

# **Determining preferred substation configurations based on reliability and cost**

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## **Abstract**

Many different substation configurations exist, each with its own space requirements, reliability and cost. Distribution planners need to choose between these numerous layouts and suggest the preferred substation configuration for future networks, but often don't understand the advantages and total life cycle cost associated with each.

The aim of this research is to identify a simplified approach that can be used to determine a set of preferred substation configurations that minimises the total life cycle cost of the substation.

An analytical approach is considered which uses deterministic reliability assessment to determine the load-based and economic performance indicators for different substation layouts. This analytical approach builds on the simplified reliability estimation approach developed by Van der Merwe (2014). This simplified approach is sufficiently complex to ensure that errors are not one-sided, while at the same time minimising the number of calculations of the reliability evaluation.

A cost estimation tool was developed to determine the utility cost for each of the substations. The purpose of this tool is to prepare preliminary estimates of substation life cycle costs during the planning stage, based on conceptual design information.

The value based reliability planning approach (VBRP) is used to determine the substation configuration with the lowest life cycle cost, given the specified design criteria. This substation is then the optimal configuration for the specific design criteria.

The research considers 432 different substation configurations, and 720 different design criteria. This results in 311 040 different substation layouts. The approach was programmed into an MS Excel model and this model was used to compare the 432 different substation configurations for each of the 720 different design criteria and 18 different customer damage functions, i.e. repeating the comparison of the 432 different substations 12 960 times. The time required to perform one comparison of the 432 different substation configurations for one given design criteria and customer damage function is approximately 2 seconds. The process was automated and the time required to run through all the design criteria and customer damage functions was 8 hours 46 minutes on a standard laptop with an i5 processor.

The optimal substation configuration obtained for each of the 12 960 scenarios were analysed and clustered in order to derive the preferred set of substation configurations. Through this process the 432 different substation configurations were reduced to only 17 different substation configurations.

The approach developed through this process is repetitive and can be used to update the preferred substation configurations every time the substation costs, equipment failure rates, maintenance regimes, customer damage functions, or any other assumptions change.

## **Keywords**

Substation design, cost of unserved energy, customer interruption cost, reliability assessment, availability, sub-transmission, transmission, performance evaluation, SAIDI, SAIFI, network planning,

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## Definitions

The definition of all **symbols** used in this document is provided in Annex A.

**Average system interruption duration index (ASIDI):** ASIDI is a measure of how long a load point would experience sustained interruptions over the course of a year. ASIDI can be calculated as:

$$ASIDI = \frac{\sum \text{Connected kVA hours interrupted}}{\text{Total connected kVA served}}$$

expressed as hours per customer year.

**Average system interruption frequency index (ASIFI):** ASIFI is a measure of how often a load point would experience sustained interruptions over the course of a year. ASIFI can be calculated as:

$$ASIFI = \frac{\sum \text{Connected kVA interrupted}}{\text{Total connected kVA served}}$$

expressed as interruptions per customer year.

**Availability:** The term availability applies either to the performance of individual components or to that of a system. Availability is defined as the long-term average fraction of time that a component or system is in service satisfactorily performing its intended function. An alternative and equivalent definition of availability is the steady state probability that a component or system is in service (Institute of Electrical and Electronics Engineers, Inc. (IEEE), 1990).

**Average load:** The average load is given by any of the following two formulas (Billinton & Allan, 1996):

(a)  $L_a = L_p f$

Where:

$L_a$ : Average load

$L_p$ : Peak load

$f$ : load factor

b)  $L_a = \frac{E_d}{t}$

Where:

$L_a$ : Average load

$E_d$ : Total energy demanded in period of interest

$t$ : Period of interest

**Customer average interruption duration index (CAIDI):** CAIDI is a measure of how long an average interruption lasts (Brown, 2002), typically measured over the course of a year. CAIDI can be calculated as:

$$CAIDI = \frac{\sum \text{Customer interruption durations}}{\text{Customers experiencing one or more interruption}}$$

expressed as hours per interruption.

**Customer average interruption frequency index (CAIFI):** CAIFI is a measure of how often an interrupted customer was interrupted over the course of a year. CAIFI can be calculated as:

$$CAIFI = \frac{\sum \text{Customer interruptions}}{\text{Customers experiencing one or more interruptions}}$$

expressed as interruptions per customer interruption.

**Cost of unserved energy (COUE):** COUE can be defined as the electricity supply's value to a specific customer, a type or class of customer or the wider economy. COUE is usually measured in a monetary amount associated with the unserved energy experienced, due to interruptions of supply.

**Energy not supplied (ENS):** ENS is the total energy not supplied by the system, and can be calculated using:

$$ENS = \sum \text{Average load} \times \text{Outage duration}$$

**Firm transformer capacity:** A substation has firm transformer capacity when there is more than one station transformer and the load supplied through the transformers can still be supplied if one transformer is out-of-service, without exceeding the rated capacity of the remaining transformer(s).

**High voltage (HV):** Nominal voltage levels > 36 kV and ≤ 145 kV, also referred to as sub-transmission voltage levels.

**Indoor switchgear:** Indoor switchgear refers to metal-clad switchgear that can be of the fixed pattern or withdrawable type. It excludes gas-insulated switchgear (GIS) and outdoor switchgear used indoors.

**Interruption (of supply):** This refers to an interruption of power to a customer that was not requested by the customer. In the context of this study, only sustained interruptions are considered.

**Medium voltage (MV):** Nominal voltage levels  $> 1$  kV and  $\leq 36$  kV.

**Sustained interruption (of supply):** A sustained interruption is an interruption lasting longer than a specified duration. For the purpose of this research a sustained interruption is defined as an interruption lasting longer than 2 minutes.

**System average interruption duration index (SAIDI):** SAIDI is a measure of how many interruption hours an average customer will experience over the course of a year (Brown, 2002). SAIDI can be calculated as:

$$SAIDI = \frac{\sum \text{Customer interruption durations}}{\text{Total connected customers served}}$$

expressed as hours per customer year.

**System average interruption frequency index (SAIFI):** SAIFI is a measure of how many sustained interruptions an average customer will experience over the course of a year (Brown, 2002). SAIFI can be calculated as:

$$SAIFI = \frac{\sum \text{Customer interruptions}}{\text{Total connected customers served}}$$

expressed as interruptions per customer year.

**Unavailability:** The long-term average fraction of time that a component or system is out-of-service due to failures or scheduled outages. An alternative definition is the steady-state probability that a component or system is out-of-service. Mathematically, unavailability can be expressed as shown in Equation 1 (Institute of Electrical and Electronics Engineers, Inc. (IEEE), 1990).

$$Unavailability = 1 - availability$$

Equation 1

**Unfirm transformer capacity:** A substation with unfirm transformer capacity can have either one transformer or more than one transformer. For the scenario with more than one transformer, the load supplied from the substation is such that, if one transformer is out-of-service, the remaining transformer(s) cannot supply all substation load without exceeding the rated capacity of the remaining transformer(s).

**Upstream and downstream busbars:** For the purpose of this research, the two busbars on either side of the substation transformer are differentiated based on the direction of power flow. Power flows from the upstream busbar, through the transformer, to the downstream busbar. This convention is applied irrespective of the busbar operating voltages (Van der Merwe, 2014). This is illustrated in Figure 0-1.

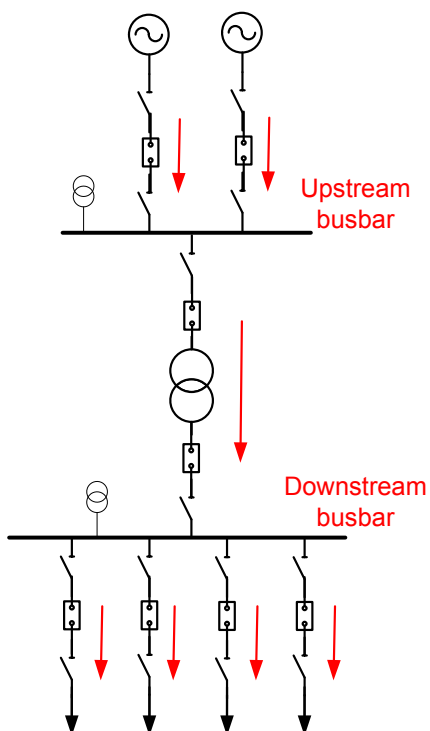


Figure 0-1: Definition of upstream and downstream busbars (Van der Merwe, 2014)

## Abbreviations

A	:	Ampere
a	:	annum
AIS	:	Air insulated switchgear
ASIDI	:	Average system interruption duration index
ASIFI	:	Average system interruption frequency index
CAIDI	:	Customer average interruption duration index
CAIFI	:	Customer average interruption frequency index
CIC	:	Customer interruption cost
CT	:	Current transformer
COUE	:	Cost of unserved energy
CCDF	:	Composite customer damage function
CDF	:	Customer damage function
ENS	:	Energy not supplied
FMEA	:	Failure mode and effect analysis
GA	:	Genetic algorithm
GIS	:	Gas insulated switchgear
h	:	hour
HV	:	High voltage
IEEE	:	The Institute of Electrical and Electronics Engineers
IPC	:	Idaho Power Company
kV	:	Kilovolt
kVA	:	Kilovolt ampere
kW	:	Kilowatt
kWh	:	Kilowatt hour
LCC	:	Life cycle cost
LE	:	Livre (French for Egyptian pound)

MS Excel	:	Microsoft Excel
MV	:	Medium voltage
MVA	:	Megavolt ampere
MW	:	Megawatt
MWh	:	Megawatt hour
N/O	:	Normally open
NECR/T	:	Neutral electromagnetic coupled resistor with auxiliary power transformer
Nersa	:	National Energy Regulator of South Africa
O&M	:	Operations and Maintenance
R	:	South African rands
R/kWh	:	South African rands per Kilowatt hour
s	:	seconds
SAIDI	:	System average interruption duration index
SAIFI	:	System average interruption frequency index
SCDF	:	Sector customer damage function
VBRP	:	Value-based reliability planning
VT	:	Voltage transformer

# 1. Introduction

Substations are the connection points between a utility's transmission network and the customers, supplied via the distribution network. These connection points are considered to be the most reliable points in a power system, but faults originating in substations can result in multiple outages of generators, lines and/or loads. The effect of these substation faults can therefore be significant and hence it is necessary to understand the expected downtime associated with different substation layouts during the planning stage.

Historically utilities used a least capital cost or a least life cycle cost approach to make infrastructure investment decisions. With society becoming more dependent on a reliable electricity supply, the cost of a supply interruption can be significant to the economy. Modern day society would like electric energy to be continuously available on demand but it is neither technically nor economically feasible to plan, construct and operate a power system which has zero probability of failure. The basic objective therefore is to satisfy the system load requirements as economically as possible and with a reasonable degree of continuity and quality (Goel & Billinton, 1991).

The purpose of this research is to develop an approach that can be used to determine a set of substation configurations that can satisfy the system load requirements as economically as possible. This research builds on the research documented in the dissertation *Simplified approach for the reliability estimation of large transmission and sub-transmission systems*, (Van der Merwe, 2014), which describes a simplified predictive reliability assessment method to determine the reliability of different substation configurations.

This chapter provides a general background to the research objective and an outline of the rest of the thesis.

## 1.1. Identifying a problem/need

Many different substation configurations exist, each with its own space requirements, reliability and cost. Distribution planners need to choose between these numerous layouts and suggest the preferred substation configuration for future networks, but often don't understand the advantages and total life cycle cost associated with each.

Comparisons between the different substation configurations are not often found in literature. The studies that do compare different substation configurations don't always include all elements of the substation configuration, e.g. the comparison only considers different busbar layouts and ignores different transformer layouts. These comparisons have the further

shortcoming that they only consider a single customer interruption cost rate and don't compare the outcomes when different customer interruption cost rates are used. Examples of substation configuration comparisons found in literature include the following:

- (a) Nagarsheth & Singh (2014) evaluate and compare two types of substations, namely air insulated switchgear (AIS) and gas insulated switchgear (GIS) substations on the basis of the i) life-cycle cost method, ii) reliability, and iii) environmental effects. The comparison only looks at the type of substation and ignores substation layout. The discussion concludes on the preferred type of substation, but doesn't include any recommendations for the busbar or transformer layout of the substation.
- (b) Bio (2012) compares different busbar configurations in terms of i) reliability, ii) cost, and iii) available area. The scope of the configurations and the nature of the assessment is illustrated in Table 1-1. Each busbar configuration is evaluated based on these three criteria, but there is no concluding statement with regards to the preferred substation configuration.

