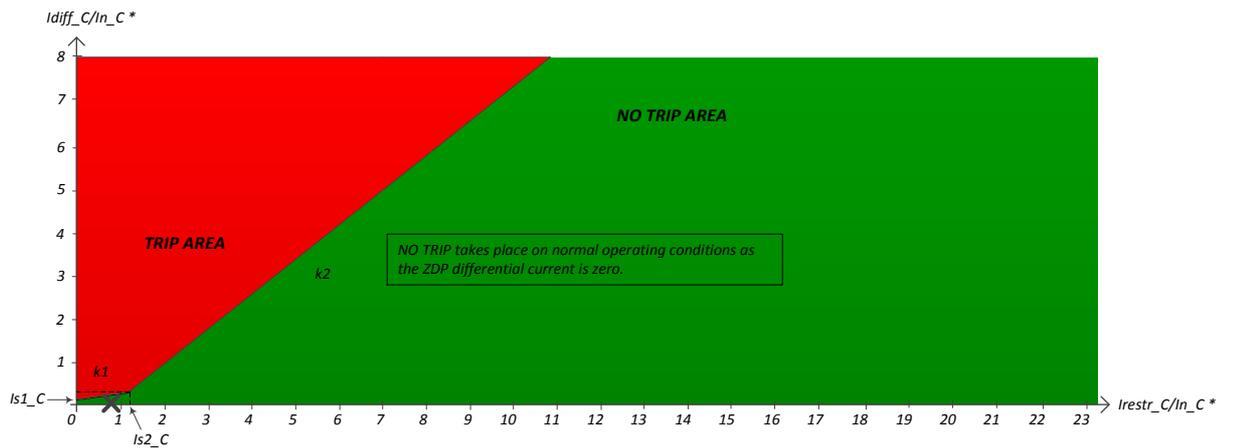
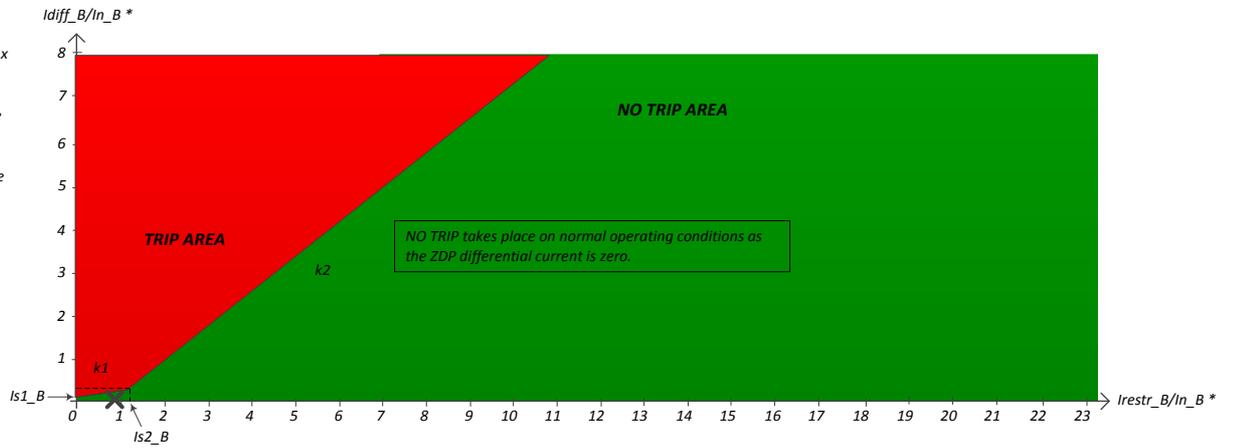
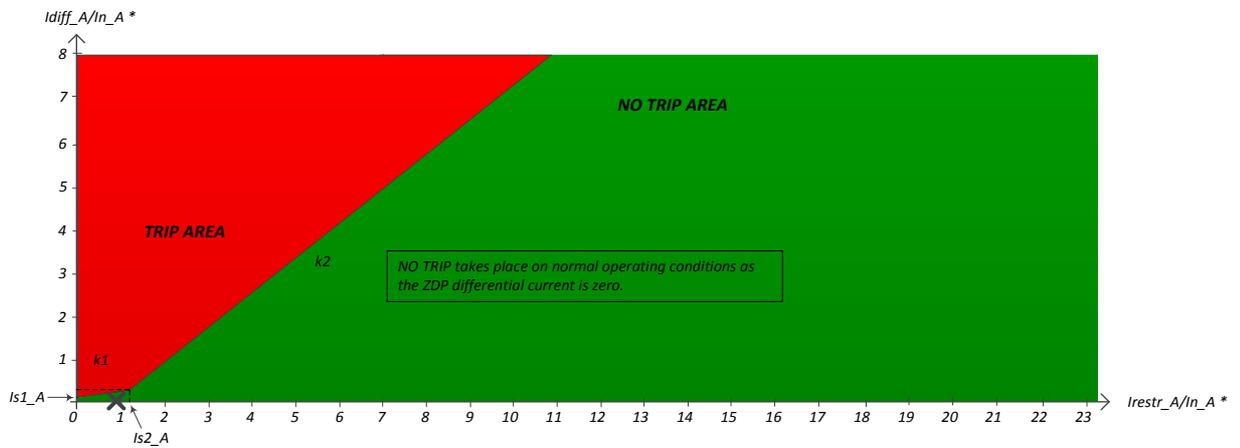
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix C6 – Power flow simulation – SP2

Simulation step 9/24

Zone : 3

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	53.61-99.31j	-113.22+12.52j	45.61+67.18j
BR3	53.63-99.32j	-113.22+12.48j	45.61+67.19j



* In_x is the rated current of the phase x of the current zone. $x = A$ or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

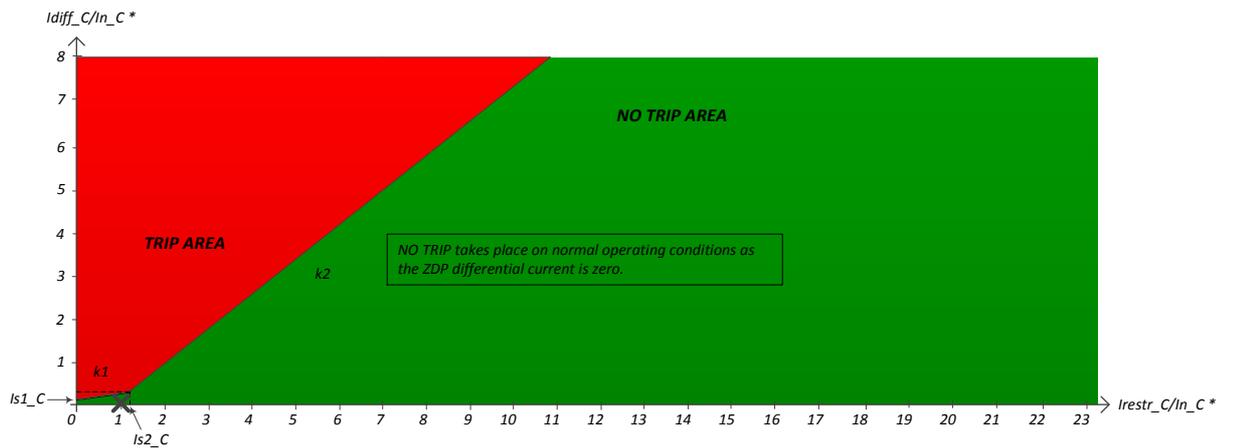
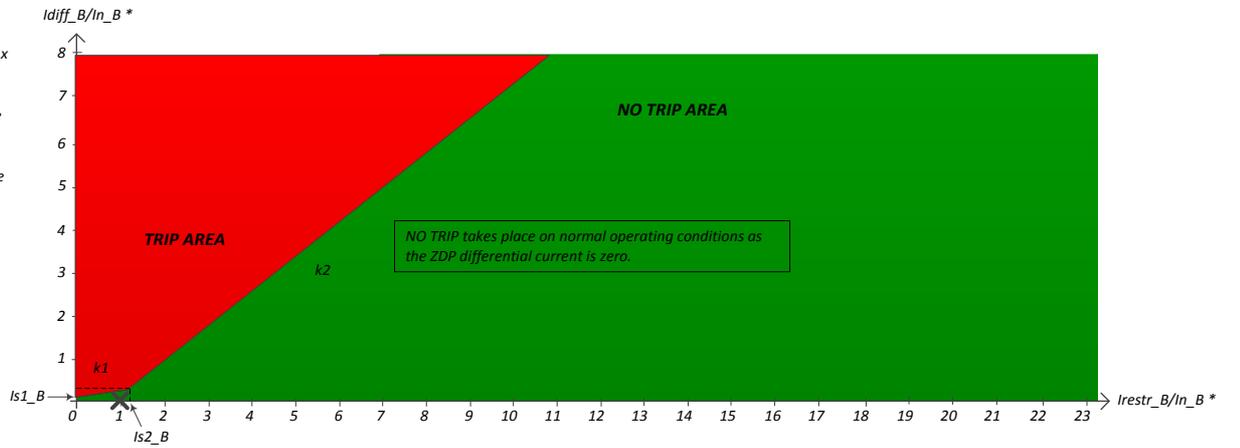
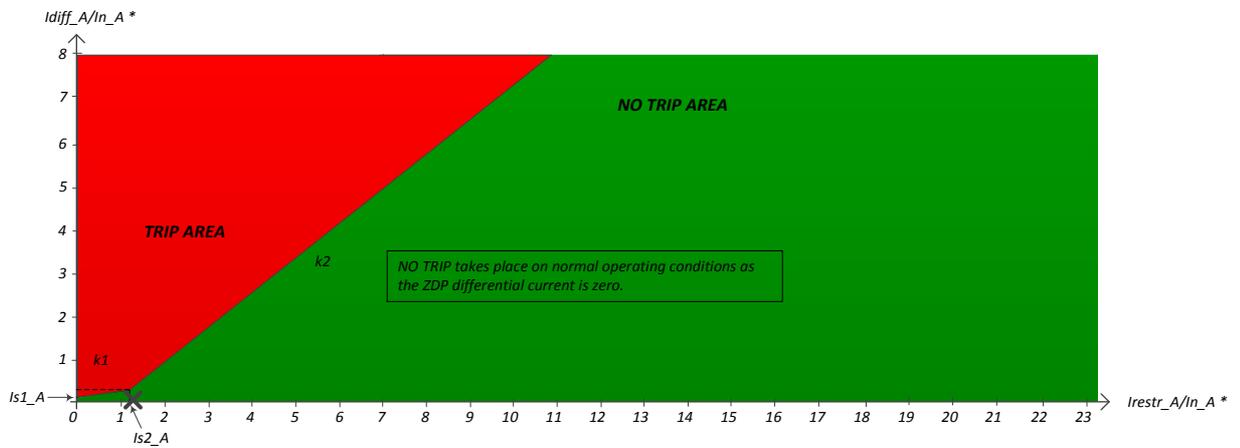
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix C6 – Power flow simulation – SP2 - continued

Simulation step 9/24

Zone : 4

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	35.68-88.46j	-91.89+19.27j	49.60+67.02j
BR5	-25.60+44.27j	29.81+0.76j	-18.20-32.53j
BR4	61.31-132.75j	-121.70+18.45j	67.78+99.54j



* In_x is the rated current of the phase x of the current zone. $x = A$ or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

