Shahram Kazemi Reliability Evaluation of Smart Distribution Grids

Aalto University

Department of Electrical Engineering

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Reliability Evaluation of Smart Distribution Grids

Shahram Kazemi

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Abstract

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Abstract

The term "Smart Grid" generally refers to a power grid equipped with the advanced technologies dedicated for purposes such as reliability improvement, ease of control and management, integrating of distributed energy resources and electricity market operations. Improving the reliability of electric power delivered to the end users is one of the main targets of employing smart grid technologies. The smart grid investments targeted for reliability improvement can be directed toward the generation, transmission or distribution system level. However, radial operating status, aging infrastructures, poor design and operation practices and high exposure to environmental conditions have caused the electric power distribution systems to be addressed as the main contributor to the customer reliability problems. Therefore, developing a smart distribution grid can be an attractive reliability enhancement solution for the electric utilities.

Whenever the targeted reliability enhancement solutions are limited to the simple conventional solutions, the available reliability assessment techniques can be easily used for purposes of the value-based reliability planning. However, the electric utilities face a challenge when the reliability enhancement solutions include sophisticated measures such as those of the smart grid technologies. Generally, the available reliability assessment approaches cannot be employed directly for such purposes. In this situation, it is necessary to develop a reliability evaluation approach for predicting the reliability performance of the electric power distribution systems when employing such sophisticated solutions.

A novel approach is proposed and demonstrated in this thesis for reliability assessment of an electric power distribution system when employing the advanced reliability enhancement technologies. In the proposed reliability evaluation approach, the overall impacts of the targeted reliability enhancement solutions on the sustained interruptions, momentary interruptions and voltage sags experienced by the customers are taken into account.

The results of various reliability case studies directed in this thesis show that employing a suitable set of the smart grid technologies in the functional zone of an electric power distribution system can virtually mitigate all the reliability indices. It is also possible to reduce the range of variation of the reliability indices among different customers. In addition, there is a possibility to reduce the burden on the utility repair crews.

Keywords Distribution Automation, Distribution Substation Automation, Distance to Fault Estimator, Dynamic Voltage Restorer, Feeder Automation, Fault Current Limiter, Fault Locator Scheme, Fault Passage Indicator, Electric Power Distribution System, Fault Management, Reliability Evaluation, Smart Grid, Sub-Transmission Substation Automation, Voltage Sag

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AUTHOR'S DECLARATION

I hereby declare that I am the sole author of this thesis. The author has had the main responsibility for all contents of the thesis, for doing all analyses and simulations, and also for developing and writing the corresponding published papers. This work has been carried out at Sharif University of Technology (Tehran, Iran) and Aalto University (Espoo, Finland) based on the cooperation agreement between these two universities for international co-supervision of my doctoral thesis. Professor Mahmud Fotuhi-Firuzabad at Sharif University of Technology and Professor Matti Lehtonen at Aalto University supervised this work.

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Finally, and most importantly, I would like to thank my loving family for the support and encouragement I received while doing my thesis.

In Espoo, Finland
August 2011

Shahram Kazemi

CONTENTS

List of Symbols and Abbreviations

a — Year

$\mathrm{AEC}^{\mathrm{MI}}_{\mathrm{C_i L_j}}$ — Contribution to annual expected cost arising from momentary interruptions affecting the load point L_j due to the contingency C_i

$\mathrm{AEC}^{\mathrm{SI}}_{\mathrm{C_i L_j}}$ — Contribution to annual expected cost arising from sustained interruptions affecting the load point L_j due to the contingency C_i

$\mathrm{AEC}^{\mathrm{VS}}_{\mathrm{C_i L_j}}$ — Contribution to annual expected cost arising from voltage sags affecting the load point L_j due to the contingency C_i

$\mathrm{AEC}^{\mathrm{MI}}_{\mathrm{L_j}}$ — Annual expected cost arising from momentary interruptions affecting the load point L_j

$\mathrm{AEC}^{\mathrm{SI}}_{\mathrm{L_j}}$ — Annual expected cost arising from sustained interruptions affecting the load point L_j

$\mathrm{AEC}^{\mathrm{VS}}_{\mathrm{L_j}}$ — Annual expected cost arising from voltage sags affecting the load point L_j

$\mathrm{AED}^{\mathrm{SI}}_{\mathrm{C_i L_j}}$ — Contribution to the annual expected duration of sustained interruptions affecting the load point L_j due to the contingency C_i

$\mathrm{AED}^{\mathrm{SI}}_{\mathrm{L_j}}$ — Annual expected duration of sustained interruptions affecting the load point L_j

$\mathrm{AEF}^{\mathrm{MI}}_{\mathrm{C_i L_j}}$ — Contribution to the annual expected frequency of momentary interruptions affecting the load point L_j due to the contingency C_i

$\mathrm{AEF}^{\mathrm{MI}}_{\mathrm{L_j}}$ — Annual expected frequency of momentary interruptions affecting the load point L_j

$\mathrm{AEF}^{\mathrm{SI}}_{\mathrm{C_i L_j}}$ — Contribution to the annual expected frequency of sustained interruptions affecting the load point L_j due to the contingency C_i

$\mathrm{AEF}^{\mathrm{SI}}_{\mathrm{L_j}}$ — Annual expected frequency of sustained interruptions affecting the load point L_j

$\mathrm{AEF}^{\mathrm{VS}}_{\mathrm{C_i L_j}}$ — Contribution to the annual expected frequency of voltage sags affecting the load point L_j due to the contingency C_i

$\mathrm{AEF}^{\mathrm{VS}}_{\mathrm{L_j}}$ — Annual expected frequency of voltage sags affecting the load point L_j

$\mathrm{AEF}^{(\mathrm{V,D})}_{\mathrm{C_i L_j}}$ — Contribution to the annual expected frequency of voltage variation events imposed on the load point L_j due to the contingency C_i. The magnitude and duration of the voltage variation events lie in the ranges specified by parameters V and D.

$\mathrm{AEF}^{(\mathrm{V,D})}_{\mathrm{L_j}}$ — Annual expected frequency of voltage variation events imposed on the load point L_j. The magnitude and duration of the voltage variation events lie in the ranges specified by parameters V and D.

$\mathrm{AENS}^{\mathrm{SI}}_{\mathrm{C_i L_j}}$	Contribution to the annual expected energy not supplied of the load point L_j due to the contingency C_i
$\mathrm{AENS}^{\mathrm{SI}}_{\mathrm{L_j}}$	Annual expected energy not supplied of the load point L_j
$\mathrm{ALD}_{\mathrm{L_j}}$	Average load connected to the load point L_j
$\mathrm{AOR}_{\mathrm{C_i}}$	Annual occurrence rate of the contingency C_i
$\mathrm{AOT}^{\mathrm{SI}}_{\mathrm{L_j}}$	Average outage time of the load point L_j
ASAI	Average System Availability Index
ASUI	Average System Unavailability Index
AVSSI	Average Voltage Sag Severity Index. It shows the average occurrence rate of the voltage sags that can cause problem for the customers.
$\mathrm{AVVFI}^{(V,D)}$	Average Voltage Variation Frequency Index. It shows the average occurrence rate of the voltage variation events that their magnitude and duration lie in a range specified by the parameters V and D.
C_i	Contingency number i
D	A range of duration of voltage variation events, e.g. $0.01 \leq D \leq 0.1$ seconds
DUR(VVE)	Duration of the voltage variation event under examination (i.e. VVE)
€	Euro
$\mathrm{ECOST}^{\mathrm{MI}}$	Total expected cost resulted from momentary interruptions
$\mathrm{ECOST}^{\mathrm{SI}}$	Total expected cost resulted from sustained interruptions
$\mathrm{ECOST}^{\mathrm{VS}}$	Total expected cost resulted from voltage sags
EENS	Expected Energy Not Supplied
eve	Event

$\mathrm{FIT}^{\mathrm{MI}}(\mathrm{VVE})$	A fitness function which is equal to one if the characteristics of the voltage variation event under examination (i.e. VVE) fit to the thresholds defined for momentary interruptions. Otherwise, its value is equal to zero for the voltage variation event under examination.
$\mathrm{FIT}^{\mathrm{SI}}(\mathrm{VVE})$	A fitness function which is equal to one if the characteristics of the voltage variation event under examination (i.e. VVE) fit to the thresholds defined for sustained interruptions. Otherwise, its value is equal to zero for the voltage variation event under examination.
$\mathrm{FIT}^{\mathrm{VS}}(\mathrm{VVE})$	A fitness function which is equal to one if the characteristics of the voltage variation event under examination (i.e. VVE) fit to the thresholds defined for voltage sags. Otherwise, its value is equal to zero for the voltage variation event under examination.
$\mathrm{FIT}^{(\mathrm{V,D})}(\mathrm{VVE})$	A fitness function which is equal to one if the characteristics of the voltage variation event under examination (i.e. VVE) fit to the magnitude and duration range specified by parameters V and D. Otherwise, its value is equal to zero for the voltage variation event under examination. As an example, consider a range such as $0.2 \leq \mathrm{V} \leq 0.3$ per unit and $0.01 \leq \mathrm{D} \leq 0.1$ seconds. The value of this function for a voltage variation event with the remaining voltage 0.27 per unit and duration 0.09 seconds is equal to one. However, for a voltage variation event with the remaining voltage 0.27 per unit and duration 0.15 seconds, the value of this function is equal to zero.
h	Hour
HV	High Voltage
$\mathrm{IC}_{\mathrm{L_j}}(\mathrm{VVE})$	The value of this function shows the financial impacts of the voltage variation event (i.e. VVE) imposed on the load point $\mathrm{L_j}$. For a voltage variation event which its characteristics fit to the thresholds of power interruptions, the duration of voltage variation event under examination is used to estimate the cost. However, in the case of a voltage variation event which its characteristics fit to the thresholds defined for the voltage sags, both magnitude and duration of the voltage variation event are normally required to estimate the cost.

$\mathrm{IMP}_{\mathrm{L_i}}^{\mathrm{VS}}(\mathrm{VVE})$	The value of this function shows the overall impacts on the customers connected to the load point L_j when the characteristics of the voltage variation event imposed on this load point (i.e. VVE) fit to the thresholds defined for voltage sags. Its value lies between zero and one. The value of this function is equal to zero when the characteristics of the imposed voltage variation event do not fit to the thresholds defined for voltage sags. Generally, the magnitude and duration of the voltage sag are compared with the voltage tolerance characteristics of sensitive equipments of the customers connected to the load point L_j to find its possible impacts. The impacts on the customers connected to the load point L_j of the voltage sag are sum up and divided by the total number of customers to estimate the value of this function.
int	Interruption
km	Kilometer
kV	Kilovolt
kW	Kilowatt
kWh	Kilowatt hour
L_j	Load point number j
LV	Low Voltage
MAIFI	Momentary Average Interruption Frequency Index
MV	Medium Voltage
MVA	Megavolt Ampere
MW	Megawatt
$\mathrm{NC}_{\mathrm{L_j}}$	Number of customers connected to the load point L_j
NCT	Total number of primary contingencies
NLP	Number of load points of the distribution system under study
$\mathrm{NS}(\mathrm{C_i})$	Total number of operating states generated for the contingency C_i

$\mathrm{NVE}(\mathrm{C_i}, \mathrm{k}, \mathrm{L_j})$	Total number of voltage variation events imposed on the load point L_j due to the contingency C_i and the operating state k
occ	Occurrence
$\mathrm{P}(\mathrm{C_i^k})$	Probability of residing in the operating state k of the contingency C_i
RMS	Root Mean Square
s	Second
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
sub	Substation
V	A range of magnitude of the voltage variation events, e.g. $0.2 \leq V \leq 0.3$ per unit
VVE	Voltage Variation Event
$\mathrm{VVE}_{\mathrm{C_i L_j}}^{\mathrm{k,m}}$	Voltage variation event number m that imposed on the load point L_j due to the operating state k of the contingency C_i. Generally, the overall effects of the generated contingency are appeared to each load points as several voltage variation events. Each one of these voltage variation events can be corresponding to a power interruption, a voltage sag or just a slight deviation from the nominal voltage. The magnitude and duration of each voltage variation event are examined in order to identify the type of events.

1 INTRODUCTION

1.1 Research Problem

Electric power distribution systems are responsible for delivering the electrical energy from the bulk power systems to the end users. Issues such as radial operating status, aging infrastructures, poor design and operation practices and high exposure to environmental conditions have caused the electric power distribution systems to be addressed as the main contributor to the customer reliability problems. Generally, about 80 to 90 percents of the customer reliability problems are originated from the electric power distribution systems [1-3]. Such statistics always reinforce the electric utilities to look after solutions that can be used for reliability enhancement of the electric power distribution systems. There are a large numbers of solutions available to electric utilities for distribution system reliability improvements. Electric utilities have traditionally improved the distribution system reliability through simple measures such as tree trimming on a regular basis, construction design modification, installation of lightning arresters, use of animal guards, replacing overhead bare conductors by covered conductors or underground cables, protection scheme modification, and so on [4-6]. In addition to these conventional solutions, there are some other advanced reliability improvement measures that nowadays are categorized as smart grid technologies. Major smart grid technologies applicable for distribution system reliability improvements are fault passage indicators, fault locator schemes, substation automation, feeder automation, distribution automation, fault current limiters and dynamic voltage restorers.

Availability of the various reliability enhancement solutions is both an opportunity and a challenge for electric utilities. They have an opportunity to find the right solutions for their own reliability problems. But, each electric utility is different from another one and has its own set of failure causes for distribution system problems. In addition, the design history and the network configuration have large impacts on the specific solutions to be selected [7]. Therefore, the challenge for electric utilities, especially in the competitive electricity market, is to identify and evaluate potential reliability reinforcement schemes and then determine and prioritize those appropriate for implementation. This procedure is usually referred to as the value-based distribution system reliability planning [8-10]. In order to perform the value-based distribution system reliability planning, it is necessary to use a suitable reliability assessment tool. This tool should quantitatively predict the various impacts that the targeted solutions may have on the reliability of electric power delivered to the customers.

Reliability assessment of the electric power distribution systems has received a great attention over the past decades [11-18]. Nowadays, several commercial softwares are available to electric utilities that can be used for reliability assessment of the electric power distribution systems. These softwares usually work based on one or a combination of well-developed reliability assessment techniques such as the analytical simulation approach and the Monte-Carlo simulation approach [3]. Whenever the targeted reliability enhancement solutions are limited to the simple conventional solutions, the available reliability assessment techniques can be easily used for purposes of the value-based reliability planning. The simple conventional solutions are reliability enhancement measures that mainly affect the failure rates of the components of an electric power distribution system. As an example, consider an electric utility which aims to assess the reliability impacts of a tree trimming on a specific area of its distribution network. In this situation, the reliability impacts of the tree trimming can be evaluated by available reliability assessment approaches. The effects of the tree trimming is modeled by appropriate manipulations of the failure rates of the components located in the targeted areas for the tree trimming. However, the electric utilities face a challenge when the reliability enhancement solutions include sophisticated measures such as those of the smart grid technologies. As an example, an electric utility may aim at comparing the impacts of various available feeder automation schemes on the reliability performance of its distribution system. The reliability impacts of the automation solutions normally depend on their operational procedures. In addition, when an automation scheme encounters with an operational failure condition, its reliability impacts deteriorate compared to the situation when it is fully available. Therefore, it is necessary to model both the operational procedure of the targeted automation solutions and their possible operational failures when conducting the related reliability assessment studies. However, the available reliability assessment approaches cannot be employed directly for such purposes. In a circumstance like this, it is necessary to develop a reliability evaluation approach for predicting the reliability performance of the electric power distribution systems when employing such sophisticated solutions.

This research aims to develop and demonstrate a comprehensive approach for reliability assessment of the electric power distribution systems equipped with the advanced reliability enhancement solutions. The majority of the advanced solutions for distribution system reliability improvement are nowadays categorized as the smart grid technologies. Therefore, hereafter in this thesis, the term “smart distribution grids” is used to refer to the electric power distribution systems equipped with the smart grid technologies for purpose of improving the reliability of electric power delivered to the customers.

1.2 Thesis Organization

After this introductory chapter, Chapter 2 provides a brief description on how the smart grid technologies can affect the reliability performance of an electric power distribution system. Chapter 3 introduces the major smart grid technologies that can be used for reliability improvement of the electric power distribution systems. Chapter 4 deals with the previous works related to the reliability assessment of distribution systems equipped with advanced technologies and the contribution of this thesis. The proposed reliability evaluation approach is described in Chapter 5. The application of the proposed reliability evaluation approach is presented in Chapter 6. Finally, Chapter 7 provides the concluding remarks.

2 APPLICATION OF SMART GRID TECHNOLOGIES FOR DISTRIBUTION SYSTEM RELIABILITY IMPROVEMENT

Sustained interruptions, momentary interruptions and voltage sags are three major attributes of the reliability of electric power delivered to the customers. A sustained interruption is referred to the situation where the electric service is interrupted for a long period of time, normally for a time greater than 1 minute [19]. A momentary interruption is a brief disruption in the electric service, usually lasting no longer than a few minutes. The maximum duration of a momentary interruption varies from utility to utility, but is typically between one and five minutes [3]. In the past, the momentary interruptions were not as noticeable to customers as they are today. In addition, today customers use sensitive equipments that can even be sensitive to the slightest variations in the power supply. Voltage sag is a significant power quality issue that can affect the majority of sensitive equipments like personal computers, adjustable speed drives, programmable logic controllers, semiconductor devices and contactors. A voltage sag is defined as the decrease in the RMS voltage between 10 to 90 percents of the nominal voltage for durations from 0.5 cycles to 1 minute [19]. Voltage sags that can cause problem for sensitive equipments are usually originated from faults within transmission and distribution systems [20]. Motor starting and transformer energizing can also cause voltage sags but their characteristics are usually not severe enough to cause equipment malfunction. The occurrence of voltage sags is far more than the number of interruptions. Hence, for specific customers, the financial losses caused by the voltage sags may even be greater than the cost associated with the power interruptions.

In the context of reliability, generation, transmission, and distribution systems are referred to as functional zones. Each functional zone is made up of several subsystems. Generation system consists of generation plants and generation substations. Transmission system consists of transmission lines, transmission switching stations, transmission substations, and sub-transmission systems. Distribution systems consist of HV/MV substations, primary (MV) distribution systems, MV/LV substations, and secondary (LV) distribution systems [3].

A core mission of an electric power distribution system is to deliver electrical energy from the supplying points to the end users. Reliability of the electric service provided to the end users can be altered by the faults originated either inside or outside of the functional zone of an electric power distribution system. Hereafter in this thesis, these faults are referred to as “internal faults” and “external faults”, respectively. Regardless of a fault occurrence location, its impact is appeared to the end users as a voltage variation event such as an interruption, a voltage sag or a slight change in the supply voltage. The effect of an external fault mainly appears to the end users as a voltage sag rather than as an interruption. This is mainly because of the mesh configuration of the transmission and sub-transmission networks which feed the supply points of an electric power distribution system. As a result, the share of external faults in the total power interruptions experienced by the end users is considerably lower than that of the internal faults. In contrast, an internal fault usually results in either an interruption or a voltage sag for the end users. The share of internal faults in the total interruptions and voltage sags experienced by the end users can be higher than that of the external faults.

The reliability improvement activities can aim at reducing the rate of external and internal faults and also mitigating their impacts on the end users. In the functional zone of an electric power distribution system, it is possible to mitigate the impacts of both external and internal faults by means of various smart grid technologies. Feeder automation is one of the major smart grid technologies that can be used for distribution system reliability improvement. Therefore, for an illustration purpose, the following section aims to show how the feeder automation schemes may affect the reliability performance of an electric power distribution system.

Without the network automation facilities, the electric utilities have to perform the fault management activities based on the customers' outage calls. Upon receiving the trouble calls from the customers, the operators look at the network configuration map and the protection design manual to determine the outage area. Then a repair crew has to be sent to patrol the outage area. When faced with a tripped circuit breaker and no indication as to where the fault lies, a repair crew has a range of options by which the faulted section is identified. In a manually operated distribution system either "feeder splitting and fault re-ignition method" or "feeder splitting and insulation test method" can be used for locating the faulted section [21]. The diagnosis of the fault in these manners can be an unsafe, rigorous and time-consuming task, which finally result in the poor service reliability. In this situation, it may take a long time to restore power to those parts of a distribution network which are undamaged but have lost power because of problems elsewhere in the distribution network (say 50 to 80 minutes) and also to restore power to customers that can only be restored after repair or replacement of the damaged component (say 1 to 5 hours). However, a suitable feeder automation scheme can be used to perform fault management activities in much more efficient manners. Hence, depending on the characteristics of the implemented feeder automation scheme, the above processes can be completed more efficiently by less people in much less time, which increase the distribution system reliability and efficiency. Moreover, the implemented automation scheme may also mitigate the voltage sags experienced by customers and the damage to the distribution network infrastructure by reducing the number of inrush current caused by the fault re-ignition activities required to locate the fault. Figure 1, as an example, shows how the fault management activities might proceed with and without employing an advanced feeder automation scheme [22]. The times shown will be extended even further during storm conditions when control center operators are managing a multiple outage scenario.

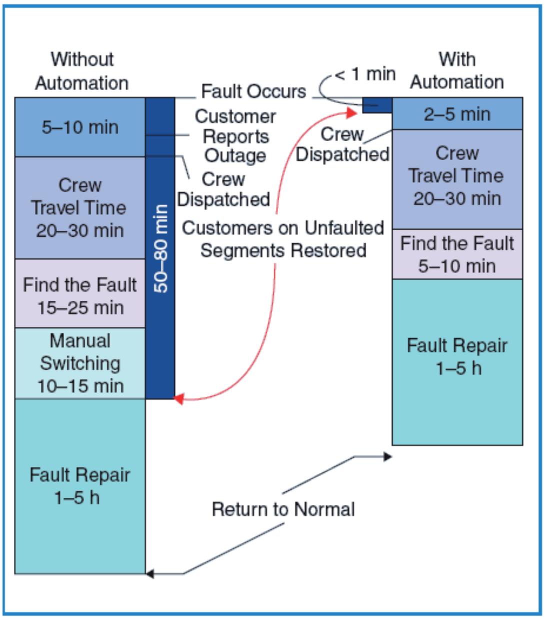

Figure 1. Fault management activities in response to a fault condition without and with employing an advanced feeder automation scheme [22].

3 SMART GRID TECHNOLOGIES

In a broad sense, the term “smart grid” is referred to a conventional electric power system that has been equipped with advanced technologies for purposes such as reliability improvement, ease of control and management, integrating of distributed energy resources and electricity market operations. The smart grid technologies can be categorized in the following five key areas [23]:

Integrated Communications – High-speed, fully integrated, two-way communication technologies will make the smart grid a dynamic, interactive “mega-infrastructure” for real-time information and power exchange. Open architecture will create a plug-and-play environment that securely networks grid components to talk, listen and interact.

Sensing and Measurement – These technologies will enhance power system measurements and enable the transformation of data into information. They evaluate the health of equipment and the integrity of the grid and support advanced protective relaying.

Advanced Components – Advanced components play an active role in determining the grid’s behavior. The next generation of these power system devices will apply the latest research in materials, superconductivity, energy storage, power electronics, and microelectronics. This will produce higher power densities, greater reliability and power quality, enhanced electrical efficiency producing major environmental gains and improved real-time diagnostics.

Improved Interfaces and Decision Support– In many situations, the time available for operators to make decisions has shortened to seconds. Thus, the smart grid will require wide, seamless, real-time use of applications and tools that enable grid operators and managers to make decisions quickly. Decision support with improved interfaces will amplify human decision making at all levels of the grid.

Advanced Control Methods – Advanced control methods are the devices and algorithms that will analyze, diagnose, and predict conditions in the smart grid and determine and take appropriate corrective actions to eliminate, mitigate, and prevent outages and power quality disturbances. To a large degree, these technologies rely on and contribute to each of the other four key technology areas. For instance, they will monitor essential components (Sensing and Measurements), provide timely and appropriate response (Integrated Communications; Advanced Components), and enable rapid diagnosis (Improved Interfaces and Decision Support) of any event.

Smart grid technologies are used for accomplishing a specific set of applications or functions in the electric power systems. For each application, there are numbers of smart grid technologies available that can be classified in the above described five key areas. The scope of this thesis is limited to the smart grid technologies that can be used in the functional zone of an electric power distribution system for improving the reliability of electric power delivered to the customers. At the moment, there are numbers of the smart grid technologies already available in the market and some others are still in the research and development stage. The main emphasis in this thesis is on the technologies which have already been implemented in the field either as a commercially available product or as a prototype project. The various products of the following well-known companies have also been examined in order to find the potential smart grid technologies applicable for purposes of this thesis:

- ABB (http://www.abb.com/)
- Advanced Control Systems (http://www.acsatlanta.com/)
- AREVA (http://www.areva.com/)
- Cooper Power Systems (http://www.cooperpower.com/)
- Deltatronic (http://www.deltatronic.com/)
- GE Energy (http://www.gepower.com/)
- G&W Electric (http://www.gwelec.com/)
- Hubbell Power Systems (http://www.hubbellpowersystems.com/)
- Motorola (http://www.motorola.com/)
- NovaTech (http://www.novatechweb.com/)
- OSI (http://www.osii.com/)
- Power Delivery Products (http://www.powerdeliveryproducts.com/)
- SEL (http://www.selinc.com/)
- Siemens (http://www.siemens.com/)
- S&C Electric Company (http://www.sandc.com/)
- SNC-Lavalin (http://www.snclavalin.com/)
- Survalent Technology (http://www.survalent.com/)
- Telvent (http://www.telvent.com/)
- Thomas & Betts (http://www-public.tnb.com/)

3.1 Distance to Fault Estimator

Distance to fault estimator is an optional module of the modern distribution protection equipment that can be used for estimating the fault location. When a fault occurs, this module calculates the fault location as a distance from the substation to the fault. It can also notify this information to the control center or the utility repair crews through a suitable communication equipment. By using the distance to fault estimators, a much smaller zone of an electricity distribution network is required to be inspected by the repair crews in search for location and isolation of the fault and restore service to the affected customers. However, when a feeder has multiple taps, there might be several probable fault locations for the fault distance indicated by this module. In this situation, the repair crews are unable to determine which tap to follow to find the fault location. However, applying fault passage indicators together with distance to fault estimators can overcome this issue.

3.2 Fault Passage Indicator

Fault passage indicator is a device that can be located at some convenient point on an electricity distribution network to give an indication as to whether the fault current has passed the point where it is located or not. It is able to distinguish between the fault current and the load current associated with the healthy feeder, and has some means of displaying its operation to a repair crew. The status of a fault passage indicator can be recognized remotely or by visiting its physical location. Usually, the status of an indicator used with overhead line networks is illustrated in the form of flashing indication. In the case of underground cable networks, it is also possible to use a kind of fault passage indicators equipped with short range wireless communication equipment. The status of such an indicator can be retrieved remotely from a short distance (a few meters) without the need to access the distribution substation to recognize its status. By using the fault passage indicators, the repair crews waste less time to travel around the network in search for location of the fault. In the past, the majority of fault passage indicators available in the market were mainly applicable for radial distribution networks with directly earthed neutral [21, 24]. However, nowadays, there are new generations of fault passage indicators available in the market that can be used in the other electricity distribution networks.

3.3 Fault Locator Schemes

Fault locator schemes are devices and algorithms that are used to identify the location of a fault. Developed schemes for automatic fault location in the electricity distribution networks are generally operate based on a special fault locating technique. Various fault location techniques have been proposed in the literatures. The principles, merits and demerits of each fault location technique in the transmission and distribution systems have been discussed in [24-26]. Most of the proposed fault location techniques have been developed for power transmission systems. Few methods have been proposed for the electric power distribution networks due to the following reasons [26]:

Variety of Conductors and Structures: Along a typical distribution feeder there are different cables, lines and configurations (cross-arm, twisted, spacer, underground, etc.); therefore, there is no linear relation between the line impedance and the distance between the fault location and the substation.

Lateral Branches: Unlike transmission lines, typical distribution feeders have several lateral branches. Thus, short circuits in different geographical locations can produce the same currents and voltages measured at the substation. Consequently, the fault location procedure may result in several different points as possible locations.

Load Distributed along the Feeder: The current measured at the substation during a fault includes a contribution given by the sum of the load currents at each node and, in contrast to transmission systems, it is impossible to estimate these currents accurately.

Modifications in the Feeder Configuration: Distribution networks are subject to constant modifications in their topology. As a result, any fault location algorithm must have access to a database, periodically updated, in order to give a better estimate of the fault point.

Over the last few decades, several fault locator schemes have been developed for employing in the electric power distribution systems. Some of these schemes mainly work based on the measurements of voltage and current signals provided by devices such as the fault passage indicators installed along the distribution feeders. Traditional fault indicators are useful tools for fault management activities. However, they require local inspection by a repair crew. Repair crews typically patrol the entire faulted circuit and spending valuable time patrolling a significant portion of a feeder without any additional information that could be provided by fault indicators located along the feeder. However, repair crews could be dispatched directly to the section of the distribution network where the fault occurred and quickly restore power to the affected customers utilizing fault location information obtained from remote indicating fault passage indicators. The status of fault passage indicators with remote indicating capability can be recognized by a remote master station located at a main substation and/or a distribution control centre. Their information might be used directly for detecting and locating of faults or indirectly to get a high level of confidence about the fault type and/or the location. More information about the fault locator schemes which mainly work based on the remote data retrieval of fault passage indicators can be found in [27-30]. There is another group of fault locator schemes. These schemes normally operate based on algorithms that use measurements of voltage and current signals provided by intelligent electronic devices located at a main substation. The intelligent electronic device could be a digital transient recorder or a digital protection equipment. These schemes often rely on additional information such as the configuration of the electricity distribution network, load profiles, characteristics of protective devices and their locations. This information can be gathered from databases available at a main substation and/or from distribution control centre databases. One of the benefits of such schemes is that they may also be useful to identify the location of transient faults and thus serve as a tool for fault prevention. More information about the fault locator schemes which normally operate based on the measurements at the substation level can be found in [31-40].

3.4 Substation Automation

Substation automation is a system which enables an electric utility to locally and remotely monitor, control and coordinate the components installed at a substation. The substation automation related functions include monitoring and data acquisition from various substation equipment, bus voltage control, circulating current control, bus load balancing, overload control, and fault management for substation related faults. In the functional zone of an electric power distribution system, substation automation systems can be implemented in both sub-transmission (HV/MV) substations and distribution (MV/LV) substations. Compared to other components of an electricity distribution network, the failure rates of components of a sub-transmission substation are very low, but their consequences can be much serious as they may result in extended outages. The substation automation system with suitable automation functions can be used to automatically isolate the failed component and restore supply to the affected feeders through proper switching actions. In addition, when encountering with a failure condition in the electricity distribution network and facing with a feeder circuit breaker operation, an alarm can be automatically issued to the distribution control centre to notify the fault condition. The data recorded by various intelligent electronic devices installed at the substation are also available to the operators. This data can be used for conducting various fault management activities. In the other hand, the substation automation system can also be implemented at distribution substations for remote data acquisition from various equipments installed at the substation and also to control the available actuators. The retrieved data can be used for approximate fault location purpose. In addition, the operators can operate the remote controlled switching devices available at the substations to isolate the fault and restore the service for as many as possible of the affected customers. More information about the substation automation systems can be found in [41-54].

3.5 Feeder Automation

Feeder automation is an automatic control scheme that is used for automatic fault detection, isolation and service restoration in an electricity distribution network. When an electricity distribution network encounters with a permanent failure condition, there are basically two groups of affected customers. First group involves the customers that have to be waiting till the end of repair process of the faulted section before power restoration. In contrast, the second group includes the customers whose power supply can be restored through main or alternative supplies by means of proper switching actions. Usually, the number of customers in the second group is much larger than that of the first group. For power restoration of the second group of customers, healthy sections of the distribution network should be isolated from the one that contains the fault. After that they can be restored from main or alternative supplies by means of appropriated switching actions. In the case of a manually operated distribution system, fault isolation and service restoration activities can just be accomplished after the fault is located by utility repair crews. However, by employing a feeder automation scheme, the interruption duration experienced by the affected customers can be reduced. Feeder automation schemes can automatically perform the necessary switching operations to isolate the faulted section from the healthy ones and restore power to as many as possible of the affected customers. However, the impact of a special feeder automation scheme on the frequency and duration of interruptions experienced by the customers are dependent on various parameters. Among the rest, the operational procedure of the implemented automation scheme, number, location and characteristics of switching devices, and also configuration and operational criteria of the targeted distribution network are considerable.

Over the last few decades, several feeder automation schemes have been developed for employing in the electricity distribution networks. Some of these feeder automation schemes perform whole fault detection, isolation and restoration process locally without any involvement of operators located at a master substation and/or a distribution control centre. These feeder automation schemes are stand alone schemes and mainly dependent on the automatic switching devices installed along the distribution feeders. Actually, the necessary intelligence for performing dedicated automatic functions is provided by appropriate equipment of such automatic switching devices. More information about this kind of feeder automation schemes can be found in [55-69]. In addition, there is another group of feeder automation schemes which perform whole or some part of the fault detection, isolation and service restoration process based on a centralized intelligence which may be located at a main substation and/or a distribution control centre. These automation schemes are actually subsets of a full distribution automation system. This approach requires a full knowledge of the distribution network, including the network topology and operation parameters. The feeder automation functions are centrally implemented and automatic switching commands are almost issued from the control centre. More information about this kind of feeder automation schemes can be found in [70-87].

3.6 Distribution Automation

Distribution automation is a complete system that enables a utility to monitor, coordinate and operate the distribution network components in a real-time mode from remote locations. Distribution automation allows utilities to implement a flexible monitoring and control of an electric power distribution system, which can be used to enhance efficiency, reliability, and quality of the electric service. Flexible monitoring and control also results in a more effective utilization and life-extension of the existing distribution system infrastructure. An advanced distribution automation system has all the necessary components required for efficient fault management activities in the feeder and the substation levels. It can automatically perform the fault detection, isolation and service restoration activities without an intervention of distribution system operators. It can also identify the fault location and assist the control center operators and the repair crews during the fault management activities. More information about various aspects of distribution automation systems can be found in [88-105].

3.7 Fault Current Limiter

Future power system will experience an increase of dense urban distribution networks and an increased penetration of distributed energy recourses which both contribute to increasingly fault current levels. In this situation, managing fault currents is crucial in order to avoid malfunctioning and damage of equipment as well as to increase system reliability. There are number of conventional solutions available for managing fault currents, such as construction of new substations, introducing a higher voltage level, bus splitting, upgrading circuit breakers, current limiting reactors and high impedance transformers, impedance grounding, and sequential breaker tripping. Normally, the application of these conventional methods leads to some technical and/or economical problems. This issue has been the main driver for developing the fault current limiters. Fault current limiter is a device which limits the amount of fault current during short circuit conditions. It has negligible impedance at a normal operating condition but high impedance when the fault current is passing through it. Currently, two broad categories of a fault current limiter technologies exist, namely high-temperature superconducting and solid-state. High-temperature superconducting types use superconducting-based material and reduce fault currents by introducing a larger-than-normal impedance into the path of the fault current. Solid-state types use high-speed solid-state switching devices to rapidly insert an energy absorbing impedance into the circuit to limit the fault current. Emerging technologies have made it feasible to develop and test the fault current limiters applicable in the sub-transmission voltages (up to 138 kV). Application aspects of various fault current limiters have been reported in [106-117].

3.8 Dynamic Voltage Restorer

Dynamic voltage restorer is a waveform synthesis device based on power electronics that is series-connected directly into the network by means of a set of single-phase insertion transformers. This device can be installed in strategic locations of an electricity distribution network to mitigate the effect of voltage sags on the customers. The dynamic voltage restorer cannot protect a load against an interruption. When the voltage of one or more phases of incoming supply drops below a preset threshold, this device injects a controlled amount of voltage into the affected phase or phases to boost the voltage of outgoing side back to a more suitable level. The commercial brands of dynamic voltage restorer are nowadays available in the market with ratings up to 50 MVA, voltage injection transformers ratings up to 46 kV, response time of around a half cycle and capability to correct the three-phase voltage sags with remaining voltage up to 50 percents of the nominal voltage. Further information about dynamic voltage restorers can be found in [118-120].

4 RELATED WORKS AND THESIS CONTRIBUTION

Two main literature surveys have been conducted for the purposes of this doctoral thesis. The first literature survey aimed at finding the major smart grid technologies applicable for reliability enhancement of distribution systems that outlined in Chapter 3. The second literature survey was concerned with the previous research activities related to the application of probabilistic methods for reliability evaluating of smart distribution grids. In the following, the results of this literature survey and also the contribution of this thesis are described.