**Table 1-1: Comparison of busbar configurations (Bio, 2012)**

<b>Configuration</b>	<b>Reliability</b>	<b>Cost</b>	<b>Available area</b>
Single bus	Least reliability – single failure can cause complete outage	Least cost – fewer components	Least area – fewer components
Double bus	Highly reliable – single failure normally isolates single component	High cost – duplicated components	Greater area – twice as many components
Main bus and transfer	Least reliable – same as single bus, but flexibility in operating and maintenance with transfer bus	Moderate cost – fewer components	Low area requirement – fewer components
Double bus, single breaker	Moderately reliable – depends on arrangement of components and bus	Moderate cost – more components	Moderate area – more components
Ring bus	Highly reliable – single failure isolates single component	Moderate cost – more components	Moderate area – increases with number of circuits
Breaker-and-a-half	Highly reliable – single circuit failure isolates single circuit, bus failures do not affect circuits	Moderate cost – breaker-and-a-half for each circuit	Greater area – more components per circuit

- (c) Bagen (2011) compares the reliability of two different 230 kV substation configurations for a utility wind interconnection project. Commercially available software, SUBREL, is used to calculate the reliability indices for each of the different substation configurations. These indices are then used to perform a benefit-cost calculation for the different configurations. The shortcoming of this analysis is that it doesn't include different transformer configurations and doesn't show the impact when a different outage cost rate is used.
- (d) Neudorf et al. (1995) compare the reliability of four different 500/230 kV busbar configurations, using a cost benefit analysis. The substation with the lowest total cost is identified, but the study only considers one outage cost rate and doesn't show the impact of using different outage cost rates. There is also no reference to different transformer configurations.
- (e) Tsao & Chang (2004) compare combinations of different busbar and distribution network configurations using the reliability worth evaluation models. The expected interruption cost and total cost (utility cost and customer interruption cost) of the different configurations are compared. They also show the effect of changing the customer type (and hence the outage cost rate of the load) supplied. The shortcoming of this analysis is again that it doesn't conclude on the preferred busbar configuration for different customer classes and different transformer configurations are not shown.

All the examples above include reliability as one of the criteria to select the preferred substation configuration. The reliability of different substation configurations can be calculated using specialised power system reliability modelling software. Modelling each of the different substation configurations using specialised software is extremely time-consuming. Furthermore these specialised software cannot be used to calculate the utility cost associated with each substation. This cost has to be calculated elsewhere, e.g. in MS Excel, and added to the customer cost calculated with specialised software. Repeating this process every time a new substation is planned requires significant manpower.

This illustrates the need for a simplified approach to determine the set of optimal substation configurations. This simplified approach to reliability modelling does not remove the need to model networks using specialised power system software for load flow purposes. These network models, used for load flow purposes, can then also be used to calculate the reliability of the entire utility network once a specific substation layout has been tested. However calculating the reliability of 432 different substation configurations for 720 different design criteria and 18 different customer damage functions, such as was done during this research, is not practical using specialized power system software.

## 1.2. Research objective

Van der Merwe (2014) explained a simplified approach to calculate the reliability of different substation configurations<sup>1</sup>. This approach can be used to calculate the technical performance of the substations, but it has the shortcoming that it doesn't provide information on the economic impact of network outages. Furthermore, the cost associated with the additional equipment required for a more reliable substation is not included in the approach, hence the cost of different substation configurations cannot be compared. This approach can therefore be used to determine the most reliable substation configuration, but it cannot be used to compare the cost vs. reliability of different configurations in order to determine the set of optimal substation configurations.

The aim of this research is to provide a reliability estimation approach that will assist planning engineers to select the substation configurations that minimise the total life cycle cost. This approach needs to meet the following criteria in order to provide engineers with a reliable decision-making tool:

- (a) The approach should require minimum user inputs.
- (b) The approach should provide the preferred substation configuration for a given set of designed parameters.
- (c) The approach should inform, with little effort, the change in preferred substation configurations if any of the assumptions, such as failure rates, are changed.

### 1.2.1. Hypothesis

The hypothesis that underlies this research is as follows:

***A simplified approach can be developed to determine the (set of) substation configuration(s) that minimises the total economic cost.***

If this hypothesis is valid, the contribution of this research is that it removes the need to do a value-based analysis, considering all possible substation configurations, every time a new substation is planned. Instead the planner can consult the set of preferred substation configurations as a decision-making tool.

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<sup>1</sup> This dissertation can be accessed at: [https://open.uct.ac.za/bitstream/item/9275/thesis\\_ebe\\_2014\\_van\\_der\\_merwe\\_j.pdf](https://open.uct.ac.za/bitstream/item/9275/thesis_ebe_2014_van_der_merwe_j.pdf)

### **1.2.2. Research questions**

The following research questions need to be answered to test the validity of the hypothesis:

- (a) What are the benefits of a more reliable substation configuration?
- (b) What is an acceptable target for substation reliability?
- (c) What criteria need to be considered when determining the optimal substation configuration?
- (d) Can a set of preferred substation layouts be defined for a given set of failure rates and equipment costs?
- (e) For which parameters are the preferred substation layouts most sensitive?

### **1.3. Scope**

The nature of the research is a theoretical analysis based on published failure data for the common categories of substation equipment. The approach is not experimental, because it is not possible to run controlled experiments for this type of study. All variables that could change in other contexts have been defined as variables and are not built into the method as constants.

This research is limited to substations and excludes the evaluation of switching stations. The same model can however be used to determine the preferred switching station configurations, provided the theory and testing does not identify constraints. The analysis of the preferred switching stations will require the input data to be changed.

The preferred line configurations are also excluded from the research. A similar approach can be used to determine the preferred line configurations, but this will require additional data.

The focus of this research is on identifying the approach to determine the preferred substation configurations. Once the approach is determined, the same approach can be applied on various different networks, such as switching stations and lines.

This study is further limited to specific substation voltages. The following voltages are included in this study:

- (a) 11 kV
- (b) 22 kV
- (c) 33 kV
- (d) 66 kV

(e) 132 kV

These are standard voltages used for distribution in Southern Africa and other systems that follow the basically British voltage ranges. The same approach can however be used to determine the preferred configurations for other substation voltages, if the failure rates and cost assumptions for these voltages are provided as inputs into the model.

This study further excludes gas insulated switchgear (GIS) and only considers air insulated switchgear (AIS). Again, the same approach can be used to determine the preferred configurations for GIS if the failure rates and cost assumptions for this switchgear are provided as inputs into the model.

#### **1.4. Outline of thesis**

This thesis is structured as follows:

- (a) Chapter 2 reviews existing literature.
- (b) Chapter 3 explains the approach for determining the preferred substation configurations.
- (c) Chapter 4 reviews the simplified network reliability modelling approach which forms the basis of this research.
- (d) Chapter 5 defines the standard substation configurations and design criteria considered in this research.
- (e) Chapter 6 develops the substation cost estimation tool.
- (f) Chapter 7 develops the customer interruption cost calculation.
- (g) Chapter 8 develops the total life cycle cost calculation and how to identify the least life cycle cost option.
- (h) Chapter 9 discusses the results and clusters some of the results to determine the set of substation configurations that minimises cost.
- (i) Chapter 10 uses existing specialised power system reliability modelling software to verify the results of the simplified approach.
- (j) Chapter 11 discusses specific answers to the research questions, the validity of the hypothesis and some concluding thoughts.

## **2. Literature review**

The literature review focuses on the following aspects:

- (a) Benefits of a more reliable substation are discussed in section 2.1.
- (b) Different reliability indices are reviewed in section 2.2.
- (c) An acceptable target for substation reliability is investigated in section 2.3.
- (d) The value based reliability planning approach is reviewed in section 2.4.
- (e) An overview of the deterministic and probabilistic planning approaches is briefly discussed in section 2.5.
- (f) A summary of the research by Van der Merwe (2014) which explains the simplified approach to the reliability estimation of substations, is given in section 2.6.
- (g) Different substation configurations are discussed in section 2.7.
- (h) Preferred substation configurations are investigated in section 2.8
- (i) Customer interruption costs are reviewed in section 2.9.
- (j) Utility life cycle costs are discussed in section 2.10.
- (k) Failure rates and maintenance frequencies are reviewed in section 2.11.
- (l) The average load supplied per load point is investigated in section 2.12.

### **2.1. Benefits of a more reliable substation configuration**

The economic impact of electricity outages is not limited to the loss of revenue by the utility, but also includes the losses incurred by the customer, as well as the indirect costs imposed on customers, society, and the environment due to the unavailability of electricity supply (Billinton & Allan, 1996). They add that in the case of the 1977 New Year blackout, the total costs of the outage were attributed as:

- (a) Consolidated Edison direct costs 3.5%;
- (b) other direct costs 12.5%;
- (c) indirect costs 84.0%.

According to this breakdown, the loss in revenue by the utility represents the smallest cost component, while the indirect costs are significantly higher than the losses incurred by the utility.

Arjona et al. (2004) agree that the outage costs due to supply interruptions are much less for utilities than for customers. They indicate that for a utility like Idaho Power Company (IPC) the loss of revenue is only a few cents per kwh, while revenue losses for customers have been estimated to be anywhere between \$1 per kwh to \$40 per kwh based on customer surveys.

From these discussions it can be concluded that the biggest benefit of a more reliable substation is that it reduces the losses incurred by customers during electricity supply outages, and to a lesser extent also reduces the loss of revenue by the utility.

## 2.2. Reliability indices

Various reliability indices are discussed by Billinton & Allan (1996) and Brown (2002). Customer-based indices include:

- (a) System average interruption duration index (SAIDI), where

$$SAIDI = \frac{\sum \text{Customer interruption durations}}{\text{Total connected customers served}}$$

- (b) System average interruption frequency index (SAIFI), where

$$SAIFI = \frac{\sum \text{Customer interruptions}}{\text{Total connected customers served}}$$

- (c) Customer average interruption frequency index (CAIFI).

- (d) Customer average interruption frequency index (CAIDI).

The reliability indices considered by Van der Merwe (2014) are discussed in section 4.4. These customer indices focus on the technical performance of the network, but they do not provide an indication of the economic impact of outages.

Brown (2002) discusses the following load-based reliability indices and explains that these indices represents better measures of reliability from a utility perspective, since larger kVA corresponds to higher revenue and should be considered when making investment decisions:

- (a) Average system interruption frequency index (ASIFI), where

$$ASIFI = \frac{\sum \text{Connected kVA interrupted}}{\text{Total connected kVA served}}$$

- (b) Average system interruption duration index (ASIDI), where

$$ASIDI = \frac{\sum \text{Connected kVA hours interrupted}}{\text{Total connected kVA served}}$$

Gupta & Goel (2004) indicate the expected energy not supplied (ENS) provides the severity associated with an outage and is therefore a more suitable index to determine interruption cost. Billinton & Allan (1996) provide the following formula for ENS:

$$ENS = \sum \text{Average load interrupted} \times \text{Outage duration}$$

If the ENS is combined with a cost per kWh, it can provide the cost associated with each outage, which is an indication of the economic impact of outages. Calculating the ENS and combining it with a cost per kWh will therefore overcome the shortcoming of considering only customer-focussed indices, which have the potential to result in funding decisions that are not closely linked to economic interest, as identified by Van der Merwe (2014).

### **2.3. Acceptable target for substation reliability**

Various options exist to reduce the frequency, duration or impact of substation faults, but these solutions require upfront investment. So the questions asked by distribution planning engineers are:

- (a) When should utilities invest in a more reliable supply?
- (b) What is viewed as acceptable supply reliability?

Acceptable supply reliability used to be based on a comparison of actual interruption frequencies and durations with arbitrary reliability targets (Chowdhury & Koval, 2004). In the past, most utilities designed their transmission systems to satisfy deterministic criteria. Justification for a transmission addition simply involved demonstrating that the transmission addition was required to meet the deterministic criteria (Neudorf et al., 1995). Chowdhury & Koval (2001) indicate that traditionally electric utilities utilised implicit criteria, planners' intuition and judgement, gut feelings, etc., for project justification.

The problem with this approach to target setting is that it ignores the trade-offs between the cost of achieving a better level of reliability and the benefits derived by the economy.

Chowdhury & Koval (2001) argue that the qualitative assessment of reliability improvements without a consistent and formal framework resulted in over/under capacity of the power systems. They suggest a quantitative comparison of reliability cost and reliability benefit of facility additions would avert the risk of over/under capacity of power systems.

Li & Choudhury (2008) agree with Chowdhury & Koval (2001) when suggesting that reliability targets should rather be based on balancing the costs incurred by a utility to improve service

reliability and the value of the benefits that these improvements bring. The basic idea is that the best alternative in system planning should achieve the minimum total cost.

Li & Lu (2005) comment that risk evaluation is only on a portion of the whole system planning process and that the economic analysis is always crucial in decision making. The benefit/cost analysis is the commonly used approach to ranking system reinforcement schemes.

According to the South African Grid Code and Distribution Code, investments should be justified as a least life-cycle cost solution (i.e. the investment that will minimise the cost of the energy supplied and the customer interruption cost), but some minimum technical performance levels are also specified, such as that investment in the transmission system, required to satisfy the minimum (n-1) redundancy requirement, shall be on a deterministic basis with no financial justification required (RSA Grid Code Secretariat, 2008 and RSA Grid Code Secretariat, 2014).