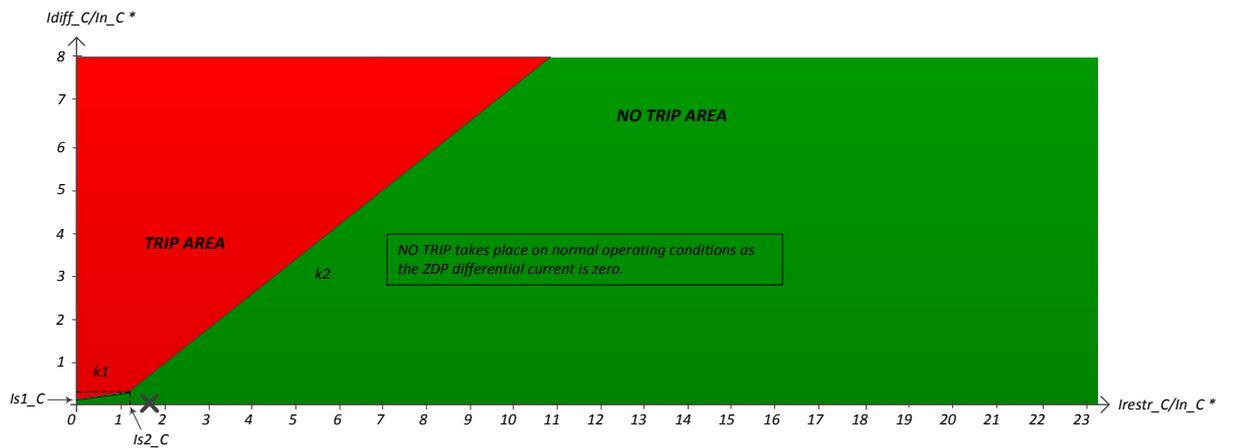
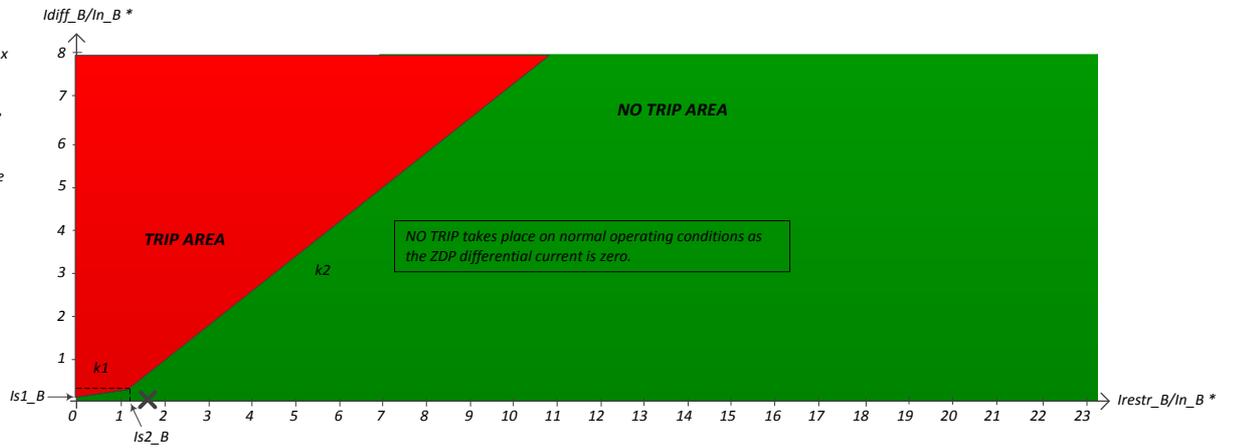
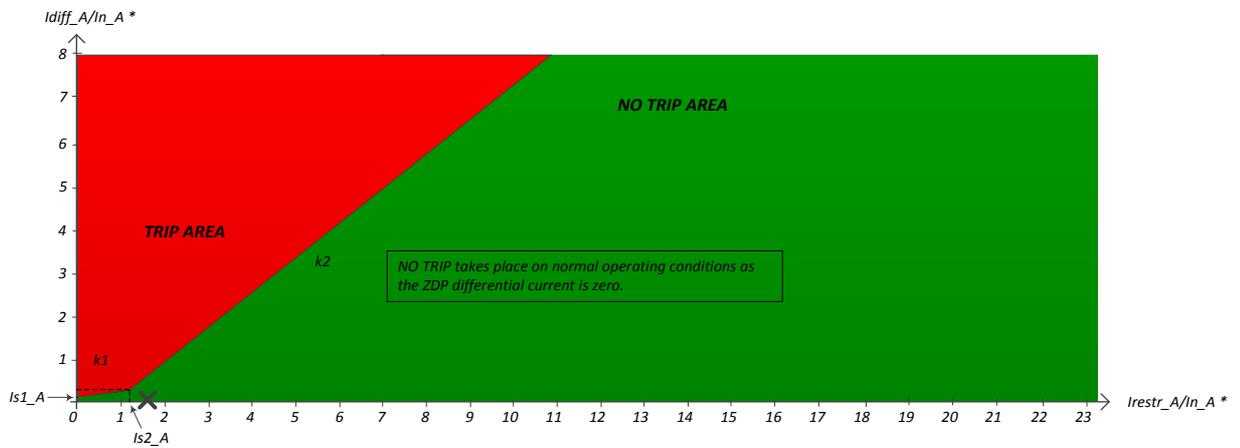
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix C6 – Power flow simulation – SP2 - continued

Simulation step 9/24

Zone : 5

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	25.58-44.26j	-29.82-0.75j	18.21+32.53j
BR5	25.60-44.27j	-29.81-0.76j	18.20+32.53j



* In_x is the rated current of the phase x of the current zone. $x = A$ or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

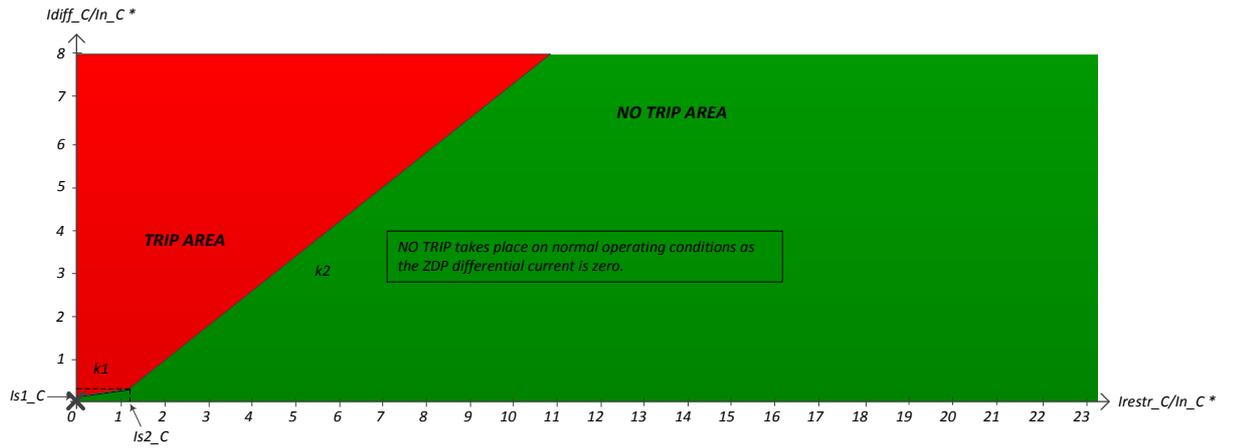
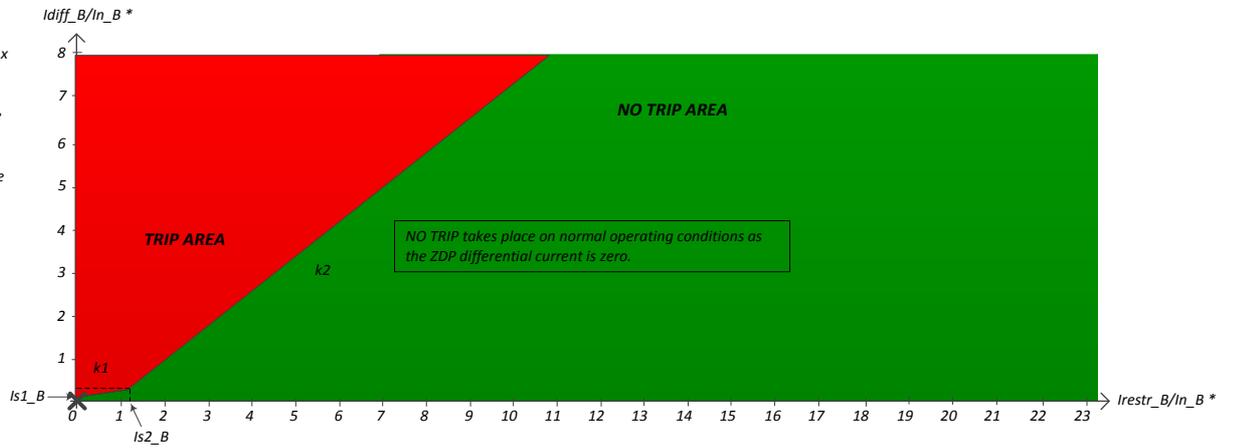
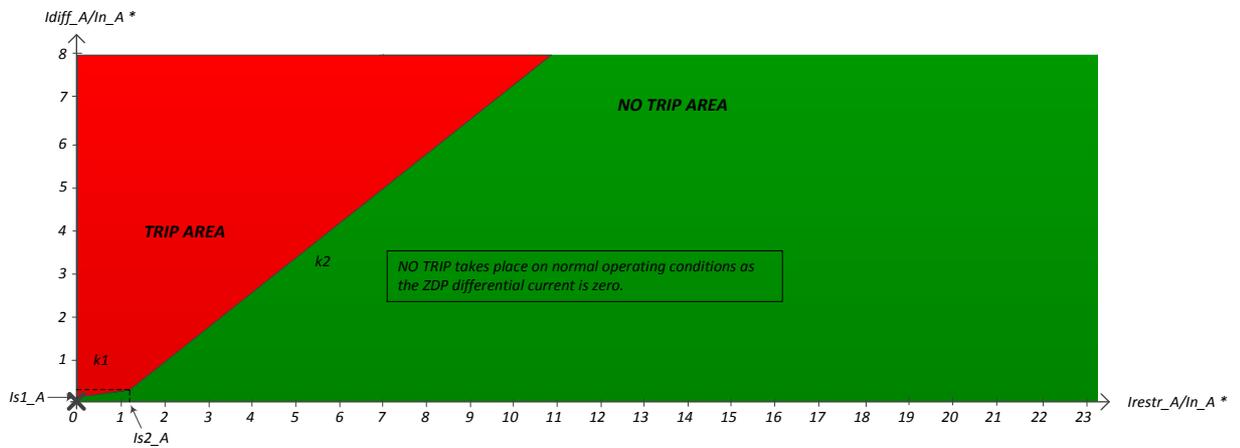
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix C6 – Power flow simulation – SP2 - continued

Simulation step 9/24

Zone : 6

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	0.00+0.00j	0.00+0.00j	0.00+0.00j
BR6	0.00+0.00j	0.00+0.00j	0.00+0.00j



* In_x is the rated current of the phase x of the current zone. $x = A$ or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