In [121-123], the impacts of different controlling strategies of dynamic voltage restorers for mitigation of voltage sags have been simulated for specific case studies. The work by Tosato et al. [124] deals with the application of fault current limiters for mitigation of voltage sags. In [125, 126], the impacts of fault current limiters on the reliability performance of various substation configurations have been studied. The work by Lawler et al. [127] discusses the reliability effects of distribution automation on the Athens Utilities Board. Several scenarios have been conducted in this paper by providing the remote controlling facilities for targeted manually operated switching devices. The reliability impacts of the automation solution concerned in this paper has been modeled by modifying the switching times of the retrofitted switching devices. In [128, 129], the optimal allocation of the specific automatic sectionalizing switching devices have been studied. These switching devices are able to diagnose the fault and eventually to reschedule the configuration of the network for restoring the power to the affected customers. The reliability impact of the targeted automation scheme has been modeled by ignoring the effects of faults on the customers that have been affected by the fault but are restored automatically through automatic switching devices. The work by Rigler et al. [130] presents the potential benefits that may be achieved by automation solutions for distribution system reliability improvement. The effects of the number and location of reclosers on the frequency and duration of sustained interruptions imposed on the customer have been examined in this paper. The works by He et al. [131, 132] describe an approach based on the event tree method for assessing the reliability impacts of the operational failures of the communication system and the protection system in the centralized feeder automation schemes. The reliability indices concerned in these papers are limited to those which only count the sustained interruptions. Brown et al. [133] models the effects of two-stage service restoration through remote controlled switching devices on the duration of sustained interruptions imposed on the customers. In [134-137], several optimization techniques have been used for the allocation of the remote controlled switching devices. The reliability impacts of adding remote controlling facility to the retrofitted switching devices have been modeled as the reduction in time required to operate these switching devices.

The reliability evaluation approaches proposed in the above described works have the following shortfalls:

1- Virtually all of the reliability assessment studies have been concentrated on the sustained interruptions, which is only one attribute of the reliability of electric power delivered to the customer. However, nowadays, customers are also sensitive to momentary interruptions and even voltage sags. Some of the available reliability enhancement solutions, such as the feeder automation schemes, improve the reliability indices corresponding to the sustained interruptions in cost of increasing the frequency of momentary interruptions and voltage sags. Therefore, the possible impacts of the implemented solutions on all three major attributes of the service reliability should be taken into account simultaneously.

2- The impacts of operational failures of the implemented reliability enhancement solutions have not been considered in the majority of previous studies. However, the implemented reliability enhancement solutions are not fully reliable [138, 139]. The operational failure modes of the implemented solution are required to be taken into account as the reliability impacts of the implemented solution may be affected due to this issue. It should be noted that the operational failure is referred to the situation where a device fails to function when it is required to operate.

3- The reliability enhancement solutions have almost been limited to only one possible solution. In other words, the integrated effects of several reliability enhancement solutions with different technologies have not been taken into account. However, when employing a specific reliability enhancement solution for improving a given set of reliability indices, there might be some negative impacts on the other reliability indices. In this situation, it is normally possible to use other reliability enhancement solutions, almost with different technologies, to mitigate the negative impacts of the primary solution.

4- The practical aspects of the realistic distribution systems have not been considered in the analyses. The majority of the previous works are concerned with the application of remote controlled or automatic sectionalizing switching devices for speeding up the fault isolation and service restoration activates. The reliability impacts of these solutions have almost been analyzed using simple reliability modeling approaches. In the most cases only manual switching times have been replaced by automatic or remote switching times. However, there are some other practical issues that should be taken into account. Among the rest, the impacts on the procedures that are followed by the electric utilities for fault detection and location, the operating criterion of an electric power distribution system in the normal and emergency conditions and also the switching sequences that are followed for isolating the fault and restoring the power service for the affected customers have not been considered in the analyses.

5- The proposed reliability evaluation approaches are case dependent. They have almost been designed for a specific reliability enhancement solution and/or a given type of an electricity distribution network. The application of these methods even for other similar solutions but with different operating logics is questionable.

This research aimed at overcoming the above described shortfalls. The research activities were organized to develop and demonstrate a comprehensive reliability evaluation approach that can be used for the reliability evaluation of smart distribution grids. The proposed methodology is capable of predicting the possible impacts of the implemented solutions on all three major attributes of the service reliability, namely sustained interruptions, momentary interruptions and voltage sags. The proposed approach has been such designed and developed that the impacts of various operational failure modes of the implemented technologies can also be considered when conducting a reliability case study. It is also possible to evaluate the reliability impacts of various technologies that are implemented at the same time. In addition, the practical issues related to normal and emergency operations of an electric power distribution system have been taken into account when developing the proposed approach.

5 PROPOSED RELIABILITY EVALUATION APPROACH

The results of research activities conducted during this doctoral research project indicated that the impacts of reliability enhancement solutions are revealed through various processes involved in the fault management activities [140-147]. When the fault effects are appeared in an electric power distribution system, specific processes designated as fault management activities are required to be carried out. The fault effects are normally appeared in the form of abnormal voltages and currents. Typical fault management activities involve the following processes:

- Autonomous System Reaction Process: The autonomous system designated for protection, control and monitoring purposes reacts against the fault effects and operates according to its operational logics. The control center operators have no involvement in this process. In what manner this process is carried out depends on the several factors such as the fault effects, settings and operational logics of associated devices, and operational policies of the electric utility. The time required to accomplish this process is almost very short; however, the outcome of this process has vital impacts on the extent of the affected customers and the type of voltage variation events that they may be encountered. The voltage variation events may range from a slight change in the RMS voltage for a few cycles to more severe situations such as complete disappearing of the supply voltage for a long period of time.

- Fault Notification Process: The control center operators should be notified about a forced outage in order to initiate the necessary remedial actions. The time required for the control center operators to be notified about a forced outage is a function of various parameters. Among the rest, the available facilities to the operators for detecting and notifying the abnormal conditions are crucial.

- Approximate Fault Location Process: When the control center operators are notified about an abnormal condition, the necessary data are collected and analyzed in order to find the approximate fault location. The time required for accomplishing this task depends on the parameters such as the fault effects and the available facilities for recording, retrieving and analyzing the related data.

- Decision Making Process: After the approximate fault location activity, the control center operators should make a decision about the overall procedure for mitigating the reliability impacts of the fault. This procedure is determined based on the factors such as the approximate fault location, type of affected customers, number, location and type of switching devices involved and also available repair crews. The time required for accomplishing this task mainly depends on the decision making facilities available to the control center operators.

- **Remote Fault Isolation and Service Restoration Process:** In order to mitigate the reliability impacts of a permanent fault on the customers, the electricity network should be properly reconfigured to isolate the fault and restore the power to as many as possible of the affected customers. In a situation where the electricity network is equipped with suitable remote controlled switching devices, the network reconfiguration can be initiated from the control center. The applicability and effectiveness of the remote network reconfiguration process depend on the number, type and location of the available remote controlled switching devices, the outcome of the approximate fault location process and also the operational policies of the electric utility.

- **Repair Crew Dispatching and Traveling Process**: Once the approximate fault location and the overall procedure for fault isolation and service restoration activities are known, the control center operators dispatch the repair crews around the damaged area. The location, date and time of fault occurrence and also availability of the facilities designated for notifying and navigation of the repair crews affects the time required to get around the damaged area.

- **Faulted Zone Location Process**: In some situations, the outcome of the approximate fault location process may just identify the faulted feeder or several zones as the probable locations of the damaged component. A zone is referred to a set of the electricity network components rather than switching devices that are permanently interconnected to each other and surrounded by switching devices. In a situation where the faulted zone is unknown, the repair crews look for a zone that contains the damaged component. The time required to accomplish this process depends on the factors such as daylight, accessibility to the suspected feeder and its components, available resources and facilities to the repair crews and also the operational policies of the electric utility.

- **Local Fault Isolation and Service Restoration Process:** After repair crews reached the damaged area and found the faulted zone, there might be possible to reconfigure the electricity network in order to further mitigate the reliability impacts of a permanent fault on the customers. This is usually done by manually and/or remotely operating the available switching devices. This process is normally coordinated between the repair crews and the control center operators in order to perform this task properly. The local network reconfiguration process may involve several switching actions. The time required to accomplish this process depends on the number, type and location of the switching devices involved, the operational policies of the electric utility, the available repair crews and their facilities and resources to access these switching devices.

- Precise Fault Location Process: The damaged component should be identified for possible repair or replacement activities. The damaged component is located in the faulted zone. As normally the faulted zone contains several components, the repair crews may need further investigation to find the failed component. Additional efforts are also required to find the damaged part of the failed component. The time required to accomplish this process depends on the factors such as the type of components involved in the faulted zone, the outcome of the approximate fault location process and also facilities and resources available to the repair crews.

- Repair or Replacement Process: The damaged component should be repaired or replaced in order to return the network configuration to the normal operating condition and to restore power to the customers that can only be restored after repair or replacement of the damaged component. The time required to accomplish this process depends on factors such as the resources available to the electric utility, operational policies of the electric utility and the damage severity.

- Return to Normal Operation Process: Usually fault isolation and service restoration activities necessitate changing the normal configuration of a faulted electricity network. As the normal configuration of an electricity network is the basis for day-to-day operating and also setting of the devices involved in the autonomous system, it is necessary to return the electricity network to its normal operating configuration. This process is initiated after completing the repair or replacement of the damaged component. It usually needs special switching sequences which may cause other interruptions for some group of the customers. The duration of this process and its effects on the customers depend on the factors such as the type, location and number of available switching devices, type and location of the customers that may be affected, operating policies of the electric utility, the available repair crews and their facilities and resources to access these switching devices.

When employing a given set of the smart grid technologies, some of the above described fault management activities are affected which finally alter the reliability of electric power delivered to the customers. Thereby, the reliability impacts of the targeted smart grid technologies can be evaluated from their effects on the fault management activities. The reliability evaluation procedure starts by enumerating a suitable contingency. Then, the impacts of the implemented smart grid technologies on the various stages of the fault management activities are identified for each contingency. This procedure is repeated for all the possible contingencies and finally, by summing up the reliability impacts of the evaluated contingencies, the load points and system oriented reliability indices are calculated. The flowchart of the procedure proposed for reliability evaluation of smart distribution grids is shown in Figure 2. A modular approach has been used for developing the reliability evaluation procedure. Each module has its own functions for performing the targeted tasks assigned to it. Following are overall explanations of each module involved in the proposed evaluation procedure:

- Module 1: This module is responsible for gathering the data related to the electric power distribution system under study. The details of data required are depending on the study purposes and characteristics of the distribution system under study. The input data may include the following information:

- Type of components (e.g. overhead line, underground cable, transformer and switching device)
- Electrical characteristics of components (e.g. rated voltage, normal capacity, emergency capacity, positive, negative and zero sequence impedances, making and breaking capability of switching devices, voltage ratio, winding connection and phase shift of transformers)
- Interconnections of components and their geographical information
- Fault rates of components (e.g. permanent failure rate and transient failure rate)
- Actual repair or replacement times for permanent faults
- Number of reclosing sequences required for clearing of multi-shot transient faults
- Operational procedures of the autonomous system designated for protection, control and monitoring purposes. The operational procedures of the implemented smart grid technologies should be clearly identified for various abnormal conditions that may occur in the distribution system under study.
- Operating characteristics for devices involved in the autonomous system (e.g. time current characteristics of protection relays and correction capabilities of dynamic voltage restorers)
- Operational failure data for the components that involve in the fault management activities. The operational failure of each component can be represented through various operating states for the component and assigning a state residing probability to each operating state. In each operating state, specific operating logics may work successively and others remain inactive or malfunction.
- Load points data (e.g. average and maximum powers, power factor, number of customers, interruption costs and their susceptibility against voltage sags)

- Module 2: This module is responsible for clarifying the details that should be considered when analyzing the reliability performance of the distribution system under study. In addition, the data related to various fault management activities are also collected in this stage. The input data may include the following information:

- Power flow operation data (e.g. base power, maximum number of iterations, maximum allowable error, voltage constraints and overload constraints)
- Short circuit operation data (e.g. fault resistance, number of fault positions in the case of overhead lines and underground cables)
- Definition of reliability attributes (e.g. voltage threshold for distinguishing interruptions from voltage sags, time threshold for distinguishing sustained interruptions from momentary interruptions and aggregation methods for evaluating the complex events)
- Availability of suitable facilities in the control center for purposes of the fault management activities (e.g. fault notification facilities, approximate fault location facilities, decision making supporting facilities and also the facilities targeted for dispatching and assisting the repair crews)
- Average times required for the control center operators to accomplish specific fault management activities with and without the aid of employed smart grid technologies (e.g. the average time required for the operators to be notified about a permanent fault, the average time required for the operators to find the damaged area, the average time required for the operators to make a decision about the fault management activities and also the average time required for the operators to dispatch the repair crews around the damaged area)
- Travelling speed of the repair crews to get around the damaged area with and without the aid of employed smart grid technologies
- Average patrolling speed of the repair crews for the precise fault location on the overhead lines
- Average time required for the precise fault location on the underground cables, including both pre-location and pinpointing activities
- Average time required for reading a set of indicators with a local indication
- Average time required for performing an insulation test on the underground cables
- Average time required for the remote operation of the remote controlled switching devices
- Average time required for the manual operation of the switching devices
- Available repair crews and the geophysical information of the trouble call centers
- Requirement for considering the effects of voltage sags originated from external faults
- Maximum number of simultaneous operational failures that should be considered in the reliability case study
- Policy of the electric utility for zonal fault location activities (e.g. feeder splitting and fault re-ignition or feeder splitting and insulation test)
- Policy of the electric utility for returning the electricity distribution network to its normal operating configuration. There are two common policies, namely the close transition and the open

transition. In the close transition, the network can be such configured to temporary operate in a loop configuration. This can avoid or reduce the number of additional interruptions imposed on the customers during the network reconfiguration activities. Contrary, in the open transition, the network is not allowed to operate in a loop configuration. Therefore, additional interruptions may be imposed on the customers during the network reconfiguration activities.

- Policy of the electric utility for managing the earth fault in the cases where the sustained operation with the earth faults is permitted

- Module 3: When requested by the analysis assumption, this module provides data related to voltage sags arising from the faults outside of the functional zone of the electricity distribution system under study. The voltage sags are assigned to specific supplying points (propagation points) of the targeted distribution network. In the case of sustained and momentary interruptions, the frequency and duration of interruptions are properly assigned to the power supplying components.

- Module 4: This module is responsible for generating a primary contingency to be analyzed in the next modules. The generated contingency can be a voltage sag arising from an external fault or a short circuit fault on a component within the functional zone of the distribution network under study. For an external fault, the generated contingency contains the necessary information related to the voltage sags such as the voltage magnitudes and phase angles of all three phases, propagation points, occurrence rates and durations of the events. For an internal fault, the generated contingency may contain the fault type (permanent: major, minor or transient: single-shot or multi-shot), the fault location along the faulted component, fault rate, actual repair or replacement time, fault resistance and also short circuit type (single-phase to ground, two-phase, two-phase to ground and three-phase).

- Module 5: When requested by the analysis assumption, the attributes of the primary contingency is further modified in this module for the situation where devices involve in the fault management activities encounter with the operational failure conditions. Possible combinations of the operational failures of these devices are considered as subsets of the primary contingency. Hence, in this module, various operating states are generated for evaluating the primary contingency. Under any circumstances, the state corresponding to no operational failure always exists in the generated operating states.

- **Module 6:** This module is responsible for evaluating the reaction of the autonomous system against the contingency under study. In this module, depending on the analysis assumption, the initial effects of the fault involved in the contingency under study are simulated based on the power flow study, short circuit study or simple energy flow check. Then, the detailed reactions of various devices designated for the protection, control and monitoring purpose are evaluated against the initial fault effects. The events identified in this process are used in the next modules.

- **Module 7:** The average time required for the control center operators to be notified about a forced outage arising from the contingency under study is estimated in this module. The effects of the employed smart grid technologies and their possible operational failures are taken into account when estimating this time period.

- **Module 8:** The average time required for the control center operators to find the approximate location of the fault involved in the contingency under study is estimated in this module. The effects of the employed smart grid technologies and their possible operational failures are also taken into account when estimating this time period.

- **Module 9:** The average time required for the control center operators to make decision about the activities required for managing the fault involved in the contingency under study is estimated in this module. The effects of the employed smart grid technologies and their possible operational failures are also taken into account when estimating this time period.

- **Module 10:** Depending on the analysis assumptions, the ratings of the available switching devices and also the fault involved in the contingency under study, a suitable set of the remote controlled switching devices are identified in this module for remote fault isolation and service restoration activities.

- **Module 11:** Based on the identified maneuvering switching devices, all the possible network configurations are generated in this module. Then, each configuration is further investigated against criterion such as fault isolation condition, radial operating status, voltage and overload constraints and also number of customers that are restored before and after the network reconfiguration. Finally, a set of the network configurations that can meet the criterion are selected as the feasible network configurations for fault isolation and service restoration purposes.

- Module 12: In this module, a feasible network configuration with the maximum fault mitigation impacts is selected as the final network configuration when the fault isolation and service restoration activities are accomplished. Then, the optimal switching sequences for transferring the present configuration to the final configuration are identified. The switching sequences are organized in a way that all the configurations in this process just involve the identified feasible network configurations.

- Module 13: In this module, the status of the electricity distribution network under study is reconfigured when the targeted switching device is operated. The switching device is either operated from the control center or by repair crews engaged in the field. The time of switching is also estimated in this module. After operating the targeted switching device, there might be some reactions from the autonomous system. Therefore, the possible reaction of autonomous system after operating the targeted switching device should be evaluated in this module as well.

- Module 14: In this module, the process involved with the notification of repair crews and their dispatching is evaluated. The outcomes of this module are the number, location, travelling speed and dispatching time of repair crews that participate in the field activities for the contingency under study.

- Module 15: In some situations, the outcome of the approximate fault location process may not be able to identify the faulted zone. In this situation, the control center operators aid the repair crews to identify the faulted zone. This module is responsible for evaluating the activities involved with the faulted zone location process. Based on the analysis assumptions, the fault involved in the contingency under study, the reaction of autonomous system, the available facilities to the repair crews for fault location purposes and also the number, location and ratings of the available switching devices, the faulted zone is identified. When the process involves any switching operation, there might be some reactions from the autonomous system. Therefore, the possible reaction of autonomous system after operating the targeted switching devices should be evaluated in this module as well.

- **Module 16:** Depending on the analysis assumptions, the ratings of the available switching devices and also the fault involved in the contingency under study, a suitable set of the switching devices are identified in this module for local fault isolation and service restoration activities.

- **Module 17:** In this module the activities involved with the precise fault location process are evaluated. This module estimates the time at which the damaged part of the failed component is identified. The activities involved in the precise fault location process depend on the analysis assumptions, type of the fault involved in the contingency under study, type of the components involved in the faulted zone, the reaction of autonomous system, the available facilities to the repair crews for fault location purposes and also the outcome of approximate fault location process.

- **Module 18:** In this module the activities involved with the repair or replacement process are evaluated. This module estimates the time at which the repair or replacement activities of the damaged component are accomplished and it gets ready to return to its normal operating status.

- **Module 19:** Depending on the analysis assumptions and also the type, number and location of switching devices whose normal operating statues have been changed due to the fault isolation and service restoration activities, a suitable set of the switching devices are identified in this module for returning the status of the electricity distribution network to its normal operating configuration.

- **Module 20:** Based on the identified maneuvering switching devices, all the possible network configurations are generated in this module. Then, each configuration is further investigated against criterion such as radial operating status, voltage and overload constraints and also number of customers that are affected before and after the network reconfiguration. Finally, a set of the network configurations that can meet the criterion are selected as the feasible network configurations for return to normal operating status.

- **Module 21:** In this module, the normal operating status of the electricity distribution network is selected as the final network configuration. Then, the optimal switching sequences for transferring the present configuration to the final configuration are identified. The switching sequences are such organized that all the configurations in this process just involve the identified feasible network configurations.

- Module 22: In this module, all the voltage variation events observed from the initiation of the contingency under study till accomplishing the targeted fault management activities are evaluated and compared against the thresholds defined for sustained interruptions, momentary interruptions and voltage sags. Finally, by applying the aggregation methods, the equivalent voltage variation events imposed on the customers are estimated for the contingency under study.

- Module 23: In this module, the impacts of various operating states generated for the primary contingency are accumulated using the concepts of expectations. The following equations are used to estimate the impacts of the primary contingency on the customers:

$$\mathrm{AEF}^{\mathrm{SI}}_{\mathrm{C_i L_j}} = \sum_{k=1}^{\mathrm{NS}(\mathrm{C_i})} \left\{ \left(\mathrm{AOR}_{\mathrm{C_i}} \times \mathrm{P}\left(\mathrm{C}_i^k\right)\right) \times \sum_{m=1}^{\mathrm{NVE}(\mathrm{C_i},k,\mathrm{L_j})} \mathrm{FIT}^{\mathrm{SI}}\left(\mathrm{VVE}^{k,m}_{\mathrm{C_i L_j}}\right) \right\} \tag{1}$$

Where:

$\mathrm{AEF}^{\mathrm{SI}}_{\mathrm{C_i L_j}}$	Contribution to the annual expected frequency of sustained interruptions affecting the load point L_j due to the contingency C_i
$\mathrm{NS}(\mathrm{C_i})$	Total number of operating states generated for the contingency C_i
C_i	Contingency number i
$\mathrm{AOR}_{\mathrm{C_i}}$	Annual occurrence rate of the contingency C_i
$\mathrm{P}\left(\mathrm{C}_i^k\right)$	Probability of residing in the operating state k of the contingency C_i
$\mathrm{NVE}\left(\mathrm{C_i}, k, \mathrm{L_j}\right)$	Total number of voltage variation events imposed on the load point L_j due to the contingency C_i and the operating state k
L_j	Load point number j
$\mathrm{FIT}^{\mathrm{SI}}(\mathrm{VVE})$	A fitness function which is equal to one if the characteristics of the voltage variation event under examination (i.e. VVE) fit to the thresholds defined for sustained interruptions. Otherwise, its value is equal to zero for the voltage variation event under examination.
$\mathrm{VVE}^{k,m}_{\mathrm{C_i L_j}}$	Voltage variation event number m that imposed on the load point L_j due to the operating state k of the contingency C_i. Generally, the overall effects of the generated contingency are appeared to each load points as several voltage variation events. Each one of these voltage variation events can be corresponding to a power interruption, a voltage sag or just a slight deviation from the nominal voltage. The magnitude and duration of each voltage

variation event are examined in order to identify the type of events.

$$AEF^{MI}_{C_i L_j} = \sum_{k=1}^{NS\,(C_i)} \left\{ \left(AOR_{C_i} \times P\left(C_i^k\right) \right) \times \sum_{m=1}^{NVE\,(C_i,k,L_j)} FIT^{MI}\left(VVE^{k,m}_{C_i L_j}\right) \right\} \tag{2}$$

Where:

$AEF^{MI}_{C_i L_j}$ Contribution to the annual expected frequency of momentary interruptions affecting the load point L_j due to the contingency C_i

$FIT^{MI}(VVE)$ A fitness function which is equal to one if the characteristics of the voltage variation event under examination (i.e. VVE) fit to the thresholds defined for momentary interruptions. Otherwise, its value is equal to zero for the voltage variation event under examination.

$$AEF^{VS}_{C_i L_j} = \sum_{k=1}^{NS\,(C_i)} \left\{ \left(AOR_{C_i} \times P\left(C_i^k\right) \right) \times \sum_{m=1}^{NVE\,(C_i,k,L_j)} IMP^{VS}_{L_i}\left(VVE^{k,m}_{C_i L_j}\right) \right\} \tag{3}$$

Where:

$AEF^{VS}_{C_i L_j}$ Contribution to the annual expected frequency of voltage sags affecting the load point L_j due to the contingency C_i

$IMP^{VS}_{L_i}(VVE)$ The value of this function shows the overall impacts on the customers connected to the load point L_j when the characteristics of the voltage variation event imposed on this load point (i.e. VVE) fit to the thresholds defined for voltage sags. Its value lies between zero and one. The value of this function is equal to zero when the characteristics of the imposed voltage variation event do not fit to the thresholds defined for voltage sags. Generally, the magnitude and duration of the voltage sag are compared with the voltage tolerance characteristics of sensitive equipments of the customers connected to the load point L_j to find its possible impacts. The impacts on the customers connected to the load point L_j of the voltage sag are sum up and divided by the total number of customers to estimate the value of this function.

$$AEF^{(V,D)}_{C_i L_j} = \sum_{k=1}^{NS\,(C_i)} \left\{ \left(AOR_{C_i} \times P\left(C_i^k\right) \right) \times \sum_{m=1}^{NVE\,(C_i,k,L_j)} FIT^{(V,D)}\left(VVE^{k,m}_{C_i L_j}\right) \right\} \tag{4}$$

Where:

$AEF_{C_iL_j}^{(V,D)}$ Contribution to the annual expected frequency of voltage variation events imposed on the load point L_j due to the contingency C_i. The magnitude and duration of the voltage variation events lie in the ranges specified by parameters V and D.

V A range of magnitude of voltage variation events, e.g. $0.2 \le V \le 0.3$ per unit

D A range of duration of voltage variation events, e.g. $0.01 \le D \le 0.1$ seconds

$FIT^{(V,D)}(VVE)$ A fitness function which is equal to one if the characteristics of the voltage variation event under examination (i.e. VVE) fit to the magnitude and duration range specified by parameters V and D. Otherwise, its value is equal to zero for the voltage variation event under examination. As an example, consider a range such as $0.2 \le V \le 0.3$ per unit and $0.01 \le D \le 0.1$ seconds. The value of this function for a voltage variation event with the remaining voltage 0.27 per unit and duration 0.09 seconds is equal to one. However, for a voltage variation event with the remaining voltage 0.27 per unit and duration 0.15 seconds, the value of this function is equal to zero.

$$AED_{C_iL_j}^{SI} = \sum_{k=1}^{NS(C_i)} \left\{ \left(AOR_{C_i} \times P\left(C_i^k\right) \right) \times \sum_{m=1}^{NVE(C_i,k,L_j)} \left(FIT^{SI}\left(VVE_{C_iL_j}^{k,m}\right) \times DUR\left(VVE_{C_iL_j}^{k,m}\right) \right) \right\} \tag{5}$$

Where:

$AED_{C_iL_j}^{SI}$ Contribution to the annual expected duration of sustained interruptions affecting the load point L_j due to the contingency C_i

$DUR(VVE)$ Duration of the voltage variation event under examination (i.e. VVE)

$$AENS_{C_iL_j}^{SI} = \sum_{k=1}^{NS(C_i)} \left\{ \left(AOR_{C_i} \times P\left(C_i^k\right) \right) \times \sum_{m=1}^{NVE(C_i,k,L_j)} \left(FIT^{SI}\left(VVE_{C_iL_j}^{k,m}\right) \times DUR\left(VVE_{C_iL_j}^{k,m}\right) \times ALD_{L_j} \right) \right\} \tag{6}$$

Where:

$AENS_{C_iL_j}^{SI}$ Contribution to the annual expected energy not supplied of the load point L_j due to the contingency C_i

ALD_{L_j} Average load connected to the load point L_j

$$AEC^{SI}_{C_iL_j} = \sum_{k=1}^{NS(C_i)} \left\{ \left(AOR_{C_i} \times P\left(C_i^k\right)\right) \times \sum_{m=1}^{NVE(C_i,k,L_j)} \left(FIT^{SI}\left(VVE^{k,m}_{C_iL_j}\right) \times IC_{L_j}\left(VVE^{k,m}_{C_iL_j}\right)\right) \right\} \tag{7}$$

Where:

$AEC^{SI}_{C_iL_j}$ Contribution to annual expected cost arising from sustained interruptions affecting the load point L_j due to the contingency C_i

$IC_{L_j}(VVE)$ The value of this function shows the financial impacts of the voltage variation event (i.e. VVE) imposed on the load point L_j. For a voltage variation event which its characteristics fit to the thresholds of power interruptions, the duration of voltage variation event under examination is used to estimate the cost. However, in the case of a voltage variation event which its characteristics fit to the thresholds defined for the voltage sags, both magnitude and duration of the voltage variation event are normally required to estimate the cost. The technique described in [148] can be used to estimate $IC_{L_j}(VVE)$. This technique has been developed by collaboration of the author.

$$AEC^{MI}_{C_iL_j} = \sum_{k=1}^{NS(C_i)} \left\{ \left(AOR_{C_i} \times P\left(C_i^k\right)\right) \times \sum_{m=1}^{NVE(C_i,k,L_j)} \left(FIT^{MI}\left(VVE^{k,m}_{C_iL_j}\right) \times IC_{L_j}\left(VVE^{k,m}_{C_iL_j}\right)\right) \right\} \tag{8}$$

Where $AEC^{MI}_{C_iL_j}$ is the contribution to annual expected cost arising from momentary interruptions affecting the load point L_j due to the contingency C_i.

$$AEC^{VS}_{C_iL_j} = \sum_{k=1}^{NS(C_i)} \left\{ \left(AOR_{C_i} \times P\left(C_i^k\right)\right) \times \sum_{m=1}^{NVE(C_i,k,L_j)} \left(FIT^{VS}\left(VVE^{k,m}_{C_iL_j}\right) \times IC_{L_j}\left(VVE^{k,m}_{C_iL_j}\right)\right) \right\} \tag{9}$$

Where

$AEC^{VS}_{C_iL_j}$ is Contribution to annual expected cost arising from voltage sags affecting the load point L_j due to the contingency C_i.

$FIT^{VS}(VVE)$ A fitness function which is equal to one if the characteristics of the voltage variation event under examination (i.e. VVE) fit to the thresholds defined for voltage sags. Otherwise, its value is equal to zero for the voltage variation event under examination.

- Module 24: In this module, the contributions of all the primary contingencies are summed up to deduce the load points and system oriented reliability indices. The following equations are used to estimate the reliability indices:

$$AEF_{L_j}^{SI} = \sum_{i=1}^{NCT} AEF_{C_i L_j}^{SI} \tag{10}$$

Where:

$AEF_{L_j}^{SI}$ Annual expected frequency of sustained interruptions affecting the load point L_j

NCT Total number of primary contingencies

$$AEF_{L_j}^{MI} = \sum_{i=1}^{NCT} AEF_{C_i L_j}^{MI} \tag{11}$$

Where $AEF_{L_j}^{MI}$ is annual expected frequency of momentary interruptions affecting the load point L_j.

$$AEF_{L_j}^{VS} = \sum_{i=1}^{NCT} AEF_{C_i L_j}^{VS} \tag{12}$$

Where $AEF_{L_j}^{VS}$ is the annual expected frequency of voltage sags affecting the load point L_j.

$$AEF_{L_j}^{(V,D)} = \sum_{i=1}^{NCT} AEF_{C_i L_j}^{(V,D)} \tag{13}$$

Where $AEF_{L_j}^{(V,D)}$ is the annual expected frequency of voltage variation events imposed on the load point L_j. The magnitude and duration of the voltage variation events lie in the ranges specified by parameters V and D.

$$AED_{L_j}^{SI} = \sum_{i=1}^{NCT} AED_{C_i L_j}^{SI} \tag{14}$$

Where $AED_{L_j}^{SI}$ is the annual expected duration of sustained interruptions affecting the load point L_j.

$$\mathrm{AOT}_{\mathrm{L_j}}^{\mathrm{SI}} = \frac{\mathrm{AED}_{\mathrm{L_j}}^{\mathrm{SI}}}{\mathrm{AEF}_{\mathrm{L_j}}^{\mathrm{SI}}} \tag{15}$$

Where $\mathrm{AOT}_{\mathrm{L_j}}^{\mathrm{SI}}$ is the average outage time of the load point $\mathrm{L_j}$.

$$\mathrm{AENS}_{\mathrm{L_j}}^{\mathrm{SI}} = \sum_{\mathrm{i=1}}^{\mathrm{NCT}} \mathrm{AENS}_{\mathrm{C_i L_j}}^{\mathrm{SI}} \tag{16}$$

Where $\mathrm{AENS}_{\mathrm{L_j}}^{\mathrm{SI}}$ is the annual expected energy not supplied of the load point $\mathrm{L_j}$.

$$\mathrm{AEC}_{\mathrm{L_j}}^{\mathrm{SI}} = \sum_{\mathrm{i=1}}^{\mathrm{NCT}} \mathrm{AEC}_{\mathrm{C_i L_j}}^{\mathrm{SI}} \tag{17}$$

Where $\mathrm{AEC}_{\mathrm{L_j}}^{\mathrm{SI}}$ is annual expected cost arising from sustained interruptions affecting the load point $\mathrm{L_j}$.

$$\mathrm{AEC}_{\mathrm{L_j}}^{\mathrm{MI}} = \sum_{\mathrm{i=1}}^{\mathrm{NCT}} \mathrm{AEC}_{\mathrm{C_i L_j}}^{\mathrm{MI}} \tag{18}$$

Where $\mathrm{AEC}_{\mathrm{L_j}}^{\mathrm{MI}}$ is the annual expected cost arising from momentary interruptions affecting the load point $\mathrm{L_j}$.

$$\mathrm{AEC}_{\mathrm{L_j}}^{\mathrm{VS}} = \sum_{\mathrm{i=1}}^{\mathrm{NCT}} \mathrm{AEC}_{\mathrm{C_i L_j}}^{\mathrm{VS}} \tag{19}$$

Where $\mathrm{AEC}_{\mathrm{L_j}}^{\mathrm{VS}}$ is the annual expected cost arising from voltage sags affecting the load point $\mathrm{L_j}$.

$$\mathrm{SAIFI} = \frac{\sum_{\mathrm{j=1}}^{\mathrm{NLP}} \left(\mathrm{AEF}_{\mathrm{L_j}}^{\mathrm{SI}} \times \mathrm{NC}_{\mathrm{L_j}}\right)}{\sum_{\mathrm{j=1}}^{\mathrm{NLP}} \mathrm{NC}_{\mathrm{L_j}}} \tag{20}$$

Where:

SAIFI — System Average Interruption Frequency Index [1, 3, 152]

NLP — Number of load points of the distribution system under study

$\mathrm{NC}_{\mathrm{L_j}}$ — Number of customers connected to the load point $\mathrm{L_j}$

$$\mathrm{MAIFI} = \frac{\sum_{j=1}^{NLP} \left(\mathrm{AEF}_{L_j}^{MI} \times \mathrm{NC}_{L_j}\right)}{\sum_{j=1}^{NLP} \mathrm{NC}_{L_j}} \tag{21}$$

Where MAIFI is the Momentary Average Interruption Frequency Index [1, 3,152].

$$\mathrm{AVSSI} = \frac{\sum_{j=1}^{NLP} \left(\mathrm{AEF}_{L_j}^{VS} \times \mathrm{NC}_{L_j}\right)}{\sum_{j=1}^{NLP} \mathrm{NC}_{L_j}} \tag{22}$$

Where AVSSI is the Average Voltage Sag Severity Index. This index shows the average occurrence rate of the voltage sags that can cause problem for the customers.

$$\mathrm{AVVFI}^{(V,D)} = \frac{\sum_{j=1}^{NLP} \left(\mathrm{AEF}_{L_j}^{(V,D)} \times \mathrm{NC}_{L_j}\right)}{\sum_{j=1}^{NLP} \mathrm{NC}_{L_j}} \tag{23}$$

Where $\mathrm{AVVFI}^{(V,D)}$ is the Average Voltage Variation Frequency Index. This index shows the average occurrence rate of the voltage variation events that their magnitude and duration lie in a range specified by the parameters V and D.

$$\mathrm{SAIDI} = \frac{\sum_{j=1}^{NLP} \left(\mathrm{AED}_{L_j}^{SI} \times \mathrm{NC}_{L_j}\right)}{\sum_{j=1}^{NLP} \mathrm{NC}_{L_j}} \tag{24}$$

Where SAIDI is the System Average Interruption Duration Index [1, 3, 152].

$$\mathrm{ASAI} = 1 - \frac{\sum_{j=1}^{NLP} \left(\mathrm{AED}_{L_j}^{SI} \times \mathrm{NC}_{L_j}\right)}{\sum_{j=1}^{NLP} \left(8760 \times \mathrm{NC}_{L_j}\right)} \tag{25}$$

Where ASAI is the Average System Availability Index [1, 3, 152].

$$\mathrm{ASUI} = \frac{\sum_{j=1}^{NLP}\left(\mathrm{AED}_{L_j}^{SI} \times \mathrm{NC}_{L_j}\right)}{\sum_{j=1}^{NLP}\left(8760 \times \mathrm{NC}_{L_j}\right)} \qquad (26)$$

Where ASUI is the Average System Unavailability Index [1, 3,152].

$$\mathrm{EENS} = \sum_{j=1}^{NLP} \mathrm{AENS}_{L_j}^{SI} \qquad (27)$$

Where EENS is the overall Expected Energy Not Supplied [1, 3, 152].

$$\mathrm{ECOST}^{SI} = \sum_{j=1}^{NLP} \mathrm{AEC}_{L_j}^{SI} \qquad (28)$$

Where ECOST^{SI} is the total expected cost resulted from sustained interruptions.

$$\mathrm{ECOST}^{MI} = \sum_{j=1}^{NLP} \mathrm{AEC}_{L_j}^{MI} \qquad (29)$$

Where ECOST^{MI} is the total expected cost resulted from momentary interruptions.

$$\mathrm{ECOST}^{VS} = \sum_{j=1}^{NLP} \mathrm{AEC}_{L_j}^{VS} \qquad (30)$$

Where ECOST^{VS} is the total expected cost resulted from voltage sags.