The literature discussed in this section comes to an agreement that supply reliability in distribution networks should not be based on arbitrary reliability targets, but the preferred system configuration should be the one that achieves the minimum total life cycle cost. This concept of balancing costs is referred to as value-based reliability planning (VBRP). This is examined in more detail in the next section.

#### **2.4. Value based reliability planning (VBRP) approach**

In the value based reliability planning approach, reliability investments are evaluated according to their impacts on the total cost of reliability (Schellenberg et al., 2014). This value-based reliability planning approach is illustrated in Figure 2-1.

The vertical axis in Figure 2-1 represents life cycle costs (capex and opex), while the horizontal axis indicates network performance (e.g. SAIDI).

Utility costs generally increase as service reliability increases. Since each incremental improvement in reliability comes at a higher cost as reliability increases, the relationship between reliability and utility cost is non-linear, reflecting diminishing returns on investment as reliability approaches perfection (Schellenberg et al., 2014). This is indicated by the green line in Figure 2-1. However, the utility cost curve can also increase significantly in the additional costs of restoring the system to a normal operating state and the loss of revenue (Koval & Chowdhury, 1998). The utility cost curve shown in Figure 2-1 is based on the belief that increased costs will achieve improved levels of distribution system reliability.

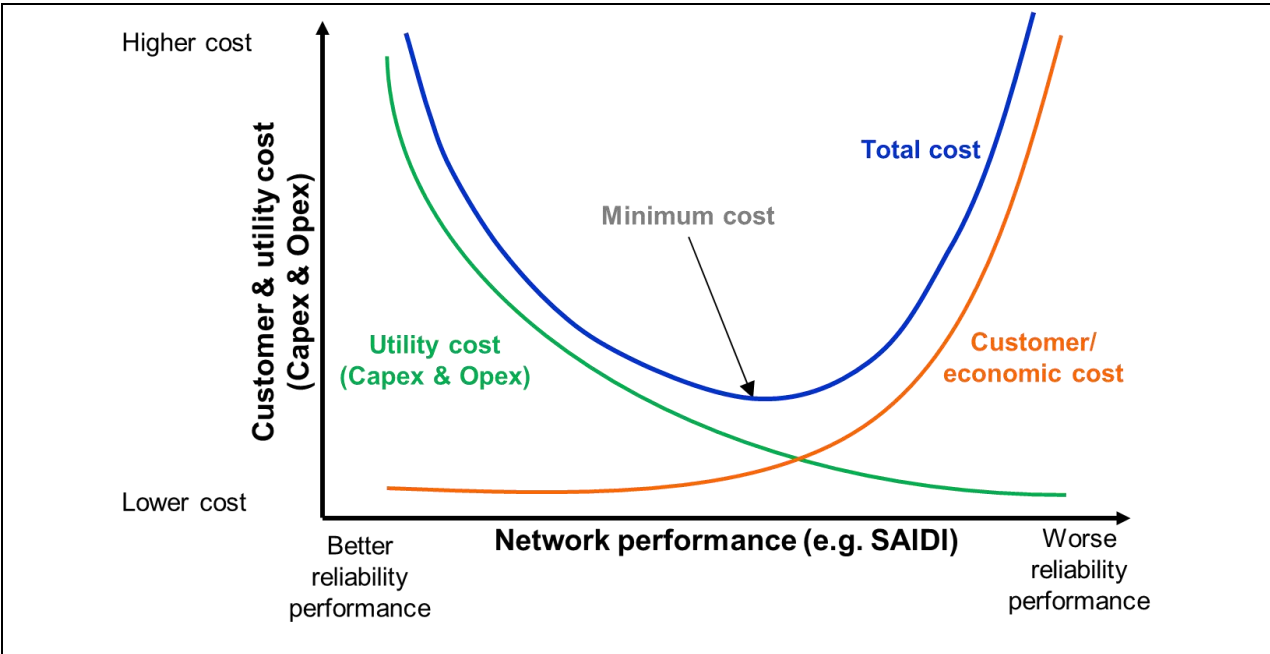
The better the performance (i.e. the lower the SAIDI) at which a utility operates, implies that customers will be without electrical supply for shorter periods. Socio-economic customer costs

associated with the unavailability of supply will therefore reduce as utility performance improves. This is indicated by the orange line in Figure 2-1 which moves towards zero as network reliability and performance improves.

The total cost curve (i.e. the sum of utility cost and customer cost) is indicated by the blue line. This line illustrates that there are levels of investment that result in a particular level of benefit for the minimum total costs. The turning point of the curve represents the optimum level of investment and the reliability level that should be aimed for. If the utility invests less than this minimum level, the total cost of service reliability is higher, due to the additional customer interruption costs that could have been cost effectively avoided by utility investment. If the utility invests more than this minimum level, the cost of service reliability is higher, because the outage costs saved by the customers are less than the investment costs made to avoid the outages.

The VBRP process attempts to establish a balance between the costs incurred by the utility to improve service reliability for various types of customers with the benefits or value that these improvements bring to the customers and the utility (Dalton et al., 1996). The balance is achieved by trying to minimise the total cost, where

$$\text{Total Cost} = \text{Utility costs} + \text{Customer outage costs} \qquad \text{Equation 2}$$



**Figure 2-1: Illustration of value-based planning concepts (adapted from Dalton et al., 1996)**

(Chowdhury & Koval, 2004) highlight that the VBRP provides a rational and consistent framework for answering the fundamental economic question of how much reliability is adequate from the customer perspective and where a utility should make reliability investments to satisfy customers' electricity requirements at the lowest cost. They further indicate that in a value-based approach, there are no absolute standards of SAIFI, SAIDI, CAIDI, etc., but the customer mix unique to each geographical service area determines whether the performance is adequate or poor. Therefore the value-based approach makes perfect sense in a competitive electricity market.

## **2.5. Deterministic vs. probabilistic power system planning**

The deterministic system planning criteria have been used in the utility industry for many years (Li, 2015). However, weaknesses associated with the deterministic criteria have been exposed in the planning practice of utilities, e.g. only consequences of outages are considered but the probabilistic or stochastic nature of the system behaviour is overlooked (Li, 2015 and Billinton & Allan, 1996).

Li (2015) explains that probabilistic power system planning can overcome the disadvantages of deterministic criteria. Probabilistic methods add one more dimension to enhance system planning rather than replacing the deterministic criteria. There is no conflict between deterministic and probabilistic criterion since these two kinds of criteria are applied at different stages in the planning process.

From these discussions it is clear that both the deterministic and probabilistic approaches are valid approaches to be used in power system planning.

## **2.6. Substation reliability evaluation techniques**

Van der Merwe (2014) performed a literature review of the different reliability evaluation techniques for large sub-transmission systems, including substations. She further developed an analytical simplified network reliability modelling approach, capable of determining the expected performance levels of a utility-scale transmission and sub-transmission network. This simplified approach forms the basis of this research and more information on this approach is provided in section 4.

## 2.7. Standard substation configurations

Various different substation configurations exist and are used by different utilities. Some substation and/or busbar configurations found in literature are discussed briefly below.

Bio (2012) and Rural Utilities Service, United States Department of Agriculture (2001) refer to the busbar configurations listed in Table 2-1.

**Table 2-1: Busbar configurations (Bio, 2012 and Rural Utilities Service, United States Department of Agriculture, 2001)**

No	Busbar configurations	
	Bio (2012)	Rural Utilities Service, United States Department of Agriculture (2001)
1	Single bus	Single bus
2	Double bus	
3	Main bus and transfer	Main and transfer bus
4	Double bus, single breaker	
5	Ring bus	Ring bus
6	Breaker-and-a-half	Breaker-and-a-half
7		Sectionalised bus
8		Double breaker, double bus

Neudorf et al. (1995) refer to the following busbar configurations:

- (a) Six-breaker arrangement with air-insulated equipment;
- (b) Six-breaker arrangement with gas-insulated equipment;
- (c) Four-breaker arrangement with air-insulated equipment.
- (d) Four-breaker arrangement with gas-insulated equipment;

Bagen. (2011) refers to the following busbar configurations:

- (a) Six-breaker arrangement;
- (b) Four-breaker arrangement.

Van der Merwe (2014) defined a substation configuration by the busbar configuration (upstream and downstream busbars) and transformer configuration. More information about the substation configurations considered in this research is provided in section 4 (see section 4.5).

## **2.8. Preferred substation configuration**

It was discussed in section 1.1 that comparisons between the different substation configurations are not often found in literature. Some examples of substation configuration comparisons found in literature are listed in section 1.1 and the shortcomings with these comparisons were identified.

Hinow et al. (2008) recognised that selecting a substation configuration while considering all potential cost influences creates a complex, multi-dimensional problem. They suggested a genetic algorithm (GA) to identify the substation with the lowest life cycle cost (LCC), considering a wide range of possible combinations of all cost parameters. This algorithm answers the questions:

- (a) For what outage cost is additional redundancy useful, and
- (b) What are the optimum technologies and arrangements to be used

The case studies shown deal with a limited number of components for a 220/110 kV substation, i.e: incoming and outgoing line bays, busbars, power transformer and power transformer bays. For each component, a redundant form is identified. Substantial input data are required for every component, including Weibull distributions of component failure rates. The total investment cost of a component (including secondary equipment and land) is defined in per unit of one GIS switchgear bay, using a ratio for rated voltage or technology (GIS, AIS) or component (50 MVA power transformer). Maintenance costs are also defined in per unit cost.

The GA finds the substation configuration with the lowest LCC and can be used to identify the break-point between AIS, GIS and single- and double-transformer bays. The algorithm forms the basis of a technique for utilities, provided that they have access to the appropriate reliability and cost data.

This approach has the advantage that the GA can skip out many configurations that give relatively high LCC, but it has the following shortcomings:

- (a) It requires lots of data, especially if a wide range of rated voltages and transformer capacities is to be assessed,
- (b) It does not assess alternative busbar arrangements.

(c) It is unclear how the failure rate probability density functions are applied.

The question of which substation configuration is the preferred configuration, considering busbar and transformer layouts, for various customer interruption costs, therefore remains unanswered.

## **2.9. Customer interruption cost**

The customer interruption cost is a measure of the loss that the customer suffers due to the unavailability of electrical supply. The customer cost associated with a loss of supply is a major element in the evaluation of reliability worth. Schellenberg et al. (2014) indicated that the VBRP is only as good as the customer interruption cost estimates that serve as a primary input into the analysis. The cost of interruption at a single customer load point is dependent entirely on the cost characteristics of that customer (Billinton & Allan, 1988).

Various different approaches can be used to evaluate customer interruption costs. These methods can be grouped into the following three categories (Wacker & Billinton, 1989):

- (a) Various indirect analytical evaluations;
- (b) Case studies of blackouts;
- (c) Customer surveys.

Of the three different types of methods employed so far, customer surveys have emerged to be the most effective and hence, most widely-used to estimate outage costs (Ratha et al., 2013).

### **2.9.1. Parameters that influence customer interruption cost**

Several parameters, which differentiate one outage from another, have a considerable effect on the cost of a particular outage (Ratha et al., 2013). The following parameters are listed from previously published studies:

- (a) Duration of the outage (Ratha et al., 2013 and Jonnavithula & Billinton, 1997)
- (b) Frequency of recurrence (Ratha et al., 2013)
- (c) Time of the day, day of the week and season (Ratha et al., 2013, Dzobo, 2010 and Jonnavithula & Billinton, 1997)
- (d) Advance warning (Ratha et al., 2013 and Jonnavithula & Billinton, 1997)
- (e) Customer type and size, e.g. residential and commercial sectors (Ratha et al., 2013)
- (f) Number of customers (Ratha et al., 2013)

- (g) Energy criticality (Ratha et al., 2013)
- (h) Degree of substitutability (Ratha et al., 2013)
- (i) Economic activity (Dzobo et al., 2014 and Jonnavithula & Billinton, 1997)
- (j) Monthly electricity bill (Dzobo, 2010 and Jonnavithula & Billinton, 1997)
- (k) Customer electrical size, measured in electricity consumption (Dzobo et al., 2014)
- (l) Customer economic size, measured in turnover (Dzobo et al., 2014)

Jonnavithula & Billinton (1997) provide weights for four of these parameters, namely total interruption time (frequency and length of outage), timing of interruption, advance notice of outage and monthly electric bill for residential, agricultural, industrial and commercial sectors. It is further explained that the total interruption time is the most important factor within each class, with importance weights of 45%, 59%, 53% and 72% in the residential, commercial, industrial and agricultural sectors respectively..

These parameters, together with the customer damage functions found in literature, will be considered to determine which parameters should be accommodated in this research.

## **2.9.2. Customer damage function (CDF)**

The customer interruption cost can be used to create a function of the interruption cost vs. interruption duration. This function is known as a customer cost of interruption or customer damage function (CDF).

### **2.9.2.1. Interruption costs for different sectors**

Billinton & Allan (1996) provides a set of interruption costs per interruption duration (\$/kW) for different customer sectors (see Table 2-2).