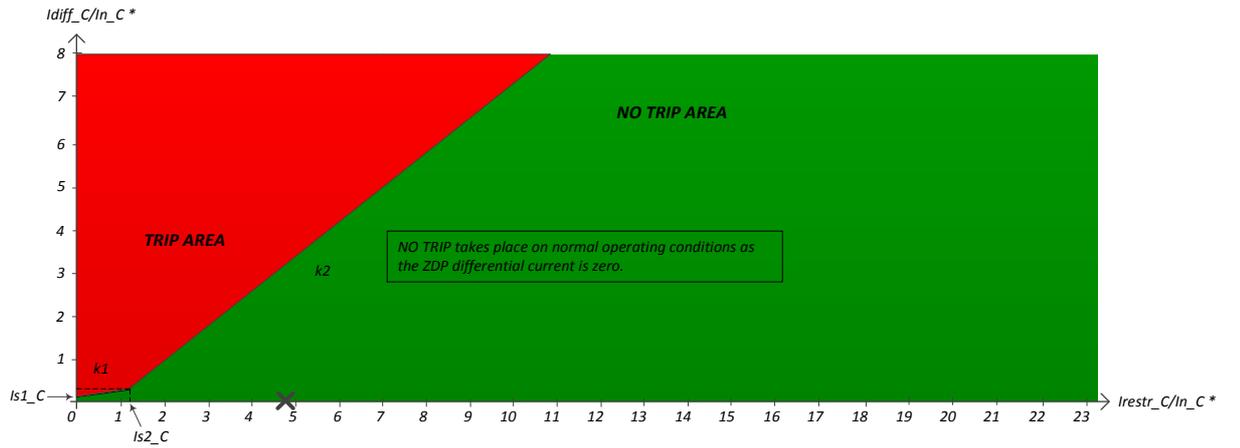
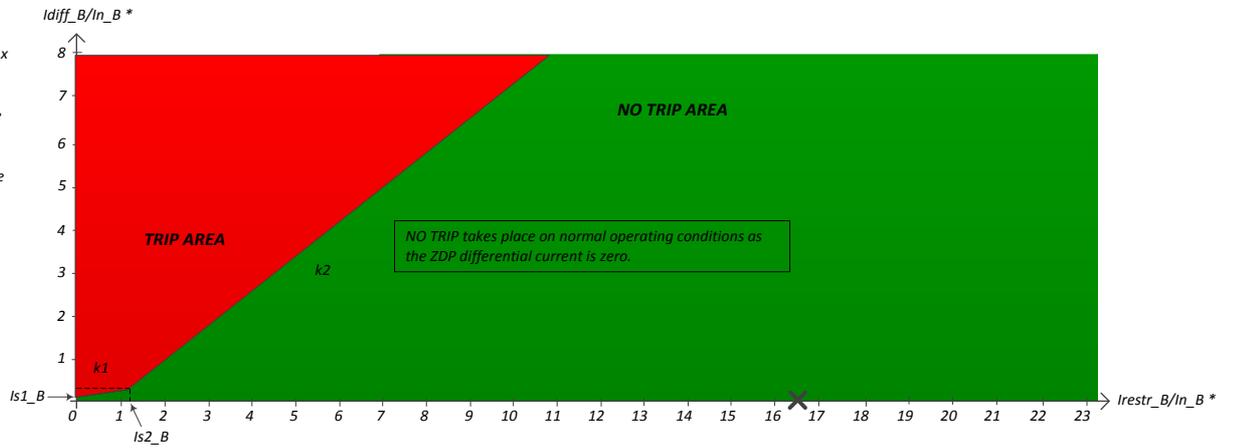
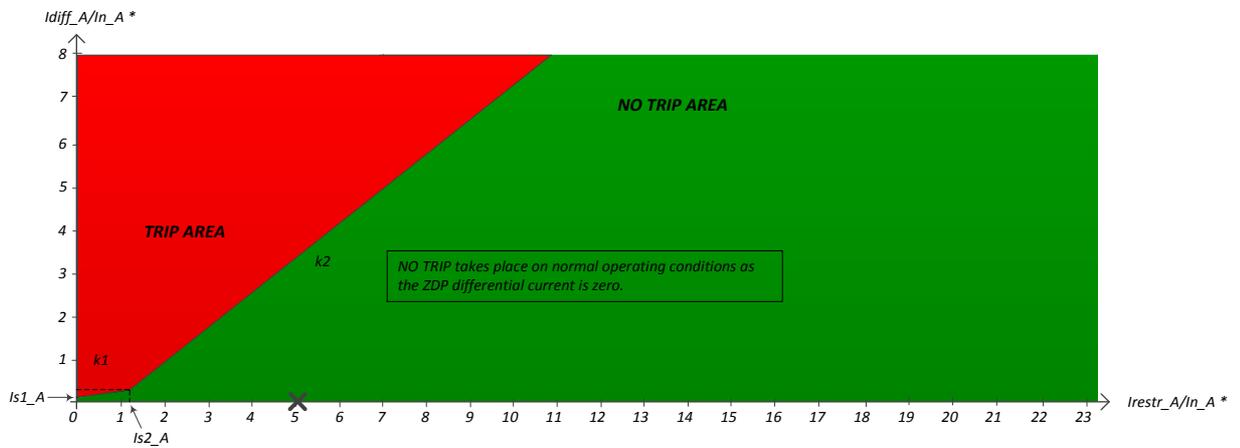
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix C6 – Power flow simulation – SP2 - continued

Simulation step 10/24

Zone : 1

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	24.00-68.14j	13.29+14.81j	38.65+72.92j
BR1	175.21-382.42j	-286.42+47.08j	184.43+309.42j
BR2	-100.97+223.46j	185.57-19.33j	-104.14-174.59j
BR3	-50.22+90.80j	114.12-12.97j	-41.65-61.91j



* In_x is the rated current of the phase x of the current zone. $x = A$ or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

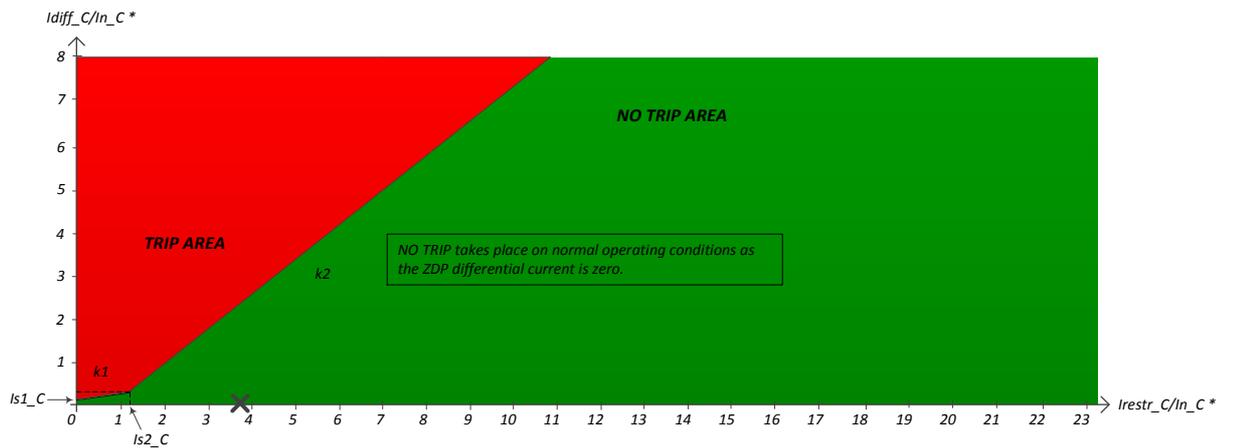
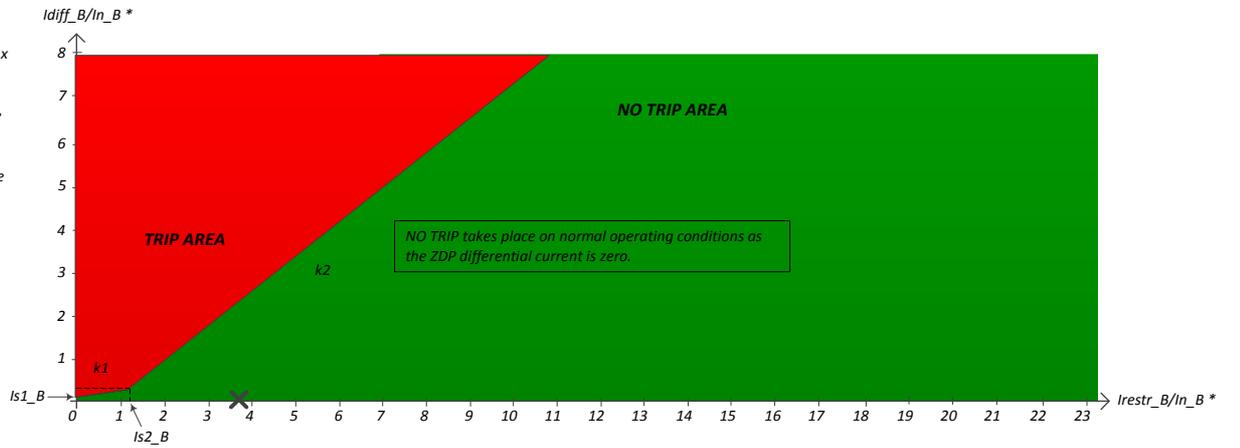
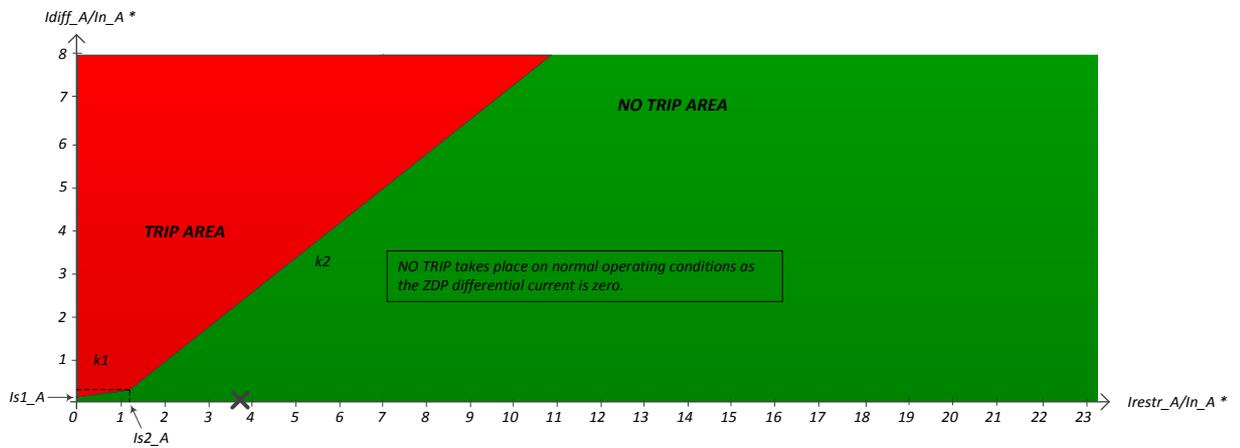
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix C6 – Power flow simulation – SP2 - continued

Simulation step 10/24

Zone : 2

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	36.57-78.53j	-58.63-0.25j	31.13+60.49j
BR2	100.97-223.46j	-185.57+19.33j	104.14+174.59j
BR4	-64.35+144.94j	126.95-19.66j	-73.05-114.10j
BR6	-0.00-0.00j	-0.00-0.00j	-0.00-0.00j



* I_{n_x} is the rated current of the phase x of the current zone. x = A or B or C

I_{diff_x} is the differential current on the phase x of the current zone.

I_{restr_x} is the restraining current on the phase x of the current zone.

I_{s1_x} is the differential current pick-up setting. It is set to 10% of the phase x rated current.