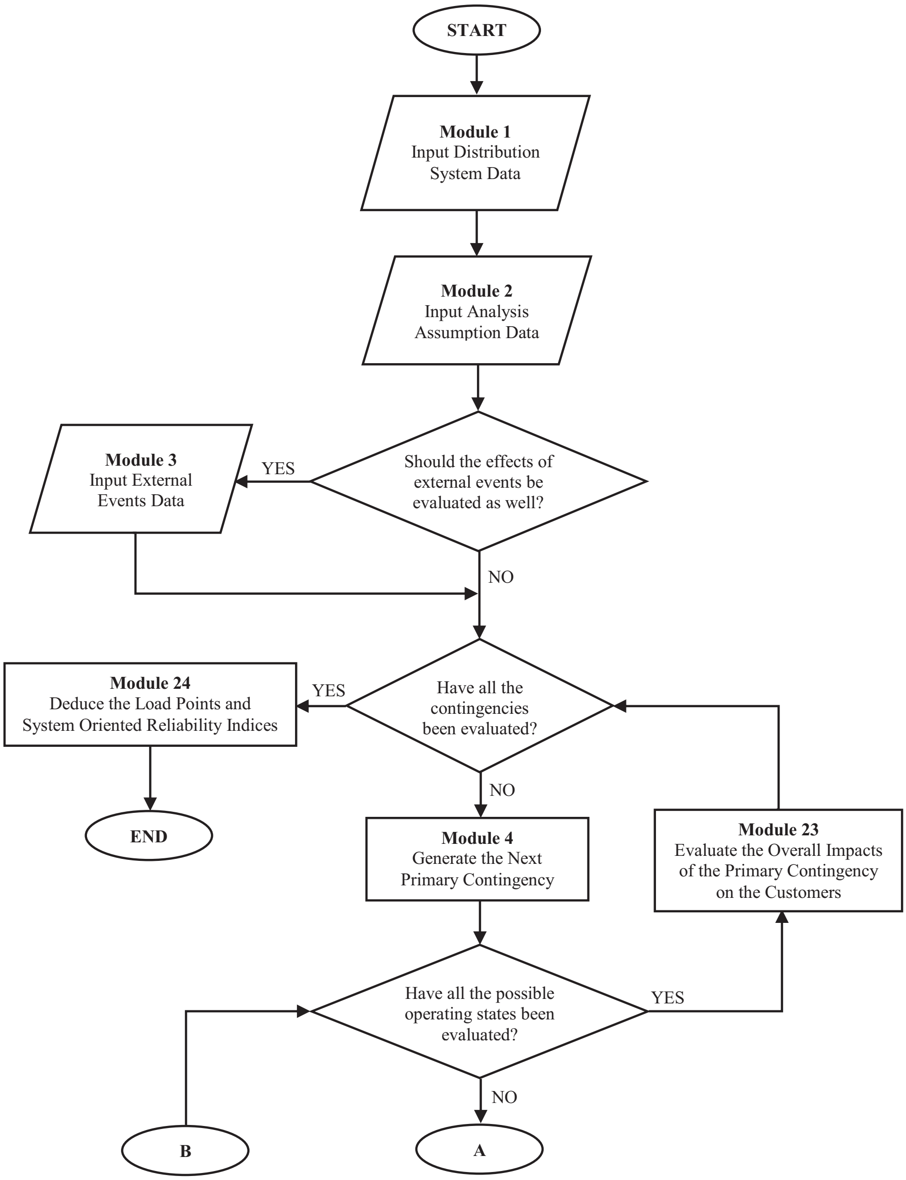

Figure 2. Flowchart of the procedure proposed for reliability evaluation of smart distribution grids (part 1 of 4).

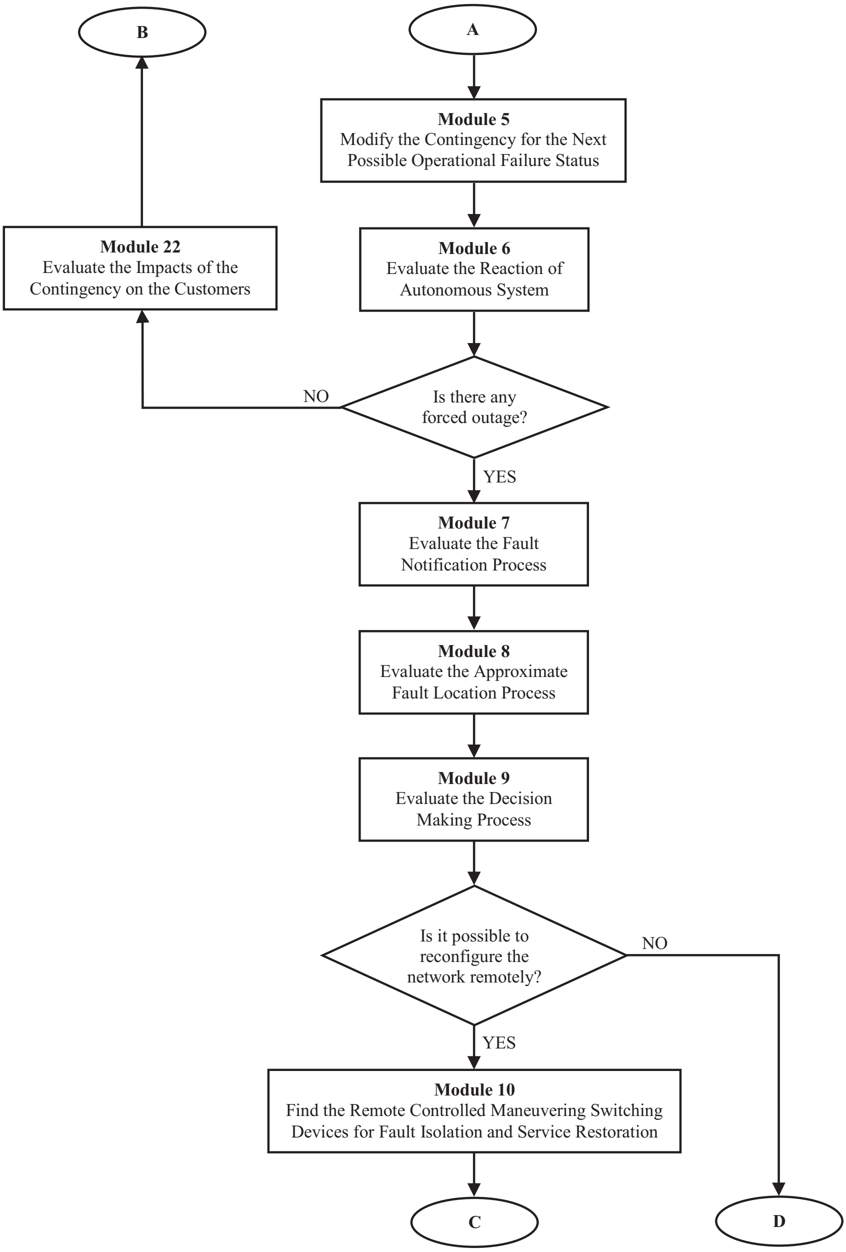

Figure 2. Flowchart of the procedure proposed for reliability evaluation of smart distribution grids (part 2 of 4).

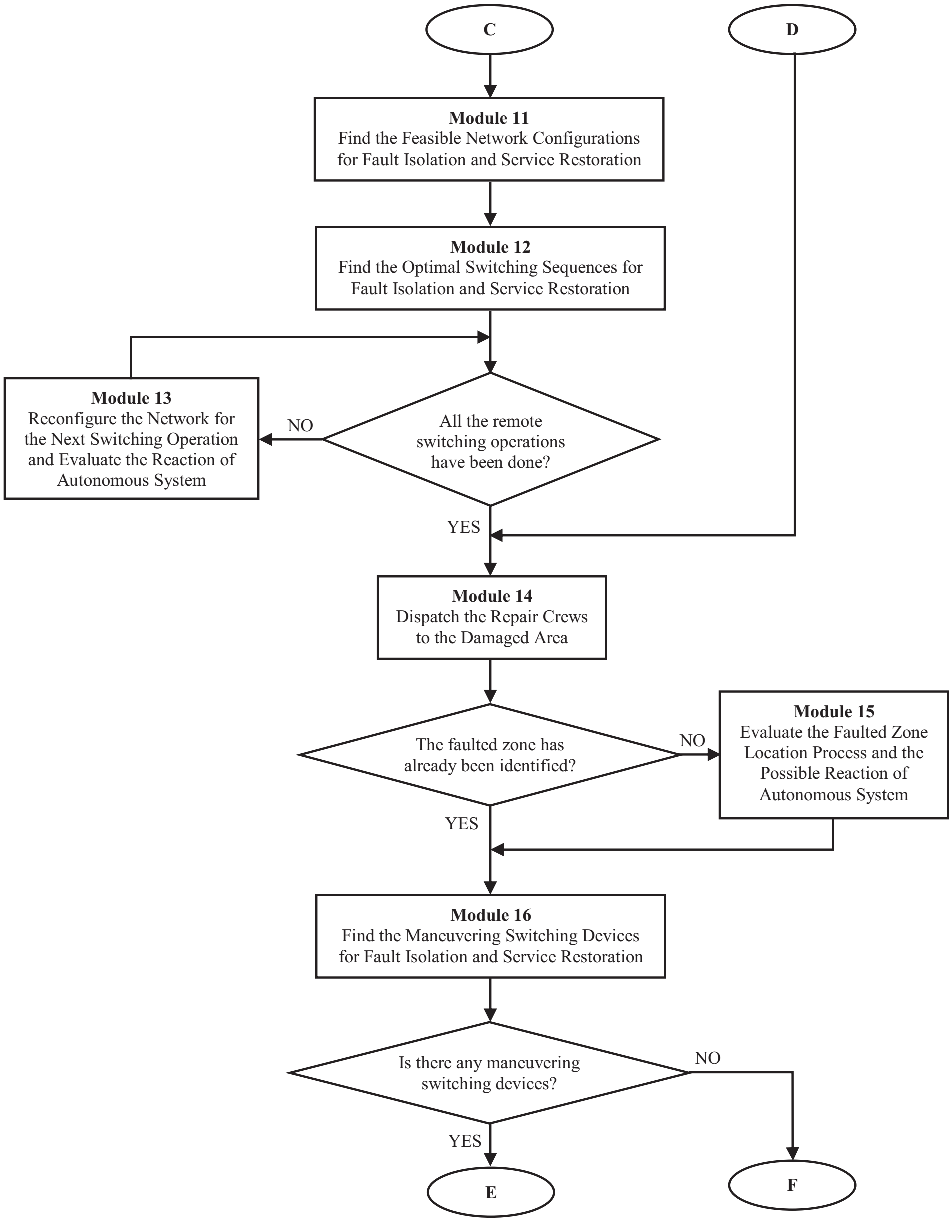

Figure 2. Flowchart of the procedure proposed for reliability evaluation of smart distribution grids (part 3 of 4).

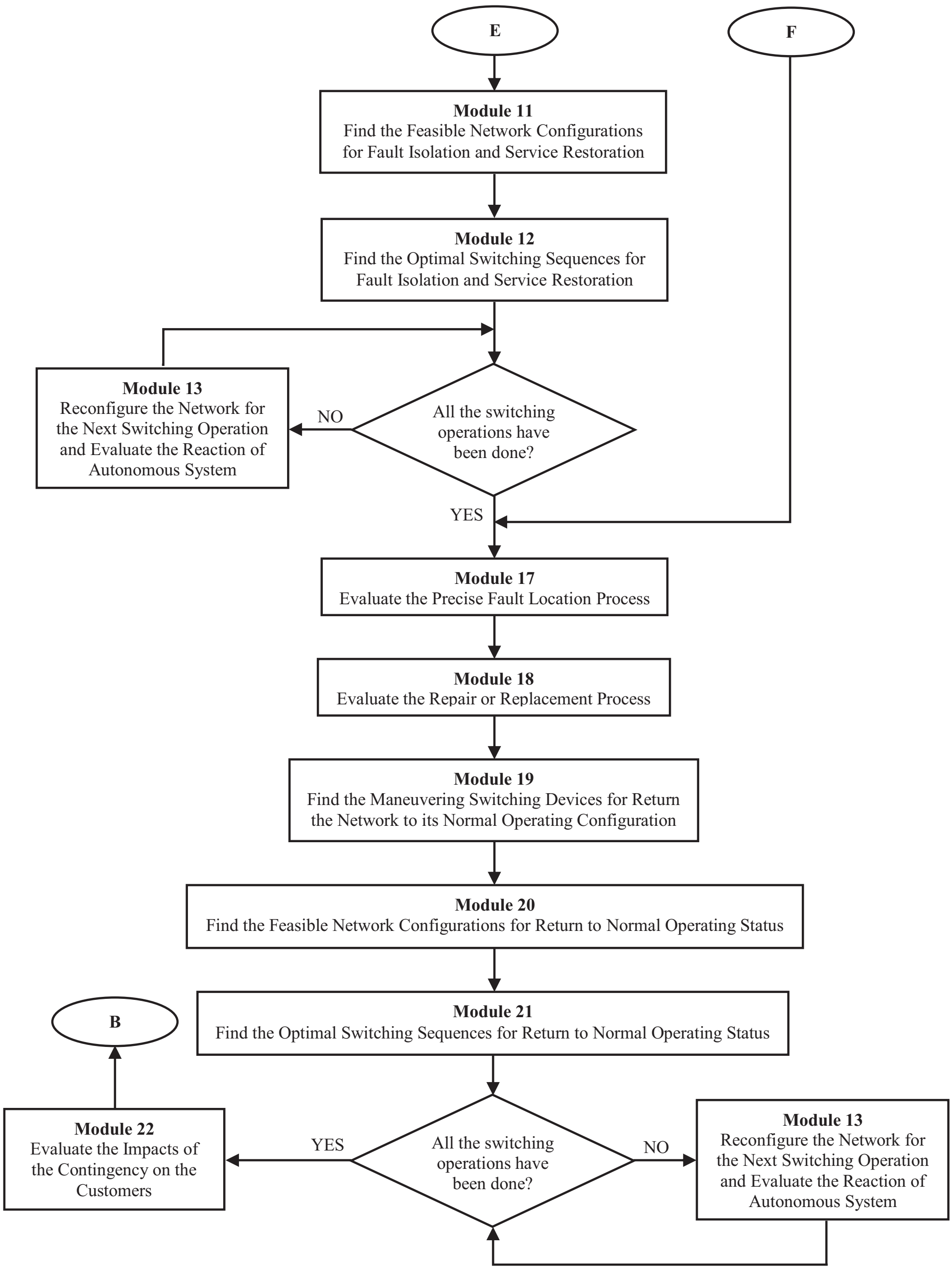

Figure 2. Flowchart of the procedure proposed for reliability evaluation of smart distribution grids (part 4 of 4).

6 Study Results

A powerful software package designated as "Smart Grid Simulator" was developed for realizing the reliability evaluation procedure proposed in this thesis. In this chapter, the results of various reliability case studies that have been conducted by the developed software are presented and discussed. Various failure modes of each component of the electricity distribution network under study are simulated in this software. For each failure mode, the detailed reactions of implemented smart grid technologies and their impacts on the different stages of the fault management activities are evaluated. As a result, the time periods required for accomplishing each step of the fault management activities and manners in which different load points have been affected are determined. Based on these outcomes, the software calculates the load points and system oriented reliability indices. The software can also predict the reliability impacts of voltage sags generated at higher voltage levels (sub-transmission and transmission networks) but propagated into the distribution system under study.

6.1 Test Systems Data and Analysis Assumptions

A typical Finnish 20 kV urban distribution network is used as a distribution test network for quantitative reliability case studies concerned in this thesis. The basic data related to the distribution test network can be found in Appendixes I, II and III. The single-line diagram of this distribution test network and its overall data are shown in Figure 3 and Table 1, respectively. There are 144 distribution substations (20/0.4 kV) in the distribution test network, which are supplied through 6 underground cable feeders originated from one sub-transmission substation. The average load factor and the average power factor for distribution substations are assumed to be 73% and 95%, respectively. Two 110/20 kV transformers each with rating 16 MVA and short circuit impedance of 10% supply this network through two incoming 110 kV feeders. The substation configuration at 110 kV level is H-connection and at 20 kV level is single-busbar. To limit the short circuit level in 20 kV level, the 20 kV switchgears are arranged to split the 20 kV busbar such that feeders 1, 2 and 3 are supplied by the first transformer and feeders 4, 5 and 6 are supplied by the second transformer.

A typical Finnish 110 kV sub-transmission network is also used in this thesis as a sub-transmission test network for simulating the voltage sags which propagate through sub-transmission network into the distribution test network. The single line diagram of this sub-transmission test network is shown in Figure 4. The sub-transmission test network consists of 24 substations, 19 underground cable circuits and 23 overhead line sections. The basic data of the overhead lines and the underground cables of the sub-transmission test network can be found in Appendixes IV and V.

It should be mentioned that the above described test networks have been taken from different areas of Finland. The components reliability data for the distribution test network and the sub-transmission test network are assumed according to Table 2.

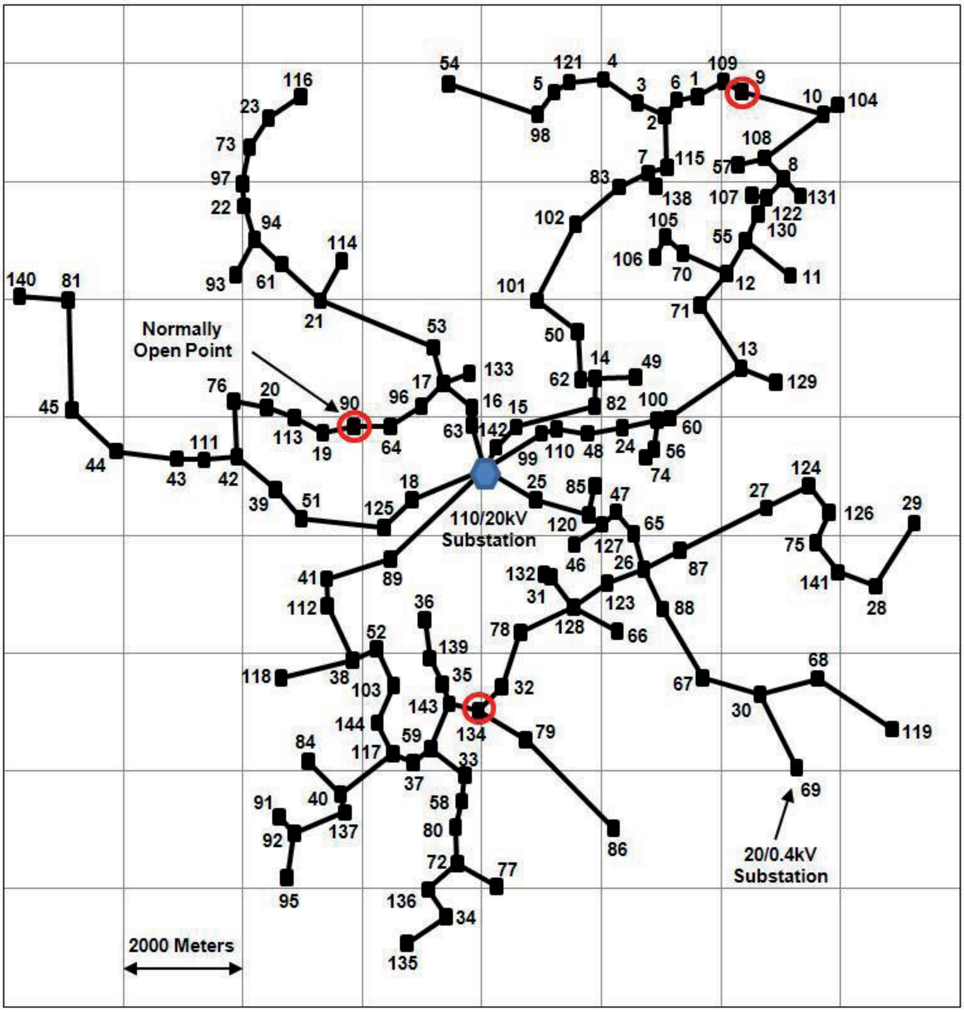

Figure 3. Single-line diagram of a typical Finnish 20 kV urban distribution network which is used as a distribution test network.

TABLE 1
BASIC DATA FOR THE DISTRIBUTION TEST NETWORK

Attribute	Number of Distribution Substations	Number of Switching Devices	Exposure (meters)	Peak Load (MW)	Average Load (MW)
Feeder 1	23	44	22606	1.41	1.03
Feeder 2	18	33	18474	1.55	1.13
Feeder 3	32	58	39595	1.57	1.15
Feeder 4	27	50	24871	2.19	1.60
Feeder 5	15	28	19878	1.43	1.06
Feeder 6	29	49	31587	1.25	0.91
Overall	**144**	**262**	**157011**	**9.40**	**6.88**

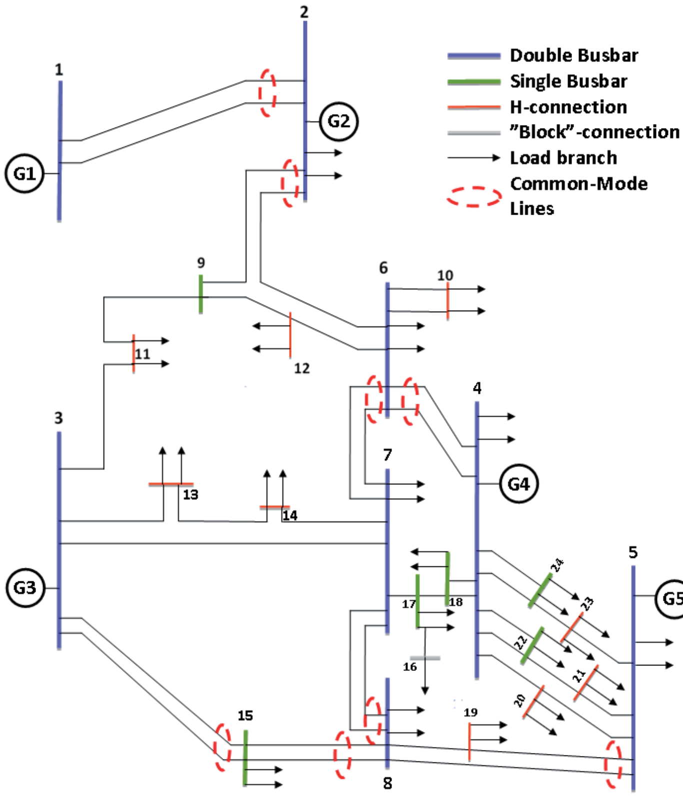

Figure 4. Single-line diagram of a typical Finnish 110 kV sub-transmission network which is used as a sub-transmission test network.

TABLE 2
COMPONENT RELIABILITY DATA FOR THE DISTRIBUTION TEST NETWORK AND THE SUB-TRANSMISSION TEST NETWORK

Component	Total Failure Rate	Actual Repair or Replacement Time (hours)
110 kV Overhead Lines	0.0218 occ/km-a	48
110 kV Underground Cables	0.001 occ/km-a	336
110/20 kV Transformers	0.023 occ/a	300
110 kV Circuit Breakers	0.00336 occ/a	100
110 kV Busbars	0.0068 occ/a	200
20 kV Underground Cables	0.006 occ/km-a	6
20/0.4 kV Transformers	0.001 occ/a	10

The following basic assumptions are also considered when evaluating the impact of voltage sags on the customers:

- The share of different fault types at 110 kV and 20 kV levels are taken from [149, 150] as shown in Table 3.
- The conventional distance relays are used for the protection of the 110 kV overhead lines. The zone 1 covers 80% of the line length and zone 2 covers the whole length of the line length. The fault clearing times for faults located in the zone 1 and zone 2 are assumed to be 4 and 20 cycles, respectively.
- The pilot protection scheme is used for the 110kV underground cable circuits. In this situation, the fault clearing time for all the faults along an underground cable circuit is assumed to be 4 cycles.
- The fault clearing time for a fault within the 110/20 kV substation (e.g. busbar and circuit breakers) is assumed to be 5 cycles.
- The fault clearing times for faults on the components of the distribution test network are determined by the fault type, fault location and also the characteristics of protection devices implemented in the test network. The feeder circuit breakers are equipped with an over-current relay with an extremely inverse time-current characteristic for short circuit faults and sensitive earth fault relay for phase to ground faults. The distribution transformers are protected against the short circuit faults by means of switch fuses equipped with K-speed fuse links rated according to the size of the transformers. The feeder circuit breaker operates for the single-phase to ground faults.
- The winding connections of the 110/20 kV transformers and the 20/0.4 kV distribution service transformers are assumed to be Yy0 and Dyn11, respectively.

- The neutral grounding at the110 kV level is impedance earthed, at the 20 kV level is resonance (compensated) earthed and at the 0.4 kV level is solidly earthed, respectively.
- The positive, negative and zero sequence impedances seen from substation number 1 are 0.152+j2.024 ohm, 0.152+j2.027 ohm and 2.902+j54.506 ohm, respectively.
- The positive, negative and zero sequence impedances seen from substation number 2 are 0.145+j1.693 ohm, 0.145+j1.695 ohm and 2.713+j53.349 ohm, respectively.
- The positive, negative and zero sequence impedances seen from substation number 3 are 0.180+j1.708 ohm, 0.180+j1.710 ohm and 2.777+j53.455 ohm, respectively.
- The positive, negative and zero sequence impedances seen from substation number 4 are 0.286+j1.834 ohm, 0.286+j1.836 ohm and 2.785+j52.791 ohm, respectively.
- The positive, negative and zero sequence impedances seen from substation number 5 are 0.323+j1.926 ohm, 0.323+j1.928 ohm and 2.994+j52.978 ohm, respectively.
- The distribution test network is assumed to be supplied through the substation number 14 of the sub-transmission test network. The short circuit levels at this substation for three-phase, phase to phase, double-phase to ground and single-phase to ground faults are 27kA, 23.4kA, 23.5kA and 3.2kA, respectively. The positive, negative and zero sequence impedances seen from this substation are 0.333+j2.306 ohm, 0.333+j2.306 ohm and 3.182+j54.3 ohm, respectively.
- The voltage sags are evaluated at the low voltage side of distribution transformers.
- The fault impedance is assumed to be zero.
- Three fault positions are considered for each 110 kV transmission line, respectively at 16.67, 50 and 83.33 percents of the line length. In the case of 20 kV cables, the faults are positioned at every one kilometer of the cable length. For the other components, one fault position is considered.
- The overall susceptibility of the customer operations against a voltage sag is represented by the ITIC (CBEMA) voltage tolerance curve, as shown in Figure 5 [151].
- The financial impacts on a customer due to an interruption resulted from a voltage sag is assumed equal to that of a momentary interruption cost.
- The definitions described in IEEE Standard 1159 [19] and IEEE Standard 1366 [152] are combined for describing the sustained interruptions, momentary interruptions and voltage sags concerned in the following case studies. The sustained interruption is defined as decline of the RMS voltage to less than 10 percents of the nominal voltage on one or more phase conductors for a time greater than 1 min. The momentary interruption is defined as decline of the RMS voltage to less than 10 percents of the nominal voltage on one or more phase conductors for a time period between

0.5 cycles and 1 minute. The voltage sag is defined as the decrease in the RMS voltage between 10 to 90 percents of the nominal voltage for durations from 0.5 cycles to 1 minute.

- The common phase aggregation method described in IEEE Standard 493 [153] is used for evaluating the three-phase voltage sags. In this method, a three-phase voltage sag is represented by a single individual event. The lowest voltage among the three phases is considered as the voltage sag magnitude and the sag duration is reported as the time until all three phase voltages have recovered above 90 percents of the nominal voltage.

- A five-minute aggregation window is used for evaluating the multiple voltage sags. In this condition, starting from the event initiation time, only one voltage sag is reported during this five-minute period which is corresponding to the most severe voltage sag among multiple events. The same aggregation window is used for evaluating the momentary interruption.

TABLE 3
SHARE OF DIFFERENT FAULT TYPES AT 110 KV AND 20 KV LEVELS [149, 150], IN PERCENTS

Voltage Level	Phase to Ground Faults	Phase to Phase Faults	Double-Phase to Ground Faults	Three-Phase Faults
110 kV	81	3	14	2
20 kV	50	9	24	17

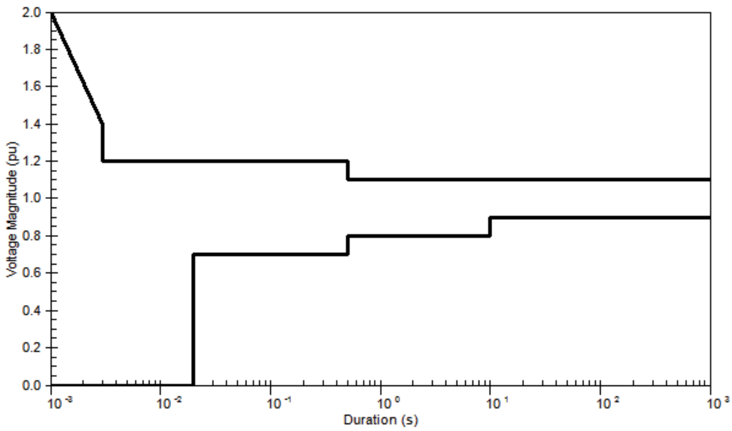

Figure 5. ITIC (CBEMA) voltage tolerance curve [151]

6.2 Comparative Case Studies

In order to compare the impacts of the identified smart grid technologies on the reliability performance of the distribution test network various case studies have been conducted. Obviously, any feasible set of the identified technologies can be evaluated as a specific case study. However, to limit the number of case studies, based on the engineering judgments, only some potential combinations of these technologies are selected for presenting in this thesis. An integrating approach is used for dealing with these technologies. The ultimate goal in this approach is to provide a premium electricity service for the customers of the distribution test network. The studies are started from a benchmark case study. Then, in the next case studies, a suitable smart grid technology is integrated to the last upgraded case study. This sequential approach is ended up when all the targeted smart grid technologies have been involved in the base case study.

6.2.1 Case Study 1: Base Case

The base case study aims to show the reliability performance of the distribution test network when it is manually operated. In this situation, the operation of protective devices for a fault within the 110/20 kV substation (e.g. transformer or circuit breaker failures) results in the power interruptions for half or all of the distribution feeders. After notifying the outage condition by the control center operators, the local operators of the 110/20 kV substation are committed to isolate the failed component and restore the power service for as many as possible of the feeders through appropriate switching actions. Otherwise, the failed component should be repaired or replaced before the power could be restored. For a failure condition on a component of distribution feeders (e.g. an underground cable section or a distribution transformer), either a feeder circuit breaker or a distribution transformer protection operates. This usually leads to a power interruption for a group of customers and a voltage sag for others. Then, the power interruptions are notified by the control center operators through outage calls received from the customers or the local operators of the 110/20 kV substation. Next, the repair crews are sent to the outage area. When a feeder circuit breaker operates due to a component failure, usually there is no information which section of the feeder might be failed. In circumstances like this, the repair crews halve the downstream sections of the operated circuit breaker by opening a suitable switching device. Then the feeder circuit breaker is committed to be reclosed to determine whether the fault is located upstream of the opened switching device or vice-versa. This trial-and-error process is repeated until the faulted section is found. Then, the faulted section is isolated and the power service is restored for other healthy sections of the network through the proper manual switching operations. By the time these tasks are accomplished, the precise fault location and the repair or replacement activities are carried out. Finally, the network is returned to its normal operating status.

The basic data related to the fault management activities for the above described case study are assumed according to Table 4. Typical data provided in this table, and similar tables that come later for other case studies, are based on the engineering judgments, the characteristics of the implemented smart grid technologies and also consulting with some experts in this area.

The system oriented reliability indices for the base case study are represented in Table 5. The load point reliability indices are shown in Figures 6-13. The distributions of expected momentary interruptions and voltage sags imposed on the customers of the distribution test network are also shown in Figures 14-17.

The study results for the base case study indicate a large variation in the reliability indices associated with sustained interruptions and moderate variation in the reliability indices associated with momentary interruptions and voltage sags. When conducting trial and error switching activities for faulted zone location, some of the customers are affected several times for the same fault. As the switching operations are carried out manually and in time periods much longer than the aggregation window for recording the momentary events (5 minutes); several sustained interruptions are experienced by the customers. Therefore, parameters such as the network configuration, location of switching devices, fault location and also trial and error switching strategy of the electric utility result in more frequent sustained interruptions for some of the customers. However, examining the distributions of momentary interruptions and voltage sags indicate the majority of momentary interruptions and severe voltage sags (remaining voltage less than 70 percents of the nominal voltage) are arising from faults within the high voltage network rather than the local medium voltage network. The momentary interruptions and voltage sags which propagated through the high voltage network affect all the customers of the distribution test network. Therefore, the reliability indices associated with the momentary interruptions and voltage sags have much less variation among different customers compared to those of sustained interruptions.

The short circuit faults close to the main substation result in the remaining voltage less than the threshold of momentary interruptions (10 percent of the nominal voltage) and appear as momentary interruptions to the customers. As the frequency of such faults is very low, the momentary interruptions experienced by the customers are low as well.

The study results also indicate that the frequency of severe voltage sags is about 1.44 times of that of sustained interruptions. However, the cost associated with severe voltage sags is about 15 percents of the cost associated with sustained interruptions. This is because, for majority of customers available in the distribution test network, the cost associated with a severe voltage sag event is far less than that of a sustained interruption.

The term "repair crew burden" in Table 5 shows the sum of hours that the utility repair crews spend annually for conducting various fault management activities.