**Table 2-2: Sector interruption cost estimates (Billinton & Allan, 1996)**

User sector	Interruption cost (\$/kW)				
	1 min	20 min	1 h	4 h	8 h
Large users	1.005	1.508	2.225	3.968	8.240
Industrial	1.625	3.868	9.085	25.163	55.808
Commercial	0.381	2.969	8.552	31.317	83.008
Agricultural	0.060	0.343	0.649	2.064	4.120
Residential	0.001	0.093	0.482	4.914	15.690
Government and institutions	0.044	0.369	1.492	6.558	26.040
Office and buildings	4.778	9.878	21.065	68.830	119.160

The data assumes that customer interruption cost is linearly proportional to the load interrupted and is also a function of outage duration and customer type/sector.

The user sector “Large users” referred to in Table 2-2 is a strange sector and does not implicate anything about the kind of activity of these customers. No additional information regarding these customers is provided in the literature.

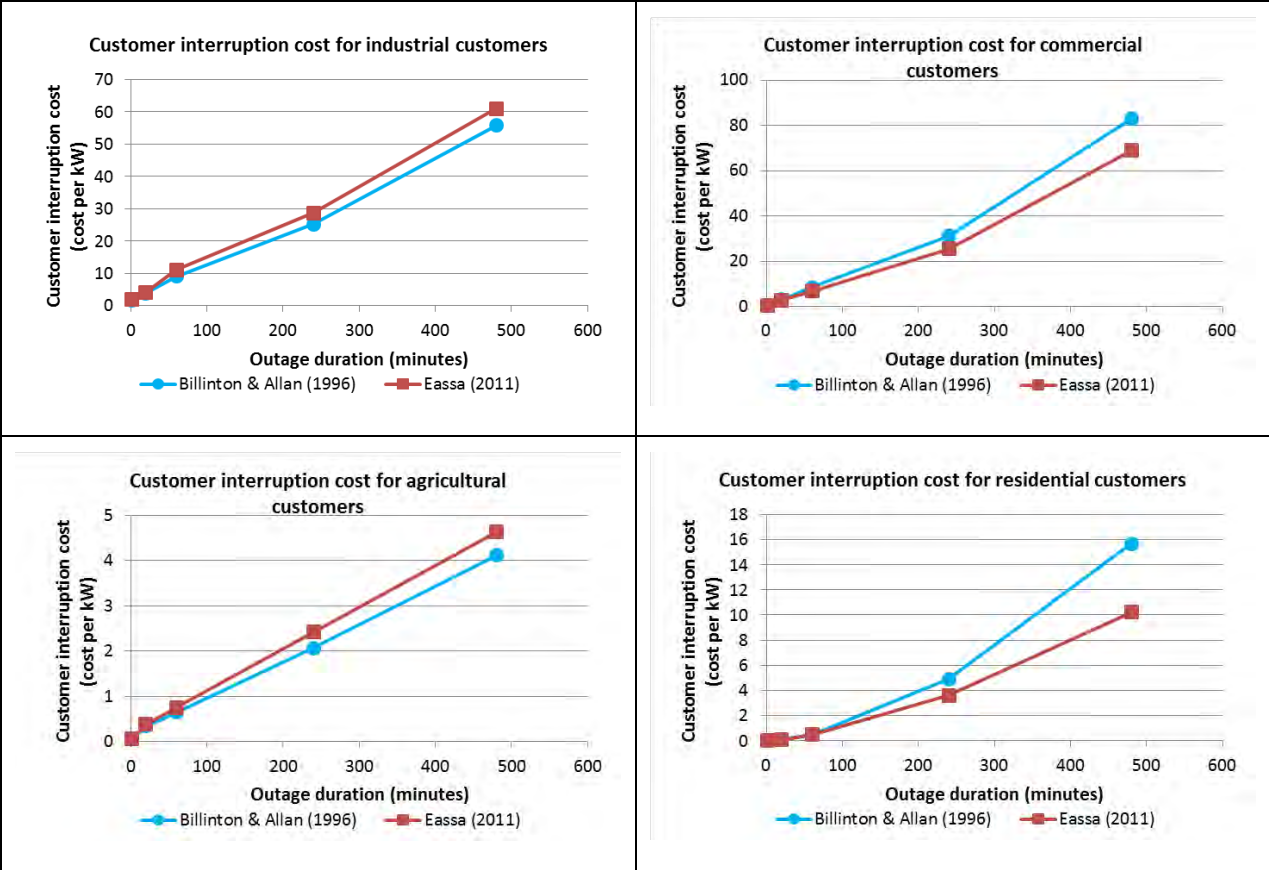
Eassa (2011) describes a customer damage function for five identified sectors, considering interruption costs for different interruption durations (LE/kW).

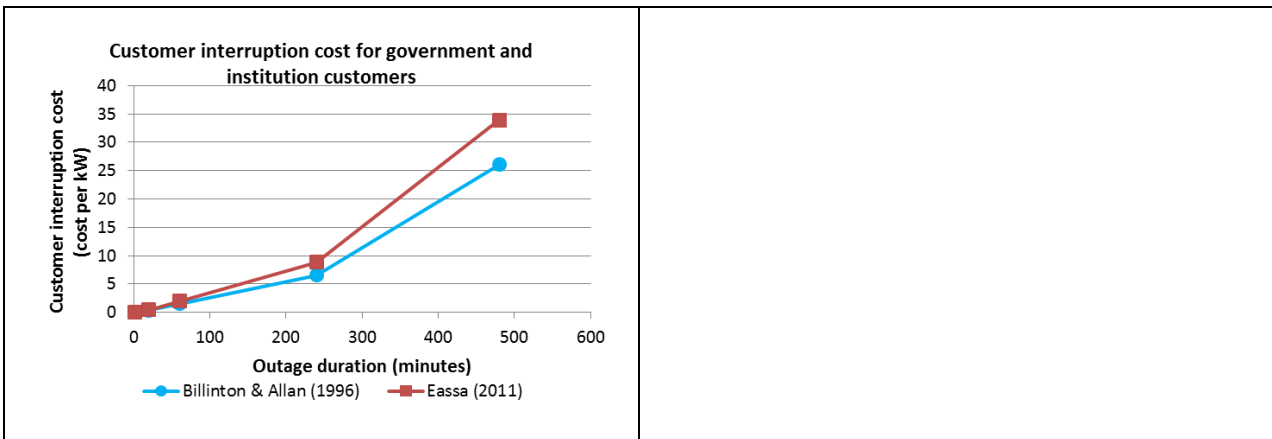
**Table 2-3: Sector interruption cost estimates (Eassa, 2011)**

User sector	Interruption cost (LE/kW)				
	1 min	20 min	1 h	4 h	8 h
Industrial	6.26	13.82	37.48	96.87	205.65
Commercial	1.26	9.47	23.05	86.12	232.84
Government and institutions	0.19	1.64	6.73	29.94	114.58
Residential	0.01	0.26	1.59	12.16	34.51
Agricultural	0.23	1.30	2.53	8.17	15.63

Again the data assumes that customer interruption cost is linearly proportional to the load interrupted and is also a function of outage duration and customer type/sector. This is consistent with the observations of (Billinton & Allan, 1996).

The costs provided by Billinton & Allan (1996) and Eassa (2011) respectively are in different currencies and published 15 years apart. It is therefore not possible to compare the absolute costs provided in these two publications. The costs provided by Eassa (2011) were therefore scaled to determine whether these two data sets generally have the same order of magnitude and the same shape in each of the different sectors. The scaling factor used was determined using the average ratio of the 8 hour (480 minute) cost ratios in each of the customer sectors, (i.e. a scaling factor of 0.296). The comparison is shown in Figure 2-2.





**Figure 2-2: Comparison of customer interruption costs provided by Billinton & Allan (1996) and Eassa (2011) respectively**

From Figure 2-2 it can be concluded that the customer damage functions have more or less the same order of magnitude and shape across the different customer sectors. The cost provided by Eassa (2011) is however higher than the costs provided by Billinton & Allan (1996) for the industrial, agriculture and government and institution customers, while its lower for the commercial and residential sectors.

### 2.9.2.2. Planned vs. unplanned interruption costs

Küfeoglu and Lehtonen (2015a) differentiate between the cost of an unexpected outage vs. planned outage for household and vacation house customers. These costs are shown in Table 2-4 and Table 2-5 respectively.

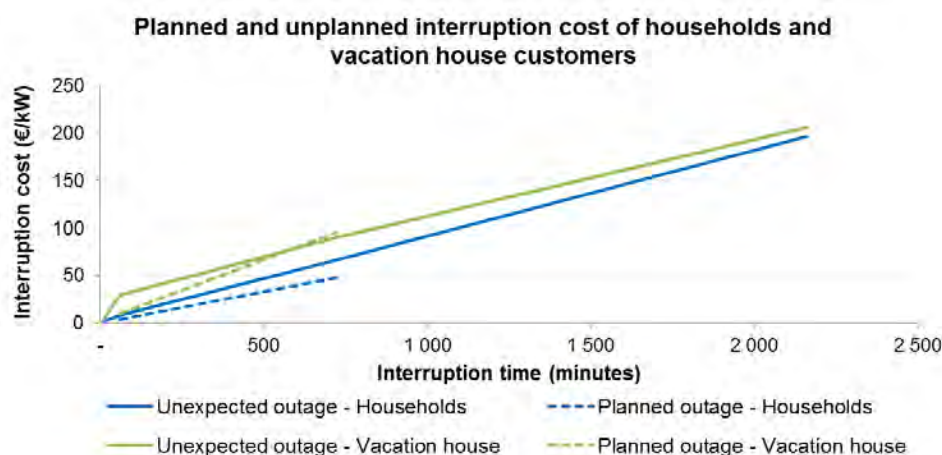
**Table 2-4: Interruption costs of planned and unplanned outages of household customers (Küfeoglu and Lehtonen, 2015a)**

Type of outage	Interruption cost (€/kW)				
	1 s	2 min	1 h	12 h	36 h
Unexpected outage	0.12	0.84	7.80	65.88	196.44
Planned outage			3.72	48.00	

**Table 2-5: Interruption costs of planned and unplanned outages of vacation house customers (Küfeoglu and Lehtonen, 2015a)**

Type of outage	Customer interruption cost (€/kW)				
	1 s	2 min	1 h	12 h	36 h
Unexpected outage	0.12	0.24	29.16	90.36	206.76
Planned outage			10.32	95.76	

The interruption costs given by Küfeoglu and Lehtonen (2015a) in Table 2-4 and Table 2-5 are compared in the graph in Figure 2-3. This figure shows that the customer interruption costs (CICs) for vacation house customers are higher than that of households, especially for the 1-12 h duration. This figure also shows that there is no specific ratio between the CICs of households vs. vacation house customers or CICs of planned vs. unplanned outages.



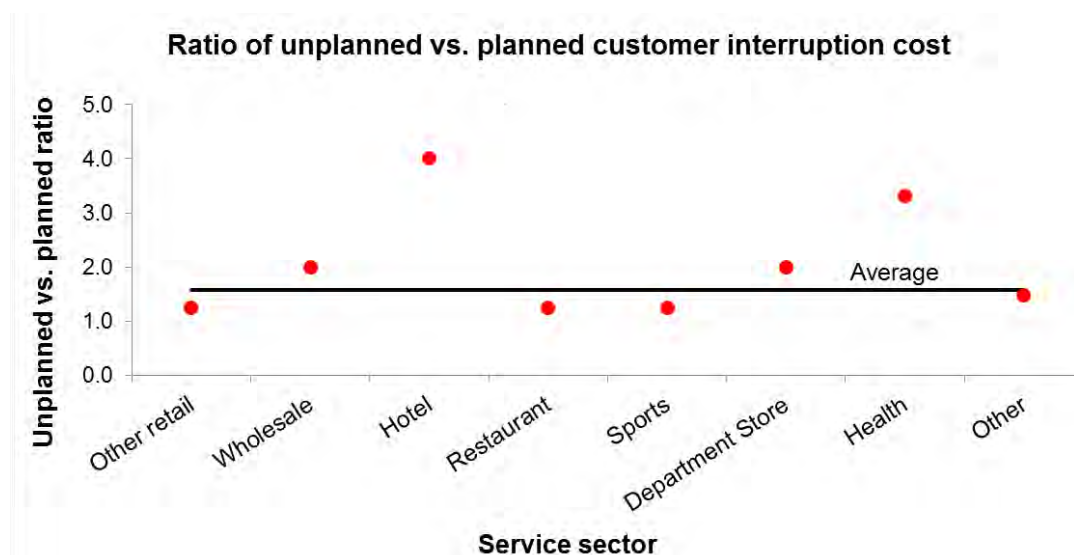
**Figure 2-3: Planned and unplanned interruption costs of households and vacation house customers**

Küfeoglu and Lehtonen (2015b) give the cost of an unexpected outage vs. planned outage for different service sector customers for one hour. These costs are shown in Table 2-6.