I_{s2_x} is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

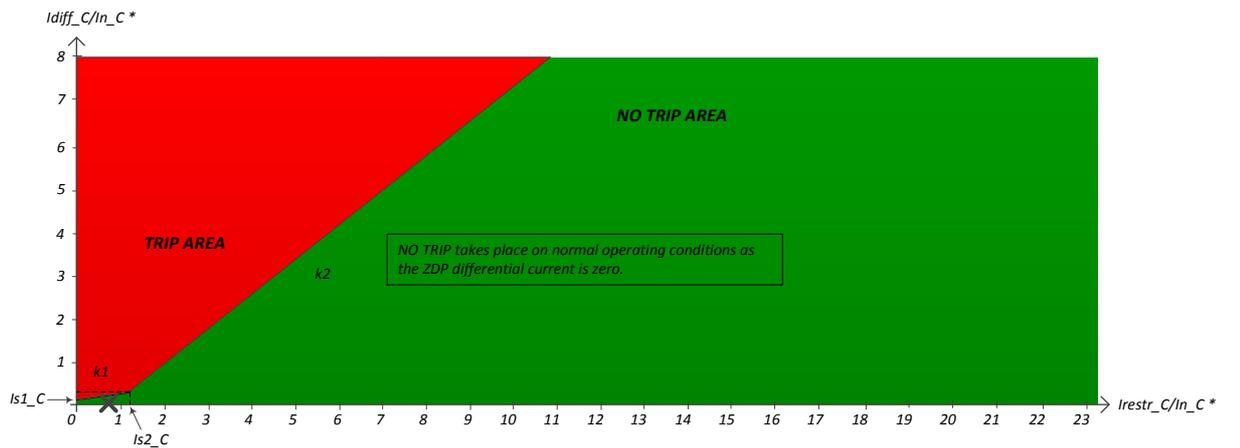
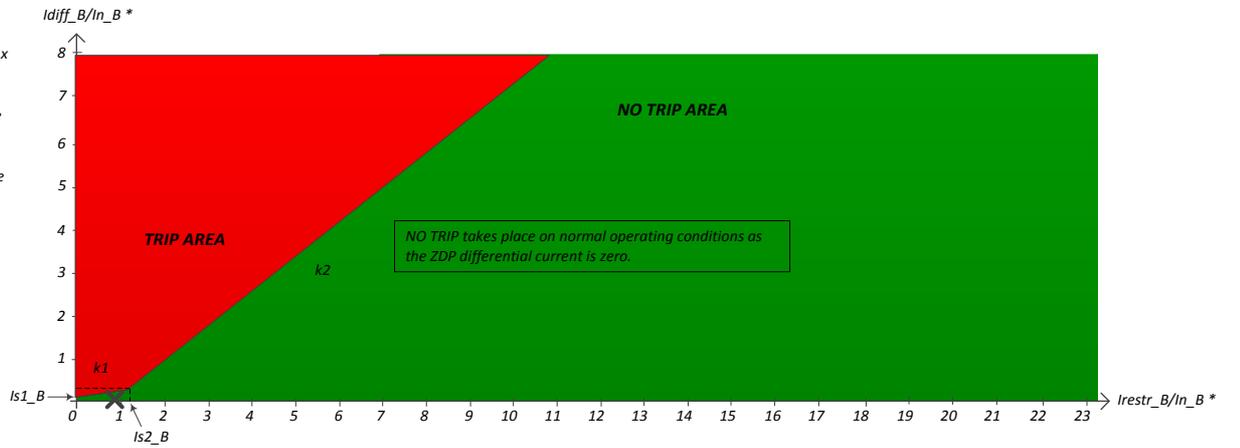
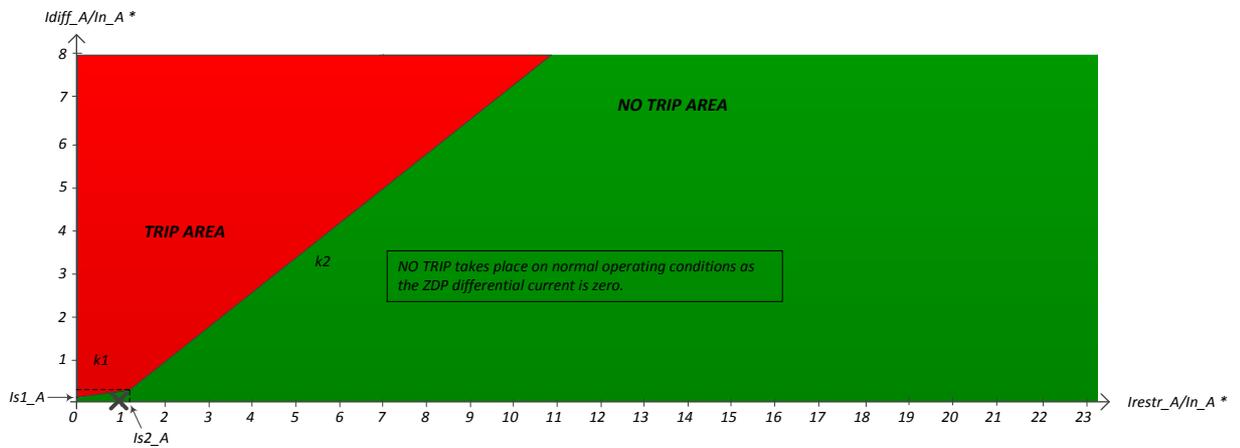
k_1, k_2 : slopes - $k_1=30\%$ & $k_2=80\%$

Appendix C6 – Power flow simulation – SP2

Simulation step 10/24

Zone : 3

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	50.20-90.79j	-114.11+13.00j	41.66+61.91j
BR3	50.22-90.80j	-114.12+12.97j	41.65+61.91j



* In_x is the rated current of the phase x of the current zone. $x = A$ or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

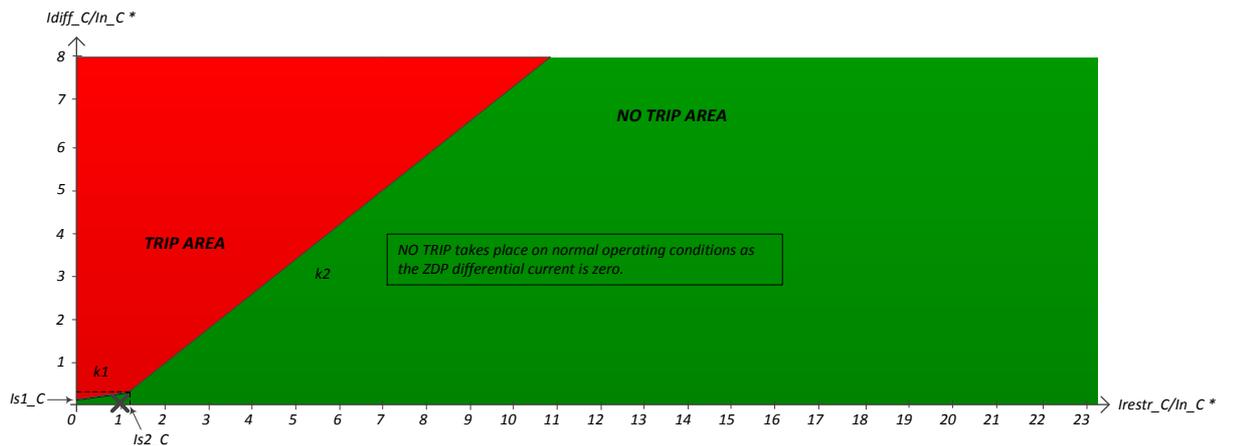
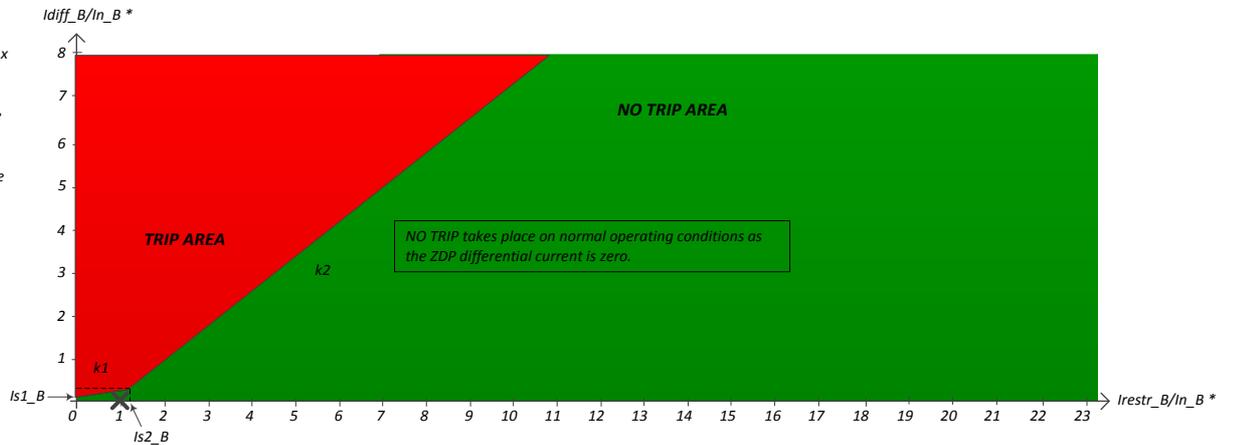
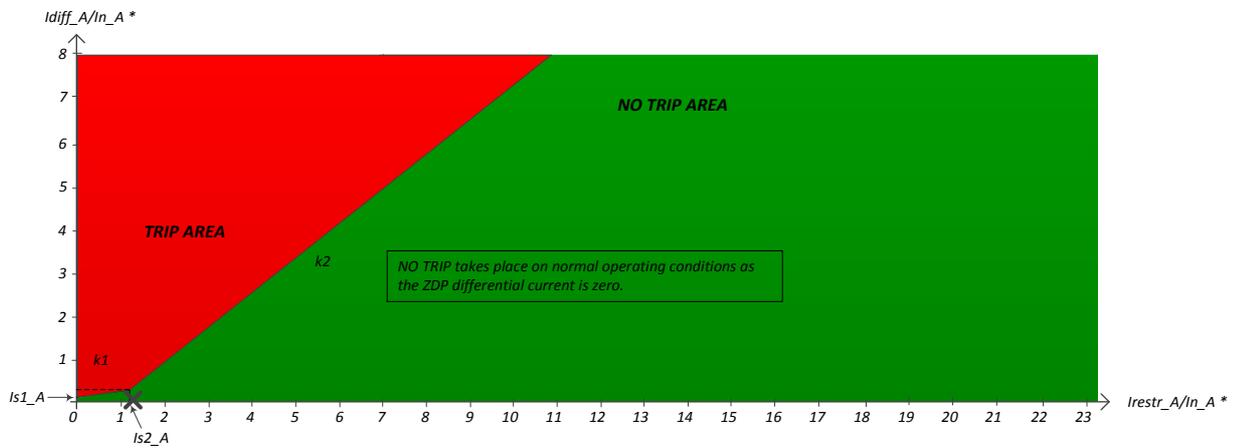
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix C6 – Power flow simulation – SP2 - continued

Simulation step 10/24

Zone : 4

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	37.20-97.96j	-96.33+20.52j	53.19+78.84j
BR5	-27.11+46.95j	30.63+0.81j	-19.89-35.27j
BR4	64.35-144.94j	-126.95+19.66j	73.05+114.10j



* In_x is the rated current of the phase x of the current zone. $x = A$ or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