TABLE 4
BASIC DATA RELATED TO THE FAULT MANAGEMENT ACTIVITIES IN CASE STUDY 1

Average time required for fault notification (s)	300
Average time required for approximate fault location (s)	600
Average time required for decision making about fault management activities (s)	600
Average time required for dispatching the repair crews (s)	300
Average speed of the repair crews for traveling to the faulted area (km/h)	40
Average time required for precise fault location on an underground cable section including both pre-location and pinpointing activities (s)	1800
Average time required for manual operation of switching devices involved in fault management activities (s)	180
Available teams of repair crews for performing fault management activities	2

TABLE 5
SYSTEM ORIENTED RELIABILITY INDICES FOR CASE STUDY 1

SAIFI (int/sub-a)	0.8444
SAIDI (h/sub-a)	0.8030
MAIFI (eve/sub-a)	0.0746
AVSSI (eve/sub-a)	1.2155
ASUI (%)	0.009169
EENS (kWh/a)	5120
$ECOST^{SI}$ (€/a)	139926
$ECOST^{MI}$ (€/a)	1291
$ECOST^{VS}$ (€/a)	21079
Total Cost (€/a)	162296
Repair Crew Burden (h/a)	80.40

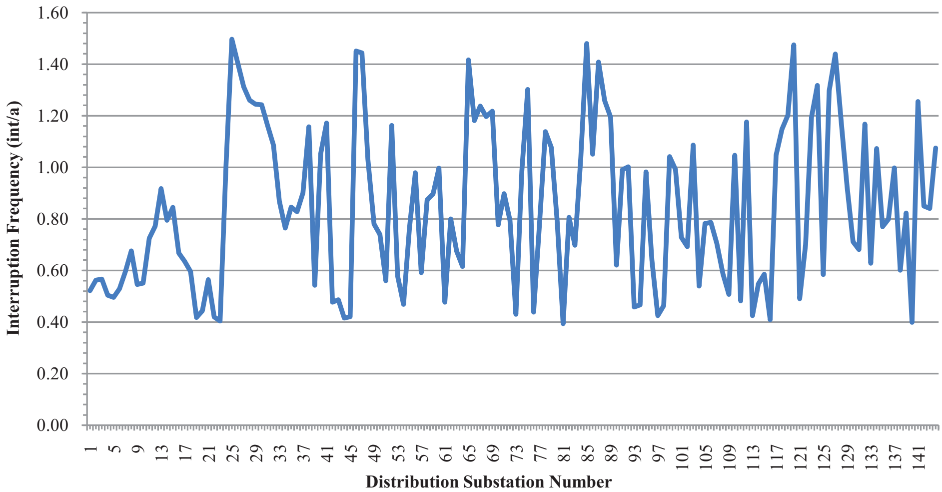

Figure 6. Annual expected frequency of sustained interruptions for distribution substations of the distribution test network, $AEF_{L_j}^{SI}$ *(Case Study 1)*

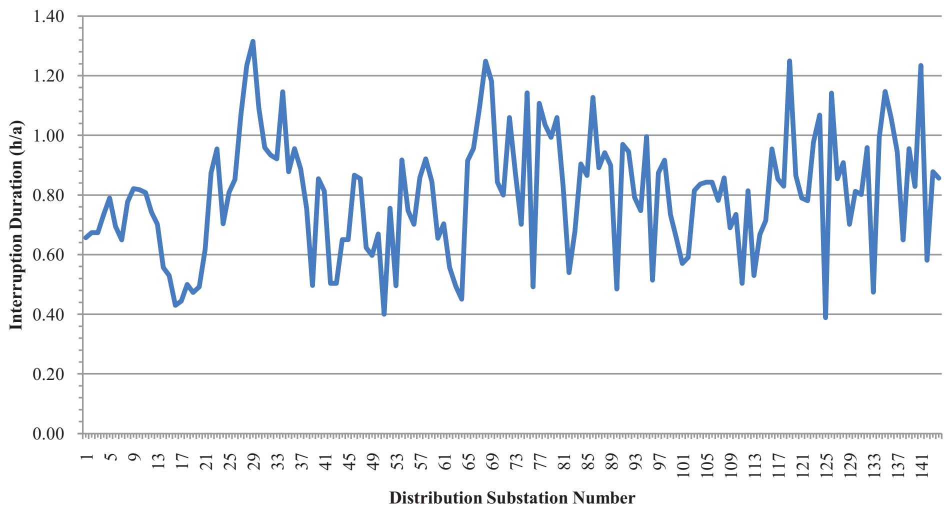

Figure 7. Annual expected duration of sustained interruptions for distribution substations of the distribution test network, $AED_{L_j}^{SI}$ *(Case Study 1)*

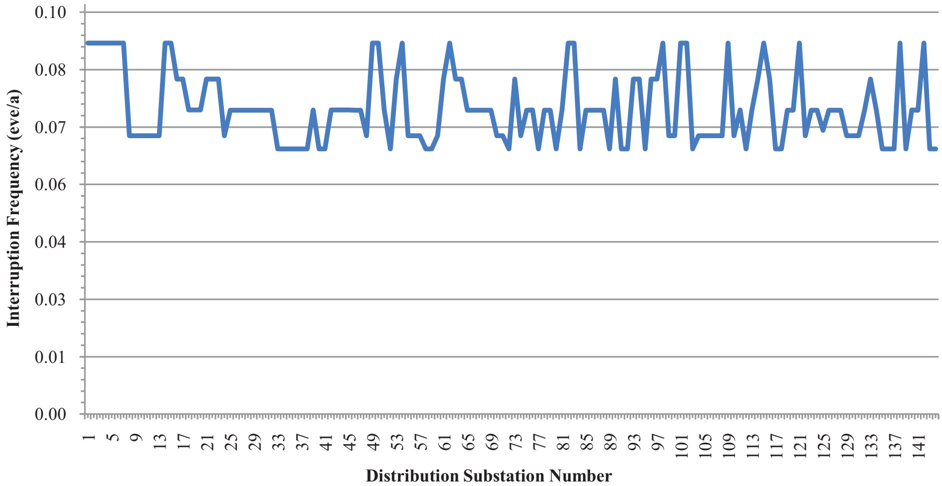

Figure 8. Annual expected frequency of momentary interruptions for distribution substations of the distribution test network, $AEF_{L_j}^{MI}$ *(Case Study 1)*

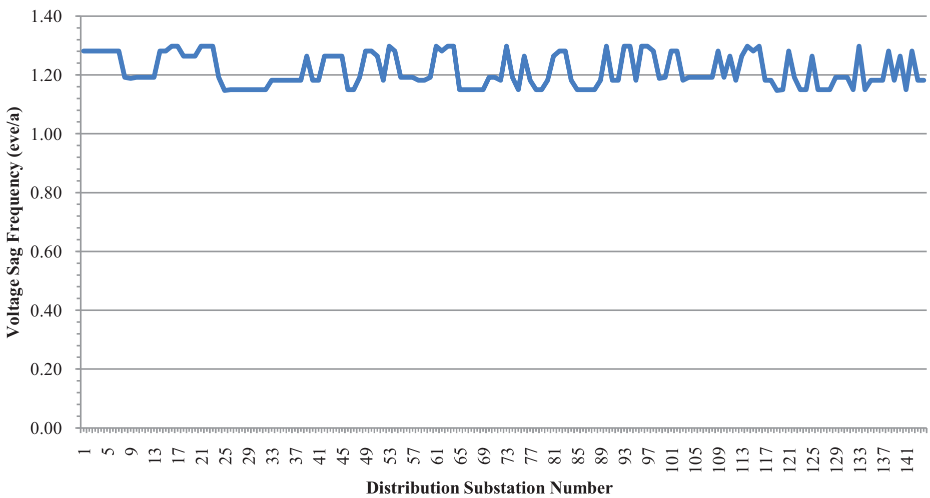

Figure 9. Annual expected frequency of voltage sags affecting distribution substations of the distribution test network, $AEF_{L_j}^{VS}$ *(Case Study 1)*

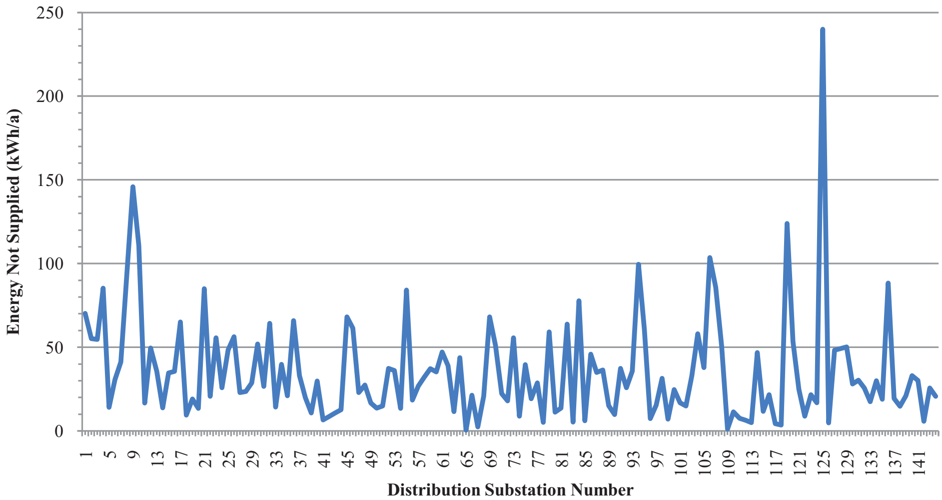

Figure 10. Annual expected energy not supplied for distribution substations of the distribution test network, $AENS_{L_j}^{SI}$ *(Case Study 1)*

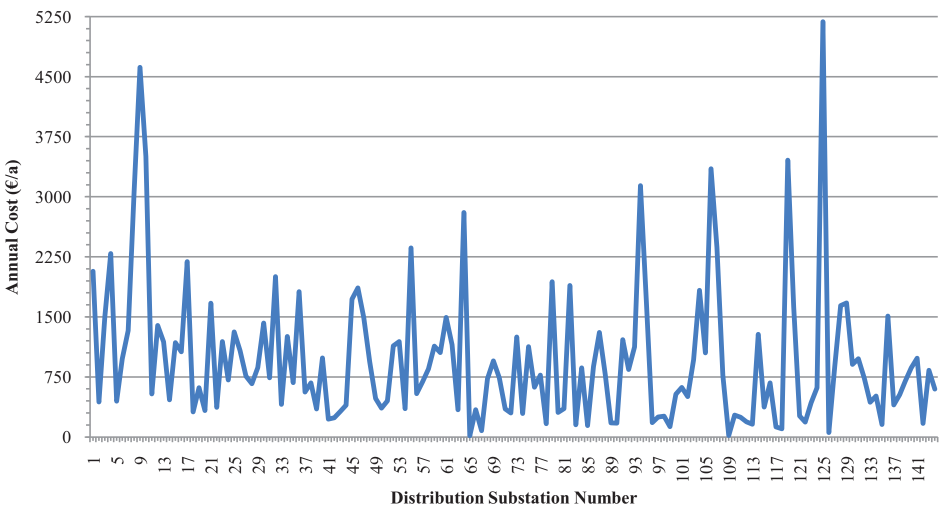

Figure 11. Annual expected cost arising from sustained interruptions for distribution substations of the distribution test network, $AEC_{L_j}^{SI}$ *(Case Study 1)*

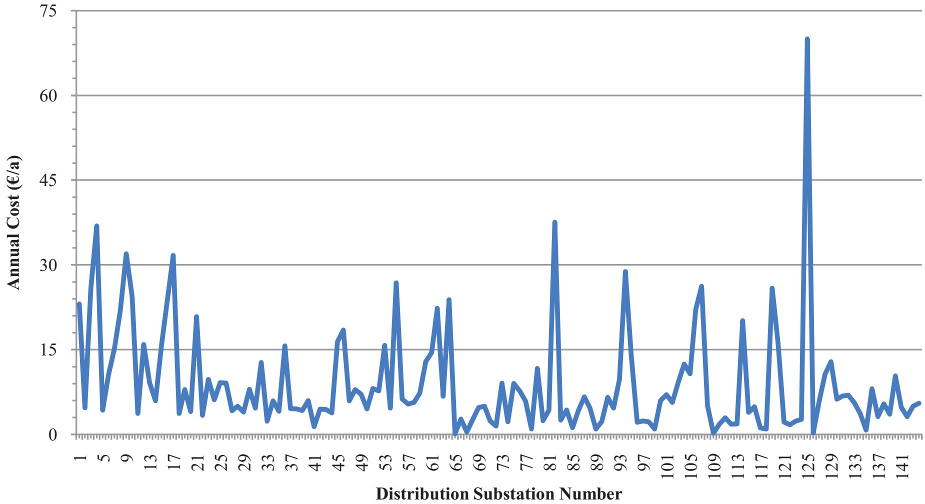

Figure 12. Annual expected cost arising from momentary interruptions for distribution substations of the distribution test network, $AEC_{L_j}^{MI}$ (Case Study 1)

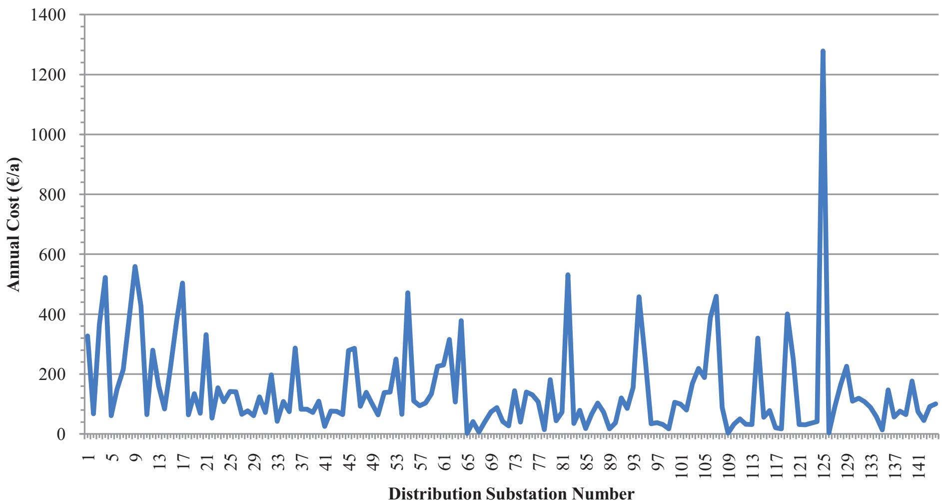

Figure 13. Annual expected cost arising from voltage sags for distribution substations of the distribution test network, $AEC_{L_j}^{VS}$ (Case Study 1)

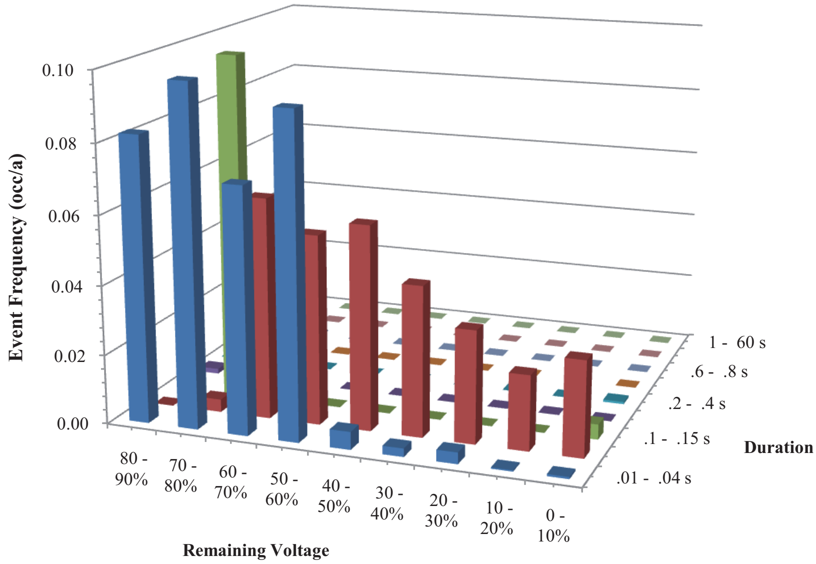

Figure 14. Density distribution of the expected voltage variation events, $AVVFI^{(V,D)}$, due to the faults originated from the distribution test network (Case Study 1)

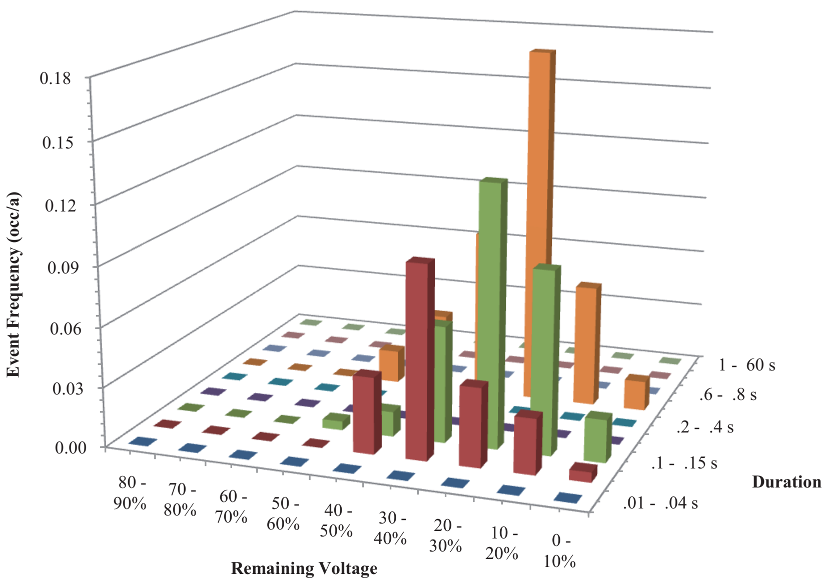

Figure 15. Density distribution of the expected voltage variation events, $AVVFI^{(V,D)}$, due to the faults originated from the sub-transmission test network (Case Study 1)

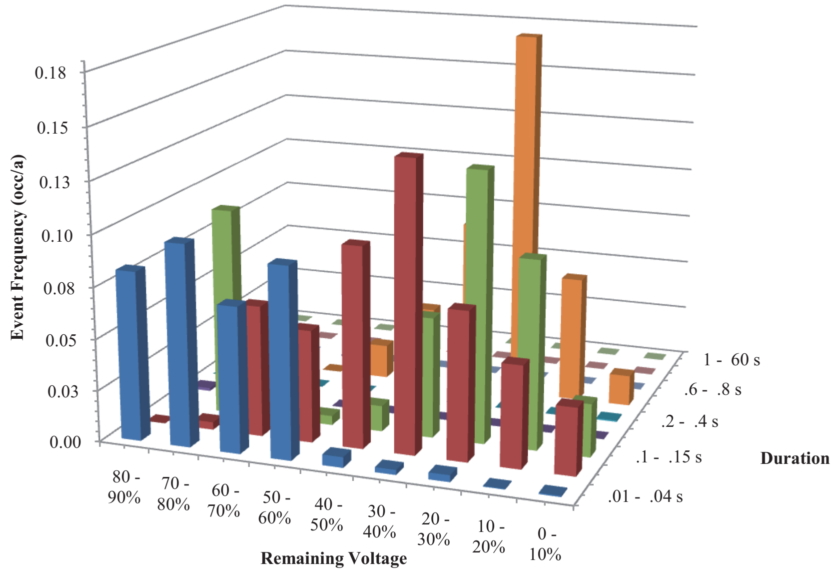

Figure 16. Density distribution of overall expected voltage variation events, AVVFI$^{(V,D)}$ (Case Study 1)

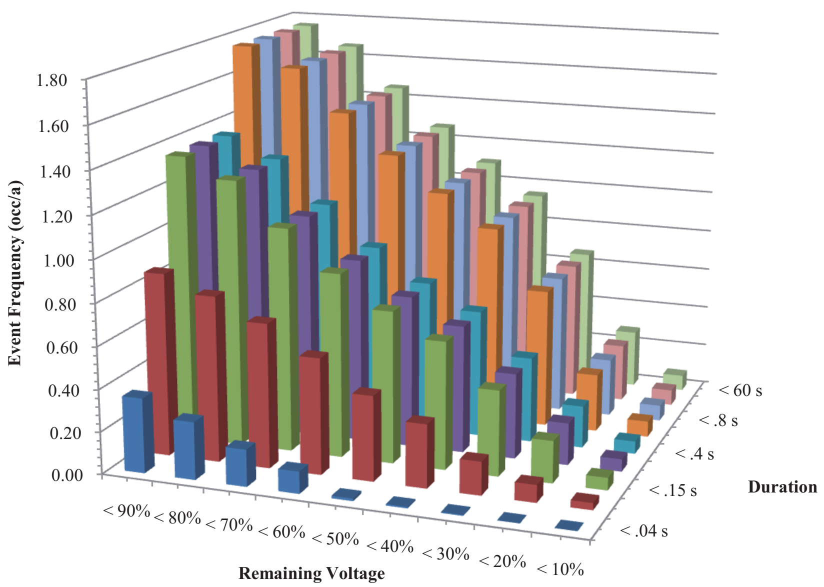

Figure 17. Cumulative distribution of overall expected voltage variation events, AVVFI$^{(V,D)}$ (Case Study 1)

6.2.2 *Case Study 2: Integrating Distance to Fault Estimators*

This case study aims to show the reliability performance of the distribution test network when distance to fault estimators are employed at the 110/20 kV substation for estimating the fault location as a distance from the substation to the fault. In this case study, it is assumed that the data retrieving from these devices requires the intervention of the local operators of the 110/20 kV substation. The basic data related to the fault management activities for this case study are assumed similar to the Case Study 1 (Table 4).

The system oriented reliability indices for this case study are represented in Table 6. The load point reliability indices are shown in Figures 18-25. The distributions of expected momentary interruptions and voltage sags imposed on the customers of the distribution test network are shown in Figures 26 and 27.

The study results show virtually all the reliability indices have been improved compared to the base case study. The degree of improvements ranges from 16 to 39 percents. Actually, by using the distance to fault estimators, a much smaller zone of the electricity distribution test network is required to be inspected by the repair crews in search for location and isolation of the fault and restore service to the affected customers. Hence, much less trial and error switching actions are required to find the faulted section. Therefore, both the frequency and duration of sustained interruptions imposed on the customers are reduced in this condition.

The study results also show that the reliability indices associated with the momentary interruptions and voltage sags have been improvement when employing the distance to fault estimators. The implemented smart grid technologies have no impact on the momentary interruptions and voltage sags arising from the faults within the high voltage network. Therefore, the improvements appeared in the reliability indices associated with the momentary interruptions and voltage sags are solely due to decrease in the trial and error switching activities required for fault location purposes.

The study results also indicate that the variation of reliability indices among different customers has been much reduced compared to those of the base case study (Case Study 1).

The results presented in Table 6 show that the burden on the utility crews are also reduced when employing the distance to the fault estimators. This is because much less field activities are required to find the faulted section compared to the base case study.

TABLE 6
SYSTEM ORIENTED RELIABILITY INDICES FOR CASE STUDY 2

Reliability Index	**Expected Value**	**Relative Change to the Base Case (%)**
SAIFI (int/sub-a)	0.5160	-38.89
SAIDI (h/sub-a)	0.5244	-34.69
MAIFI (eve/sub-a)	0.0531	-28.82
AVSSI (eve/sub-a)	1.0218	-15.94
ASUI (%)	0.005986	-34.71
EENS (kWh/a)	3278	-35.98
$ECOST^{SI}$ (€/a)	88706	-36.61
$ECOST^{MI}$ (€/a)	913	-29.28
$ECOST^{VS}$ (€/a)	17624	-16.39
Total Cost (€/a)	107242	-33.92
Repair Crew Burden (h/a)	75.97	-5.50

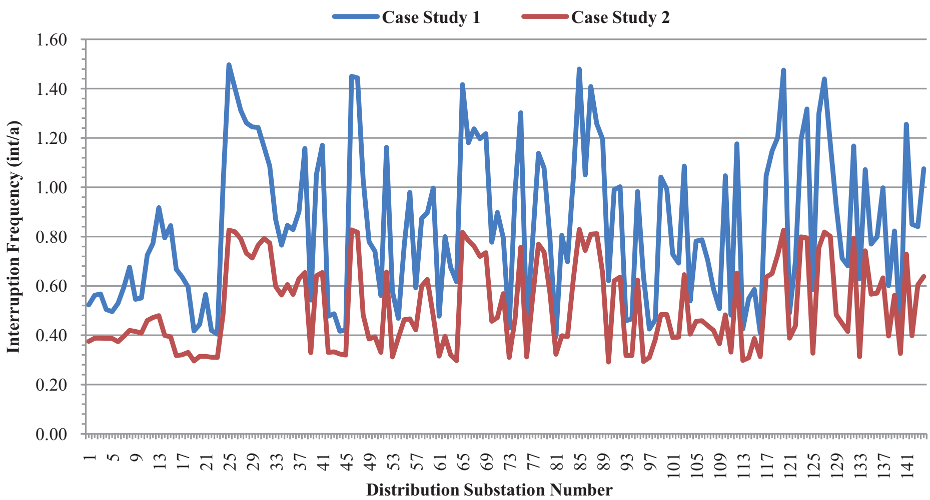

Figure 18. Annual expected frequency of sustained interruptions for distribution substations of the distribution test network, $AEF_{L_j}^{SI}$ (Case Studies 1&2)

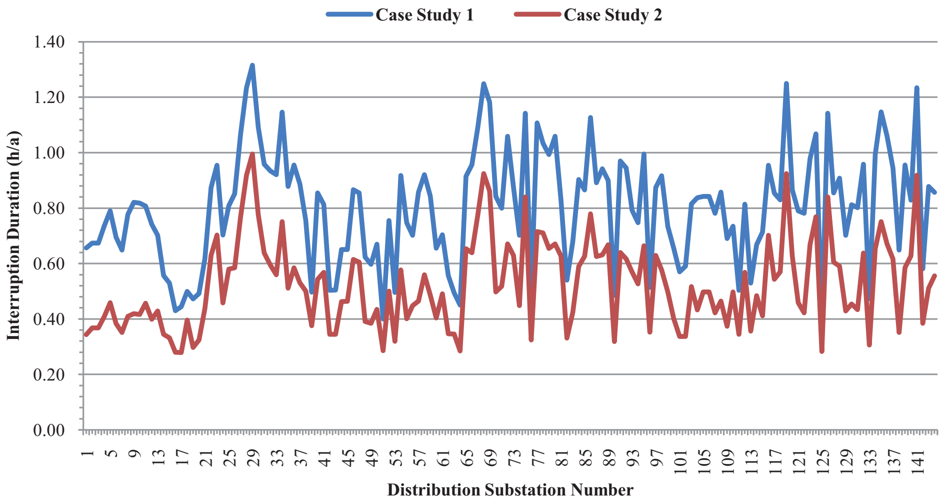

Figure 19. Annual expected duration of sustained interruptions for distribution substations of the distribution test network, $AED_{L_j}^{SI}$ *(Case Studies 1&2)*

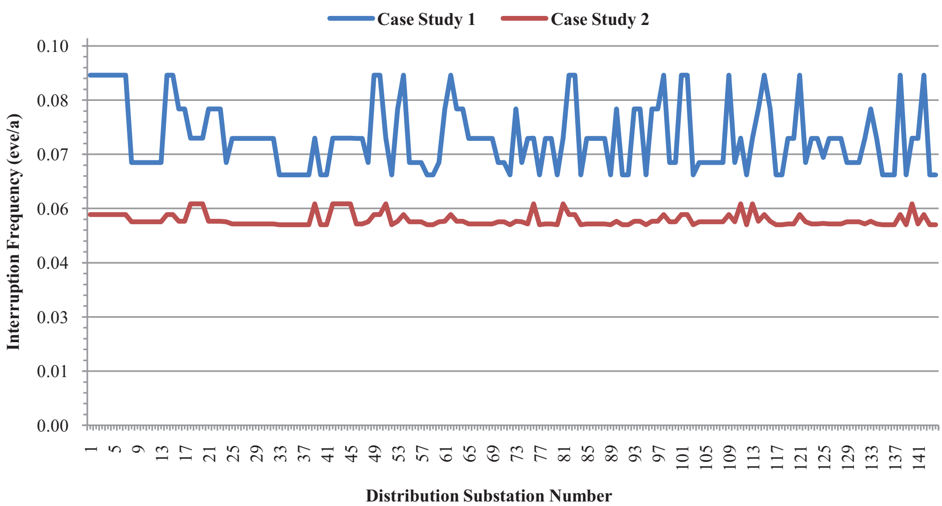

Figure 20. Annual expected frequency of momentary interruptions for distribution substations of the distribution test network, $AEF_{L_j}^{MI}$ *(Case Studies 1&2)*

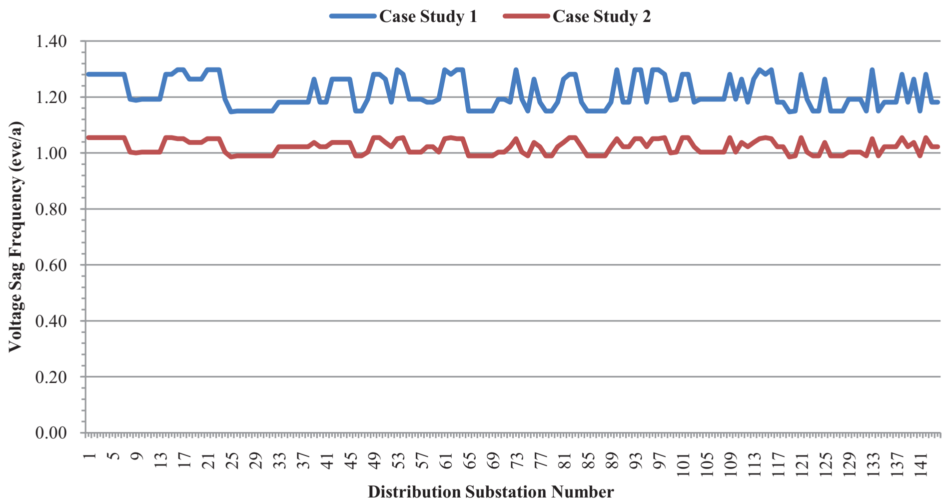

Figure 21. Annual expected frequency of voltage sags affecting distribution substations of the distribution test network, $AEF_{L_j}^{VS}$ (Case Studies 1&2)

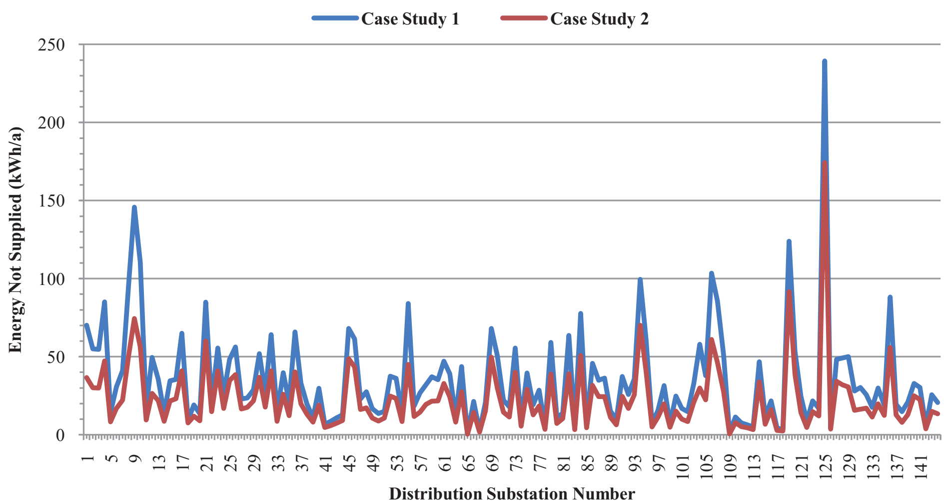

Figure 22. Annual expected energy not supplied for distribution substations of the distribution test network, $AENS_{L_j}^{SI}$ (Case Studies 1&2)

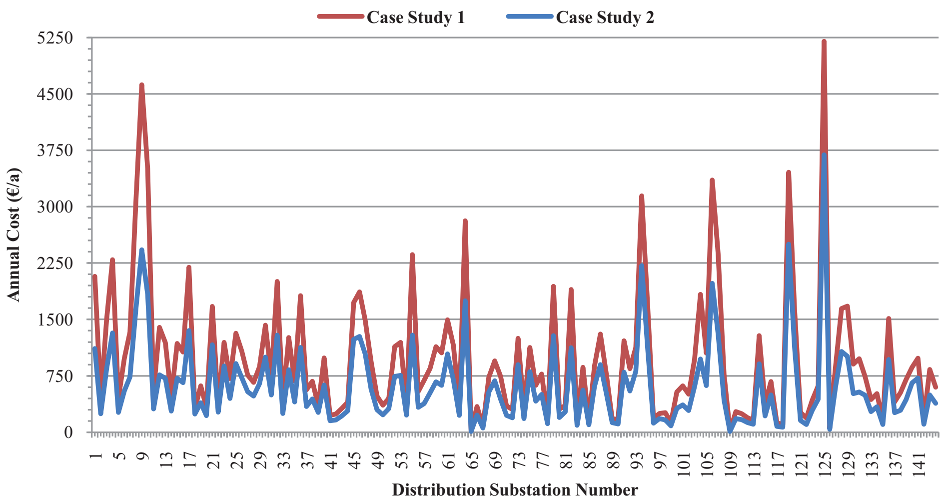

Figure 23. Annual expected cost arising from sustained interruptions for distribution substations of the distribution test network, $AEC_{L_j}^{SI}$ (Case Studies 1 &2)

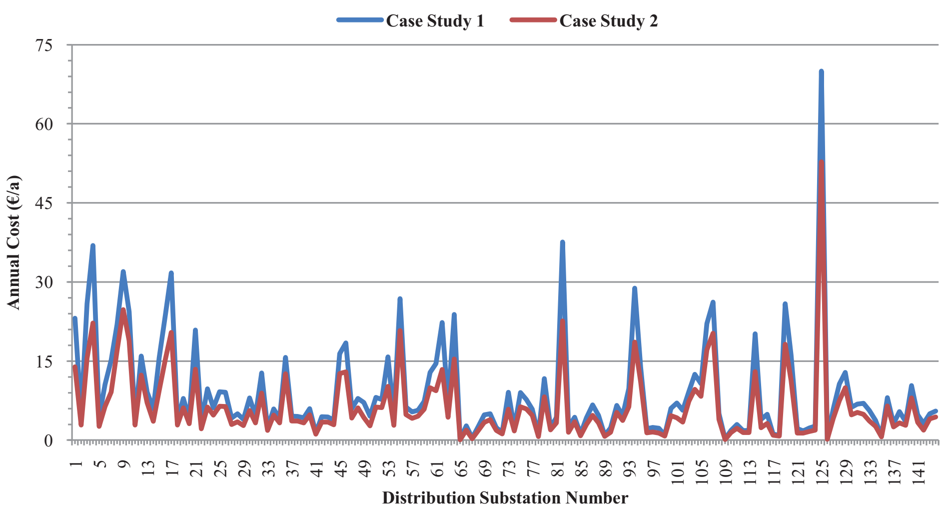

Figure 24. Annual expected cost arising from momentary interruptions for distribution substations of the distribution test network, $AEC_{L_j}^{MI}$ (Case Studies 1 &2)

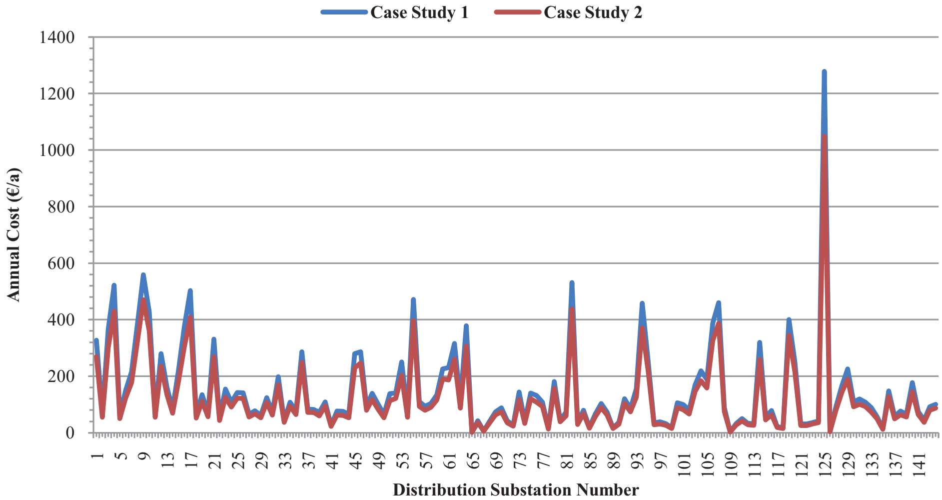

Figure 25. Annual expected cost arising from voltage sags for distribution substations of the distribution test network, $AEC_{L_j}^{VS}$ (Case Studies 1 &2)

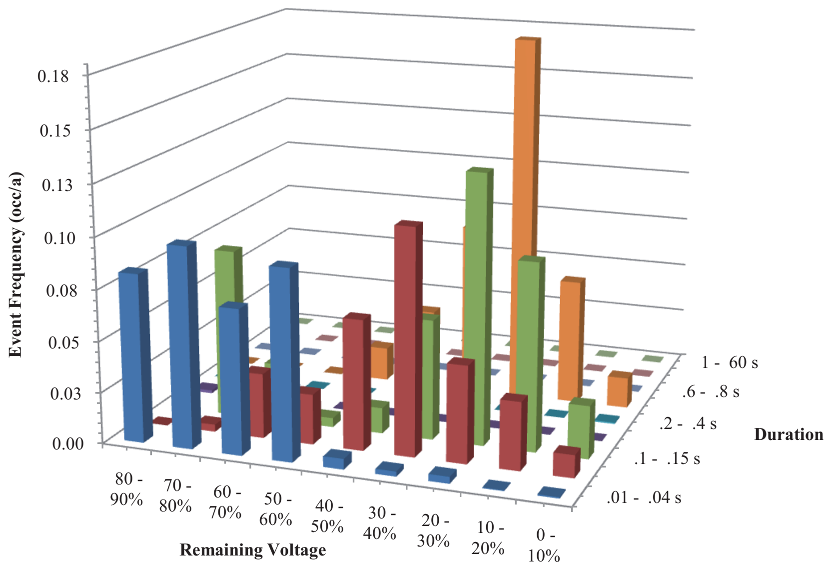

Figure 26. Density distribution of overall expected voltage variation events, $AVVFI^{(V,D)}$ (Case Study 2)

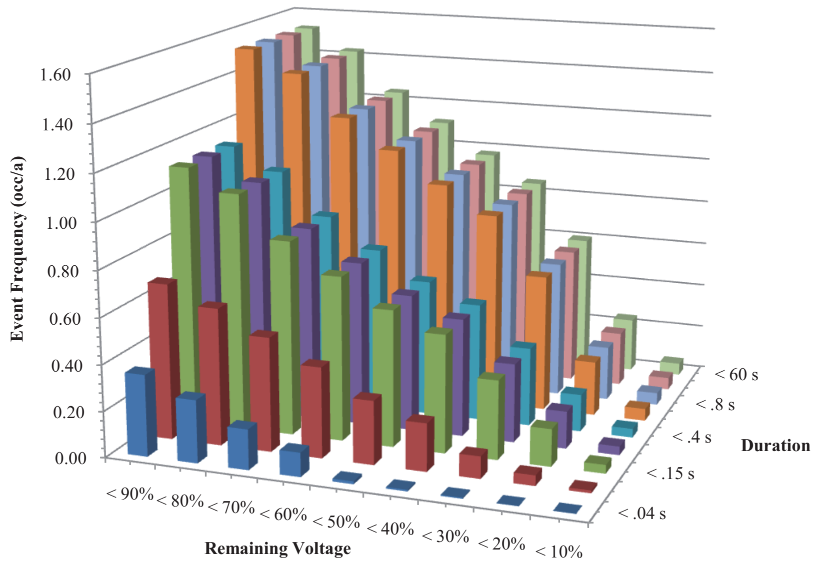

Figure 27. Cumulative distribution of overall expected voltage variation events, $AVVFI^{(V,D)}$ (Case Study 2)

6.2.3 Case Study 3: Integrating Fault Passage Indicators

Examination of the distribution test network shows that the majority of the distribution feeders have multiple taps. When a feeder has multiple taps, there might be several probable fault locations for the fault distance indicated by the distance to fault estimators employed in the Case Study 2. In this circumstance, the repair crews are unable to determine which tap to follow to find the location of the fault. Therefore, they need to perform trial and error switching actions to find the right tap that contains the faulted section, which deteriorates the service reliability. However, applying fault passage indicators together with distance to fault estimators can overcome this issue. This case study aims to show the reliability performance of the distribution test network when the fault passage indicators are used along the distribution feeders together with the distance to fault estimators. The basic data related to the fault management activities for this case study are assumed similar to the Case Studies 1 and 2 (Table 4). In addition, it is assumed that the average time required for reading the status of a set of fault passage indicators is 5 minutes per each visited distribution substation.

The system oriented reliability indices for this case study are represented in Table 7. The load point reliability indices that differ from those of the Case Study 2 are shown in Figures 28-33. The distributions of expected momentary interruptions and voltage sags imposed on the customers of the distribution test network are shown in Figures 34 and 35.

The study results show that virtually all the reliability indices have been improved compared to the base case study. The results presented in Table 7 also show that the rates of sustained interruptions and severe voltage sags have been decreased when the fault passage indicators are used with the distance to fault estimators. However, the average duration of sustained interruptions are slightly increased as the repair crews may have to visit more distribution substations to read the status of the fault passage indicators. Instead, the less trial and error switching actions are required to find the faulted section compared to the Case Studies 1 and 2. As a result, the frequency and financial impacts on the customers due to voltage sags are decreased in this case study compared to those of the Case Studies 1 and 2.