**Table 2-6: Interruption costs of planned and unplanned outages of different service sector customers for one hour (Küfeoglu and Lehtonen, 2015b)**

Service sector	Customer interruption cost (€/kW)	
	Unplanned Outages	Planned Outages
Other retail	1.900	1.520
Wholesale	0.040	0.020
Hotel	0.600	0.150
Restaurant	0.310	0.250
Sports	4.860	3.890
Department Store	0.006	0.003
Health	3.120	0.940
Other	3.650	2.470
Average	1.810	1.150

The ratios between the planned and unplanned interruption costs of the different service sector customers given in Table 2-6 are plotted in Figure 2-4. This figure shows a great variation in the ratio of unplanned vs. planned interruption cost for the different service sectors (i.e. a ratio of between 1 and 4 times).



**Figure 2-4: Planned and unplanned interruption costs of different service sector customers**

Dzobo et al. (2012) showed that sectors with backup power supply incurred different customer interruption costs. One would expect “Health” customers to have backup power supply such that the costs of planned and unplanned interruptions (as shown in Table 2-6) were the same.

The data by Küfeoglu and Lehtonen (2015a) and Küfeoglu and Lehtonen (2015b) assumes that customer interruption cost is linearly proportional to the load interrupted and is also a function of outage duration. The customer interruption cost is further dependent on the customer type (i.e. residential vs. vacation house customers) and whether advance warning was given (i.e. planned vs. unplanned).

### **2.9.2.3. South African interruption costs**

The South African Distribution Code specifies that the customer interruption cost (cost of unserved energy) shall be determined by a Nersa approved process (RSA Grid Code Secretariat, 2014). These costs have not yet been determined and therefore no standardised set of cost of unserved energy (COUE) rates per customer segment exists in South Africa for the use of project justification (Cameron & Van der Merwe, 2014).

According to the Energy Research Centre, University of Cape Town (2009) Eskom has used a single CIC of R20 470/MWh while Nersa’s consultants have proposed using R18 228/MWh. No information is given on how these figures were derived. The Department of Minerals and Energy, Republic of South Africa (2006), used a single rate of R75/kWh to justify generation capacity. Again, no information is given on how this figure was derived. None of these South African figures differentiate between different customer segments, e.g. industrial and residential customers, as required for distribution planning purposes. Furthermore there is no evidence that these customer interruption costs were derived using customer surveys, which was identified by Ratha et al. (2013) as the most effective and widely-used method to estimate customer outage cost.

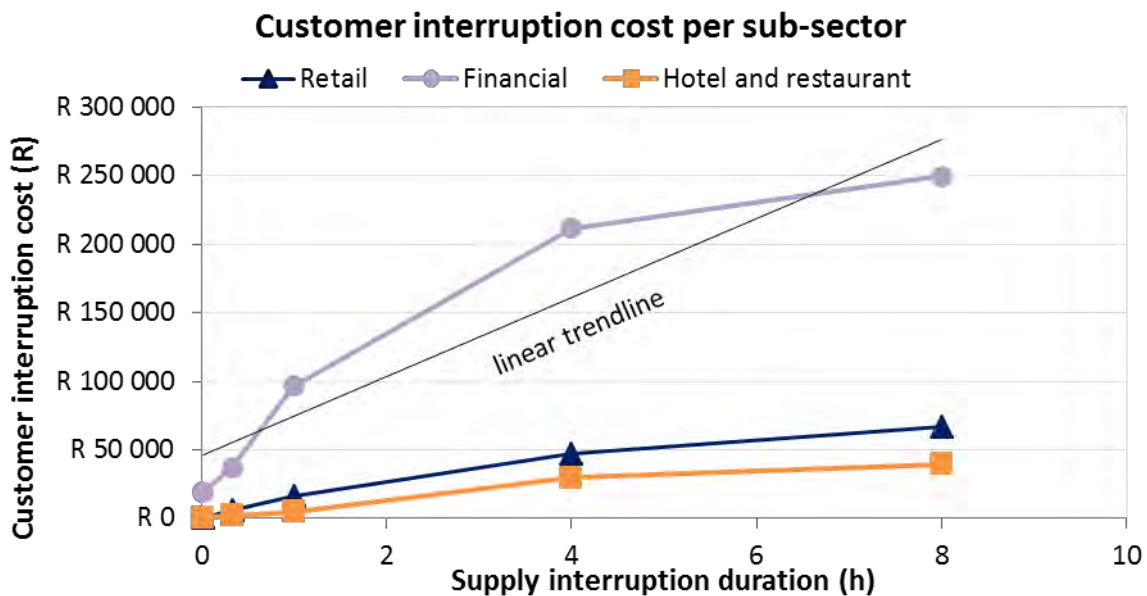
Dzobo (2010) provides customer interruption costs for industrial and commercial electricity consumers in Cape Town, considering their sector, and size as reflected in the monthly electricity bill.

Herman & Gaunt (2008) conducted a survey in South Africa to determine the customer damage function for specific customer sectors. The mean values of the customer interruption costs for different sub-sectors are shown in Table 2-7.

**Table 2-7: Sub-sector customer interruption cost (Herman & Gaunt, 2008)**

Customer class	Interruption cost (R)				
	2 s	20 min	1 h	4 h	8 h
Retail	182	6 398	16 303	47 042	67 111
Financial	18 936	37 252	96 765	211 703	249 506
Hotel and restaurant	455	2 054	4 958	29 542	39 624

The data by Herman & Gaunt (2008) assumes that customer interruption cost is a function of the outage duration and the customer type. The customer interruption costs provided by Herman & Gaunt (2008) above are plotted as a function of the supply interruption duration in Figure 2-5. It is clear from this figure that the customer damage function is not linearly proportional to the duration of the interruption.



**Figure 2-5: Customer interruption cost per sub-sector, from customer interruption costs provided by Herman & Gaunt (2008)**

Cameron & Van der Merwe (2014) refer to the set of cost-of-unserved energy rates shown in Table 2-8. No information is provided on how these rates were derived. The data assumes that customer interruption cost is linear proportional to the energy not supplied and is also a function of the customer type.

**Table 2-8: Assumed COUE rates (Cameron & Van der Merwe, 2014)**

<b>Customer class</b>	<b>Hypothetical set of COUE rates (R/kWh)</b>
Agriculture	23.00
Commercial	77.00
Industrial	6.00
Mining	11.00
Redistributors	5.00
Residential	1.00
Traction	109.00

Considering the parameters that influence customer interruption cost, as discussed in section 2.9.1, and the customer damage functions discussed in this section, it can be concluded that the following parameters are the most important when calculating the customer interruption cost:

- a) Load interrupted;
- b) Duration of the outage;
- c) Customer type/sector and
- d) Whether advance warning was given.

### **2.9.3. Composite customer damage function (CCDF)**

Composite customer damage functions (CCDF) may also be derived. A CCDF is defined as the aggregated interruption cost for a mixture of customer sectors in a region (e.g. aggregated at a feeder, busbar or substation level). The CCDF is derived by combining the SCDF according to the relative representation of the individual sectors in a particular service area (Chowdhury & Koval, 1999). This is shown in Equation 3, where the CCDF of sampled customers is calculated by weighting the energy utilisation ratio with the sector customer damage function (SCDF) (Teansri et al., 2011).

$$CCDF(t) = \sum_{s=1}^S SCDF_s(t) \times W_s \quad \text{Equation 3}$$

Where:

$CCDF_s(t)$	= Composite customer damage function at outage duration t
$SCDF_s(t)$	= Sector customer damage function at outage duration t
$W_s$	= Weighting factor from electricity consumption in each sector
$S$	= Number of sectors

#### 2.9.4. Summary

From the above literature, the following can be summarised regarding the customer interruption cost:

- (a) The customer interruption cost estimates is a crucial input into VBRP.
- (b) Various parameters should be considered to determine the customer damage function, e.g. customer type, load interrupted, outage duration and whether it is a planned or unplanned outage.
- (c) The interruption cost experienced by customers due to the interruption of a load is determined by combining the different customer types to create a composite customer damage function.
- (d) No standardised set of customer interruption costs could be obtained for any country and/or utility. The 2014 version of the South African Distribution Code specifies that the customer interruption cost (cost of unserved energy (COUE)) shall be determined by a Nersa approved process, but currently no standardised set of customer interruption costs per customer segment exists in South Africa for the use of project justification.

#### 2.10. Utility costs

The VBRP approach requires utility cost vs. reliability as an input into the approach. For this purpose the total life cycle cost (LCC) of each substation needs to be considered. Hinow & Mevissen (2010) explain that the total LCC of a substation consists of the following costs:

- (a) Acquisition cost
- (b) Operational cost
  - (i) Scheduled maintenance

- (ii) Unscheduled maintenance
  - Component replacement cost
  - Penalty cost

(c) Renewal cost

The unscheduled maintenance, or failure-, cost also includes loss of revenue from customers not served. These costs usually form a very small part of the total outage cost, as discussed in section 2.1

Jeromin et al. (2009) refers to six cost-causing phases (concept/definition, design/development, manufacturing, installation, operation & maintenance, disposal) and then group these phases into three groups, namely investment, operating and recycling.

Kutlev et al. (2007) provide the formula in Equation 4 to calculate the total life cycle cost of a substation:

$$LLC = IC + FC + VC \times \left[ \frac{(1 + p)^n - 1}{p \times (1 + p)^n} \right] \quad \text{Equation 4}$$

Where:

- $LCC$  = Life cycle cost
- $IC$  = Investment cost
- $FC$  = O&M cost, i.e. fixed annual cost
- $VC$  = Interruption cost, i.e. variable cost
- $n$  = Substation planned life time
- $p$  = Interest rate

Karlsson et al. (1997) provide the formula in Equation 5 to calculate the total life cycle cost of a substation:

$$LLC = CI + CO + CM + CF \quad \text{Equation 5}$$

Where:

- $LCC$  = Life cycle cost

<i>IC</i>	=	Investment costs
<i>CO</i>	=	Operation costs (calculated for different real rate of interest and a specific substation life)
<i>CM</i>	=	Maintenance costs (calculated for different real rate of interest and a specific substation life)
<i>CF</i>	=	Outage cost (calculated for different real rate of interest and a specific substation life)

The life cycle cost components provided by Hinow & Mevissen (2010), Jeromin et al. (2009), Kutlev et al. (2007) and Karlsson et al. (1997) include similar cost components, but have the following discrepancies:

- (a) Kutlev et al. (2007) and Karlsson et al. (1997) ignore the renewal cost;
- (b) Hinow & Mevissen (2010) don't refer to the calculation of the net present value of specific cost components;
- (c) Karlsson et al. (1997) convert the operation, maintenance and outage cost to a net present value, while Kutlev et al. (2007) only convert the O&M cost to a net present value.

It is expected that all future costs should be converted to a net present value. The renewal cost will only be a factor if all substations components don't have the same project life, or if the evaluation period is different from the component project life.

A literature review of the different cost components was performed and is summarised below.

### **2.10.1. Cost of acquisition**

The cost of acquisition represents the costs associated with establishing the substation. Howard (2011) refers to the following cost components as part of the acquisition cost:

- (a) Switchgear, busbars, transformers, control & protection and telecoms, including civil cost and installation.
- (b) Common elements of the site development, which have relatively little impact on the overall compound size, such as the control room, transformer bunds and miscellaneous items, e.g. access roadways.
- (c) Land acquisition.

### **2.10.1.1. Land acquisition cost**

Howard (2011) used a land acquisition costs of €116 000 for an AIS substation with a switchgear cost of €12 284 470. The land acquisition cost therefore equates to 0.94% of the switchgear cost. He also provides the land acquisition costs of a GIS substation, but since GIS substations are excluded from this study, this cost is not considered in this literature review.

Karlsson et al. (1997) indicates that land cost can vary a factor of 100 or more for different locations.

Considering the information above it is not possible to conclude on a good estimate for land acquisition cost that will be valid for all substations. It is therefore important that the land acquisition cost is an input assumption in the costing model and can be changed by the user.

### **2.10.1.2. Common elements of site development**

Howard (2011) explained that the common elements of the site development include elements such as the control room, transformer bunds and miscellaneous items such as access roadways. He identified switchgear, civil & common costs of €19 517 980 for an AIS substation with switchgear cost of €12 284 470.

The civil and common costs only are therefore €7 233 510, which is 58.9 % of the switchgear cost.

### **2.10.1.3. Switchgear**

Howard (2011) compared the cost of a new 400/110 kV substation with air insulated switchgear (AIS) and gas insulated switchgear (GIS) respectively. The new substation is required to allow sufficient space to cater for the following equipment:

- (a) Minimum 6 x 400 kV bays;
- (b) 1 x 400 kV double busbar;
- (c) 1 x 400 kV coupler;
- (d) 2 x 400/110 kV 250 MVA double wound transformers;
- (e) 1 x 110 kV double busbar (rated to 2500 A);
- (f) 2 x 110 kV coupler (one of which is to be a spare);
- (g) Minimum 9 x 110 kV bays.