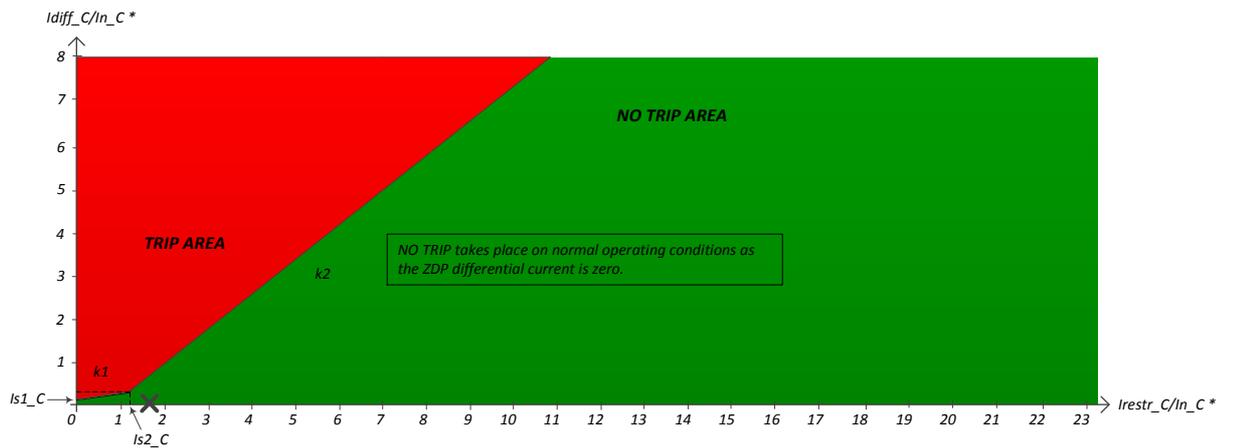
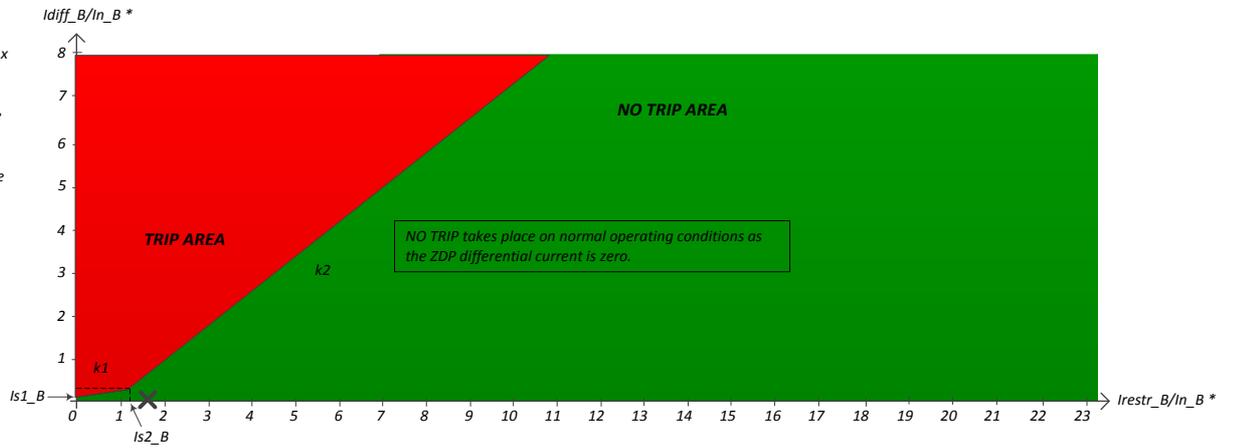
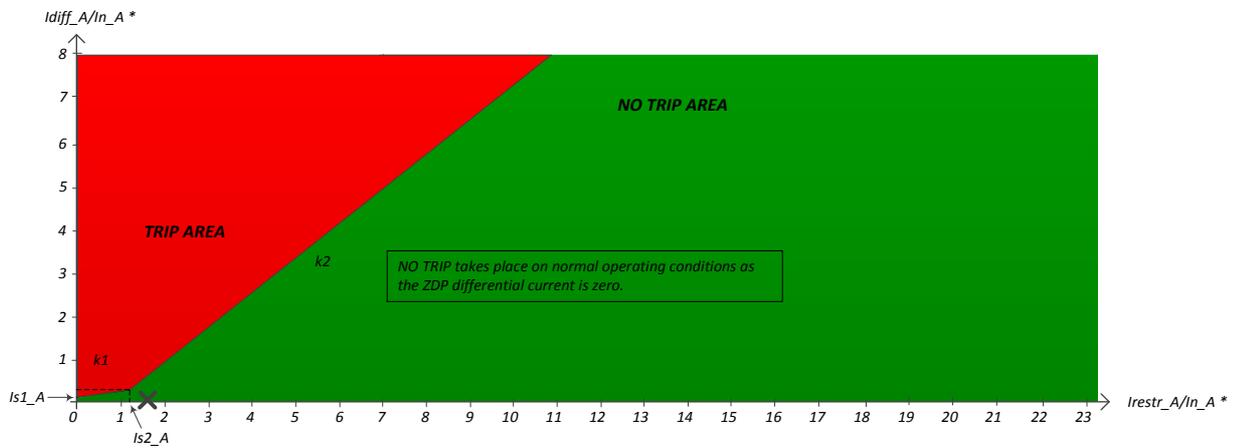
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix C6 – Power flow simulation – SP2 - continued

Simulation step 10/24

Zone : 5

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	27.09-46.94j	-30.64-0.79j	19.90+35.27j
BR5	27.11-46.95j	-30.63-0.81j	19.89+35.27j



* In_x is the rated current of the phase x of the current zone. $x = A$ or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

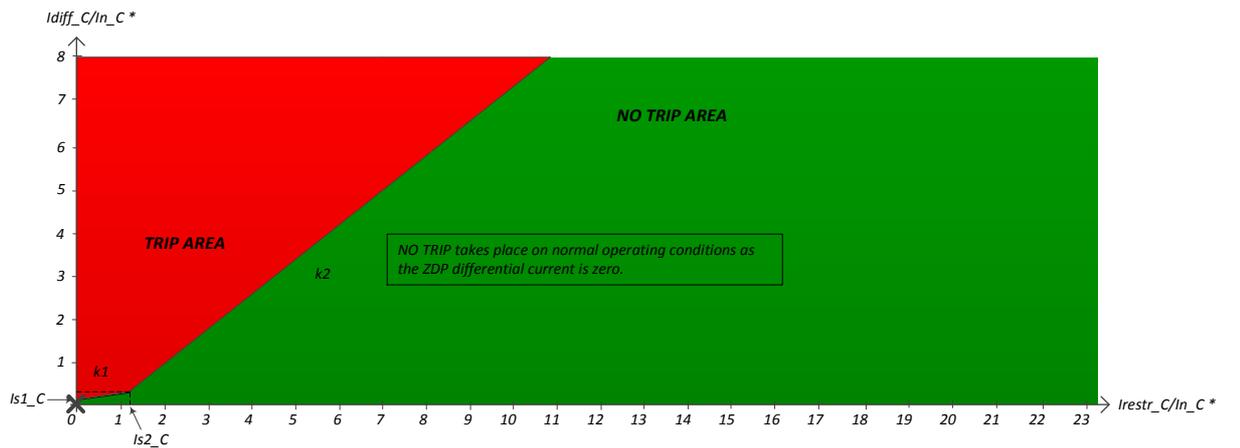
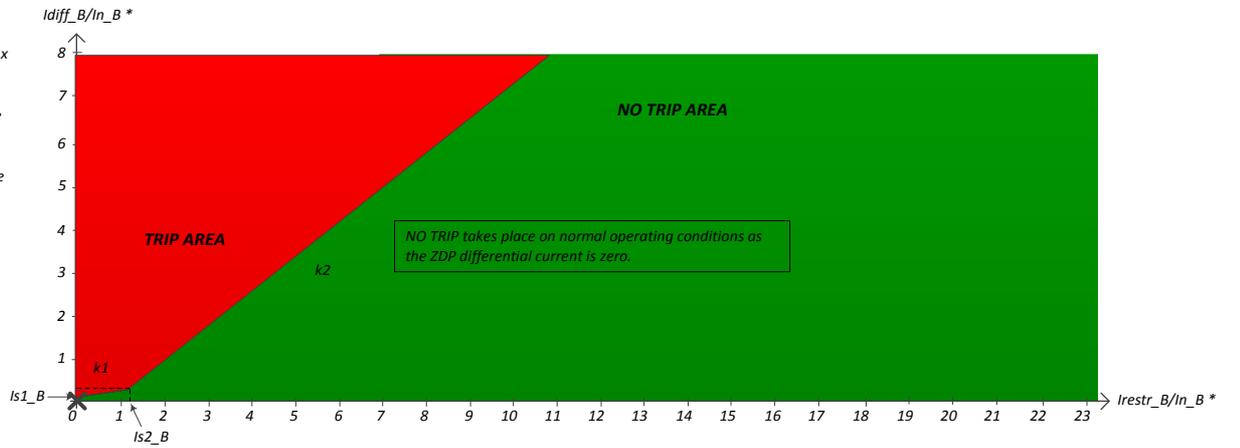
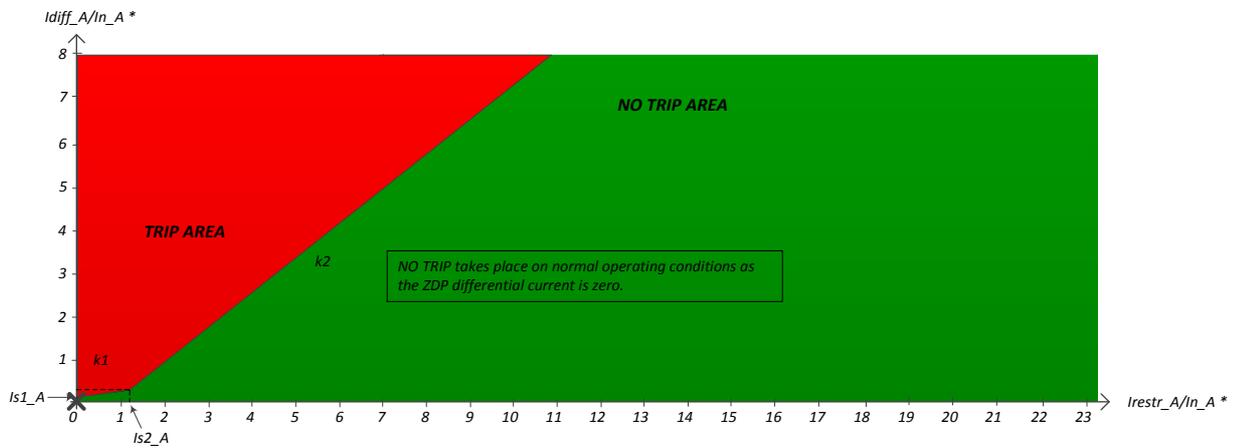
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix C6 – Power flow simulation – SP2 - continued

Simulation step 10/24

Zone : 6

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	0.00+0.00j	0.00+0.00j	0.00+0.00j
BR6	0.00+0.00j	0.00+0.00j	0.00+0.00j



* I_{n_x} is the rated current of the phase x of the current zone. x = A or B or C

I_{diff_x} is the differential current on the phase x of the current zone.

I_{restr_x} is the restraining current on the phase x of the current zone.

I_{s1_x} is the differential current pick-up setting. It is set to 10% of the phase x rated current.