The study results also show that the reliability indices associated with the momentary interruptions have not been improvement compared to those of the Case Study 2. Actually, the origin of momentary interruptions is the short circuit faults close to the 110/20 kV substation. The implemented smart grid technologies in the Case Studies 2 and 3 have no mitigation on the momentary interruptions arising from the faults within the high voltage network. In addition, the first few kilometers of the feeders outgoing from the 110/20 kV substation have no or few taps. The short circuit faults within these short distances almost cause momentary interruptions for the customers connected to the neighboring feeders. However, when employing the distance to fault estimators, the faulted zone can be identified for these short distances. Therefore, applying the fault passage indicators do not provide further information for locating the faults close to the 110/20 kV substation. Hence, as the study results show, there is no improvement in the reliability indices associated with the momentary interruptions compared to those of the Case Study 2.

The study results also indicate that the variation of reliability indices among different customers has been much reduced compared to those of the Case Studies 1 and 2.

The results presented in Table 7 also show that the burden on the utility crews is the same as that of the Case Study 2. This is because, when employing the fault passage indicators, the repair crews have to visit more distribution substations to read the status of the fault passage indicators. The overall time required for accomplishing the activities involved in this process is virtually about the same of that of previous trial and error switching activities involved in the Case Study 2. Therefore, the burden on the utility crews is almost the same for Case Studies 2 and 3.

TABLE 7
SYSTEM ORIENTED RELIABILITY INDICES FOR CASE STUDY 3

Reliability Index	Expected Value	Relative Change to Case Study 2 (%)	Relative Change to the Base Case (%)
SAIFI (int/sub-a)	0.3285	-36.34	-61.10
SAIDI (h/sub-a)	0.5401	+2.99	-32.74
MAIFI (eve/sub-a)	0.0531	0.00	-28.82
AVSSI (eve/sub-a)	0.9777	-4.32	-19.56
ASUI (%)	0.006166	+3.01	-32.75
EENS (kWh/a)	3400	+3.72	-33.59
$ECOST^{SI}$ (€/a)	88965	+0.29	-36.42
$ECOST^{MI}$ (€/a)	913	0.00	-29.28
$ECOST^{VS}$ (€/a)	16850	-4.39	-20.06
Total Cost (€/a)	106728	-0.48	-34.24
Repair Crew Burden (h/a)	75.97	0.00	-5.50

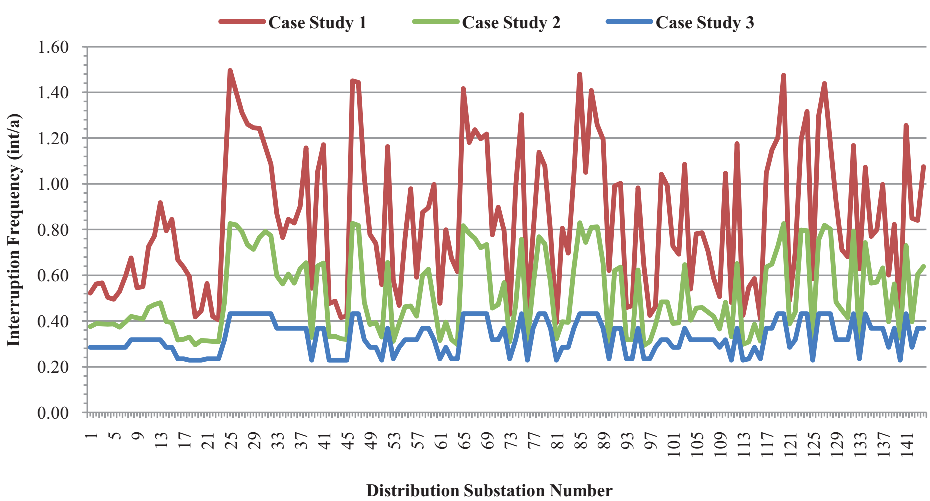

Figure 28. Annual expected frequency of sustained interruptions for distribution substations of the distribution test network, $AEF_{L_j}^{SI}$ (Case Studies 1, 2&3)

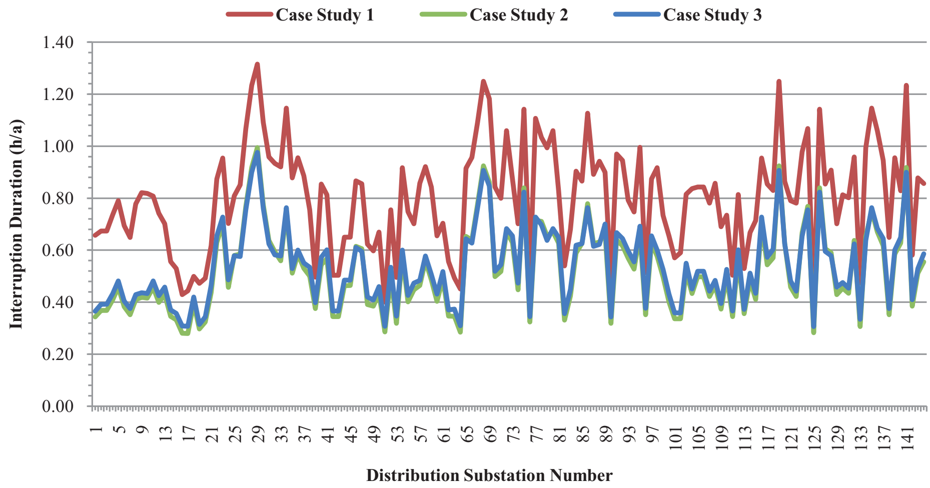

Figure 29. Annual expected duration of sustained interruptions for distribution substations of the distribution test network, $AED_{L_j}^{SI}$ (Case Studies 1, 2&3)

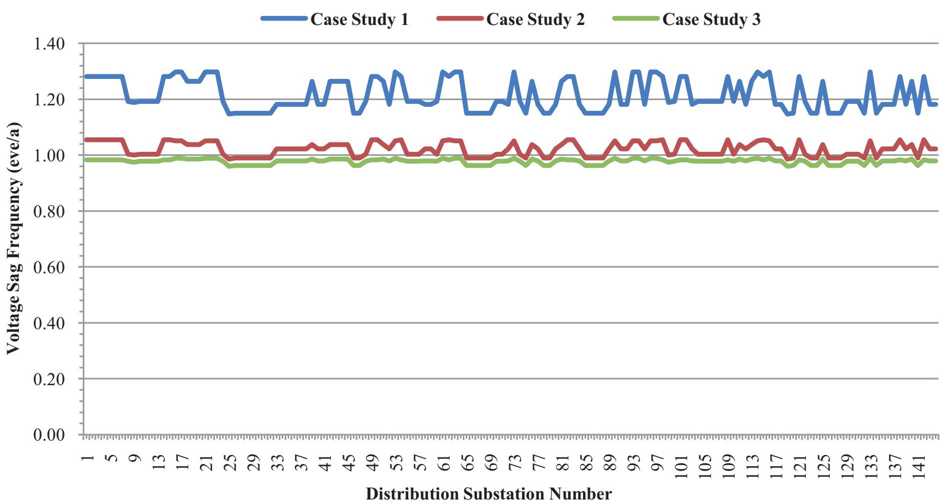

Figure 30. Annual expected frequency of voltage sags affecting distribution substations of the distribution test network, $AEF_{L_j}^{VS}$ (Case Studies 1, 2&3)

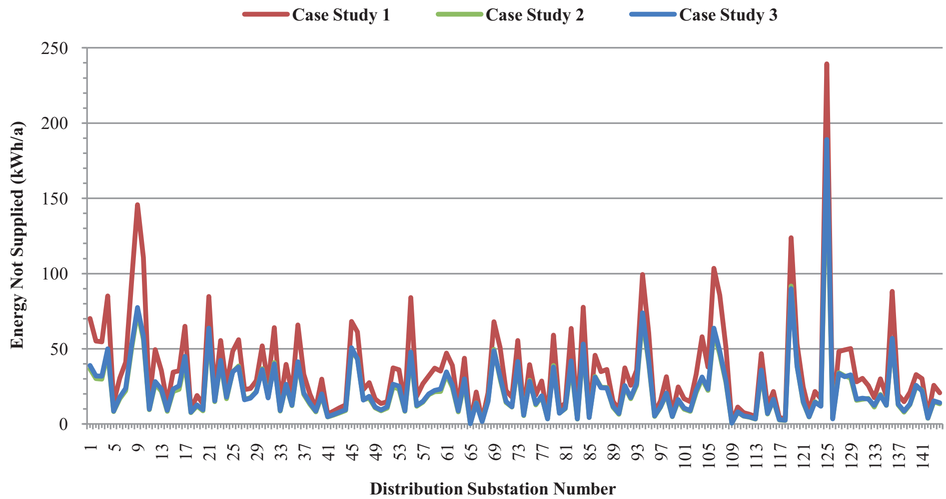

Figure 31. Annual expected energy not supplied for distribution substations of the distribution test network, $AENS_{L_j}^{SI}$ (Studies 1, 2&3)

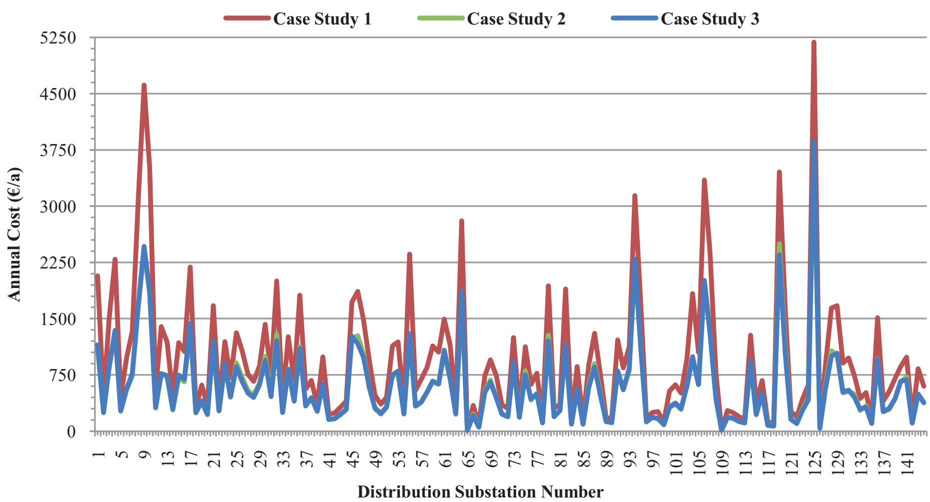

Figure 32. Annual expected cost arising from sustained interruptions for distribution substations of the distribution test network, $AEC_{L_j}^{SI}$ (Studies 1, 2&3)

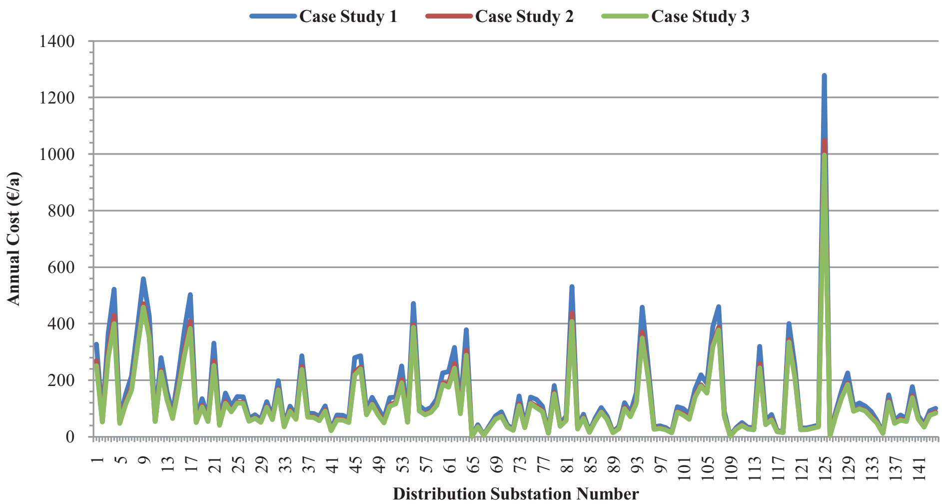

Figure 33. Annual expected cost arising from voltage sags for distribution substations of the distribution test network, $AEC_{L_j}^{VS}$ (Case Studies 1, 2&3)

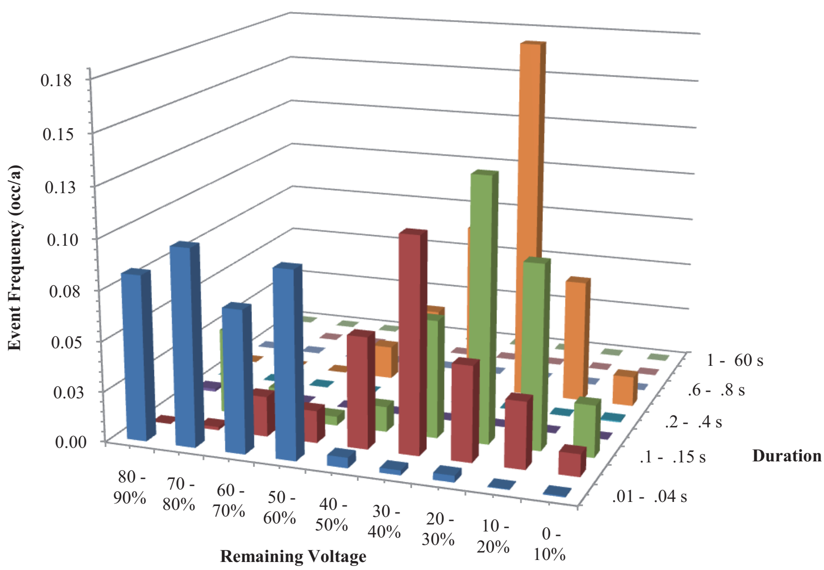

Figure 34. Density distribution of overall expected voltage variation events, $AVVFI^{(V,D)}$ (Case Study 3)

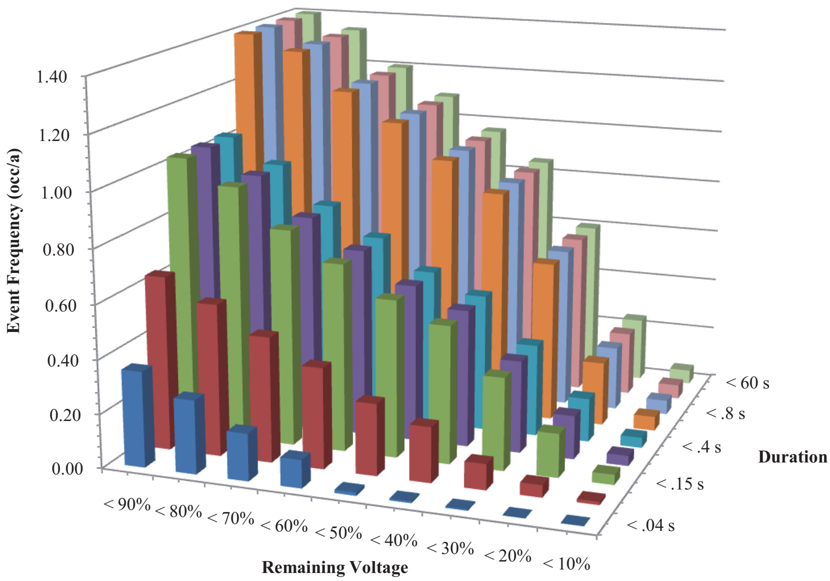

Figure 35. Cumulative distribution of overall expected voltage variation events, $AVVFI^{(V,D)}$ (Case Study 3)

6.2.4 Case Study 4: Integrating Fault Locator Scheme

The smart grid technologies implemented through the Case Studies 2 and 3 can be replaced or retrofitted to develop a fault locator scheme. These facilities can be arranged such that the fault notification and location activities accomplish automatically. As an example, the status of fault passage indicators installed along the distribution feeders can be retrieved over a communication link. This data together with the outcome of the distance to fault estimators are then automatically analyzed to find the fault location. Then, the control center operators and the utility repair crews are automatically notified about the outage condition and the probable fault location.

This case study aims to evaluate the impact of the above described fault locator scheme on the reliability performance of the distribution test network. In this situation, the basic data related to the fault management activities are assumed according to Table 8.

The system oriented reliability indices for this case study are represented in Table 9. The load point reliability indices that differ from those of the Case Study 3 are shown in Figures 36-38. The distributions of expected momentary interruptions and voltage sags imposed on the customers of the distribution test network are similar to those of the Case Study 3.

The study results show that the durations of the sustained interruptions have been reduced compared to the Case Study 3. As a result, the energy not supplied, service unavailability and also the financial impacts of the sustained interruptions have also been reduced compared to those of the Case Study 3.

The reliability indices corresponding to the momentary interruptions and voltage sags remain the same as those of the Case Study 3. Actually, the fault locator scheme implemented in this case study cannot further decrease the impact of voltage sags. This is because, in both Case Studies 3 and 4, all the faults can be located without the need for any trial and error switching activities. The remaining voltage sags are either due to the impacts of the faults originated from the sub-transmission network or the faults within the distribution test networks.

The study results also indicate that the variation of reliability indices among different customers has been reduced again compared to those of the Case Studies 1, 2 and 3.

The results presented in Table 9 also show that the burdens on the utility crews are reduced when employing the fault locator scheme. This is because much less field activities are required to find the faulted section compared to the other case studies.

TABLE 8

BASIC DATA RELATED TO THE FAULT MANAGEMENT ACTIVITIES IN CASE STUDY 4

Average time required for fault notification (s)	60
Average time required for approximate fault location (s)	60
Average time required for decision making about fault management activities (s)	600
Average time required for dispatching the repair crews (s)	120
Average speed of the repair crews for traveling to the faulted area (km/h)	40
Average time required for precise fault location on an underground cable section including both pre-location and pinpointing activities (s)	1800
Average time required for manual operation of switching devices involved in fault management activities (s)	180
Available teams of repair crews for performing fault management activities	2

TABLE 9
SYSTEM ORIENTED RELIABILITY INDICES FOR CASE STUDY 4

Reliability Index	Expected Value	Relative Change to Case Study 3 (%)	Relative Change to the Base Case (%)
SAIFI (int/sub-a)	0.3285	0.00	-61.10
SAIDI (h/sub-a)	0.3027	-43.95	-62.30
MAIFI (eve/sub-a)	0.0531	0.00	-28.82
AVSSI (eve/sub-a)	0.9777	0.00	-19.56
ASUI (%)	0.003455	-43.97	-62.32
EENS (kWh/a)	1897	-44.21	-62.95
$ECOST^{SI}$ (€/a)	51815	-41.76	-62.97
$ECOST^{MI}$ (€/a)	913	0.00	-29.28
$ECOST^{VS}$ (€/a)	16850	0.00	-20.06
Total Cost (€/a)	69578	-34.81	-57.13
Repair Crew Burden (h/a)	72.81	-4.16	-9.43

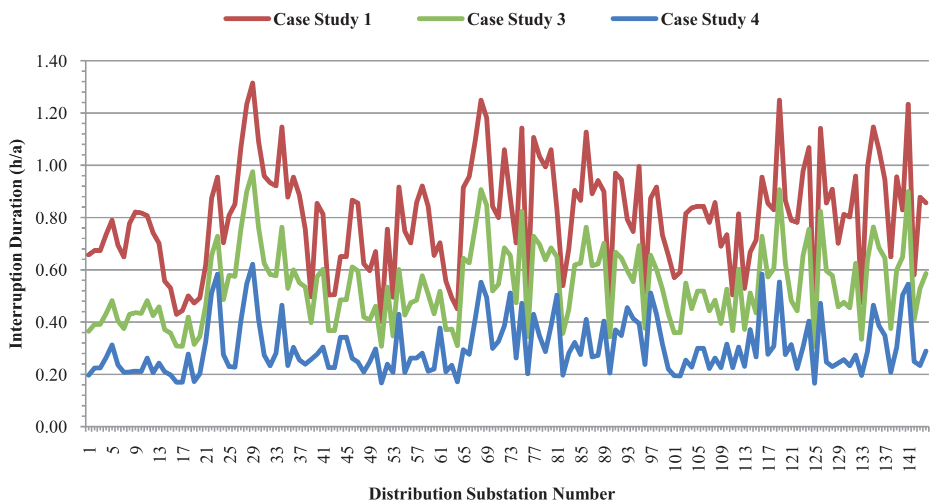

Figure 36. Annual expected duration of sustained interruptions for distribution substations of the distribution test network, $AED_{L_j}^{SI}$ (Case Studies 1, 3&4)

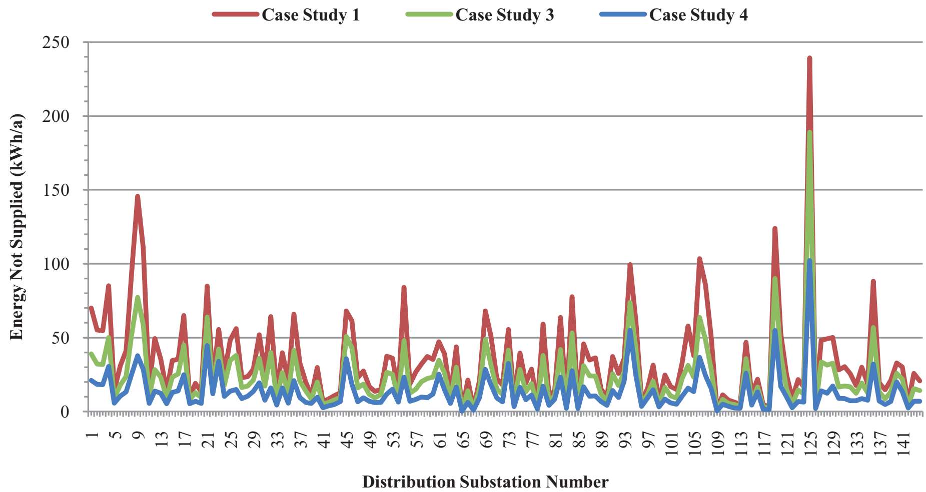

Figure 37. Annual expected energy not supplied for distribution substations of the distribution test network, $AENS_{L_j}^{SI}$ (Studies 1, 3&4)

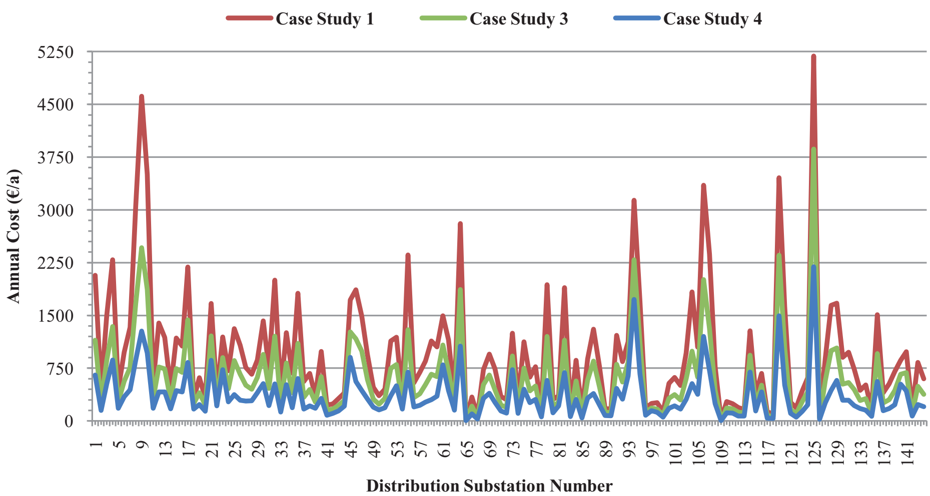

Figure 38. Annual expected cost arising from sustained interruptions for distribution substations of the distribution test network, $AEC_{L_j}^{SI}$ (Studies 1, 3&4)

6.2.5 Case Study 5: Integrating Sub-Transmission Substation Automation

Employing a suitable set of the substation automation functions at the 110/20 kV substation can help to further improve the reliability level achieved in the Case Study 4. The substation automation scheme, which is responsible for performing the targeted functions, can be deployed by means of various smart grid technologies. For an illustration purpose, it is assumed that a substation automation scheme is implemented at the 110/20 kV substation to automatically perform the fault detection, isolation and service restoration activities for faults within this substation. The basic data related to the fault management activities are assumed similar to that of the Case Study 4 (Table 8).

The system oriented reliability indices for this case study are represented in Table 10. The load point reliability indices that differ from those of the Case Study 4 are also shown in Figures 39-44. The distributions of expected momentary interruptions and voltage sags imposed on the customers of the distribution test network are also shown in Figures 45 and 46.

By comparing the study results presented for the Case Studies 4 and 5, it can be found that the reliability indices associated with the sustained interruptions have been improved. However, the situation is different for the reliability indices associated with the momentary interruptions. Actually, employing the automatic fault detection, isolation and service restoration function at the 110/20 kV sub-transmission substation only result in the shorter interruptions for the substation originated faults. In other word, the lengthy interruptions originated from the substation faults are now becoming momentary interruptions due to the automatic switching operations. However, as the failure rate of the substation components are much lower than that of the components of the distribution test network, the levels of reliability improvements in this case study are not much higher than that of the Case Study 4.

The automated switching scheme implemented in the Case Study 5 has no impacts on the voltage sags experienced by the customers. Therefore, the reliability indices associated with the voltage sags remains similar to those of the Case Study 4.

As the switching operation activities within the 110/20 kV substation are conducted by its local operators rather than the utility repair crews, the burdens on the utility crews remain similar to those of the Case Study 4.

TABLE 10

SYSTEM ORIENTED RELIABILITY INDICES FOR CASE STUDY 5

Reliability Index	Expected Value	Relative Change to Case Study 4 (%)	Relative Change to the Base Case (%)
SAIFI (int/sub-a)	0.2987	-9.07	-64.63
SAIDI (h/sub-a)	0.2967	-1.98	-63.05
MAIFI (eve/sub-a)	0.0828	+55.93	+10.99
AVSSI (eve/sub-a)	0.9777	0.00	-19.56
ASUI (%)	0.003387	-1.97	-63.06
EENS (kWh/a)	1856	-2.16	-63.75
$ECOST^{SI}$ (€/a)	50271	-2.98	-64.07
$ECOST^{MI}$ (€/a)	1424	+55.97	+10.30
$ECOST^{VS}$ (€/a)	16850	0.00	-20.06
Total Cost (€/a)	68546	-1.48	-57.76
Repair Crew Burden (h/a)	72.81	0.00	-9.43

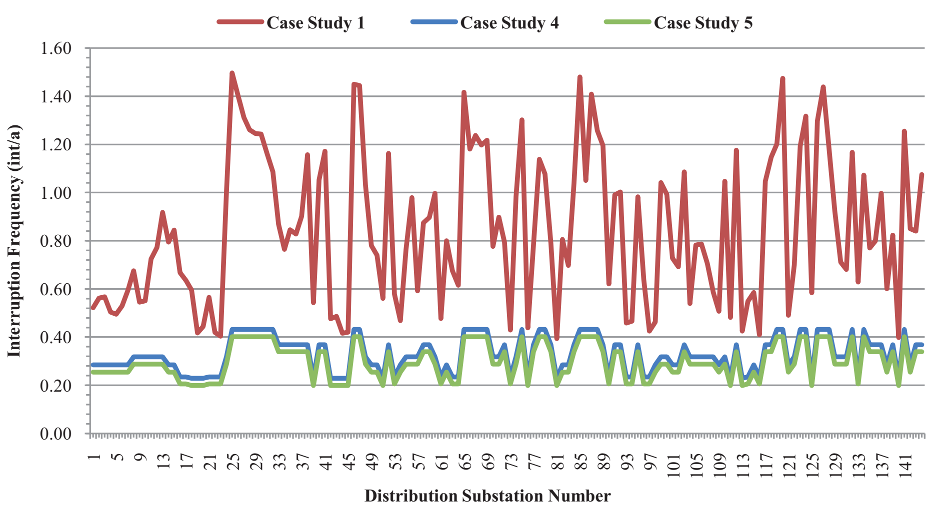

Figure 39. Annual expected frequency of sustained interruptions for distribution substations of the distribution test network, $AEF_{L_j}^{SI}$ (Case Studies 1, 4&5)

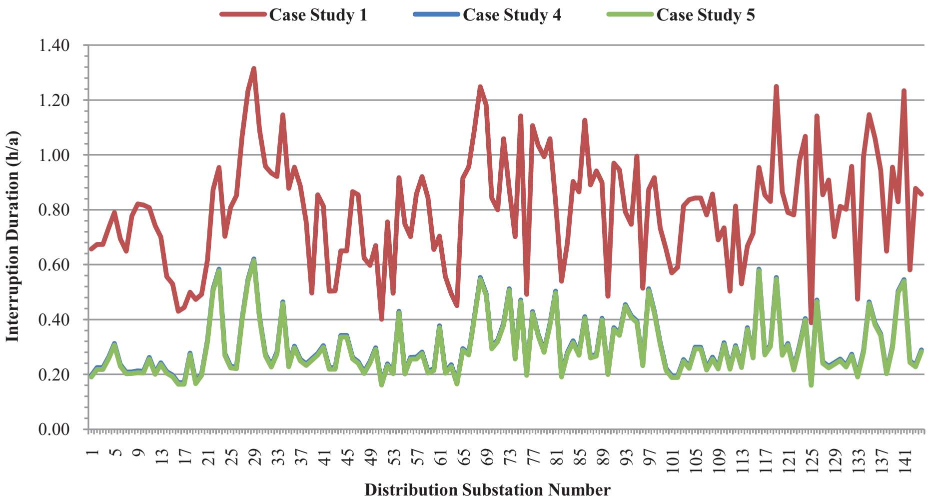

Figure 40. Annual expected duration of sustained interruptions for distribution substations of the distribution test network, $AED_{L_j}^{SI}$ (Case Studies 1, 4&5)

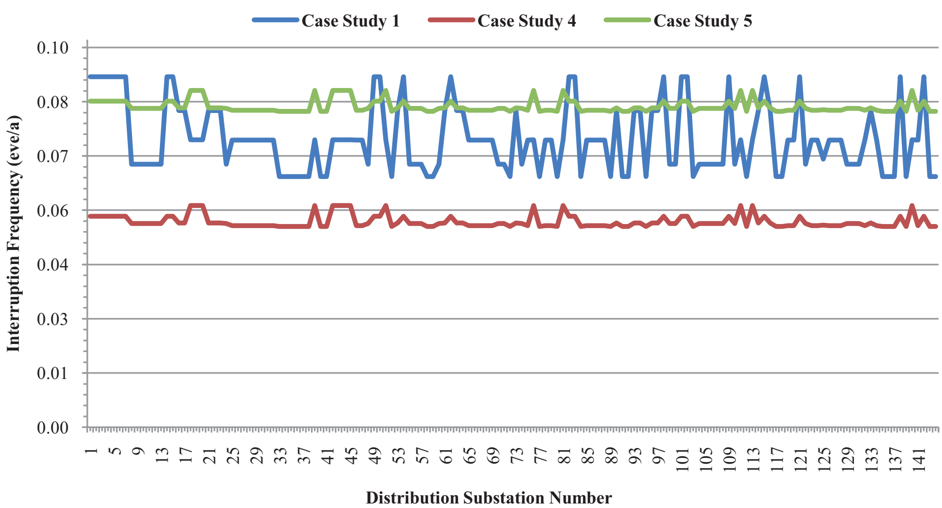

Figure 41. Annual expected frequency of momentary interruptions for distribution substations of the distribution test network, $AEF_{L_j}^{MI}$ (Case Studies 1, 4&5)

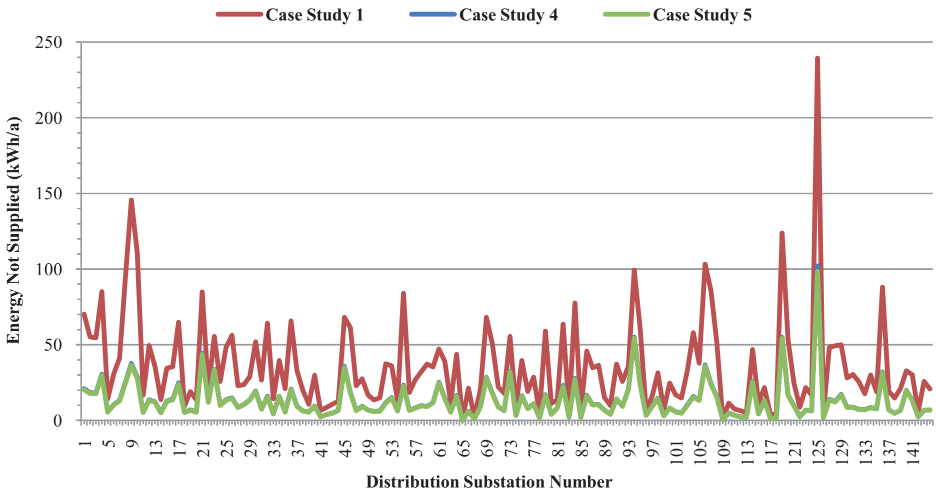

Figure 42. Annual expected energy not supplied for distribution substations of the distribution test network, $AENS_{L_j}^{SI}$ *(Studies 1, 4&5)*

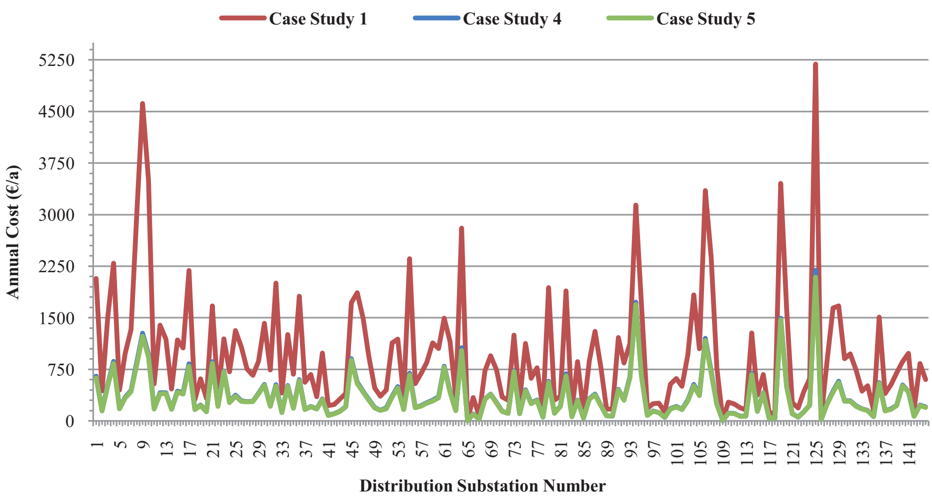

Figure 43. Annual expected cost arising from sustained interruptions for distribution substations of the distribution test network, $AEC_{L_j}^{SI}$ *(Studies 1, 4&5)*

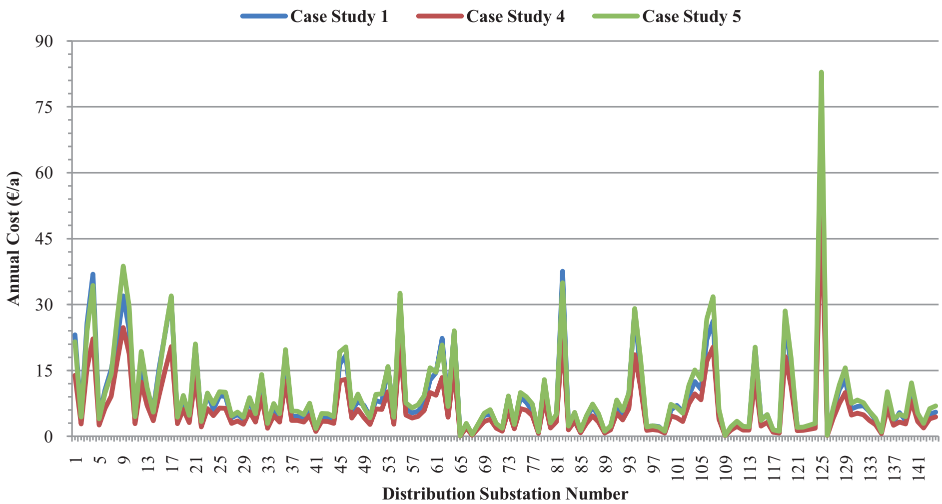

Figure 44. Annual expected cost arising from momentary interruptions for distribution substations of the distribution test network, $AEC_{L_j}^{MI}$ (Case Studies 1, 4&5)

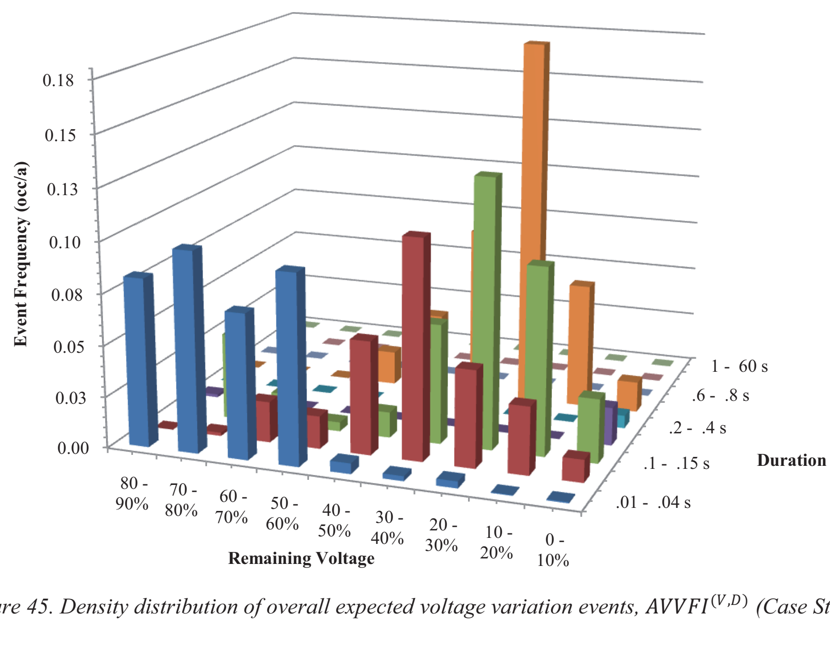

Figure 45. Density distribution of overall expected voltage variation events, $AVVFI^{(V,D)}$ (Case Study 5)

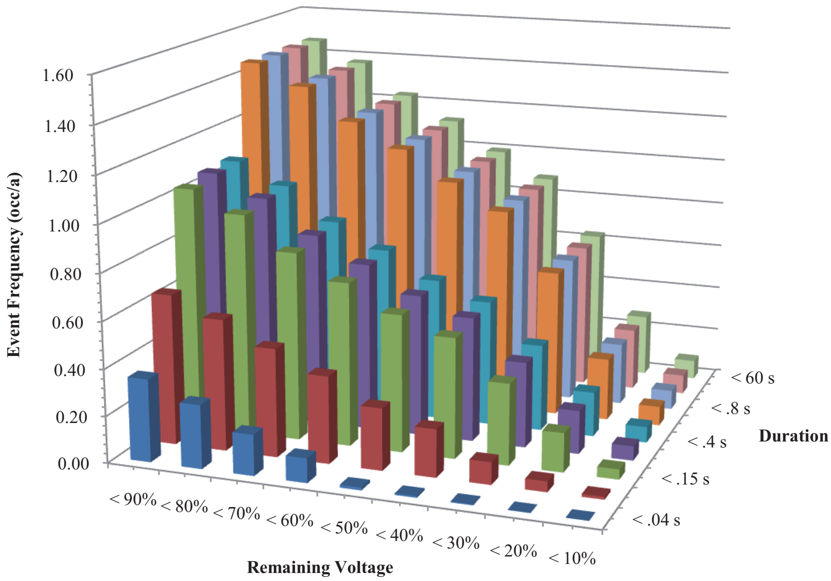

Figure 46. Cumulative distribution of overall expected voltage variation events, $AVVFI^{(V,D)}$ (Case Study 5)

6.2.6 Case Study 6: Integrating Distribution Substation Automation

The substation automation scheme implemented in the 110/20 kV substation was only responsible for control and monitoring the equipment installed within this substation. However, it is possible to increase the scope of this substation automation scheme such that the distribution substations fed by its feeders can also be remotely monitored and controlled. The number and location of distribution substations that are going to be modernized can affect the level of reliability improvement. Optimal allocation of these distribution substations requires a course of cost-benefit studies. However, for sake of simplicity, the shared distribution substations between each pair of feeders (containing normally open tie switch) and midpoint substations of each feeder are selected for upgrading. The selected distribution substations are 7, 9, 12, 17, 26, 42, 90, 117 and 134. It is also assumed that all the switching devices of the targeted distribution substations are retrofitted with suitable actuators for remote control and monitoring purpose.