The switchgear cost for the AIS substation is €12 284 470 (He also provides the costs of a GIS substation, but since GIS substations are excluded from this study, this cost is not considered here.)

Kutlev et al. (2007) compared the cost of an AIS ring bus configuration with a GIS ring bus configuration, using a 138/13.8 kV substation. The substation has 2 x 138 kV feeder bays, but no information is provided on the number of transformers and 13.8 kV feeder bays. The investment cost for the AIS substation is \$5 000 000 (He also provides the costs of a GIS substation, not considered here.)

The United States Department of Agriculture (2001) has done a relative cost comparison of different substation configurations (see Table 2-9). The comparison is based on four circuits for each configuration and excludes costs associated with a power transformer. It is further stated that the cost relationships between the configurations may change, depending on the number of circuits and protective devices that are used.

**Table 2-9: Cost comparison of substation configurations (United States Department of Agriculture, 2001)**

Configuration	Relative cost
Single bus	100%
Sectionalised bus	122%
Main and transfer bus	143%
Ring bus	114%
Breaker and a half	158%
Double breaker – double bus	214%

It is clear from this information that finding costs for various different substation configurations are challenging since no single publication was found which included all required substation components included in the different substation configurations, for all relevant voltage levels (listed in section 1.3). Using costs from different publications is problematic since different cost elements are included in the costing of each (e.g. primary plant, secondary plant, construction, commissioning, etc.). Furthermore different publications consider cost data in different currencies and from different base years, which makes it difficult to derive a comprehensive cost database.

### **2.10.2. Operations and maintenance cost**

Operations and maintenance (O&M) cost refers to the cost incurred by the utility for planned maintenance and breakdown events. The different O&M costs found in literature are briefly discussed below.

Kutlev et al. (2007) use an O&M cost of \$37 000/a for an AIS substation with an investment cost of \$5 000 000. This equates to an O&M cost of 0.74% per annum of the upfront investment cost.

Howard (2011) gives the 50 year maintenance costs for an AIS substation with a switchgear cost of €12 284 470 as €5 770 990. This equates to an O&M cost of 0.94% per annum of the upfront switchgear cost.

Tsao & Cheng (2014) expressed the O&M cost as a percentage of the capital cost and uses an annual O&M cost of 2% of the total capital cost.

The O&M cost provided by Tsao & Cheng (2014) is more than double the O&M cost provided by Kutlev et al. (2007) and Howard (2011). The only conclusion that can be drawn from this data is that the annual O&M cost is between 0.74% and 2% per annum of the upfront investment cost.

Another important point to note is that Kutlev et al. (2007) use a 30 year substation life to calculate the total O&M cost over the life of the substation. Howard (2011) refers to a 50 year maintenance costs, which is almost double the substation life referred to by Kutlev et al. (2007). Considering some other literature, Karlsson et al. (1997) suggest a 30 year substation life, while Arjona et al. (2004) use a 50 year substation life when comparing different substation configurations. The South African Distribution Code (RSA Grid Code Secretariat, 2014) specifies that calculations used to justify investment shall assume a typical project life expectancy of 25 years, except where otherwise dictated by plant life or project life expectancy.

From the above literature the suggested substation life varies from 25 to 50 years. It is not clear from the literature why there is this significant difference in the expected substation life.

### **2.10.3. Summary**

It is clear from the costs provided in this section that no single publication included all required substation components (for all relevant voltage levels). Furthermore different cost elements (e.g. primary plant, secondary plant, construction, commissioning, etc.) are included in the costing provided in the different publications. The different publications also consider cost data from different currencies and base years.

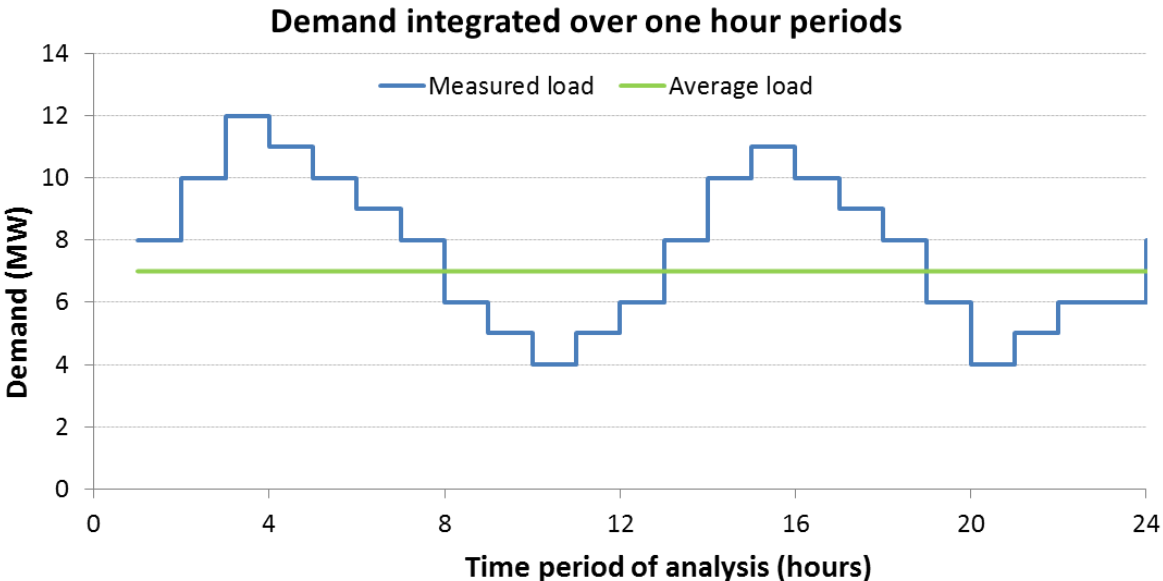
The land acquisition and O&M costs show great variability and only one cost was found for the common elements of the site development. The only conclusion that could therefore be drawn from the data was the range of values that can be considered for these cost parameters. In order to overcome this variation in cost, the costs should not be included as constants in the benefit/cost approach, but all costs should be inputs into the approach which can be changed by the user.

**2.11. Failure rates, maintenance frequencies and outage durations**

Component failure rates and repair durations as well as maintenance frequencies and outage durations are documented in various literature (Bollen, 1993, Xu et al., 2002, Zhou et al., 2012 and Allan et al., 1979). Van der Merwe (2014) conducted a literature review of failure rates, repair durations, maintenance frequencies and outage durations for use in her simplified reliability estimation approach. More information on this literature review is provided in section 4 (see section 4.6).

**2.12. Average load supplied per load point**

An important parameter required in the evaluation of load- and energy-orientated indices is the average load at each load point busbar. Billinton & Allan (1996) indicate that it is necessary to know the load-duration curve of each load point in order to evaluate the energy not supplied. Such a load profile is shown in Figure 2-6.



**Figure 2-6: Variation of demand in hourly intervals (adapted from Billinton & Allan, 1996)**

The load factor can vary significantly from one load to the next. The CSIR (2005) refers to the load factors in Table 2-10 for the planning and design of residential townships.

**Table 2-10: Annual load factor for residential township customers (CSIR, 2005)**

Consumption class	Annual load factor (%)
Very high	> 42
High	35 to 42
Medium	31 to 35
Low	29 to 31
Very low	28 to 29

The free basic electricity in South Africa is set at 50 kWh per month. A very low consumption class customer therefore uses 600 kWh in a year. With a maximum load of 2 kVA, this means the load factor of an individual customer is 3.4% ( $600/(2*24*365) = 0.034$ ), which is significantly lower than the 28% - 29% suggested in Table 2-10 even after allowing for substantial diversity between customer peak loads in a community.

Starke (2013) provides load factors for different industrial customers, as shown in Table 2-11.

**Table 2-11: Annual load factor for different industrial customers (Starke, 2013)**

Two-digit SIC	Sector description	Load factor
20	Food and kindred products	0.66
22	Textile mill products	0.71
23	Apparel and other textile mill products	0.54
24	Lumber and wood products, except furniture	0.43
25	Furniture and fixtures	0.54
26	Paper and allied products	0.78
27	Printing, publishing, and allied industries	0.69
28	Chemicals and allied products	0.81
29	Petroleum refining and related industries	0.58
30	Rubber and Miscellaneous plastics products	0.79

Two-digit SIC	Sector description	Load factor
31	Leather and products	0.61
32	Stone, clay, glass, and concrete products	0.66
33	Primary metal sector	0.72
34	Fabricated metal products	0.63
35	Computer equipment and industrial and commercial machinery	0.63
36	Electronics and other electrical equipment and components	0.68
37	Transportation equipment	0.63

### 2.13. Conclusions from literature review

Some of the research questions have already been answered by the literature review. These questions and the answers are briefly discussed below.

#### **What are the benefits of a more reliable substation configuration?**

The benefits of a more reliable substation are:

- (a) The loss of revenue incurred by the utility is less;
- (b) The cost in fault repairs, incurred by the utility, is less<sup>2</sup>;
- (c) The economic losses incurred by customers are less.

#### **What is an acceptable target for substation reliability?**

Acceptable supply reliability used to be based on a comparison of actual interruption frequencies and durations with arbitrary reliability targets. The problem with this approach to target setting is that it ignores the trade-offs between the cost of achieving a better level of reliability and the benefits derived by the utility and the economy.

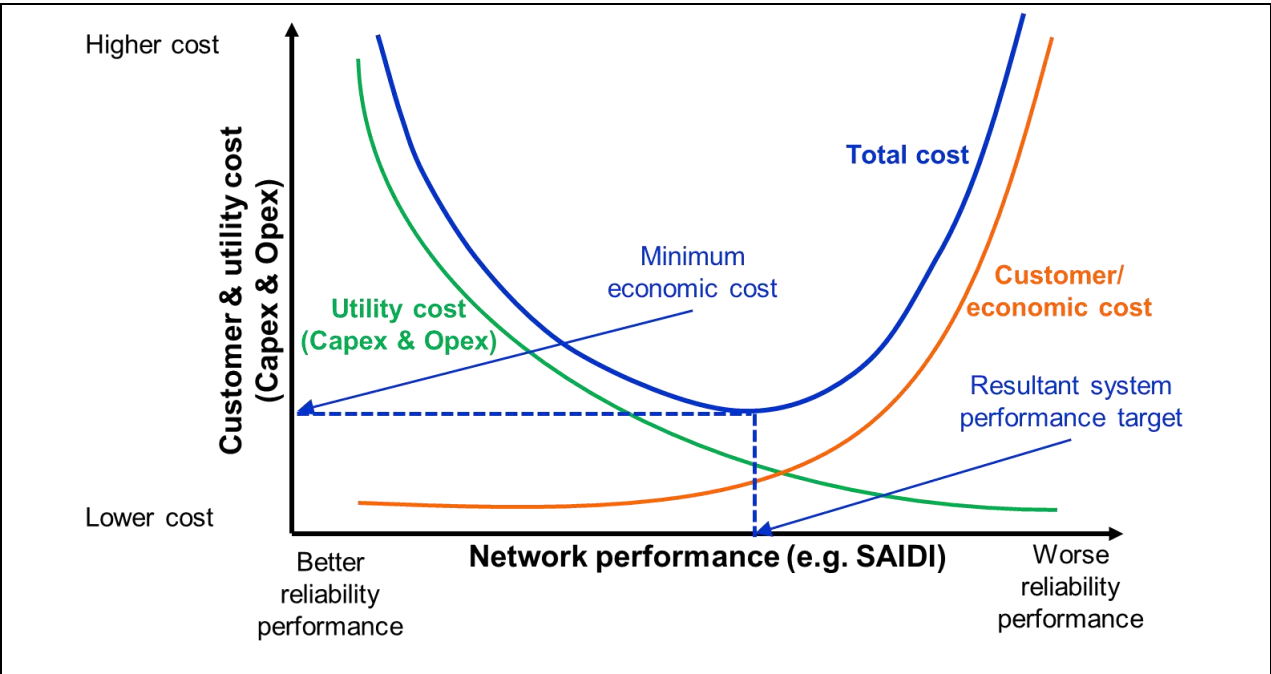
The literature suggests that the approach used to determine reliability targets should be based on balancing the costs incurred by a utility to improve service reliability and the value of the

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<sup>2</sup> If the same number of faults occur, there will be no cost saving, but a more reliable substation can also mean a substation for which the equipment failure rate is lower. Fewer faults will result in lower repair costs.

benefits that these improvements bring to the utility and its customers. This is referred to as the value based reliability planning process (VBRP). This approach considers the total life cycle cost associated with each substation, which includes the costs incurred by the utility as well as the economic losses to customers due to supply interruptions.

The reliability target for the substation is therefore not an arbitrary target, but rather an outcome of the VBRP process, which minimises the total cost. The basic idea is that the best alternative in system planning should be the option that achieves the minimum total cost. This is illustrated in Figure 2-7, using Figure 2-1. For electric cooperatives in particular, incorporating customer interruption costs into reliability planning is especially viable because customers are part owners of the utility.