I_{s2_x} is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

k_1, k_2 : slopes - $k_1=30\%$ & $k_2=80\%$

APPENDIX C7

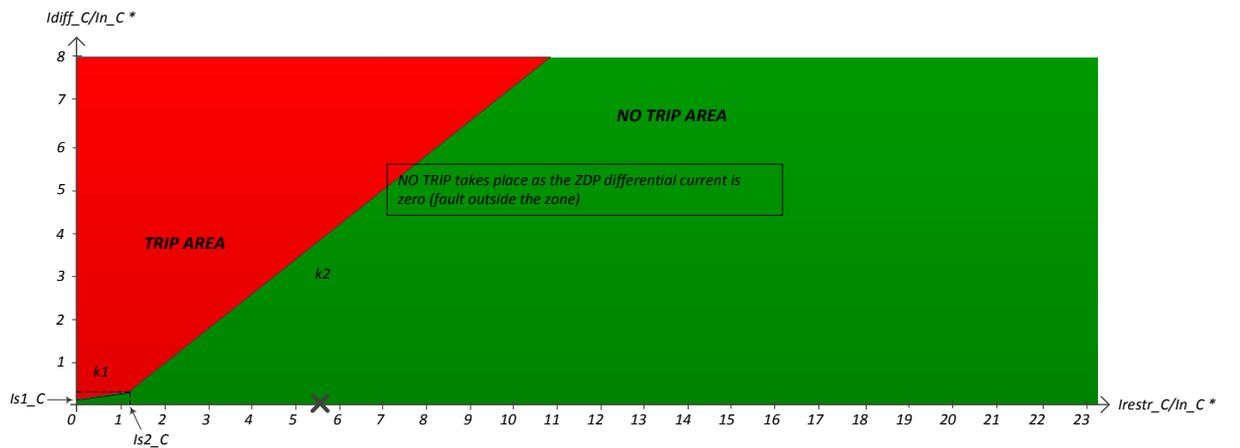
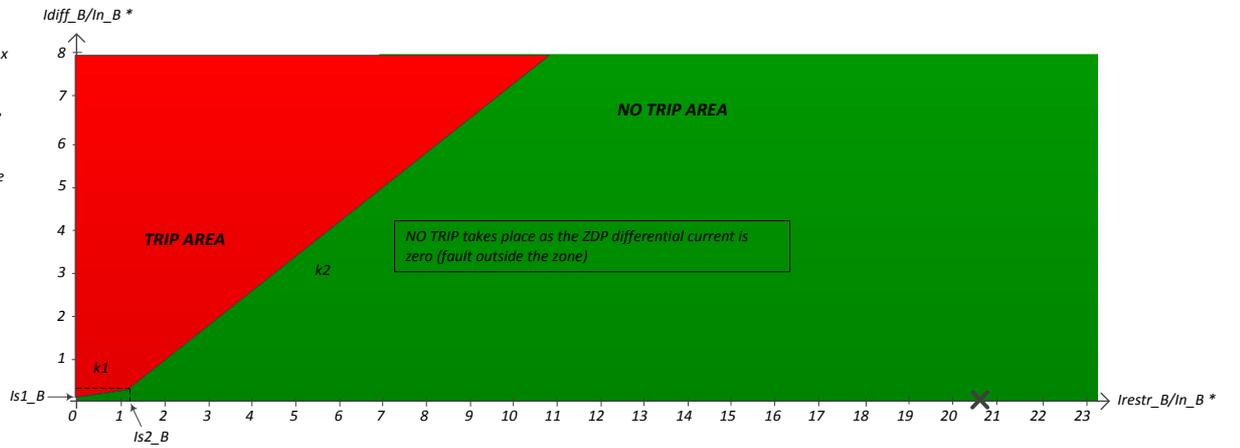
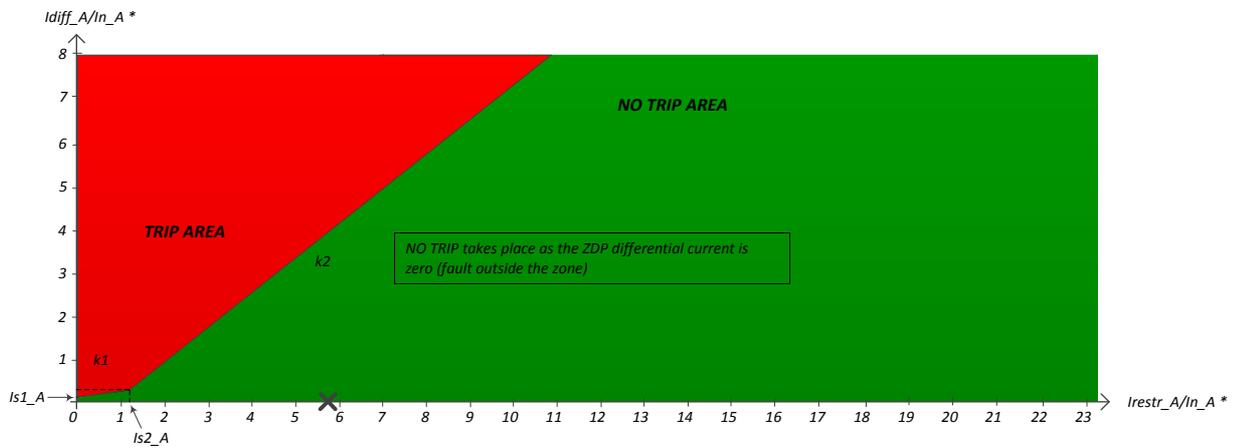
Short circuit simulation results in SP2

Appendix C7 – Short-circuit simulation – SP2

[Fault at bus 251 (newly added bus in Zone 3) - Fault on phase = B – Fault resistance R = 50 ohms]

Zone : 1

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	42.35-83.53j	13.47+22.25j	50.95+88.94j
BR1	295.82-384.75j	-358.88-47.01j	130.23+387.96j
BR2	-190.58+181.35j	195.80+67.33j	-22.98-218.20j
BR3	-62.89+119.84j	176.54+1.88j	-56.31-80.85j



* In_x is the rated current of the phase x of the current zone. x = A or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

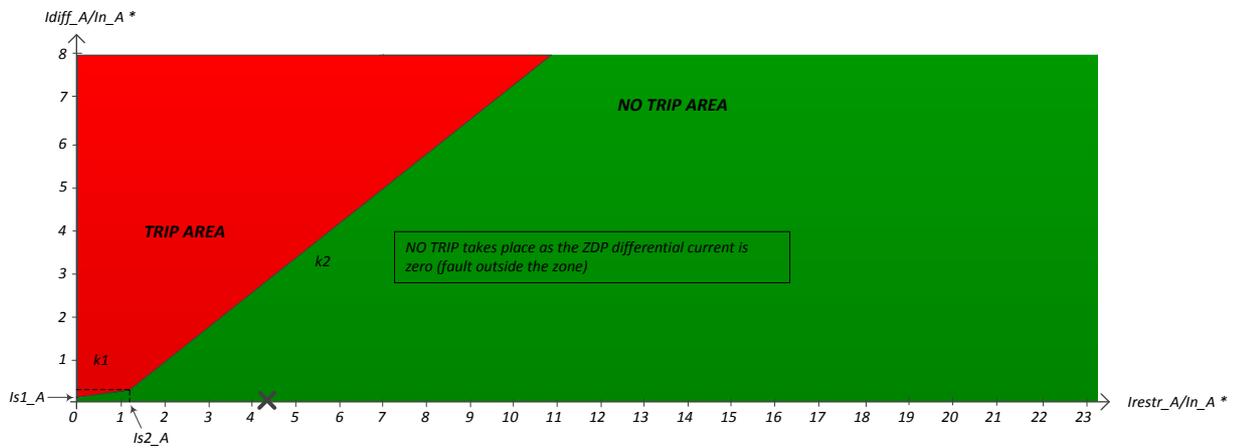
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix C7 – Short-circuit simulation – SP2

[Fault at bus 251 (newly added bus in Zone 3) - Fault on phase = B – Fault resistance R = 50 ohms]

Zone : 2

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	42.22-92.71j	-79.85+1.22j	39.21+70.05j
BR2	190.58-181.35j	-195.80-67.33j	22.98+218.20j
BR4	-148.34+88.65j	115.99+68.47j	16.18-148.14j
BR6	-0.00-0.00j	-0.00-0.00j	-0.00-0.00j



* I_{n_x} is the rated current of the phase x of the current zone. x = A or B or C

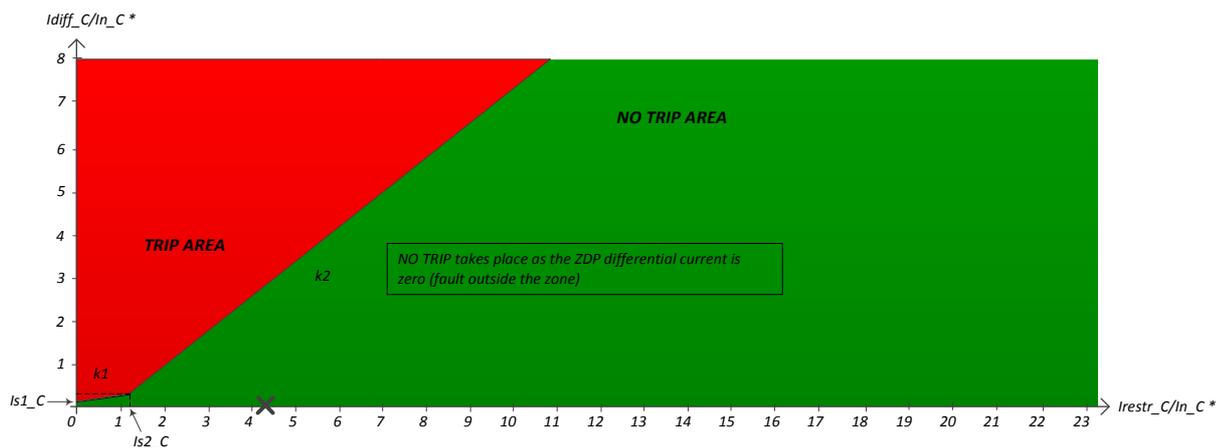
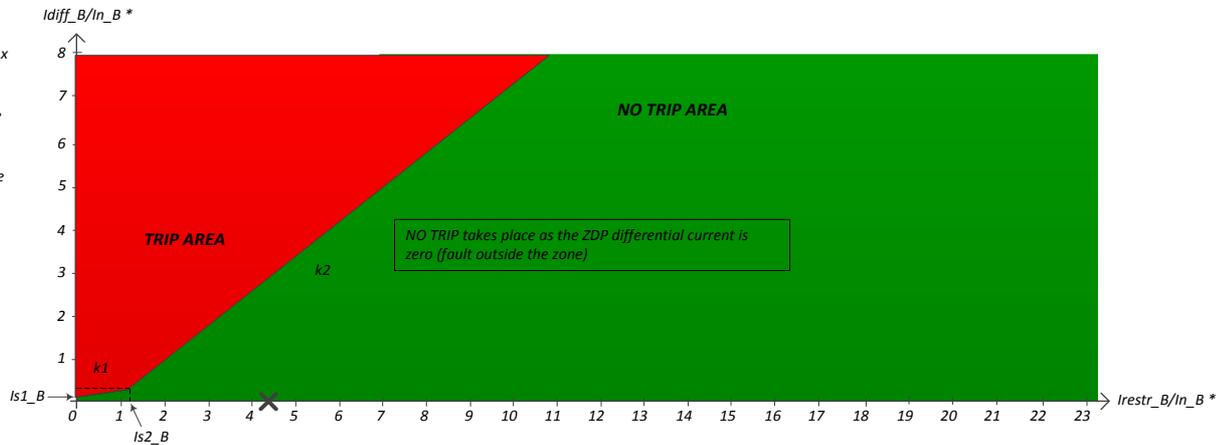
I_{diff_x} is the differential current on the phase x of the current zone.

I_{restr_x} is the restraining current on the phase x of the current zone.

I_{s1_x} is the differential current pick-up setting. It is set to 10% of the phase x rated current.