The basic data related to the fault management activities are assumed similar to that of the Case Studies 4 and 5 (Table 8). In addition, it is assumed that the uncoordinated and coordinated remote switching operation can be accomplished within 5 and 120 seconds, respectively. Uncoordinated remote switching operation is conducted whenever the repair crews have not been engaged with the fault management activities yet. However, the coordinated remote switching operation is carried out whenever the repair crews are engaging with the fault management activities and due to the safety issues they should be aware of any ongoing remote switching operation.

The system oriented reliability indices for this case study are represented in Table 11. The load point reliability indices that differ from those of the Case Study 5 are also shown in Figures 47-49. The distributions of expected momentary interruptions and voltage sags imposed on the customers of the distribution test network are similar to those of the Case Study 5.

The study results show the durations of the sustained interruptions have been reduced compared to those of the Case Study 5. As a result, the energy not supplied, service unavailability and also the financial impacts of the sustained interruptions have also been reduced compared to those of the Case Study 5. However, the reliability indices associated with the momentary interruptions and voltage sags are similar to those of the Case Study 5. Actually, the remote controlled switching devices available in the upgraded distribution substations can aid the repair crews and the control center operators to perform the necessary switching activities in a much shorter period of time. It is also possible to perform both remote and local fault isolation and service restoration activities. In this method, first using the available remote controlled switching devices, the faulted feeder is broken to the several zones. Then the power service is restored to as many as possible of these zones by means of remote controlled switching devices. Afterwards, when the repair crews reach to the faulted area, they can conduct the local fault isolation and service restoration activities. They normally first isolate the faulted section from the other healthy parts of the feeder by means of the manually operated switching devices. Then, the power service is restored to as many as possible of the customer through proper switching operations. The remote fault isolation and service restoration activities in this method require the intervention of the distribution system operators. Usually the time required for restoring the power supply for the affected customers in this method is much above the aggregation window for recording the momentary events (5 minutes). As a result, only the durations of sustained interruptions are reduced and their frequencies remain the same to those of the Case Study 5.

TABLE 11
SYSTEM ORIENTED RELIABILITY INDICES FOR CASE STUDY 6

Reliability Index	**Expected Value**	**Relative Change to Case Study 5 (%)**	**Relative Change to the Base Case (%)**
SAIFI (int/sub-a)	0.2987	0.00	-64.63
SAIDI (h/sub-a)	0.2734	-7.85	-65.95
MAIFI (eve/sub-a)	0.0828	0.00	+10.99
AVSSI (eve/sub-a)	0.9777	0.00	-19.56
ASUI (%)	0.003121	-7.85	-65.96
EENS (kWh/a)	1703	-8.24	-66.74
$ECOST^{SI}$ (€/a)	46429	-7.64	-66.82
$ECOST^{MI}$ (€/a)	1424	0.00	+10.30
$ECOST^{VS}$ (€/a)	16850	0.00	-20.06
Total Cost (€/a)	64704	-5.60	-60.13
Repair Crew Burden (h/a)	72.66	-0.21	-9.62

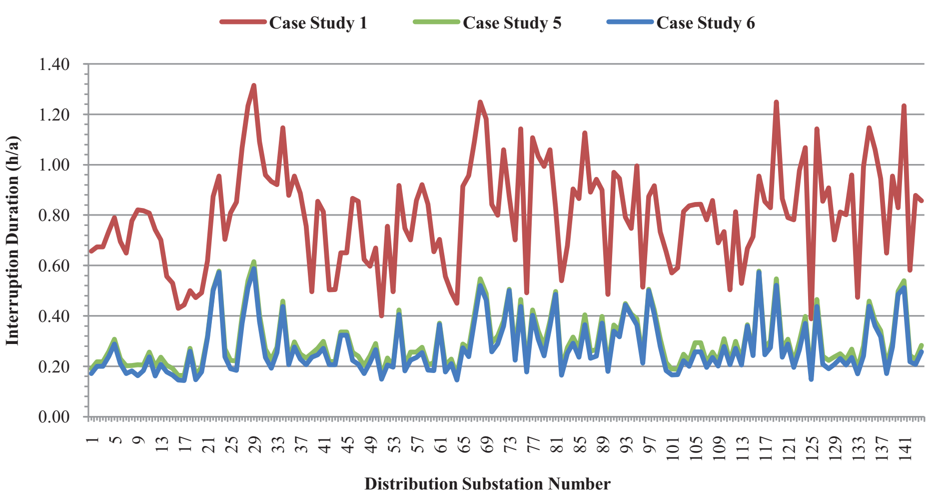

Figure 47. Annual expected duration of sustained interruptions for distribution substations of the distribution test network, $AED_{L_j}^{SI}$ *(Case Studies 1, 5&6)*

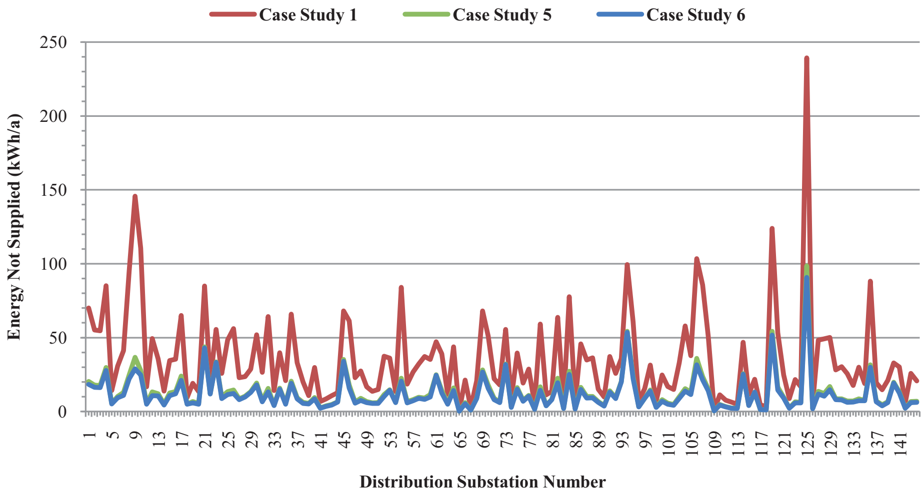

Figure 48. Annual expected energy not supplied for distribution substations of the distribution test network, $AENS_{L_j}^{SI}$ (Studies 1, 5&6)

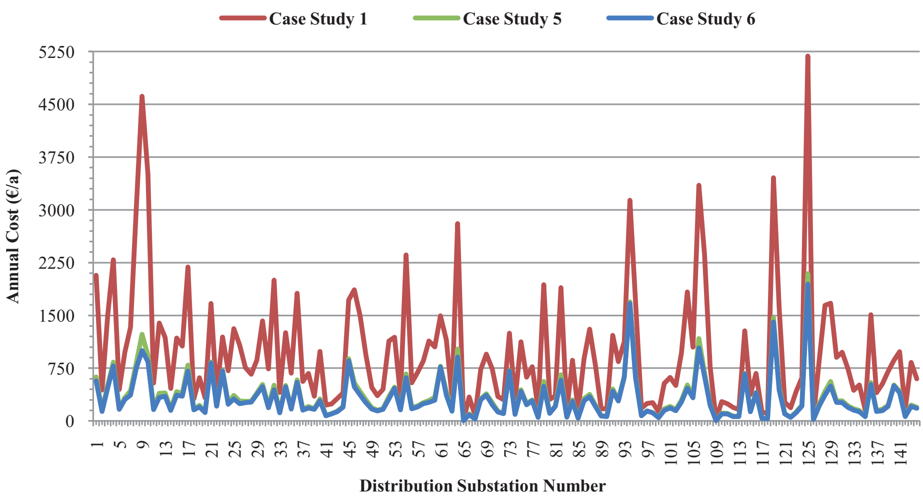

Figure 49. Annual expected cost arising from sustained interruptions for distribution substations of the distribution test network, $AEC_{L_j}^{SI}$ (Studies 1, 5&6)

6.2.7 Case Study 7: Integrating Feeder Automation

In the Case Study 6, several distribution substations were equipped with suitable facilities for remote control and monitoring purposes. It is possible to develop a feeder automation scheme in order to perform automatic fault detection, isolation and service restoration activities in the distribution feeder level. The operational procedure of the targeted feeder automation scheme depends on several factors such as the type of automated switching devices, network structure, the neutral grounding method, type of customers, utility safety regulations and so on. For an illustration purpose, an advanced feeder automation scheme that can be implemented in the distribution test network is described here as follows.

The neutral grounding at the 20 kV level of the distribution test network is resonance (compensated) earthed. In this situation, normally the fault currents for phase to ground faults in 20 kV level can be interrupted by the load breaking switching devices available in the automated distribution substations. In addition, this kind of fault does not cause any voltage sag for the customers supplied by the faulted feeder. Therefore, it is possible to develop an advanced feeder automation scheme capable of distinguish between phase to ground faults and the other over-current short circuit faults. The main benefit of such an automation scheme is its ability in decreasing the extent of outages for phase to ground faults. In this condition, for a phase to ground fault located between feeder circuit breaker and the automated distribution substation, the supply of customers located downstream of the automated distribution substation are rerouted to the neighboring healthy feeder through automatic closed-transition switching actions without any power interruption for the customers. For a phase to ground fault located downstream of the automated distribution substation, instead of the feeder circuit breaker, a switching device located at the automated distribution substation operates and isolates the fault. For a fault which results in an over-current condition, the feeder circuit breaker is operated. Then, the proper switching operations are automatically carried out in order to isolate the faulted zone and restore as many as possible of the customers.

The basic data related to the fault management activities are assumed similar to that of the Case Study 6. The system oriented reliability indices for this case study are represented in Table 12. The load point reliability indices that differ from those of the Case Study 6 are shown in Figures 50-55. The distributions of expected momentary interruptions and voltage sags imposed on the customers of the distribution test network are also shown in Figures 56 and 57.

The study results show that all the reliability indices associated with the sustained interruptions have been improved compared to those of the Case Study 6. Actually, the automated switching devices available in the upgraded distribution substations can perform the necessary switching activities in a much shorter period of time. As the automatic fault isolation and service restoration activities in this method do not require the intervention of the control center operators, the restoration time for the affected customers is much below the aggregation window for recording the momentary events (5 minutes). Therefore, both the frequencies and durations of the sustained interruptions have been reduced compared to those of the Case Study 6. Instead, the number of momentary interruptions imposed on the customers is increased. The voltage sags experienced by the customers remain the same to those of the Case Study 6.

The study results also indicate that the variation of reliability indices associated with momentary interruptions has been increased compared to those of the Case Study 6.

TABLE 12
SYSTEM ORIENTED RELIABILITY INDICES FOR CASE STUDY 7

Reliability Index	Expected Value	Relative Change to Case Study 6 (%)	Relative Change to the Base Case (%)
SAIFI (int/sub-a)	0.1212	-59.42	-85.65
SAIDI (h/sub-a)	0.2373	-13.20	-70.45
MAIFI (eve/sub-a)	0.1325	+60.02	+77.61
AVSSI (eve/sub-a)	0.9777	0.00	-19.56
ASUI (%)	0.002709	-13.20	-70.45
EENS (kWh/a)	1470	-13.68	-71.29
$ECOST^{SI}$ (€/a)	37701	-18.80	-73.06
$ECOST^{MI}$ (€/a)	2221	+55.97	+72.04
$ECOST^{VS}$ (€/a)	16850	0.00	-20.06
Total Cost (€/a)	56773	-12.26	-65.02
Repair Crew Burden (h/a)	72.66	0.00	-9.63

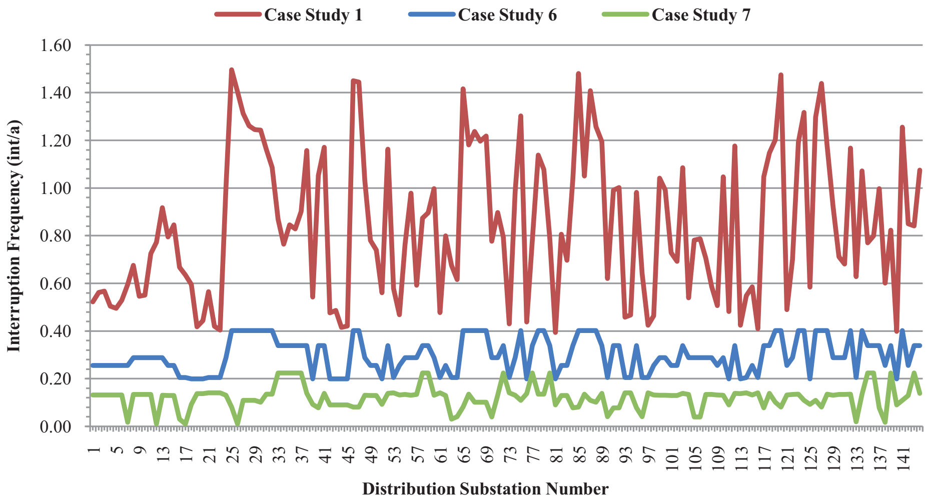

Figure 50. Annual expected frequency of sustained interruptions for distribution substations of the distribution test network, $AEF_{L_j}^{SI}$ (Case Studies 1, 6&7)

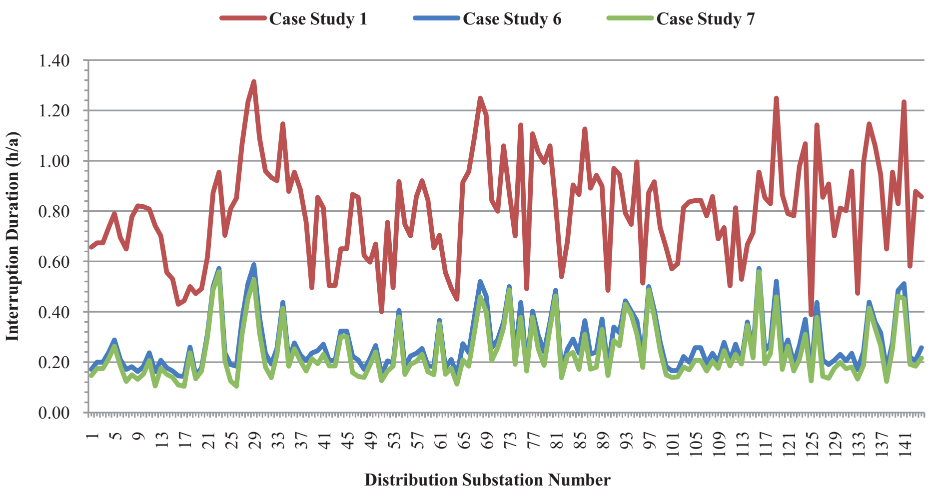

Figure 51. Annual expected duration of sustained interruptions for distribution substations of the distribution test network, $AED_{L_j}^{SI}$ (Case Studies 1, 6&7)

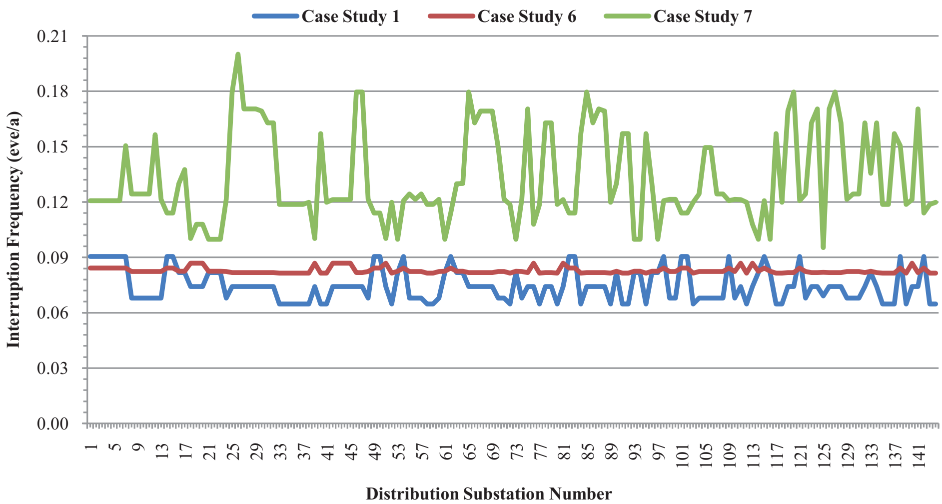

Figure 52. Annual expected frequency of momentary interruptions for distribution substations of the distribution test network, $AEF_{L_j}^{MI}$ (Case Studies 1, 6&7)

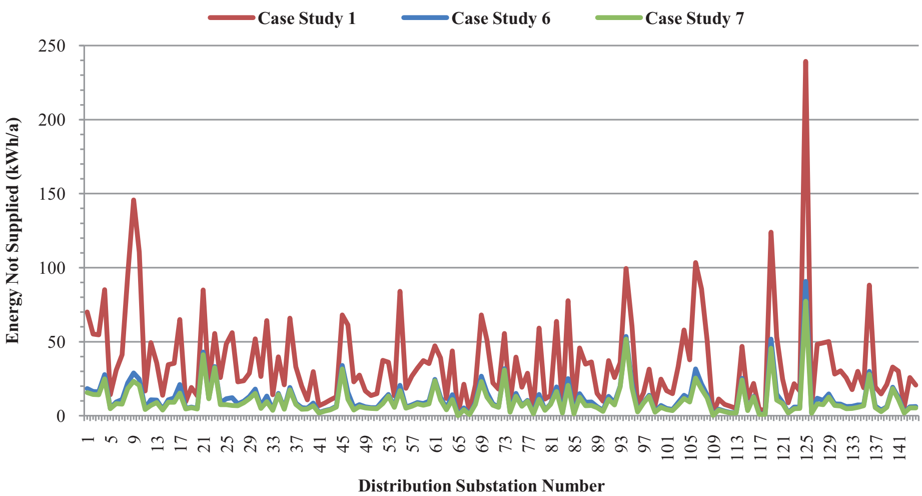

Figure 53. Annual expected energy not supplied for distribution substations of the distribution test network, $AENS_{L_j}^{SI}$ (Studies 1, 6&7)

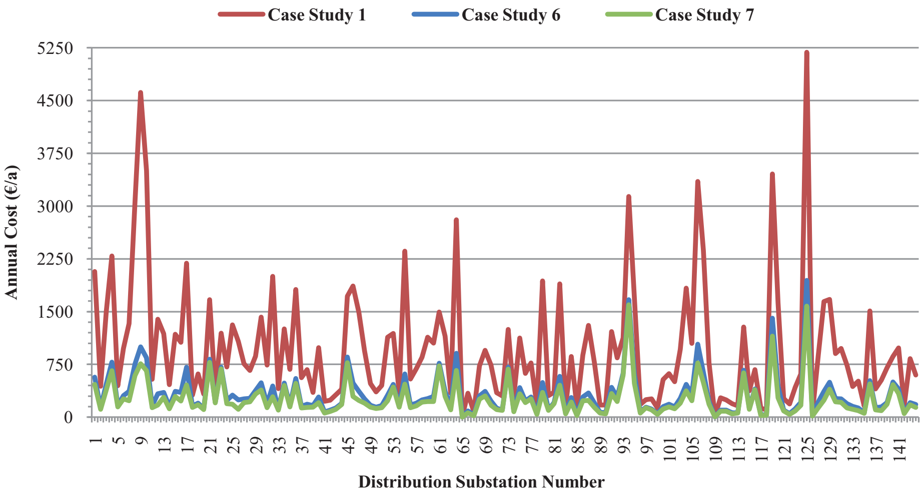

Figure 54. Annual expected cost arising from sustained interruptions for distribution substations of the distribution test network, $AEC_{L_j}^{SI}$ (Studies 1, 6&7)

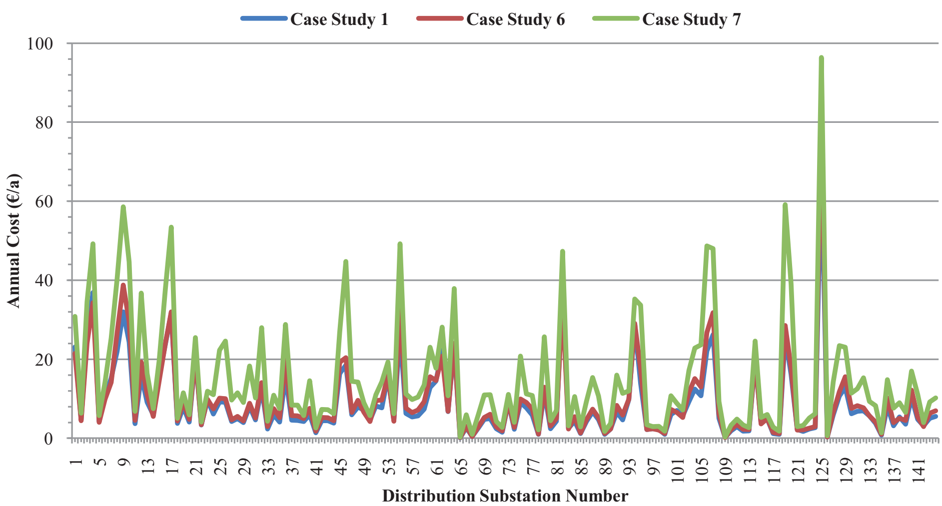

Figure 55. Annual expected cost arising from momentary interruptions for distribution substations of the distribution test network, $AEC_{L_j}^{MI}$ (Case Studies 1, 6&7)

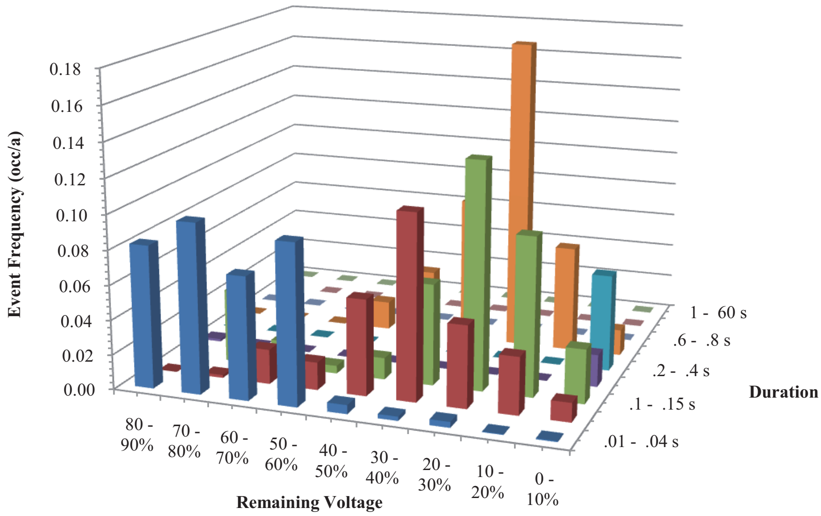

Figure 56. Density distribution of overall expected voltage variation events, $AVVFI^{(V,D)}$ (Case Study 7)

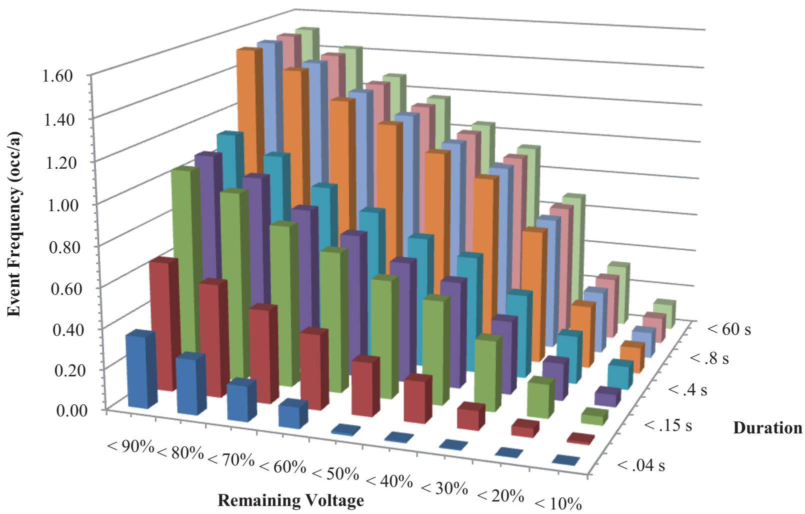

Figure 57. Cumulative distribution of overall expected voltage variation events, $AVVFI^{(V,D)}$ (Case Study 7)

6.2.8 Case Study 8: Integrating Distribution Automation System

The Case Study 7 contains the majority of infrastructures required to develop a distribution automation system. Therefore, it is possible to develop an advanced distribution automation system by integrating the implemented smart grid technologies with some new or modified technologies such as high speed communication systems and improved interfacing and decision supports. In this situation, the fault management activities can be accomplished more efficiently. For an illustration purpose, when employing this distribution automation system, it is assumed that the fault management activities in the distribution test network are now accomplished according to Table 13.

The system oriented reliability indices for this case study are represented in Table 14. The load point reliability indices that differ from those of the Case Study 7 are also shown in Figures 58-63. The distributions of expected momentary interruptions and voltage sags imposed on the customers of the distribution test network are also shown in Figures 64 and 65.

The study results show that the reliability indices associated with the sustained interruptions have been improved compared to those of the Case Study 7. However, the reliability indices associated with the momentary interruptions have been deteriorated compared to those of the Case Study 7. As some of the fault condition cannot be managed completely by the available feeder automation scheme, the remote fault detection, isolation and service restoration activities are required to restore the power to as many as possible of the customers. In the Case Study 7, the time required for accomplishing this task was much above the aggregation window for recording the momentary events (5 minutes). Therefore, the customers whose power services were restored by remote switching operation faced sustained interruptions instead of momentary interruptions. However, when employing the advanced distribution automation system, the remote fault detection, isolation and service restoration activities can be accomplished in a period of time well below the threshold of a momentary interruption. As a result, the number and duration of sustained interruptions are decreased and the frequency of momentary interruptions is increased. This can also be found by comparison of the results provided in Figures 56 and 64. As it can be seen in these figures, the number of events corresponding to momentary interruptions (remaining voltage less than 10 percents of the nominal voltage) has been increased in the range 1-60 seconds for the Case Study 8 compared to that of the Case Study 7.

The smart grid technologies implemented in this case study do not have any impacts on the voltage sags experienced by the customers compared to those of the Case Study 7.

The results presented in Table 14 show that the burden on the utility crews is also reduced when employing the advanced distribution automation system. This is because much less time is required to dispatch the repair crews and also they spend less time for travelling around the network in order to perform field activities.

TABLE 13
BASIC DATA RELATED TO THE FAULT MANAGEMENT ACTIVITIES IN CASE STUDY 8

Average time required for fault notification (s)	5
Average time required for approximate fault location (s)	10
Average time required for decision making about fault management activities (s)	25
Average time required for dispatching the repair crews (s)	20
Average speed of the repair crews for traveling to the faulted area (km/h)	60
Average time required for precise fault location on an underground cable section including both pre-location and pinpointing activities (s)	1800
Average time required for manual operation of switching devices involved in fault management activities (s)	180
Average time required for uncoordinated remote switching operation (s)	5
Average time required for coordinated remote switching operation (s)	120
Available teams of repair crews for performing fault management activities	2

TABLE 14
SYSTEM ORIENTED RELIABILITY INDICES FOR CASE STUDY 8

Reliability Index	**Expected Value**	**Relative Change to Case Study 7 (%)**	**Relative Change to the Base Case (%)**
SAIFI (int/sub-a)	0.1050	-13.37	-87.57
SAIDI (h/sub-a)	0.2195	-7.50	-72.67
MAIFI (eve/sub-a)	0.1487	+12.23	+99.33
AVSSI (eve/sub-a)	0.9777	0.00	-19.56
ASUI (%)	0.002505	-7.53	-72.68
EENS (kWh/a)	1353	-7.96	-73.57
$ECOST^{SI}$ (€/a)	34547	-8.37	-75.31
$ECOST^{MI}$ (€/a)	2538	+14.27	+96.59
$ECOST^{VS}$ (€/a)	16850	0.00	-20.06
Total Cost (€/a)	53935	-5.00	-66.77
Repair Crew Burden (h/a)	71.67	-1.36	-10.85

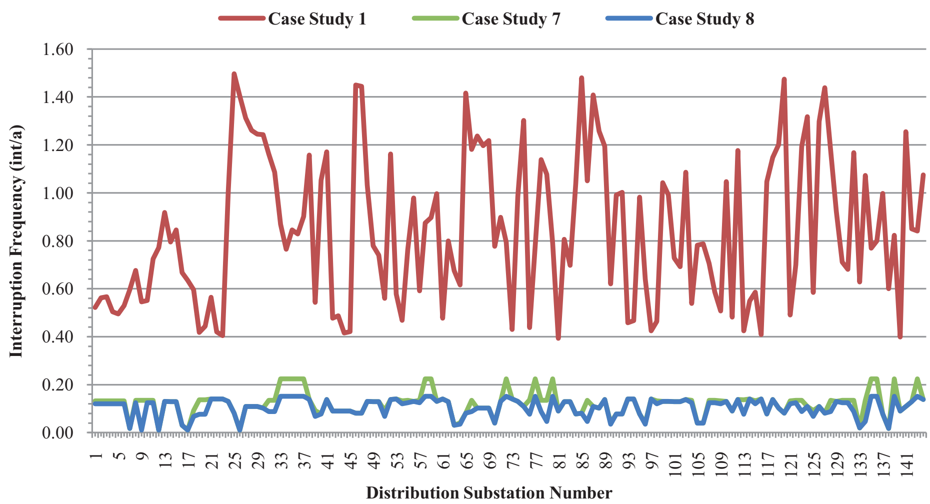

Figure 58. Annual expected frequency of sustained interruptions for distribution substations of the distribution test network, $AEF_{L_j}^{SI}$ (Case Studies 1, 7&8)

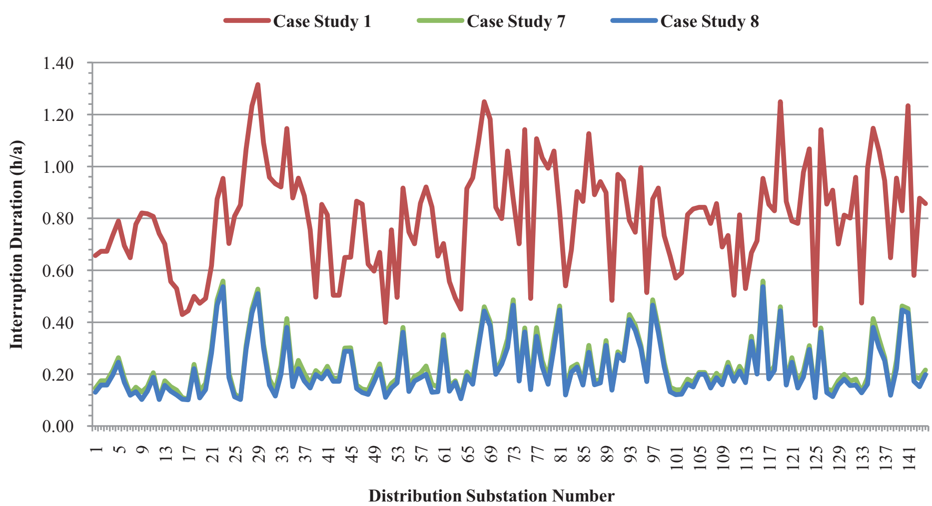

Figure 59. Annual expected duration of sustained interruptions for distribution substations of the distribution test network, $AED_{L_j}^{SI}$ (Case Studies 1, 7&8)

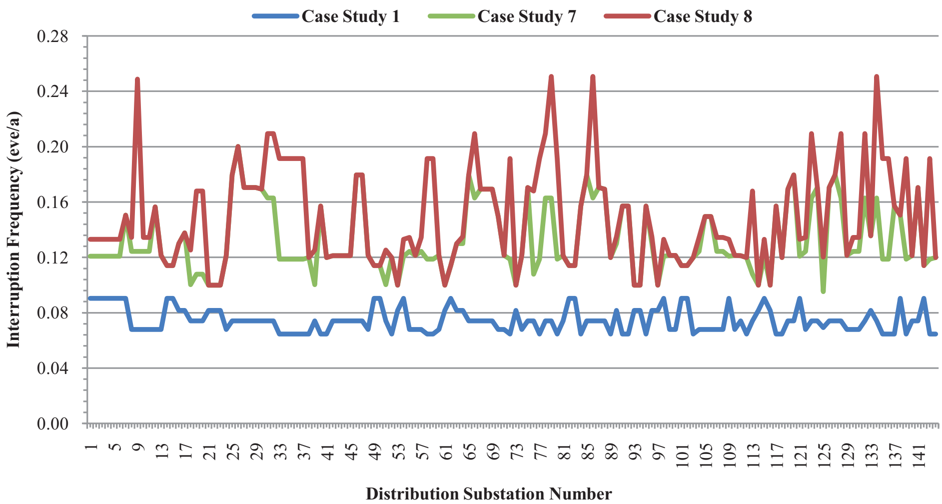

Figure 60. Annual expected frequency of momentary interruptions for distribution substations of the distribution test network, $AEF_{L_j}^{MI}$ *(Case Studies 1, 7&8)*

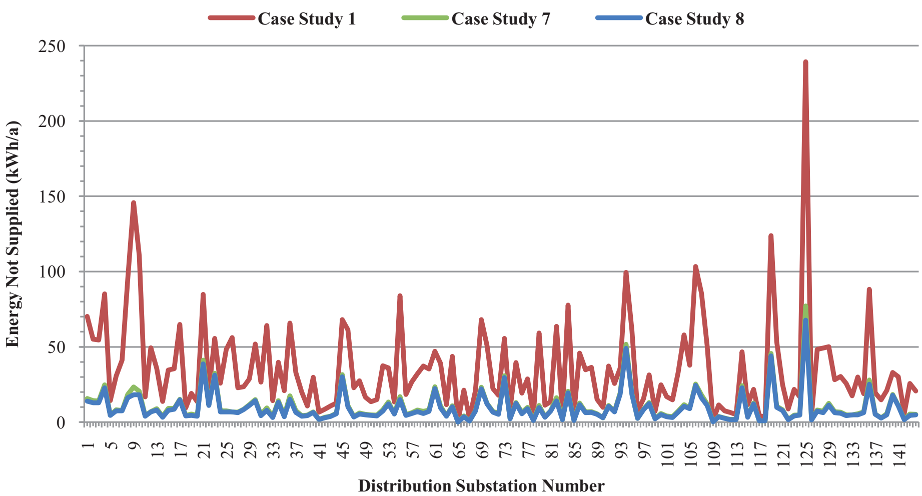

Figure 61. Annual expected energy not supplied for distribution substations of the distribution test network, $AENS_{L_j}^{SI}$ *(Studies 1, 7&8)*