**Figure 2-7: Using VBRP to determine system reliability targets**

The following question is partly answered by the literature review:

**What criteria need to be considered when determining the optimal substation configuration?**

Considering the VBRP approach, the following need to be considered when determining the optimal substation configuration:

- (a) The cost to the utility, which consists of the capital cost and O&M cost. Other utility costs, such as losses in revenue due to unsupplied loads, are small compared to the main costs and can therefore be ignored.
- (b) The interruption cost to the customers, which is influenced by the customer type (i.e. industrial, commercial, residential, etc.), load interrupted, duration of the interruptions and whether advance warning was given.

The literature does not provide answers regarding which substation parameters have the biggest influence on the utility and customer costs, and this need to be answered by further research.

The following research questions remain unanswered after this literature review and need to be answered by further research.

- (a) Can a set of preferred substation layouts be defined for a given set of failure rates and equipment costs?
- (b) For which parameters are the preferred substation layouts most sensitive?

The literature review highlighted that selecting the preferred substation configuration while considering all potential cost influences creates a complex, multi-dimensional problem. It is necessary to develop an approach that can accommodate all these dimensions when calculating the preferred option. This approach needs to be repeatable such that it can be applied to different substation design criteria, e.g. voltage levels, and different customer interruption costs.

### 3. Approach

This research will consider a deterministic approach to reliability modelling to determine the preferred substation configurations. Therefore only the consequences of outages are considered while the probabilistic or stochastic nature of the system behaviour is ignored. Mean values will be used for parameters such as equipment failure rates, maintenance frequencies, outage durations, etc. Advantages of a probabilistic approach have been highlighted in section 2.5, but probabilistic criteria requires a range of values as inputs for parameters such as failure rates, which depend on the environment and maintenance policies and is therefore not generally available for substation components. The sensitivity of the outcomes to changes in input data/ parameters was tested by changing the failure rates and assessing the robustness of the outcomes. The approach is not as rigorous as a full probability study, but in the absence of probability based failure rates the outcomes of a probability study may be misleading. Therefore this research considered the deterministic approach and adopted the scenario approach for testing the sensitivity of the outcomes.

In section 2.7 it was discussed that various different substation configurations exist and are used by different utilities. In order to compare different substation configurations, all possible substation configurations need to be identified. The first step in the approach is to identify different substation configurations available to choose from (see Figure 3-1). The standard substation configurations are discussed in detail in section 5.

From the literature discussion in section 2.2 it was concluded that supply reliability in distribution networks should not be based on arbitrary reliability targets, but that the preferred system configuration should be the one that achieves the minimum total life cycle cost – the VBRP concept. This research will use this VBRP approach to identify the preferred substation configuration(s). The steps involved in the VBRP approach are numbered 2, 3, 4 and 5 in Figure 3-1.

In section 2.4 it was explained that the VBRP approach considers (a) the utility life cycle cost and (b) the customer/economic cost associated with each configuration. The following approaches will be used to calculate these costs:

- (a) Van der Merwe (2014) developed an analytical simplified network reliability modelling approach capable of determining the expected performance levels of substations. This approach groups the different components in a substation into sub-systems, and considers only the sub-systems in the reliability calculation. The same approach forms the basis of this research, so more information is provided in section 4, and it is

extended to incorporate the calculation of additional indices required to determine the preferred substation configurations.

In section 2.2 it was explained that the application of the reliability benefit-cost concept requires the expected energy not supplied (ENS) associated with each substation configuration to determine the customer interruption cost. The expected energy not supplied (ENS) will be calculated for each of the standard substation configurations. This is discussed in more detail in section 7.1.

In section 2.9 it was explained that the customer interruption cost is calculated using the energy-orientated indices and a customer damage function. The various customer damage functions and the calculation of the customer interruption cost are discussed in section 7.1.4.

- (b) In section 2.10 it was concluded that no single publication exists that includes the acquisition cost for all required substation components at all relevant voltage levels. Furthermore different cost elements (e.g. primary plant, secondary plant, construction, commissioning, etc.) are included in the costing provided in the different publications. Therefore a substation cost estimation tool was developed. The approach considered in this tool also groups the different components in a substation into sub-systems, and considers these sub-systems in the cost calculation. The cost estimation tool calculates the total life cycle cost, which includes the initial investment cost as well as the O&M cost. This tool is discussed in detail in section 6.

Once the utility cost and customer interruption cost has been calculated, the total life cycle cost associated with each substation configuration can be calculated. This step is discussed in detail in section 8.1. All future cost assumptions, such as O&M costs and failure costs, are assumed to be converted to a net present value before input into the model and no additional calculation is performed to convert these values to a net present value.

From the total life cycle cost the preferred substation configuration can be identified, which is the configuration with the minimum total cost (see no. 6 in Figure 3-1). This step is discussed in detail in section 8.2.

The theory underlying the approach is developed in the following sections. The final approach used to determine the preferred configurations is summarised in the discussions and conclusions section (see Figure 11-1 in section 11).

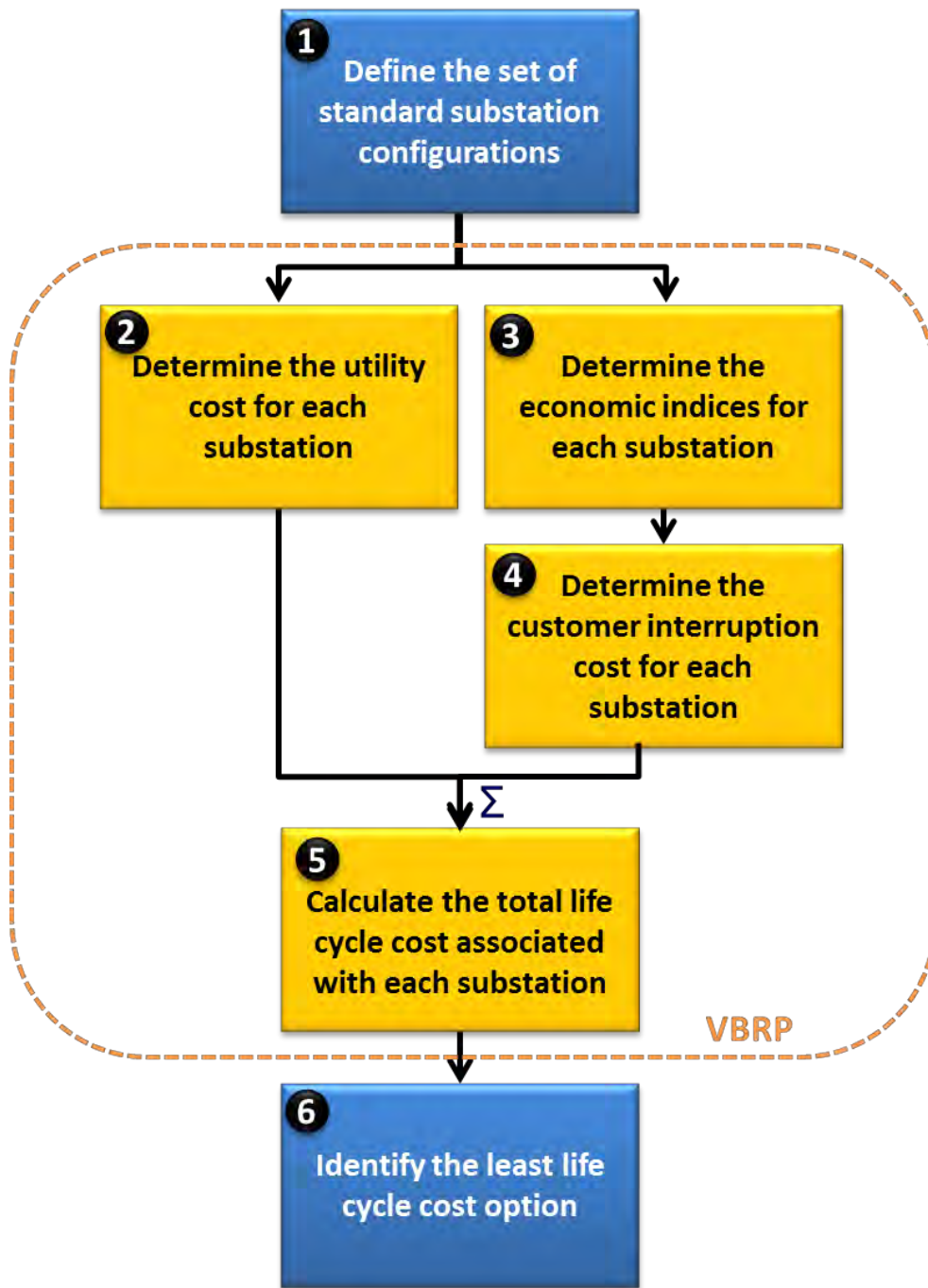


Figure 3-1: Approach to determining the preferred set of substation configurations

## **4. Simplified approach to the reliability estimation of substations**

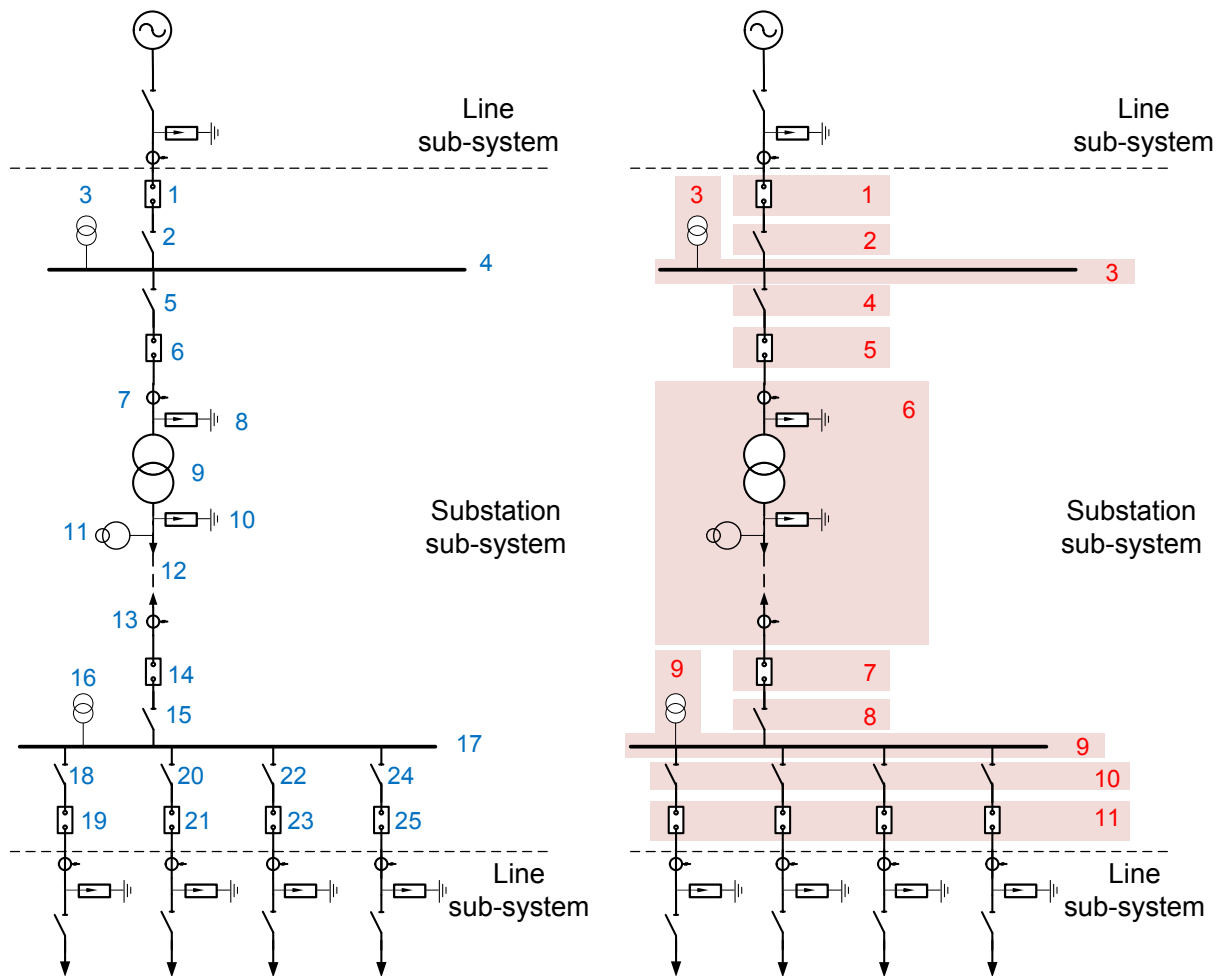
As explained in the literature review in section 2.6, Van der Merwe (2014) developed an analytical simplified network reliability modelling approach, capable of determining the expected performance levels of a utility-scale transmission and sub-transmission network. More information on Van der Merwe's approach is provided in this section, also expanding on some areas of it.