I_{s2_x} is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

k_1, k_2 : slopes - $k_1=30\%$ & $k_2=80\%$

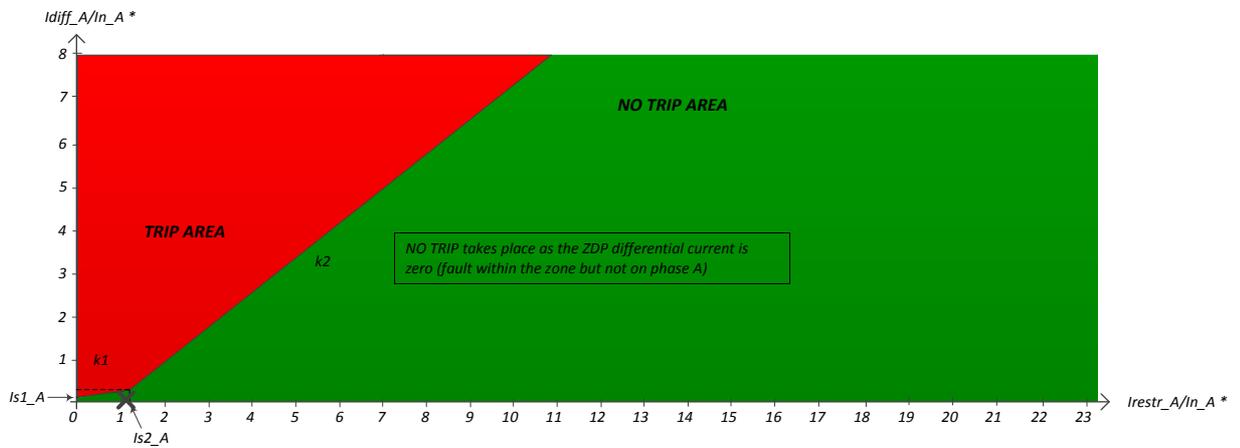


Appendix C7 – Short-circuit simulation – SP2

[Fault at bus 251 (newly added bus in Zone 3) - Fault on phase = B – Fault resistance R = 50 ohms]

Zone : 3

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	62.88-119.82j	-135.35+18.67j	56.32+80.84j
BR3	62.89-119.84j	-176.54-1.88j	56.31+80.85j



* I_{n_x} is the rated current of the phase x of the current zone. x = A or B or C

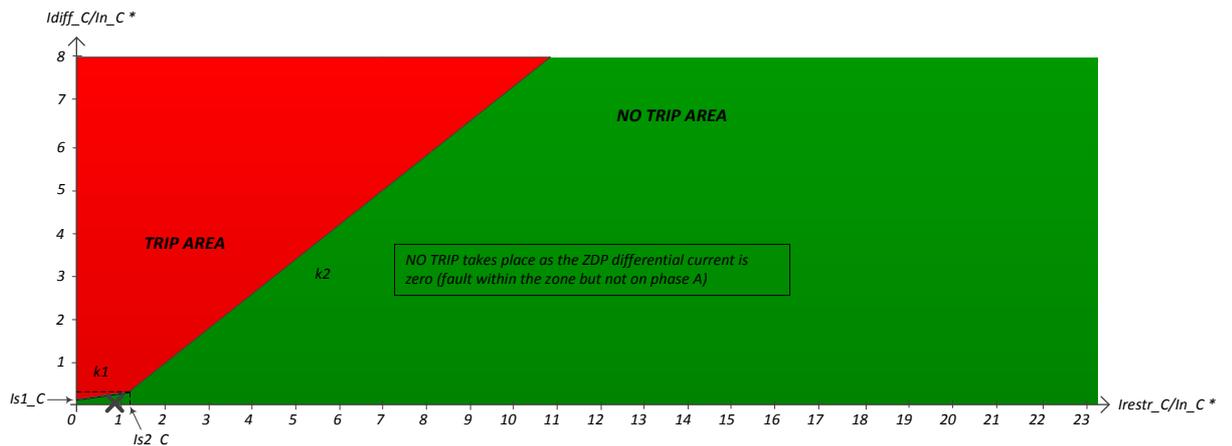
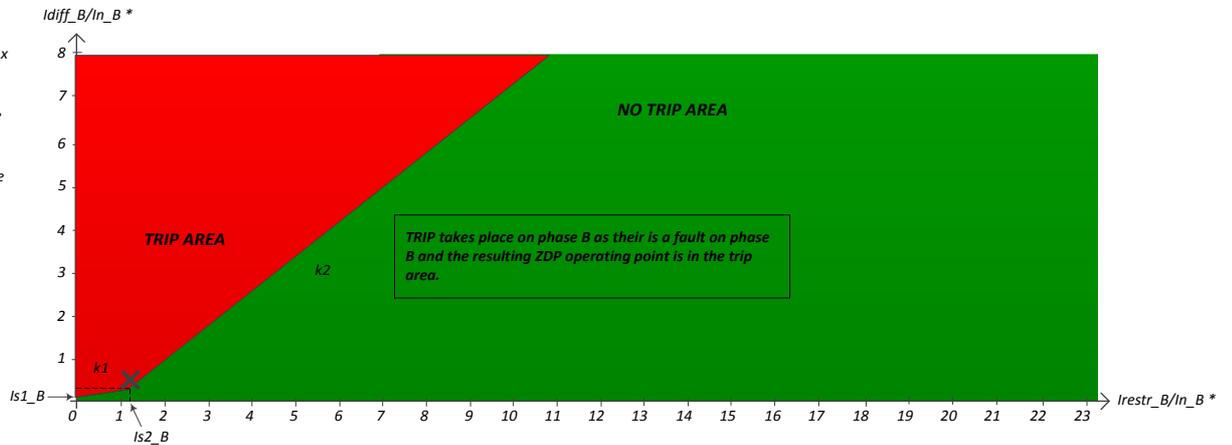
I_{diff_x} is the differential current on the phase x of the current zone.

I_{restr_x} is the restraining current on the phase x of the current zone.

I_{s1_x} is the differential current pick-up setting. It is set to 10% of the phase x rated current.

I_{s2_x} is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

k_1, k_2 : slopes - $k_1=30\%$ & $k_2=80\%$

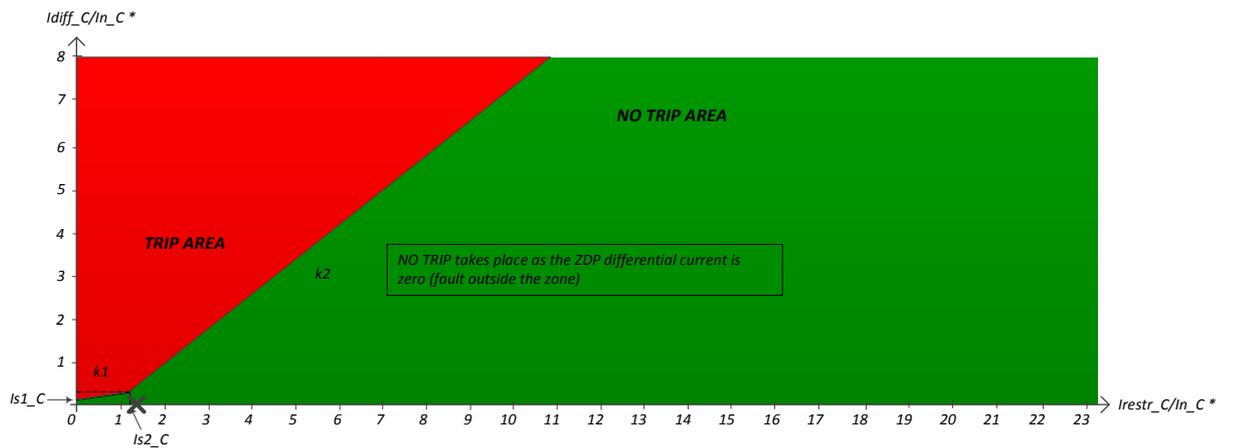
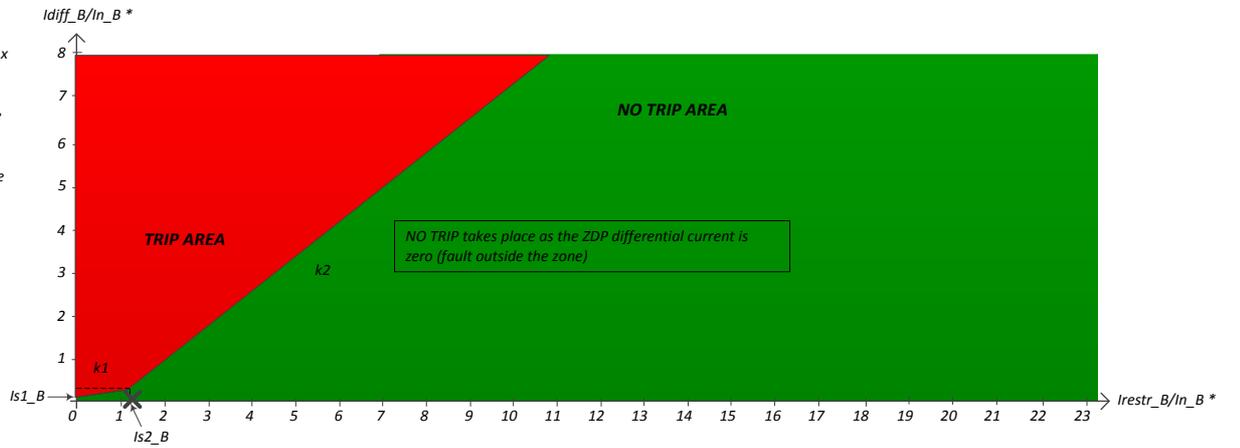
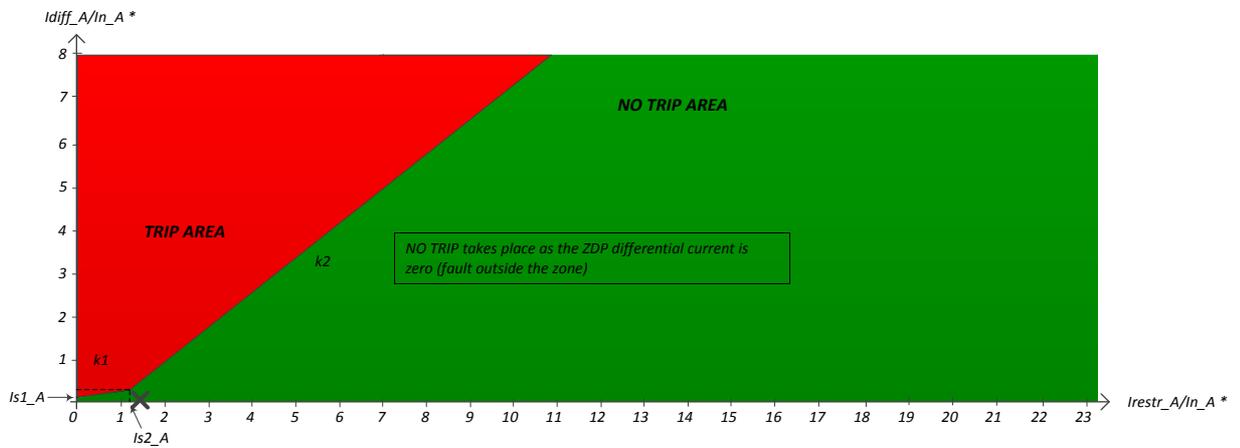


Appendix C7 – Short-circuit simulation – SP2

[Fault at bus 251 (newly added bus in Zone 3) - Fault on phase = B – Fault resistance R = 50 ohms]

Zone : 4

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	117.46-31.45j	-77.36-68.45j	-40.97+106.21j
BR5	-30.88+57.18j	38.69-0.02j	-24.83-41.93j
BR4	148.34-88.65j	-115.99-68.47j	-16.18+148.14j