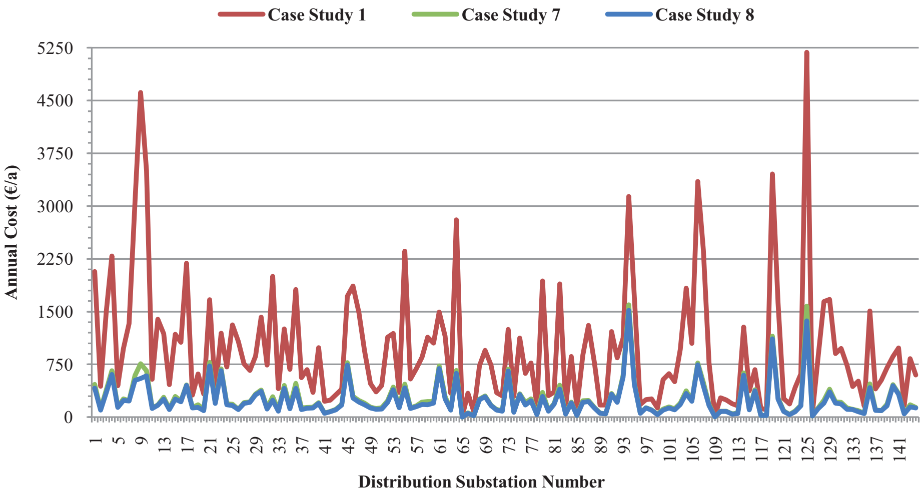

Figure 62. Annual expected cost arising from sustained interruptions for distribution substations of the distribution test network, $AEC_{L_j}^{SI}$ (Studies 1, 7&8)

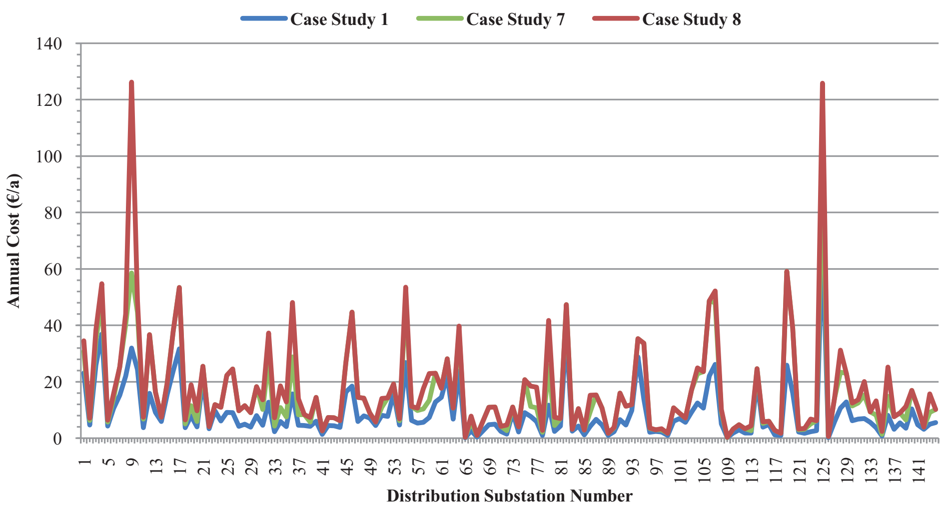

Figure 63. Annual expected cost arising from momentary interruptions for distribution substations of the distribution test network, $AEC_{L_j}^{MI}$ (Case Studies 1, 7&8)

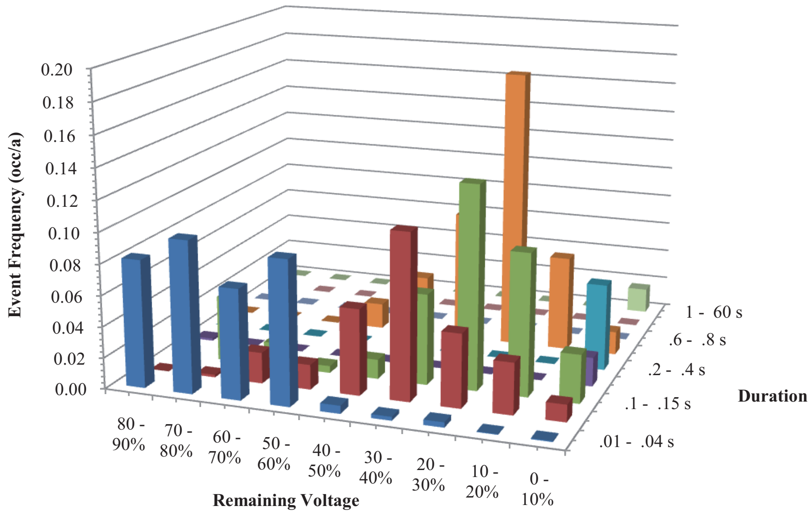

Figure 64. Density distribution of overall expected voltage variation events, $AVVFI^{(V,D)}$ (Case Study 8)

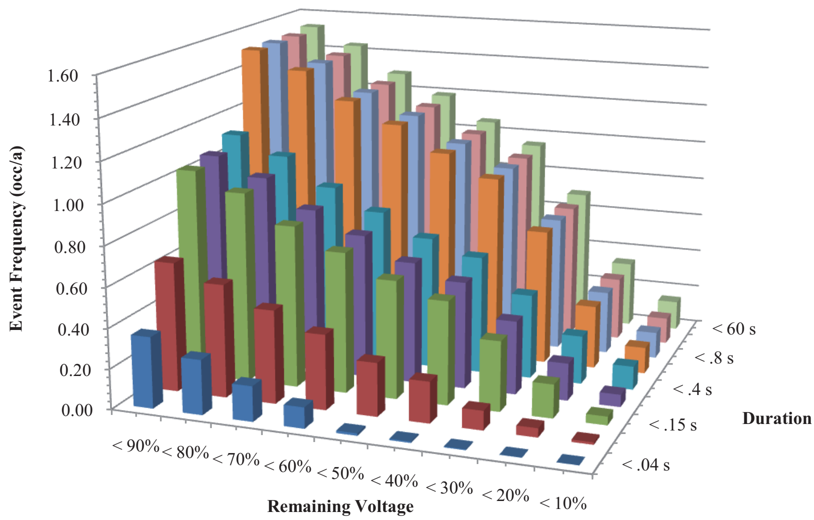

Figure 65. Cumulative distribution of overall expected voltage variation events, $AVVFI^{(V,D)}$ (Case Study 8)

6.2.9 *Case Study 9: Integrating Fault Current Limiters*

The smart grid technologies implemented in the Case Studies 2 and 3 could alleviate the voltage sags experiencing by the customers. Hence, the frequency of severe voltage sags was reduced for these case studies. However, employing the smart grid technologies targeted in the Case Studies 4-8 could not result in any further mitigation in the voltage sags experiencing by the customers. Actually, these technologies are mainly used for reducing the number and duration of sustained interruptions imposed on the customers. However, there are some other smart grid technologies available that can be used in the functional zone of the electricity distribution networks to further mitigate the voltage sags experienced by the customers.

Fault current limiters are one of the attractive smart grid technologies that are mainly used for managing the fault currents in the electric power systems. Appropriate allocation of the fault current limiters may also alleviate the voltage sags arising from the over-current faulty conditions. Installing the fault current limiters immediately downstream of the feeder circuit breaker is one of the most potential locations for such purpose. In this method, it might be possible to close the normally-open tie switching device between medium voltage buses which results in a better voltage regulation and enhanced substation reliability. In the case of an over-current fault condition, the voltage drop across the fault current limiter keeps the busbar voltage high enough for majority of downstream faults. This will lead to the less severe voltage sags on the other feeders originated from the common busbar. For an illustration purpose, it is assumed that the fault current limiters are installed at immediately downstream of each feeder circuit breaker of the distribution test network. It is also assumed that the technology of the fault current limiters is based on the high-temperature superconducting materials. In this situation, the reaction time of the fault current limiters is around 5 milliseconds. The activated impedance of the fault current limiters is chosen to be 4 ohms in order to keep the voltage of 20 kV busbar above 75 percents of the nominal voltage for downstream three-phase faults close to the 110/20 kV substation. The basic data related to the fault management activities are assumed similar to that of the Case Study 8.

The system oriented reliability indices for this case study are represented in Table 15. The load point reliability indices associated with the momentary interruptions and voltage sags are also shown in Figures 66-69. The other reliability indices are similar to those of the Case Study 8. The distributions of expected momentary interruptions and voltage sags imposed on the customers of the distribution test network are also shown in Figures 70 and 71.

In the previous case studies, the short circuit faults close to the main substation result in the remaining voltage less than the threshold of the momentary interruptions (10 percent of the nominal voltage) and appear as the momentary interruptions to the customers. However, after installing the fault current limiters, the voltage drop across the fault current limiter keeps the busbar voltage high enough for majority of downstream faults and hence the frequency of the momentary interruptions is reduced compared to those of the Case Study 8. But, the frequency of the momentary interruptions is still much higher than that of the base case study.

The study results also show that the number and hence the financial impacts of the severe voltage sags have been alleviated when employing the fault current limiters. By comparing the results presented in Figures 64 and 70, it can be found that after installing the fault current limiters the density of severe voltage sags which cause malfunction for majority of the customers (e.g. events with remaining voltage less than 70 percents of the nominal voltage) has been decreased and instead the density of shallow voltage sags has been increased.

TABLE 15
SYSTEM ORIENTED RELIABILITY INDICES FOR CASE STUDY 9

Reliability Index	**Expected Value**	**Relative Change to Case Study 8 (%)**	**Relative Change to the Base Case (%)**
SAIFI (int/sub-a)	0.1050	0.00	-87.57
SAIDI (h/sub-a)	0.2195	0.00	-72.67
MAIFI (eve/sub-a)	0.1219	-18.02	+63.40
AVSSI (eve/sub-a)	0.8913	-8.84	-26.67
ASUI (%)	0.002505	0.00	-72.68
EENS (kWh/a)	1353	0.00	-73.57
$ECOST^{SI}$ (€/a)	34547	0.00	-75.31
$ECOST^{MI}$ (€/a)	2075	-18.24	+60.73
$ECOST^{VS}$ (€/a)	15363	-8.82	-27.12
Total Cost (€/a)	51984	-3.62	-67.97
Repair Crew Burden (h/a)	71.67	0.00	-10.85

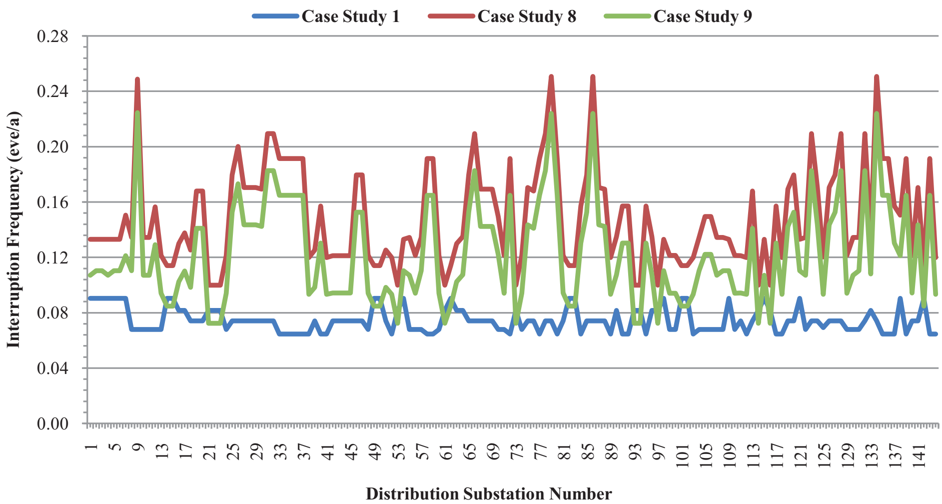

Figure 66. Annual expected frequency of momentary interruptions for distribution substations of the distribution test network, $AEF_{L_j}^{MI}$ *(Case Studies 1, 8&9)*

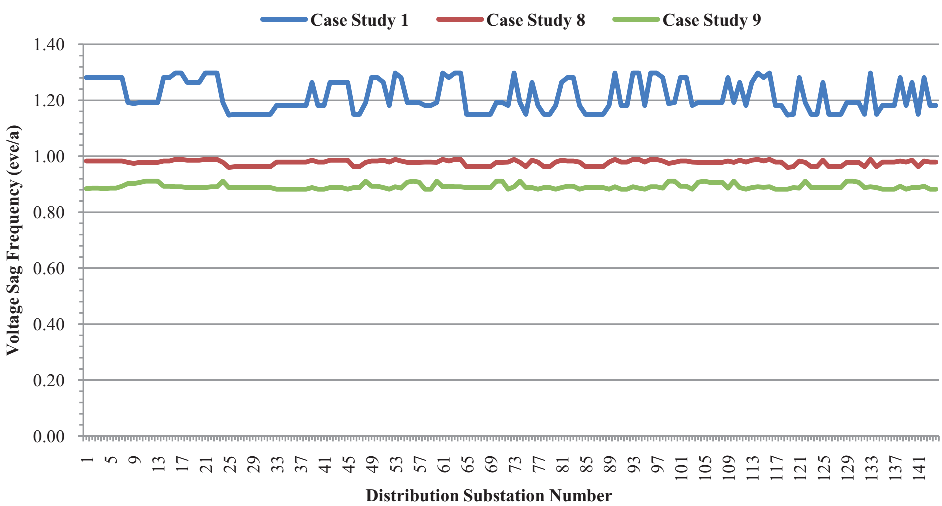

Figure 67. Annual expected frequency of voltage sags affecting distribution substations of the distribution test network, $AEF_{L_j}^{VS}$ *(Case Studies 1, 8&9)*

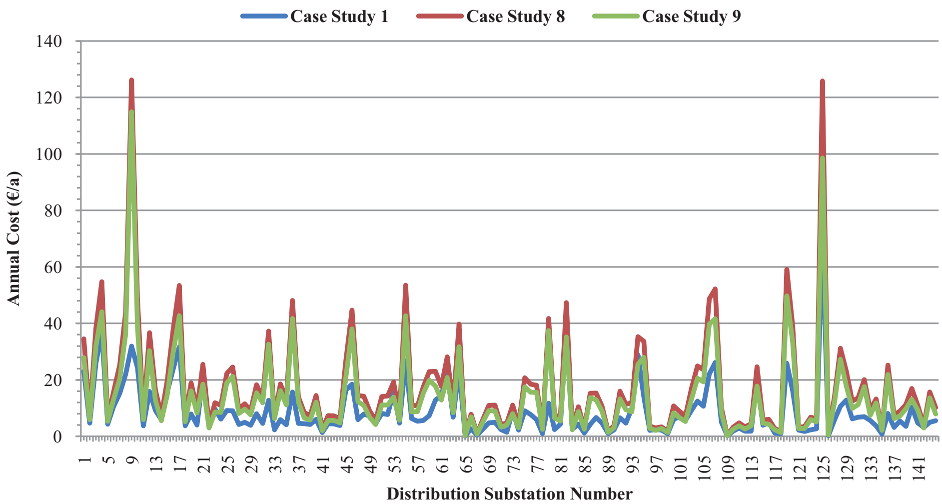

Figure 68. Annual expected cost arising from momentary interruptions for distribution substations of the distribution test network, $AEC_{L_j}^{MI}$ (Case Studies 1, 8&9)

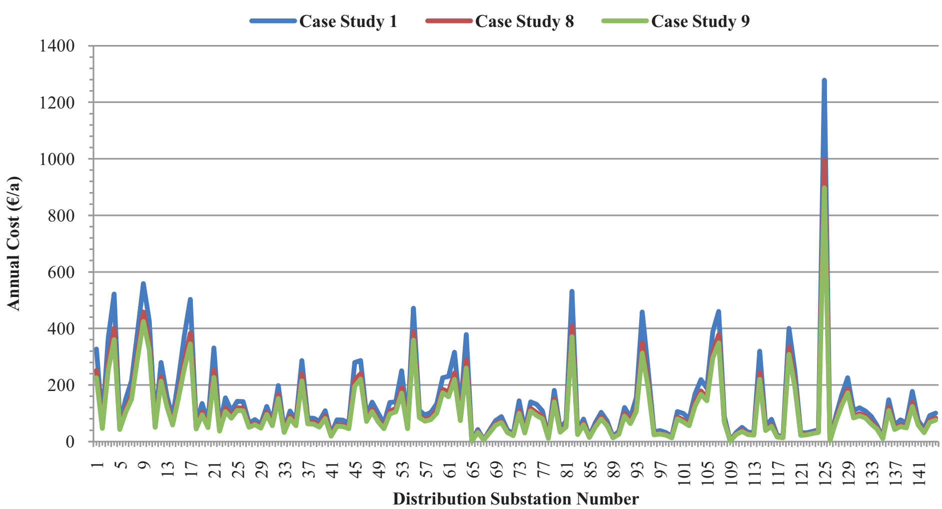

Figure 69. Annual expected cost arising from voltage sags for distribution substations of the distribution test network, $AEC_{L_j}^{VS}$ (Case Studies 1, 8&9)

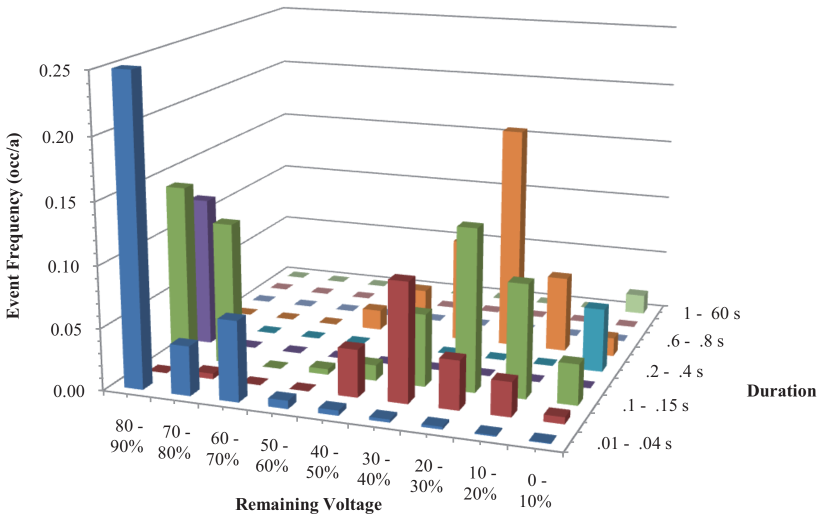

Figure 70. Density distribution of overall expected voltage variation events, $AVVFI^{(V,D)}$ (Case Study 9)

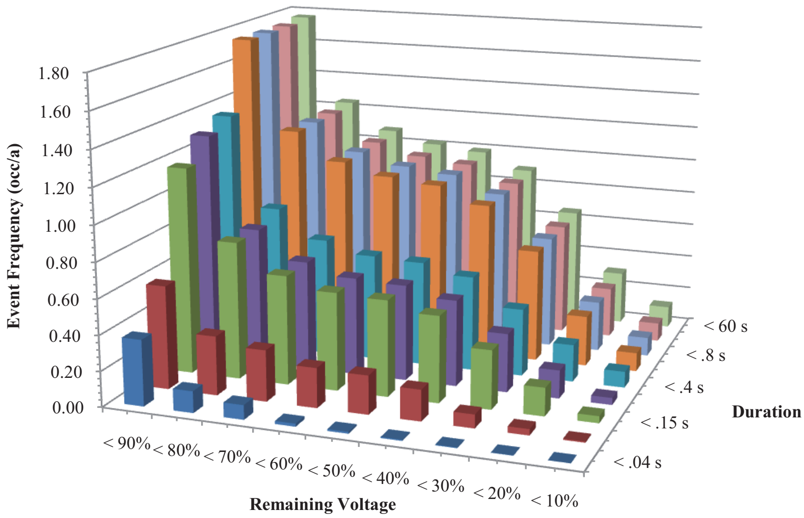

Figure 71. Cumulative distribution of overall expected voltage variation events, $AVVFI^{(V,D)}$ (Case Study 9)

6.2.10 Case Study 10: Integrating Dynamic Voltage Restorers

The fault current limiters implemented in the Case Study 9 could just mitigate the voltage sags originated from the faults within the distribution test network. They cannot alleviate the voltage sags that propagated from the sub-transmission network into the distribution test network. The frequency and severity of the voltage sags arising from external faults can be alleviated at the transmission and sub-transmission levels by means of fault prevention schemes, network configuration modification, advanced protection schemes and so on. However, within the functional zone of an electricity distribution system, it is possible to use the dynamic voltage restorers to mitigate the voltage sags regardless of their origins. Optimal allocation of the dynamic voltage restorers for voltage sag mitigation purpose requires a course of cost-benefit analyses. However, for the sake of simplicity, it is assumed that the distribution substations 4, 9, 10, 17, 55, 82, 94, 107, 119 and 125 are equipped with dynamic voltage restorers. These distribution substations have high contribution to the overall costs associated with the voltage sags. It is also assumed that all the dynamic voltage restorers have the same correction capability. The correction capability of the dynamic voltage restorers is modeled according to the characteristics of a commercially available device in the market (ABB-PCS 100AVC). Activation time less than half a cycle, full correction for three-phase sags down to 70 percents of the nominal voltage and also full correction for single-phase sags down to 55 percents of the nominal voltage are the main characteristic of the employed dynamic voltage restorers. It is assumed that for the voltage sags with the remaining voltage less than 50 percents of the nominal voltage, the dynamic voltage restorers stay in the bypass mode. In this situation, there is no boosting in the sagged phases.

The basic data related to the fault management activities are assumed similar to that of the Case Study 8. The system oriented reliability indices for this case study are represented in Table 16. The load point reliability indices associated with the voltage sags are shown in Figures 72 and 73. The other reliability indices are similar to those of the Case Study 9. As an example, the distributions of expected momentary interruptions and voltage sags imposed on the customers of the distribution substation number 4 before and after employing the dynamic voltage restorers are also shown in Figures 74 and 75.

The study results show that the number and hence the financial impacts of the voltage sags for the distribution substations equipped with dynamic voltage restorers have been considerably alleviated. As dynamic voltage restorers are capable of correcting the voltage sags regardless of their origin, much better improvements are achieved when employing these devices compared to the situation where fault current limiters are used for voltage sag mitigation purposes. Actually, application of the fault current limiters is an effective solution for mitigation of voltage sags originated from faults within the distribution network. However, in a situation where the contribution of externally generated voltage sags in the overall cost is dominated, other solutions such as employing the dynamic voltage restorers at strategic locations can be a potential option.

The dynamic voltage restorers alleviate the voltage sags experienced by the customers connected downstream of their locations. Instead, the fault current limiters have the reverse behavior. The fault current limiters alleviate the voltage sag experienced by the upstream customers and aggravate those experienced by downstream customers.

TABLE 16
SYSTEM ORIENTED RELIABILITY INDICES FOR CASE STUDY 10

Reliability Index	Expected Value	Relative Change to Case Study 9 (%)	Relative Change to the Base Case (%)
SAIFI (int/sub-a)	0.1050	0.00	-87.57
SAIDI (h/sub-a)	0.2195	0.00	-72.67
MAIFI (eve/sub-a)	0.1214	-0.41	+62.73
AVSSI (eve/sub-a)	0.8484	-4.81	-30.20
ASUI (%)	0.002506	0.00	-72.67
EENS (kWh/a)	1353	0.00	-73.57
$ECOST^{SI}$ (€/a)	34548	0.00	-75.31
$ECOST^{MI}$ (€/a)	2064	-0.53	+59.88
$ECOST^{VS}$ (€/a)	12542	-18.36	-40.50
Total Cost (€/a)	49155	-5.44	-69.71
Repair Crew Burden (h/a)	71.67	0.00	-10.85

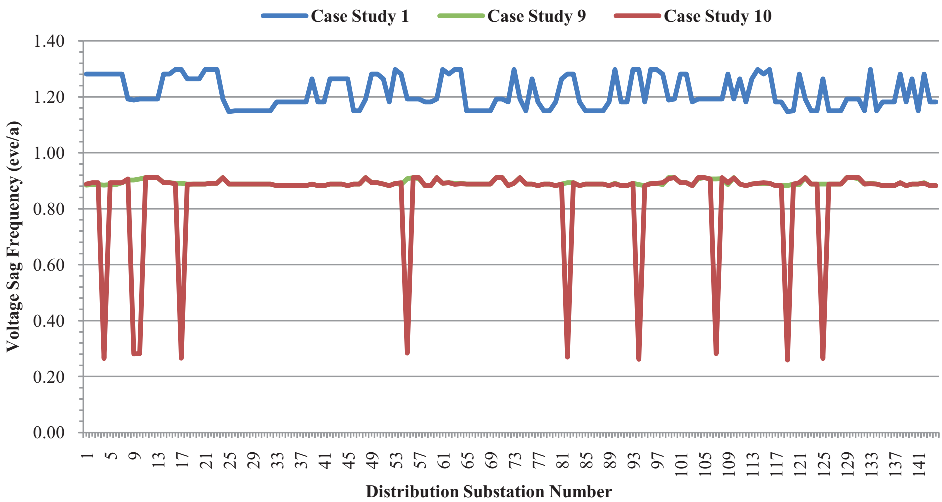

Figure 72. Annual expected frequency of voltage sags affecting distribution substations of the distribution test network, $AEF_{L_j}^{VS}$ (Case Studies 1, 9&10)

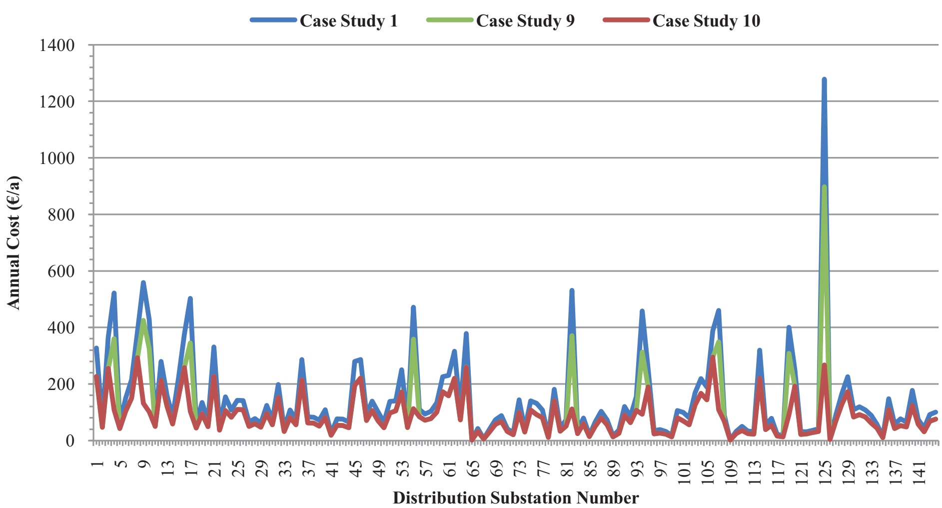

Figure 73. Annual expected cost arising from voltage sags for distribution substations of the distribution test network, $AEC_{L_j}^{VS}$ (Case Studies 1, 9&10)

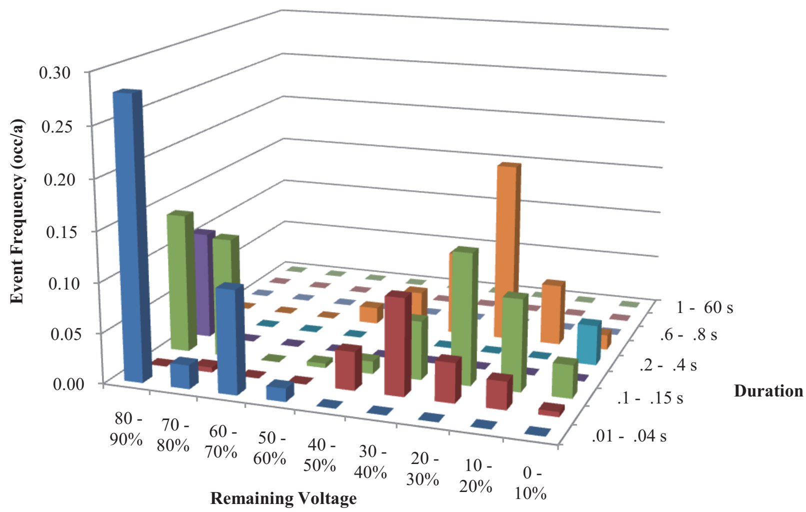

Figure 74. Density distribution of overall expected voltage variation events, $AVVFI^{(V,D)}$, imposed on the distribution substation number 4 (before employing dynamic voltage restorers)

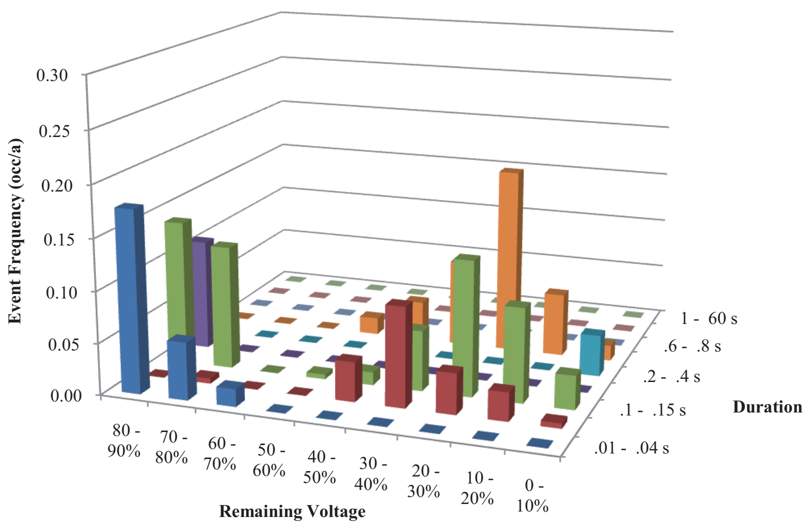

Figure 75. Density distribution of overall expected voltage variation events, $AVVFI^{(V,D)}$, imposed on the distribution substation number 4 (after employing dynamic voltage restorers)

6.3 Comparison of Implemented Smart Grid Technologies

Various smart grid technologies were examined in the previous sections to estimate their impacts on the reliability of electric power delivered to the customers of the distribution test network. The study results show that various smart grid technologies have different reliability impacts. The impacts of the examined smart grid technologies on the various system oriented reliability indices of the distribution test network have been compared against each other in Figures 76-80.

Figure 76 shows that after integrating the distance to fault estimators (Case Study 2), the fault passage indicators (Case Study 3) and also the feeder automation scheme (Case Study 7), the average frequency of the sustained interruptions has been considerably reduced. Integrating other smart grid technologies has no or only little impact on SAIFI.

As it can be seen from Figure 77, after integrating the distance to fault estimators (Case Study 2) and the fault locator scheme (Case Study 4), the average duration of sustained interruptions has been considerably decreased. Integrating the automation solutions toward the complete distribution automation system (Case Studies 5 to 8) could also result in some additional improvements in SAIDI. Integrating the fault passage indicators (Case Study 3) has negative impact on SAIDI. The fault current limiters (Case Study 9) and the dynamic voltage restorers (Case Study 10) have no impacts on SAIDI.

Figure 78 shows that after integrating the distance to fault estimators (Case Study 2), the frequency of the momentary interruptions has been considerably reduced. The value of MAIFI remains the same after integrating the fault passage indicators (Case Study 3) and the fault locator scheme (Case Study 4). However, integrating the sub-transmission substation automation (Case Study 5), the feeder automation scheme (Case Study 7) and the distribution automation system (Case Study 8) have negative impacts on MAIFI. Although employing the fault current limiters (Case Study 9) cause a little bit improvement in MAIFI, but the value of MAIFI is still much above of that of the base case study.

As it can be seen from Figure 79, integrating the distance to fault estimators (Case Study 2) could significantly alleviate the impacts of the voltage sags on the customers. After integrating the fault passage indicators (Case Study 3), the fault current limiters (Case Study 9) and the dynamic voltage restorers (Case Study 10) additional improvements have also been achieved in AVSSI. Integrating other smart grid technologies has no impact on AVSSI.

Figure 80 shows the overall cost of the service reliability issues on the customers of the distribution test network. This figure shows the accumulated impacts of the sustained interruptions, momentary interruptions and voltage sags on the customers. Therefore, the overall effects of the examined smart grid technologies can be well understood from this figure. As it can be seen from Figure 80, after integrating each smart grid technology, an improvement is appeared in the overall expected cost. However, the levels of improvements are dominated when integrating the distance to fault estimators (Case Study 2) and the fault locator scheme (Case Study 4). Actually, when a customer encounters with an abnormal situation due to a severe voltage sag, a momentary interruption or a sustained interruption; the imposed costs on the customer are almost the same at the beginning of the event. However, the sustained interruptions last for longer time periods; hence, the costs associated with the sustained interruptions are increased proportional with the duration of interruptions. Therefore, normally, the costs associated with the momentary interruptions and voltage sags can only be reduced by mitigating the occurrence frequency of such events. Instead, the costs of sustained interruptions can be mitigated through reducing both frequency and duration of interruptions. Therefore, as it can be seen from the results presented in Figure 80, the impacts of the smart grid technologies which reduce the annual duration of sustained interruptions (SAIDI) are more dominated.

Figure 81 shows the impact of the examined smart grid technologies on the burdens on the utility crews. The results presented in this figure indicate that integrating technologies toward a complete distribution automation system can considerably reduce the burdens on the utility repair crews.

When dealing with the results presented in Figures 76-81, it should be noted that the technologies have been added to a set of previously implemented technologies. As an example, when integrating the sub-transmission substation automation it has been assumed that the distance to fault estimators, fault passage estimators and fault locator scheme have already been implemented in the distribution test network. The integrating sequence which has been used in this thesis follows the practical chronology of developing smart distribution grids. Therefore, if this sequence changes from that used in this thesis, different reliability impacts might be obtained for each implemented technology. However, the overall improvement remains the same regardless of the sequence that these technologies are integrated.