* In_x is the rated current of the phase x of the current zone. x = A or B or C

$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

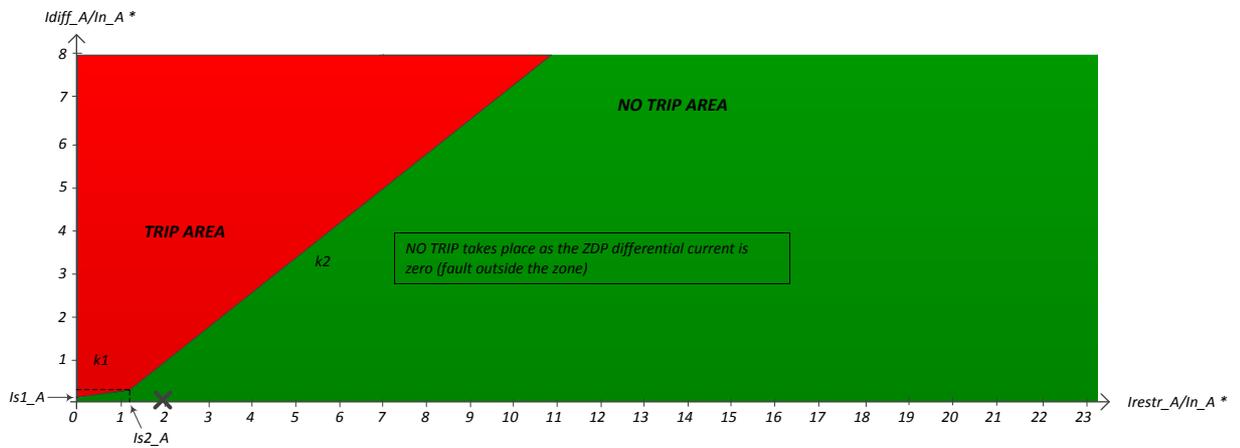
$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

Appendix C7 – Short-circuit simulation – SP2

[Fault at bus 251 (newly added bus in Zone 3) - Fault on phase = B – Fault resistance R = 50 ohms]

Zone : 5

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	30.88-57.15j	-38.70+0.04j	24.84+41.92j
BR5	30.88-57.18j	-38.69+0.02j	24.83+41.93j



* In_x is the rated current of the phase x of the current zone. $x = A$ or B or C

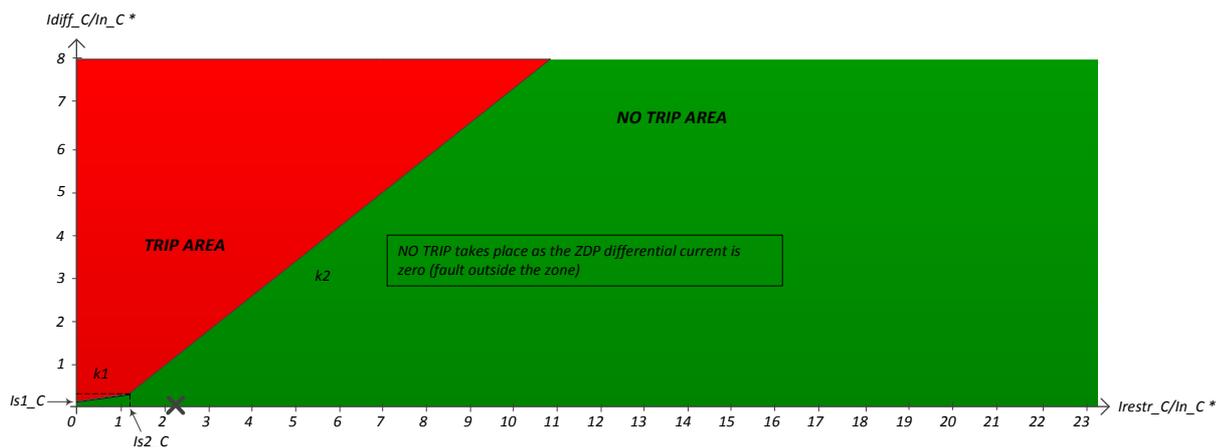
$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$

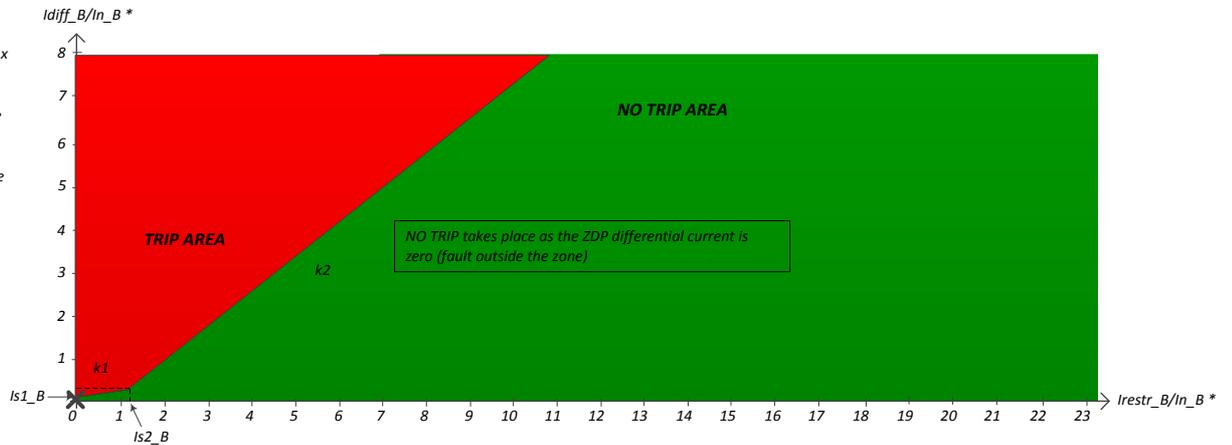
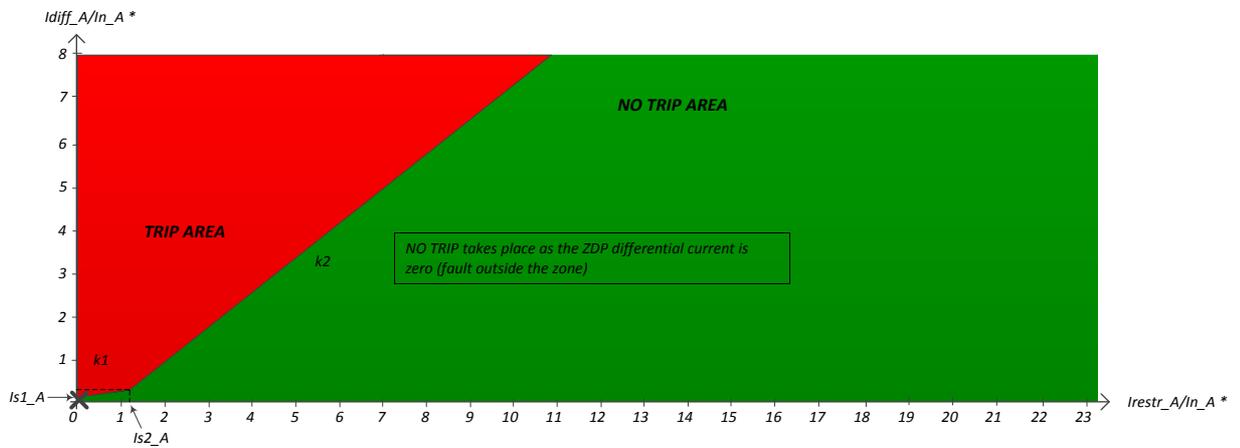


Appendix C7 – Short-circuit simulation – SP2

[Fault at bus 251 (newly added bus in Zone 3) - Fault on phase = B – Fault resistance R = 50 ohms]

Zone : 6

	Phase A	Phase B	Phase C
Σ internal (Load – gen)	0.00+0.00j	0.00+0.00j	0.00+0.00j
BR6	0.00+0.00j	0.00+0.00j	0.00+0.00j



* In_x is the rated current of the phase x of the current zone. x = A or B or C

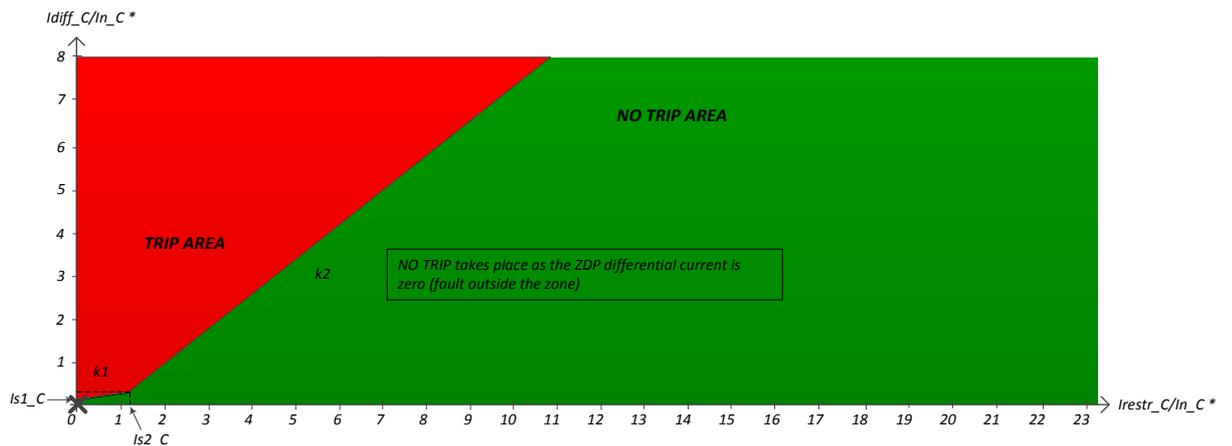
$Idiff_x$ is the differential current on the phase x of the current zone.

$Irestr_x$ is the restraining current on the phase x of the current zone.

$Is1_x$ is the differential current pick-up setting. It is set to 10% of the phase x rated current.

$Is2_x$ is the restraining current pick-up setting. It is set to 120% of the phase x rated current.

$k1, k2$: slopes - $k1=30\%$ & $k2=80\%$



TITLE :

Using IEC 61850 and Common Information model (CIM) for an incremental and distributed management of an electrical distribution network in presence of DERs.

ABSTRACT :

The presence of Distributed Energy Resources on conventional distribution systems has not only brought changes on the energy supply paradigm but also on distribution automation functions inducing new technical challenges on protection coordination systems, voltage control, to name a few. It has also increased the level of controllability and observability, making the network control more complex. To keep the electric system developing in the most efficient way, it is necessary to differently organize the current distributed automation functions. This research work uses the harmonization between the Control Center data model (CIM) and the one at the feeder level (IEC 61850), to propose a new mindset for supporting the feeder automation by transferring to it, part of the global knowledge of the Control Center through a secure incremental management of the distribution system. The mindset is declined on a Zone Differential Protection (ZDP) to improve the protection coordination.

KEYWORDS :

Smart Grid, decentralized control, incremental management, interoperability, harmonization IEC 61850/CIM, connectivity model, zone differential protection, node breaker model.

TITRE :

Utilisation des modèles IEC 61850 et CIM (Common Information model) pour la gestion incrémentale et distribuée d'un réseau électrique notamment en présence de DERs.

RESUME :

La présence des DERs sur les réseaux de distribution traditionnels a créé un nouveau paradigme aussi bien au niveau de la fourniture d'énergie que des fonctions d'automatisme entraînant des défis techniques, entre autres, sur la coordination des protections, le contrôle de tension. Elle a aussi rendu le contrôle du réseau plus complexe en augmentant le niveau de commandabilité et d'observabilité. Pour un développement plus efficace du réseau dans ce contexte, une réorganisation des fonctions d'automatisme de distribution est nécessaire. Un nouveau 'mindset' a été proposé pour supporter les fonctions du feeder automation en transférant au feeder de distribution une partie de la connaissance globale du Centre de Conduite. Cela requiert, au préalable, l'harmonisation entre les modèles de données du Centre de Conduite (CIM) et du feeder (IEC 61850). A partir ce 'mindset', nous avons proposé une protection différentielle de zone comme solution possible à la coordination des protections.

MOTS CLEFS :

Smart Grid, gestion décentralisée, gestion incrémentale, interopérabilité, harmonisation IEC 61850/CIM, modèle de connectivité, protection différentielle de zone, modèle 'node breaker'