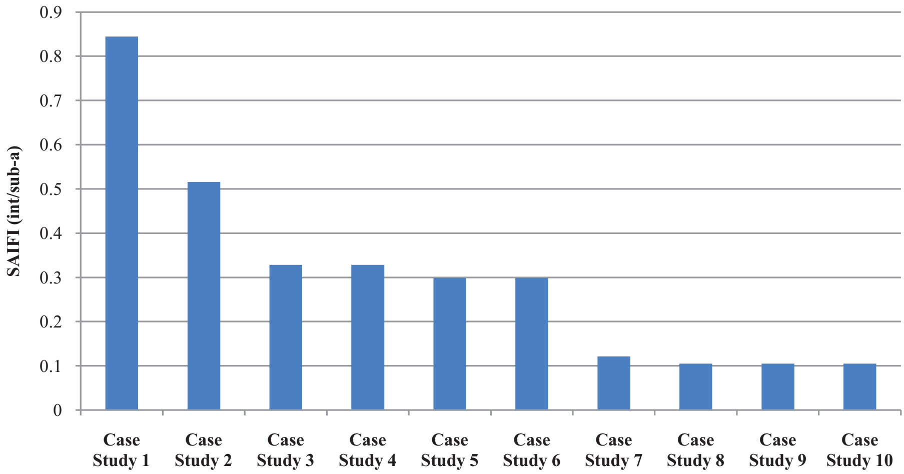

Figure 76. Impacts of the examined smart grid technologies on SAIFI of the distribution test network

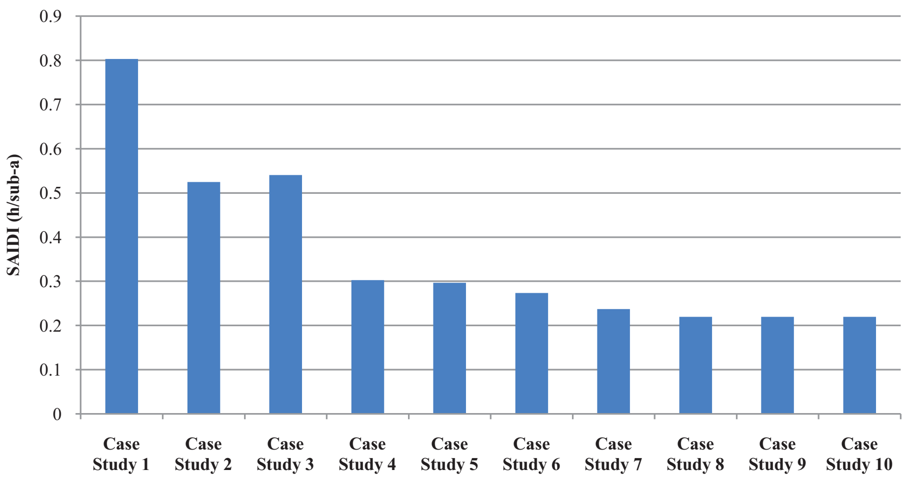

Figure 77. Impacts of the examined smart grid technologies on SAIDI of the distribution test network

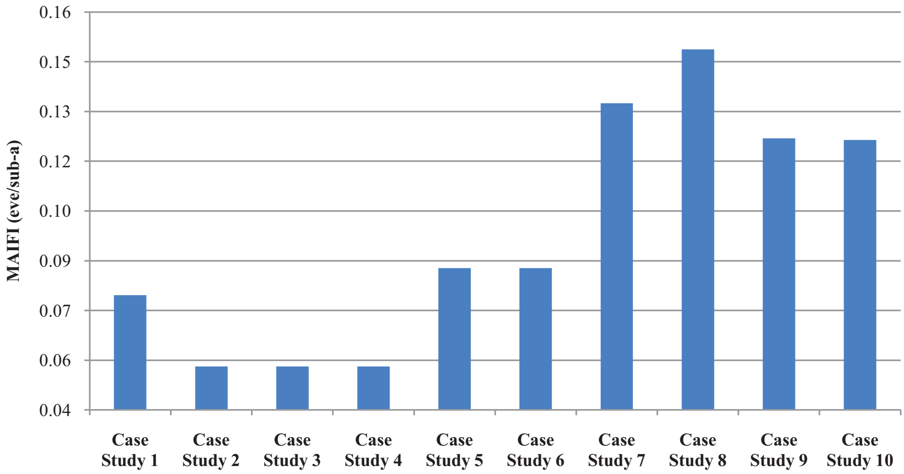

Figure 78. Impacts of the examined smart grid technologies on MAIFI of the distribution test network

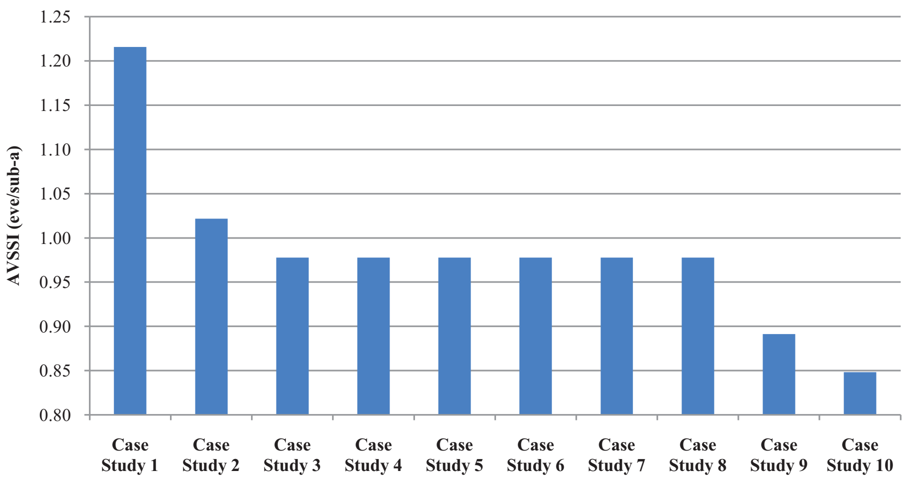

Figure 79. Impacts of the examined smart grid technologies on AVSSI of the distribution test network

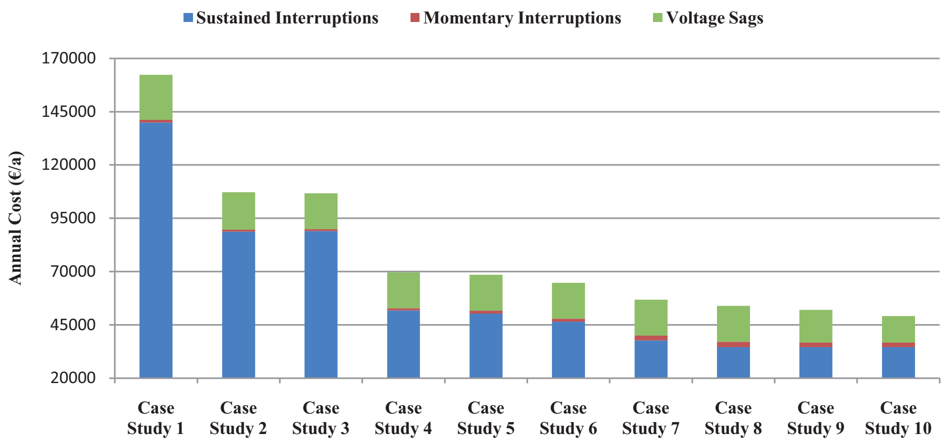

Figure 80. Impacts of the examined smart grid technologies on the annual cost of the service reliability issues imposed on the customers of the distribution test network

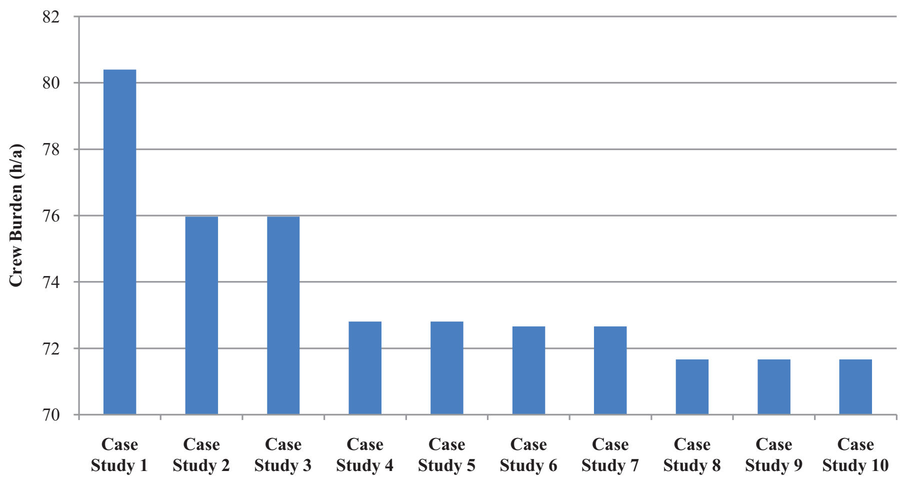

Figure 81. Impacts of the examined smart grid technologies on the burdens on the utility repair crews

6.4 Impacts of Operational Failure of Smart Grid Technologies

In the previous sections, the reliability impacts of major smart grid technologies were evaluated and compared against each other. When conducting the related reliability studies, it was assumed that the implemented smart grid technologies are fully reliable. This assumption may not be correct. Similarly to other components of an electricity distribution network, the implemented smart grid technologies may have some failure modes. However, the advanced smart grid technologies are normally equipped with sophisticated fault diagnosis algorithms that automatically monitor the status of devices and initiate a suitable alarm if required. Therefore, some of the failure modes of the implemented smart grid technologies are detected and mitigated during normal operating status of an electric power distribution network. But, there is always a chance to face a situation where a device is required to do specific tasks in response to an abnormal condition but fails to function properly. This failure condition, which is referred to as operational failure mode, may cause serious reliability impacts.

In order to evaluate the reliability impacts of operational failure modes of a smart grid technology, it is necessary to use a specific reliability model. This reliability model normally represents the possible statuses that a smart grid technology may reside when it fully functions and also when it encounters with various operational failure modes. The targeted functions of a smart grid technology may be altered due to its operational failure modes. Therefore, for each status of the reliability model, specific functions of a smart grid technology are available and the others are unavailable. Although, it is possible to deduce a suitable reliability model for representing the operational failure modes of a smart grid technology, but there is a common problem: the data. A smart grid technology should remain in service for a quite long time in order to gather the data that are of interest for modeling its operational failure modes.

In this section, for illustrative purposes, the reliability impacts of operational failure modes are evaluated for two of the examined smart grid technologies. They are distance to fault estimators and fault current limiters. For sake of simplicity and also due to lack of the relevant data, it is assumed that the targeted smart grid technology operates successfully in 95 percents of times and encounters with an operational failure 5 percents of times. However, in [140] - [145], the operational failure modes have been analyzed in more details for several feeder automation schemes.

6.4.1 Case Study 11: Impacts of Operational Failure of Distance to Fault Estimators

This case study aims to evaluate and compare the effects of the operational failure of distance to fault estimators on the reliability indices of the distribution test network. The basic data related to the fault management activities are assumed similar to that of the Case Study 2.

The system oriented reliability indices for this case study are represented in Table 17. The study results show that virtually all the reliability indices have been deteriorated compared to those of the Case Study 2. The degree of deteriorations ranges from 1 to 3 percents. Actually, when employing the distance to fault estimators, a much smaller zone of the electricity distribution network is required to be inspected by the repair crews. Therefore, much less trial and error switching actions are required to find the faulted section. However, in a situation that the distance to fault estimators encounter with the operational failure condition, the repair crews have to use the trial and error switching method to find the faulted zone. This process is time consuming as the repair crews have to travel around the network and perform the necessary switching activities. As a result, both the frequency and duration of sustained interruptions are increased.

The trial and error switching operations for fault location purposes normally cause the re-ignition of a fault. The effects of the fault re-ignition appear to the customers supplied by the other healthy feeders either as a momentary interruption or a voltage sag. Therefore, as the study results indicate, the reliability indices associated with the momentary interruptions and voltage sags have also been deteriorate compared to the Case Study 2.

The results presented in Table 17 also show that the burden on the utility crews is increased compared to the Case Study 2. This is because more field activities are required to find the faulted section when the distance to fault estimators encounter with the operational failure conditions.

TABLE 17
SYSTEM ORIENTED RELIABILITY INDICES FOR CASE STUDY 11

Reliability Index	Expected Value	Relative Change to Case Study 2 (%)
SAIFI (int/sub-a)	0.5324	+3.19
SAIDI (h/sub-a)	0.5383	+2.66
MAIFI (eve/sub-a)	0.0541	+1.96
AVSSI (eve/sub-a)	1.0315	+0.95
ASUI (%)	0.006145	+2.66
EENS (kWh/a)	3370	+2.81
$ECOST^{SI}$ (€/a)	91267	+2.89
$ECOST^{MI}$ (€/a)	932	+2.03
$ECOST^{VS}$ (€/a)	17797	+0.98
Total Cost (€/a)	109995	+2.57
Repair Crew Burden (h/a)	76.19	+0.29

6.4.2 Case Study 12: Impacts of Operational Failure of Fault Current Limiters

This case study aims to evaluate and compare the effects of the operational failure of the fault current limiters on the reliability indices of the distribution test network. The basic data related to the fault management activities are assumed similar to that of the Case Study 9. When conducting this case study, it is assumed that each feeder circuit breaker can interrupt short circuit currents up to 4500 amperes.

The system oriented reliability indices for this case study are represented in Table 18. The study results show that the reliability indices associated with the momentary interruptions and voltage sags have been a little bit deteriorated compared to the Case Study 9. The degree of deteriorations is less than 1.5 percents. Actually, when a fault current limiter fails to operate successfully, a much higher fault current is expected compared to the situation when it operates successfully. This condition can cause a momentary interruption or a voltage sag for the customers supplied by the other healthy feeders. In a situation where a fault current limiter fails to operate successfully and the fault current is above the interrupting capability of the feeder circuit breaker, the backup circuit breakers have to operate for interrupting the fault current. This will result in an interruption for several feeders. However, the substation automation scheme can detect this abnormal condition and automatically perform the necessary switching operations to restore the power of the affected healthy feeders. As a result, the duration of such an interruption is limited well below the threshold of the momentary interruptions. There are also conditions where a fault current limiter fails to operate successfully but the fault current is below the interrupting capability of the feeder circuit breaker. In this situation, the circuit breaker of the faulted feeder operates to interrupt the fault current. Situation like this normally causes a voltage sag for the customers supplied by the other healthy feeders.

It should be noted that factors such as existing of the substation automation scheme, small value of operational failure probability for the fault current limiters, feasibility of the feeder circuit breakers for interrupting the fault currents within their ratings, no contribution from single-phase to ground faults in the over-current fault conditions, decreasing the fault current and its effects on the customers for faults far from the main substation have caused the impact of the operational failure of the fault current limiters to be as small as that observed in this case study.

TABLE 18
SYSTEM ORIENTED RELIABILITY INDICES FOR CASE STUDY 12

Reliability Index	**Expected Value**	**Relative Change to Case Study 9 (%)**
SAIFI (int/sub-a)	0.1050	0.00
SAIDI (h/sub-a)	0.2195	0.00
MAIFI (eve/sub-a)	0.1237	+1.48
AVSSI (eve/sub-a)	0.8949	+0.40
ASUI (%)	0.002505	0.00
EENS (kWh/a)	1353	0.00
$ECOST^{SI}$ (€/a)	34547	0.00
$ECOST^{MI}$ (€/a)	2106	+1.49
$ECOST^{VS}$ (€/a)	15424	+0.40
Total Cost (€/a)	52077	+0.18
Repair Crew Burden (h/a)	71.67	0.00

7 CONCLUSIONS

This doctoral research project was aimed at developing an approach for predicting the reliability impacts of advanced reliability enhancement solutions within the functional zone of an electric power distribution system. The results indicate that the impacts of the reliability enhancement solutions are revealed through the various processes involved in the fault management activities. When employing a given set of the smart grid technologies, some of the fault management activities are affected which finally alter the reliability of electric power delivered to the customers. Thereby, the proposed reliability evaluation approach was such designed that the impacts of the targeted smart grid technologies can be evaluated from their effects on the fault management activities. This reliability assessment technique is capable of predicting the impacts of targeted reliability enhancement solutions on the sustained interruptions, momentary interruptions and voltage sags experienced by the end-users.

Various smart grid technologies, applicable in the functional zone of an electricity distribution system, were identified during this doctoral research project. The fault passage indicators, fault locator schemes, substation automation, feeder automation, distribution automation, fault current limiters and dynamic voltage restorers were recognized as the major smart grid technologies applicable for distribution system reliability improvements. Therefore, in order to demonstrate the capabilities of the proposed reliability evaluation approach and also to have some ideas about the possible effects of the identified smart grid technologies, it was necessary to conduct a course of reliability case studies on a realistic power distribution system. Hence, considerable effort was put forth to develop a computer software that can be used for reliability evaluation of smart distribution grids. This software is now available and can be used for estimating the impacts of various distribution system reliability enhancement solutions.

Two groups of the reliability case studies were directed in this doctoral thesis. The first group included ten comparative case studies which aimed at comparing the reliability impacts of the identified smart grid technologies. An integrating approach was used for dealing with these case studies. The ultimate goal was to provide a premium electricity service for the customers of the distribution test network. The studies were started from a benchmark case study. Then, in the next case studies, a suitable smart grid technology was integrated to the last upgraded case study. The study results showed that employing a suitable set of the smart grid technologies in the distribution test network can mitigate all the reliability indices within a range of 30 to 88 percents. The study results also indicated that, using a suitable set of the smart grid technologies, it is possible to reduce the range of variation of reliability indices among different customers. In addition, more than 10 percents reduction on the burden on the utility repair crews were observed when employing appropriate set of the smart grid technologies. The second group of the reliability case studies aimed at evaluating the effects of operational failure of the implemented smart grid technologies. The distance to fault estimators and the fault current limiters were selected for purposes of this study. The study results indicated that the operational failure of the targeted smart grid technologies can deteriorate the service reliability. However, whenever there are some facilities for supporting fault management activities while the targeted smart grid technology fails to operate successfully, it is possible to mitigate the overall impacts of such failures. The first case study in this group was concerned with the operational failure of the distance to fault estimators. In this case study, when the distance to fault estimators encounter with the operational failure condition, there was no other facilities for approximate location of the fault. Therefore, the repair crews had to use the trial and error switching method to find the faulted zone. This process is time consuming and normally causes the re-ignition of the fault. Hence, all the reliability indices associated with the sustained interruptions, momentary interruptions and voltage sags were deteriorated in this case study. However, the second case study which was concerned with the operational failure of the fault current limiters showed different results. In this case study, the substation automation scheme available in the main substation was able to automatically detect and mitigate the abnormal condition arising from the operational failure of the fault current limiters. As a result, the overall impact of the operational failure of the fault current limiters on the service reliability was insignificant.

The smart grid technologies examined in this doctoral thesis are already available in the market. However, there are some other technologies still in the research and development stage. The reliability evaluation procedure proposed in this doctoral thesis can be used for evaluating the impacts of emerging distribution system reliability enhancement technologies as well. The main requirement is to know how the targeted technologies may affect the process involved with the fault management activities.

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Appendix I: Basic Data of Distribution Substations of the Distribution Test Network

Substation Number	X and Y Coordinates with Respect to the HV/MV Substation (meters)		Peak Demand (kVA)	Transformer Rating (kVA)	Transformer Impedance (%)	Interruption Cost *	
						€/kW	€/kWh
1	3497	6925	154.00	315	4	2.39	27.60
2	2965	6574	118.00	200	4	0.64	7.41
3	2515	6812	117.00	200	4	3.52	24.50
4	1956	7249	167.00	315	4	3.52	24.50
5	1142	7013	25.90	100	4	2.65	29.90
6	3155	6870	63.60	100	4	2.65	29.90
7	2691	5509	91.40	200	4	2.65	29.90
8	4919	5411	176.00	315	4	2.65	29.90
9	4227	7015	256.00	500	4	2.65	29.90
10	5575	6598	195.00	315	4	2.65	29.90
11	5031	3604	29.80	100	4	2.65	29.90
12	3983	3649	96.10	200	4	3.52	24.50
13	4221	1870	73.20	200	4	2.65	29.90
14	1821	1696	35.70	100	4	2.65	29.90
15	514	787	94.00	200	4	2.65	29.90
16	-211	1145	119.00	200	4	3.52	24.50
17	-685	1596	211.00	315	4	2.65	29.90
18	-1198	-575	27.40	100	4	2.65	29.90
19	-2669	683	58.10	100	4	2.65	29.90
20	-3591	1158	39.60	100	4	2.00	22.60
21	-2710	3137	198.00	315	4	1.86	18.00
22	-3969	4898	34.00	100	4	1.75	17.10
23	-3561	6535	83.90	200	4	2.05	20.60
24	2260	776	53.00	100	4	2.46	24.10
25	834	-573	86.30	200	4	2.07	23.30
26	2617	-1856	95.10	200	4	1.86	16.10
27	4636	-719	30.90	100	4	2.65	29.90
28	6433	-2175	27.60	100	4	3.52	24.50
29	7073	-1002	31.50	100	4	2.43	27.90
30	4529	-4177	68.60	100	4	2.27	24.80
31	1083	-1995	40.00	100	4	2.26	25.10
32	277	-4041	99.10	200	4	2.50	28.30
33	-332	-5689	22.30	100	4	2.33	26.30
34	-637	-8328	49.90	100	4	2.65	29.90

* These values represent the overall per-unit interruption costs for all the customers supplied by the dedicated substations. In this thesis, the financial impacts of the sustained interruptions and momentary interruptions are estimated by the following equations:

Cost of a Sustained Interruption = [(Peak Demand of the Substation — in kW) × (Load Factor of the Substation — in per unit)] × [(Value Corresponding to €/kW) + ((Length of the Interruption — in h) × (Value Corresponding to €/kWh)]

Cost of a Momentary Interruption = (Peak Demand of the Substation — in kW) × (Load Factor of the Substation — in per unit) × (Value Corresponding to €/kW)

In this thesis, the financial impacts on a customer due to an interruption resulted from a voltage sag is assumed equal to that of a momentary interruption. However, on availability of the required data, the technique described in [148] can be used to gain more accurate results.

Appendix I: Basic Data of Distribution Substations of the Distribution Test Network (Continued)

Substation Number	X and Y Coordinates with Respect to the HV/MV Substation (meters)		Peak Demand (kVA)	Transformer Rating (kVA)	Transformer Impedance (%)	Interruption Cost	
						€/kW	€/kWh
35	-699	-3995	34.40	100	4	2.65	29.90
36	-991	-2799	99.40	200	4	3.52	24.50
37	-1178	-5462	53.70	100	4	1.89	15.10
38	-2179	-3547	38.00	100	4	2.65	29.90
39	-3449	-373	31.10	100	4	2.65	29.90
40	-2382	-6045	50.30	100	4	2.65	29.90
41	-2609	-2035	11.80	100	4	2.65	29.90
42	-4086	235	24.70	100	4	3.52	24.50
43	-5072	195	30.90	100	4	2.78	26.60
44	-6077	338	28.20	100	4	2.62	29.60
45	-6803	1097	151.00	315	4	2.11	23.90
46	1476	-1400	102.00	200	4	3.52	24.50
47	2162	-792	38.60	100	4	3.00	60.00
48	1691	666	63.50	100	4	2.65	29.90
49	2485	1714	40.20	100	4	2.83	25.10
50	1528	2564	29.20	100	4	2.48	23.80
51	-3022	-918	53.80	100	4	2.94	26.00
52	-1783	-3346	71.40	200	4	2.40	26.70
53	-849	2267	105.00	200	4	2.65	29.90
54	-597	7161	21.10	100	4	3.52	24.50
55	4296	4256	162.00	315	4	3.52	24.50
56	2788	376	37.90	100	4	3.52	24.50
57	4170	5660	45.00	100	4	2.53	24.00
58	-380	-6169	50.20	100	4	2.52	24.10
59	-895	-5188	63.60	100	4	2.57	27.80
60	3039	951	77.60	200	4	3.52	24.50
61	-3351	3816	96.60	200	4	2.65	29.90
62	1576	1658	101.00	200	4	3.52	24.50
63	-216	829	33.80	100	4	3.52	24.50
64	-1557	791	140.00	315	4	3.00	60.00
65	2449	-1204	0.73	100	4	3.52	24.50
66	2177	-3005	32.10	100	4	1.64	14.00
67	3587	-3873	3.31	100	4	2.48	28.50
68	5484	-3893	24.00	100	4	2.13	33.10
69	5134	-5553	83.00	200	4	1.12	12.80
70	3266	4013	87.20	200	4	1.22	13.40
71	3545	3047	40.10	100	4	1.26	14.30

Appendix I: Basic Data of Distribution Substations of the Distribution Test Network (Continued)

Substation Number	X and Y Coordinates with Respect to the HV/MV Substation (meters)		Peak Demand (kVA)	Transformer Rating (kVA)	Transformer Impedance (%)	Interruption Cost	
						€/kW	€/kWh
72	-455	-7338	24.40	100	4	1.36	15.80
73	-3881	5996	91.60	200	4	1.75	21.60
74	2645	221	18.00	100	4	2.65	29.90
75	5451	-1372	49.90	100	4	3.52	24.50
76	-4134	1266	56.50	100	4	2.65	29.90
77	194	-7762	37.30	100	4	3.52	24.50
78	583	-3037	7.10	100	4	2.65	29.90
79	675	-5038	85.80	200	4	2.65	29.90
80	-480	-6658	15.40	100	4	3.52	24.50
81	-6863	3145	23.60	100	4	3.52	24.50
82	1802	1177	170.00	315	4	3.52	24.50
83	2206	5249	11.40	100	4	3.52	24.50
84	-2914	-5439	124.00	200	4	0.78	10.20
85	1811	-316	10.20	100	4	2.29	19.20
86	2120	-6673	58.60	100	4	1.41	17.90
87	3213	-1499	56.40	100	4	2.30	33.80
88	2934	-2601	55.60	100	4	1.64	19.20
89	-1557	-1671	24.20	100	4	0.87	10.40
90	-2159	790	29.20	100	4	1.40	15.90
91	-3384	-6466	55.40	100	4	2.65	29.90
92	-3142	-6779	39.30	100	4	2.65	29.90
93	-4108	3609	65.10	100	4	2.65	29.90
94	-3792	4282	192.00	315	4	2.65	29.90
95	-3259	-7597	87.80	200	4	3.52	24.50
96	-1043	1164	20.60	100	4	1.86	22.30
97	-3993	5299	25.50	100	4	1.67	15.30
98	873	6592	49.40	100	4	0.73	7.86
99	932	666	14.00	100	4	1.50	16.00
100	2837	906	54.40	100	4	2.35	18.10
101	853	3136	42.70	100	4	2.62	33.20
102	1497	4561	36.30	100	4	2.49	31.10
103	-1507	-4020	58.50	100	4	3.52	24.50
104	5816	6778	99.90	200	4	2.65	29.90
105	2967	4330	64.70	100	4	3.52	24.50
106	2802	3950	177.00	315	4	2.65	29.90
107	4393	5093	158.00	315	4	3.52	24.50
108	4607	5788	85.50	200	4	1.26	14.30

Appendix I: Basic Data of Distribution Substations of the Distribution Test Network (Continued)

Substation Number	X and Y Coordinates with Respect to the HV/MV Substation (meters)		Peak Demand (kVA)	Transformer Rating (kVA)	Transformer Impedance (%)	Interruption Cost	
						€/kW	€/kWh
109	3933	7208	2.43	100	4	1.36	15.80
110	1181	752	22.30	100	4	1.75	21.60
111	-4626	175	21.70	100	4	2.65	29.90
112	-2593	-2543	11.40	100	4	3.52	24.50
113	-3135	957	13.60	100	4	2.65	29.90
114	-2358	3880	101.00	200	4	3.52	24.50
115	3002	5620	23.60	100	4	2.65	29.90
116	-3036	6922	32.80	100	4	2.65	29.90
117	-1516	-5281	7.36	100	4	3.52	24.50
118	-3357	-3882	6.07	100	4	3.52	24.50
119	6707	-4831	143.00	315	4	3.52	24.50
120	1708	-853	89.00	200	4	3.52	24.50
121	1392	7198	45.20	100	4	0.78	10.20
122	4638	5043	16.20	100	4	2.29	19.20
123	2014	-2118	32.00	100	4	1.41	17.90
124	5338	-310	22.70	100	4	2.30	33.80
125	-1664	-1079	889.00	1250	6	1.64	19.20
126	5667	-809	6.11	100	4	0.87	10.40
127	1932	-1026	81.40	200	4	1.40	15.90
128	1462	-2557	78.20	200	4	2.65	29.90
129	4788	1618	103.00	200	4	2.65	29.90
130	4497	4737	49.90	100	4	2.65	29.90
131	5198	5085	54.60	100	4	2.65	29.90
132	974	-1950	38.50	100	4	3.52	24.50
133	-252	1785	53.40	100	4	1.86	22.30
134	-112	-4489	43.50	100	4	1.67	15.30
135	-1284	-8806	23.70	100	4	0.73	7.86
136	-935	-7814	120.00	200	4	1.50	16.00
137	-2310	-6382	29.70	100	4	2.35	18.10
138	2814	5268	32.90	100	4	2.62	33.20
139	-909	-3515	31.80	100	4	2.49	31.10
140	-7667	3212	57.30	100	4	3.52	24.50
141	5818	-1917	35.30	100	4	2.65	29.90
142	178	407	14.30	100	4	3.52	24.50
143	-588	-4359	42.20	100	4	2.65	29.90
144	-1773	-4714	34.90	100	4	3.52	24.50

Appendix II: Basic Data of Underground Cables used in the Distribution Test Network

Cable Size	Rated Voltage (kV)	Positive (Negative) Sequence Impedance (ohms/m)		Zero Sequence Impedance (ohms/m)		Rated Current (A)
		Resistance	Inductance	Resistance	Inductance	
1	24	0.000451	0.000132	0.001804	0.000528	155
2	24	0.000262	0.000123	0.001048	0.000492	210

Appendix III: Basic Data of Sections of the Distribution Test Network

Leaving Substation	Switching Device	Entering Substation	Switching Device	Exposure (meters)	Cable Size	Emergency Rating (%)
Main	Yes	142	No	628	2	120
Main	Yes	18	No	1879	2	120
Main	Yes	25	Yes	1431	2	120
Main	Yes	63	No	1212	2	120
Main	Yes	89	No	3230	2	120
Main	Yes	99	No	1620	2	120
1	Yes	109	No	735	2	120
2	No	3	No	720	1	120
2	Yes	6	No	497	2	120
3	Yes	4	No	1003	1	120
4	Yes	121	No	801	1	120
5	Yes	98	No	707	1	120
6	No	1	Yes	490	2	120
7	Yes	83	No	778	2	120
7	Yes	115	No	467	2	120
8	Yes	108	No	692	2	120
8	Yes	131	No	607	1	120
9	Yes	10	Yes	1995	1	120
10	Yes	104	No	425	1	120
12	Yes	55	Yes	966	2	120
12	Yes	70	No	1137	1	120
13	Yes	71	No	1920	2	120
13	No	129	No	877	1	120
14	Yes	49	No	939	1	120
14	No	62	No	351	2	120
15	Yes	82	Yes	1903	2	120
16	Yes	17	Yes	925	2	120
17	Yes	53	No	977	1	120
17	Yes	96	No	793	1	120
17	Yes	133	No	668	1	120
18	No	125	Yes	971	2	120
19	Yes	113	No	765	1	120
20	No	76	No	783	1	120
21	Yes	61	No	1321	1	120
21	Yes	114	No	1163	1	120
22	No	97	No	568	1	120
23	No	116	No	922	1	120
24	No	100	Yes	836	2	120

Appendix III: Basic Data of Sections of the Distribution Test Network (Continued)

Leaving Substation	Switching Device	Entering Substation	Switching Device	Exposure (meters)	Cable Size	Emergency Rating (%)
25	Yes	120	Yes	1298	2	120
26	Yes	87	No	983	1	120
26	Yes	88	No	1145	1	120
26	Yes	123	No	930	1	120
27	No	124	No	1149	1	120
28	Yes	29	No	1890	1	120
30	Yes	68	No	1409	1	120
30	Yes	69	No	2126	1	120
31	No	128	Yes	959	1	120
31	No	132	No	167	1	120
32	Yes	78	No	1484	1	120
33	No	58	No	682	1	120
34	No	135	No	1138	1	120
35	No	143	No	538	1	120
37	No	59	Yes	557	2	120
38	No	52	No	628	2	120
38	Yes	118	No	1732	1	120
39	No	51	Yes	979	2	120
40	Yes	84	No	1140	1	120
40	Yes	137	No	487	1	120
41	No	112	No	719	2	120
42	Yes	39	No	1245	2	120
42	No	111	No	768	1	120
43	Yes	44	No	1436	1	120
44	No	45	No	1485	1	120
45	Yes	81	No	2898	1	120
46	No	127	No	834	1	120
47	Yes	65	No	710	2	120
48	Yes	24	No	820	2	120
50	No	101	Yes	1251	2	120
51	Yes	125	Yes	1934	2	120
52	Yes	103	No	1030	2	120
53	Yes	21	No	2905	1	120
55	Yes	11	No	1389	1	120
55	Yes	130	No	737	2	120
56	No	74	No	298	1	120
58	Yes	80	No	706	1	120
59	Yes	33	No	1066	1	120

Appendix III: Basic Data of Sections of the Distribution Test Network (Continued)

Leaving Substation	Switching Device	Entering Substation	Switching Device	Exposure (meters)	Cable Size	Emergency Rating (%)
59	Yes	143	Yes	1250	1	120
60	Yes	13	Yes	2117	2	120
61	Yes	94	No	907	1	120
62	Yes	50	No	1283	2	120
63	No	16	Yes	447	2	120
64	Yes	90	No	851	1	120
65	No	26	Yes	952	2	120
67	No	30	No	1400	1	120
68	No	119	No	2180	1	120
70	No	105	No	616	1	120
71	No	12	Yes	1053	2	120
72	Yes	77	No	1096	1	120
72	No	136	No	956	1	120
73	Yes	23	No	886	1	120
75	Yes	141	No	929	1	120
76	Yes	42	Yes	1460	1	120
79	Yes	86	No	3086	1	120
80	No	72	No	962	1	120
81	No	140	No	1141	1	120
82	Yes	14	Yes	734	2	120
83	No	102	Yes	1397	2	120
87	Yes	27	No	2295	1	120
88	Yes	67	No	2022	1	120
89	No	41	Yes	1574	2	120
90	Yes	19	Yes	737	1	120
92	Yes	91	No	560	1	120
92	Yes	95	No	1169	1	120
94	Yes	22	No	906	1	120
94	Yes	93	No	1051	1	120
96	No	64	Yes	898	1	120
97	No	73	No	998	1	120
98	No	54	No	2229	1	120
99	No	110	No	373	2	120
100	Yes	56	No	753	1	120
100	No	60	No	293	2	120
101	Yes	102	Yes	2211	2	120
103	Yes	144	No	1051	2	120
105	No	106	No	586	1	120

Appendix III: Basic Data of Sections of the Distribution Test Network (Continued)

Leaving Substation	Switching Device	Entering Substation	Switching Device	Exposure (meters)	Cable Size	Emergency Rating (%)
108	Yes	10	Yes	1785	2	120
108	No	57	No	644	1	120
109	Yes	9	No	497	2	120
110	No	48	Yes	731	2	120
111	No	43	No	631	1	120
112	No	38	Yes	1536	2	120
113	No	20	Yes	705	1	120
115	No	2	Yes	1350	2	120
117	Yes	37	No	542	2	120
117	No	40	No	1633	1	120
120	No	85	No	773	1	120
120	No	127	Yes	400	2	120
121	No	5	No	440	1	120
122	Yes	8	Yes	655	2	120
122	No	107	No	354	1	120
123	No	128	Yes	997	1	120
124	Yes	126	No	845	1	120
126	No	75	No	853	1	120
127	Yes	47	No	464	2	120
128	Yes	66	No	1193	1	120
128	Yes	78	No	1416	1	120
130	No	122	Yes	476	2	120
134	Yes	32	Yes	839	1	120
134	No	79	No	1357	1	120
136	Yes	34	No	840	1	120
137	No	92	No	1304	1	120
138	No	7	No	383	1	120
139	No	35	Yes	741	1	120
139	No	36	No	1019	1	120
141	No	28	No	943	1	120
142	No	15	Yes	717	2	120
143	Yes	134	Yes	698	1	120
144	No	117	Yes	880	2	120

Appendix IV: Basic Data of Overhead Lines of the Sub-Transmission Test Network

Sending Bus	Receiving Bus	Circuit Number	Conductor Type	Length (km)	Resistance (Ω/km)	Reactance (Ω/km)	Rating (MVA)
6	12	1	2 Finch	3.018	0.027	0.260	410
4	6	1	2 Duck	5.902	0.049	0.282	281
4	6	2	2 Duck	5.810	0.049	0.282	281
6	7	1	2 Duck & 3*2000Cu	4.660	0.058	0.252	225
6	7	2	2 Duck & 3*2000Cu	4.700	0.058	0.252	225
2	6	1	2 Finch	8.600	0.027	0.266	410
8	15	1	2 Duck	3.708	0.049	0.279	281
8	15	2	2 Duck	3.722	0.049	0.279	281
3	15	1	2 Duck	8.368	0.049	0.291	281
3	15	2	2 Duck	8.368	0.049	0.291	281
2	9	1	2 Finch	3.927	0.027	0.262	410
8	19	1	2 Duck	3.611	0.049	0.285	281
5	19	1	2 Duck	3.373	0.049	0.297	281
9	12	1	2 Finch	1.761	0.027	0.256	410
5	8	1	2 Duck	6.991	0.049	0.296	281
7	8	1	Ibis	6.164	0.142	0.390	110
7	8	2	Ibis	6.197	0.142	0.390	110
3	7	1	2 Duck	7.717	0.049	0.287	281
7	14	1	2 Duck	3.637	0.049	0.287	281
3	13	1	2 Duck	4.820	0.049	0.285	281
3	11	1	2 Duck	8.243	0.049	0.324	281
9	11	1	2 Duck	7.552	0.049	0.294	281
1	2	1	2 Finch	5.496	0.027	0.265	410
1	2	2	2 Finch	5.496	0.027	0.265	410
13	14	1	2 Duck	3.637	0.049	0.287	281

Appendix V: Basic Data of Underground Cables of the Sub-Transmission Test Network

Sending Bus	Receiving Bus	Circuit Number	Conductor Type	Length (km)	Resistance (Ω/km)	Reactance (Ω/km)	Nominal Rating (MVA)
6	10	1	3x300Al	4.100	0.125	0.141	82
6	10	2	3x300Al	4.040	0.125	0.141	82
21	21	1	3x800Al	0.985	0.053	0.116	134
4	22	1	3x300Cu & 3x800Al	3.896	0.069	0.119	104
4	22	2	3x800Al	4.542	0.054	0.128	134
23	24	1	3x300Cu & 3x800Al	1.38	0.074	0.142	104
4	24	1	3x300Cu & 3x800Al	2.083	0.076	0.133	104
4	24	2	3x800Al	2.593	0.054	0.126	134
5	23	1	3x300Cu & 3x800Al	3.147	0.082	0.129	104
17	18	1	3x400Cu & 3x800Al	1.64	0.054	0.120	120
7	17	1	3x400Cu & 3x800Al	4.50	0.066	0.114	120
16	17	1	3x800Al	0.45	0.145	0.195	134
5	21	1	3x300Cu & 3x800Al	2.259	0.079	0.136	104
5	20	1	3x800Al	3.093	0.053	0.116	134
4	20	1	3x800Al	3.603	0.051	0.123	134
4	18	1	3x400Cu & 3x800Al	1.95	0.058	0.118	120
4	18	2	3x800Al	2.241	0.053	0.128	134

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Electric utilities have always been faced with a challenge when evaluating the reliability impact of the advanced solutions such as those of the smart grid technologies. Generally, the available reliability assessment approaches cannot be employed directly for such purposes. A novel approach is proposed and demonstrated in this thesis for reliability assessment of an electric power distribution system when employing the advanced reliability enhancement solutions. In the proposed approach, the impacts of the targeted reliability enhancement solutions on the sustained interruptions, momentary interruptions and voltage sags experienced by the customers are taken into account.

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