### **4.1. Approach**

Van der Merwe's (2014) approach decouples the substation reliability estimation from the transmission and sub-transmission reliability estimation and each substation and sub-transmission line is considered as a separate sub-system.

A detailed model of the substation is created, including all internal components. These components are then grouped into sub-systems, or modules, using the network reduction method. The simplified approach, therefore, doesn't ignore any components, but groups them together in order to minimise the user inputs and simplify the model calculations. It significantly reduces the number of elements considered in the reliability calculation.

Consider the single transformer substation with one source feeder and four load feeders shown in Figure 4-1. This substation has 25 individual components. After grouping components into sub-systems, only 11 sub-systems need to be considered in the reliability calculation.



**Figure 4-1: Grouping substation components into sub-systems**

## 4.2. Substation modules

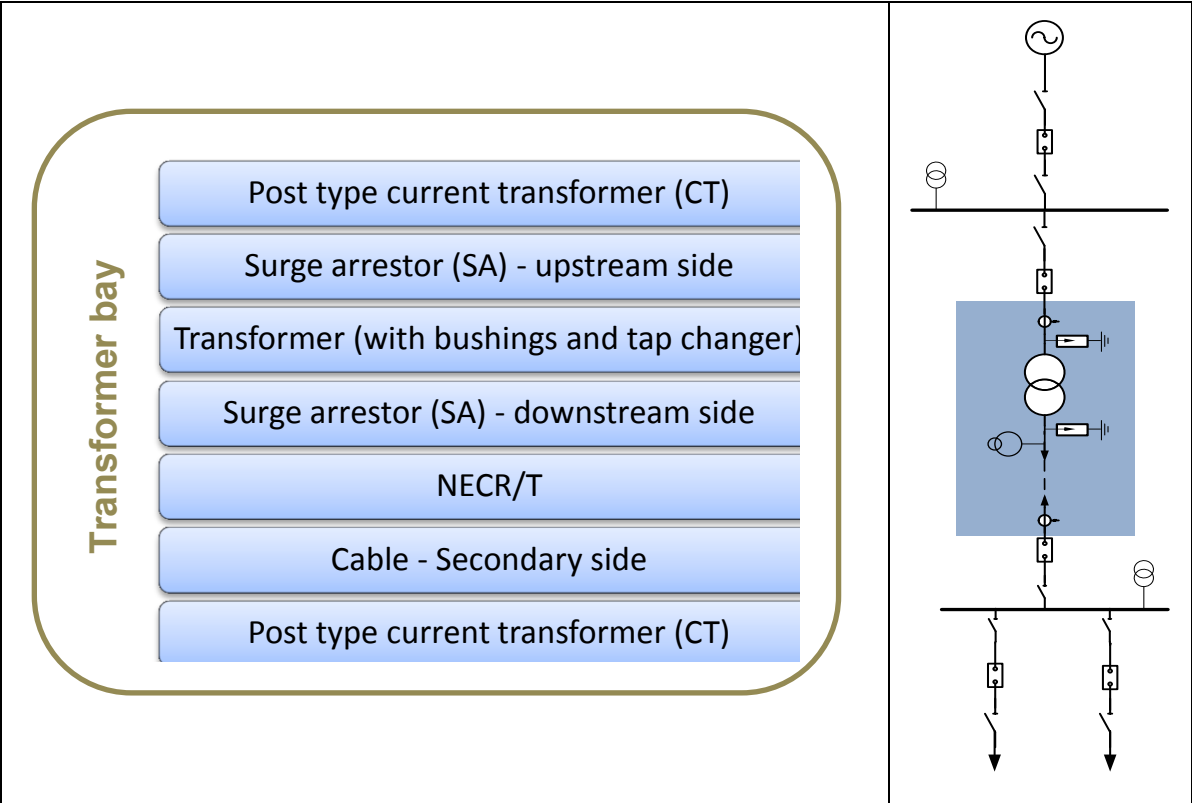
In order to determine the different substation modules, all components were analysed to determine which series components have the same post-fault and repair network states. Using this process two different modules were defined:

- (a) a transformer module and
- (b) a busbar module.

These two different substation modules are elaborated below.

**4.2.1. Transformer module**

The transformer module includes all components between the upstream transformer breaker and the downstream transformer breaker. These components are shown in Figure 4-2. A failure of any of these components will result in a trip of the upstream transformer breaker and the transformer will be out-of-service for the full repair duration of the component, hence these components have the same post-fault and repair network states.



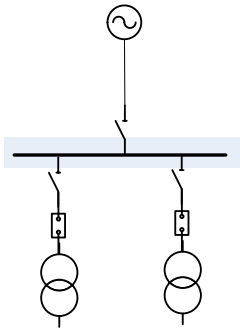
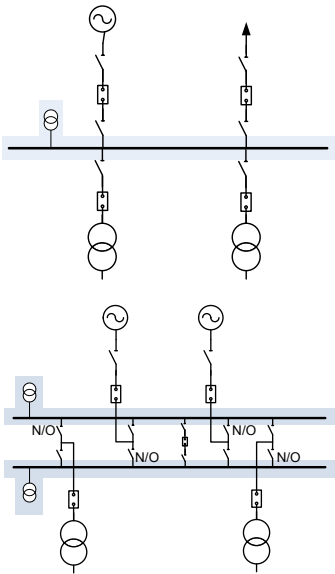
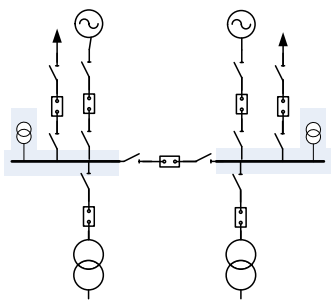
**Figure 4-2: Transformer module (Van der Merwe, 2014)**

**4.2.2. Busbar module**

The busbar and voltage transformer (VT) are grouped together and referred to as the busbar module. The number of VTs per busbar depends on the number of source feeders, number of load feeders, number of transformers and whether there is a bus-section. Three different busbar modules are considered in order to cater for the different busbar configurations and the number of VTs per busbar for each configuration. This is summarised in Table 4-1 and illustrated in Figure 4-3 (see highlighted blue sections).

**Table 4-1 : Number of VTs per busbar (Van der Merwe, 2014)**

No. of source feeders	No. of load feeders	No. of transformers	Bus-section?	No. of VTs
1	0	$\geq 1$	No	0
$\geq 1$	$\geq 1$	$\geq 1$	No	1
$\geq 1$	$\geq 0$	$\geq 1$	Yes	2 (one VT on each bus-section)

Description	No VTs	One VT	Two VTs
Illustration			
Comment	Applies to busbars with a single source feeder, no load feeders	Applies to single busbars (with load feeders or more than one source feeder) and busbars with bus-couplers	Applies to busbars with bus-section (no bus-couplers)

**Figure 4-3: Busbar modules for different busbar configurations (Van der Merwe, 2014)**

It is important to note that the breakers and isolators of the bus-section and bus-coupler are not considered to be part of the busbar module. Similarly, the line/transformer isolators are not considered to be part of the busbar module.

### 4.3. Failure mode and effect analysis (FMEA)

A failure mode and effect analysis is then applied to all sub-systems within the substation. The probability of each component failure and the impact of each failure on the customers supplied are evaluated. An enumerative method is used that calculates the expected frequency of interruptions due to the different component failures and adds all these frequencies to determine the total interruption frequency caused by the failures of all the components in the system. This is explained by the formula in Equation 6:

$$Interruption\ frequency_j = \sum_{i=1}^n \#_i \times \lambda_i \times \%Unsupplied_i \quad \text{Equation 6}$$

Where:

- $Interruption\ frequency_j$  = Number of interruptions experienced by a customer supplied by busbar j
- $\#_i$  = Number of components of type i
- $\lambda_i$  = Failure rate of component/module i (occ/a)
- $\%Unsupplied_i$  = Percentage of customers unsupplied if component i fails
- $n$  = Number of distinct components/modules

The duration of each interruption is added to Equation 6 to calculate the unavailability of supply experienced by each customer. The formula for the unavailability is shown in Equation 7.

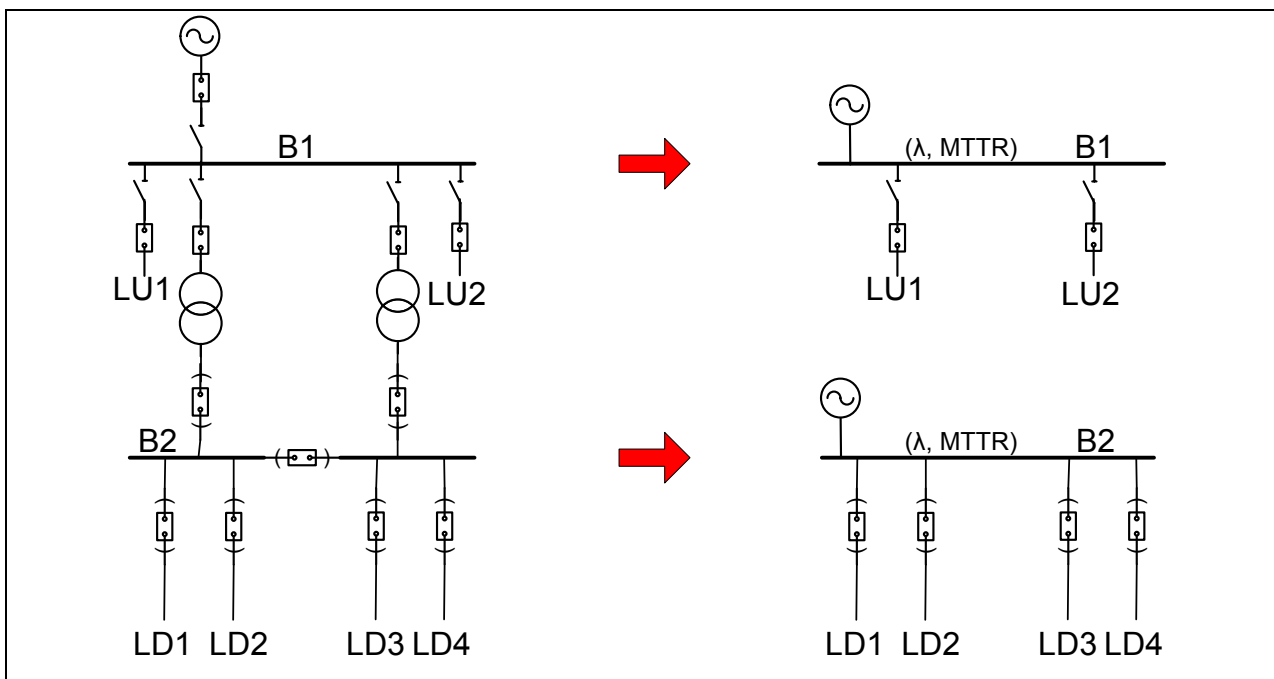
$$Unavailability_j = \sum_{i=1}^n \#_i \times \lambda_i \times (S_i \times \%Unsupplied_{i_s} + R_i \times \%Unsupplied_{i_r}) \quad \text{Equation 7}$$

Where:

- $Unavailability_j$  = Duration of interruptions experienced by a customer supplied by busbar j
- $\#_i$  = Number of components of type i
- $\lambda_i$  = Failure rate of component/module i (occ/a)

- $S_i$  = Time that elapse from the fault occurs until the operator can start with the fault repair, e.g. the time required to drive to site (h/occ)
- $R_i$  = Repair time of component/module i (h/occ)
- $\%Unsupplied_{i_s}$  = Percentage customers unsupplied, immediately after the protection has operated, if component i fails
- $\%Unsupplied_{i_{\bar{s}}}$  = Percentage customers that remain unsupplied after switching, while the faulty component i is being repaired
- $n$  = Number of distinct components/modules

This simplified approach reduces the detail of each substation and calculates the interruption frequency and interruption duration of each busbar, as illustrated in Figure 4-4. The annual outage frequency of the busbar, together with the number of customers supplied, is then used to calculate the SAIDI and SAIFI of the system.



**Figure 4-4: Reducing a substation to busbars with equivalent unavailability (Van der Merwe, 2014)**

#### **4.4. Reliability indices**

Van der Merwe identified the following load point indices in her approach:

- (a) Interruption frequency;
- (b) Interruption duration;
- (c) Availability.

She used the following customer-based indices to report on the reliability of the total network:

- (a) System Average Interruption Duration Index (SAIDI);
- (b) System Average Interruption Frequency Index (SAIFI);

She concluded that the calculated system indices (SAIDI and SAIFI) provide an indication of the technical performance of the network, but don't provide information on the economic impact of network outages. These technical indices have the potential to result in funding decisions that are not closely linked to economic interest. For this purpose economic indices are required. She then indicates that this simplified approach can be developed further to include the calculation of economic indices.

For the purpose of this research Van der Merwe's (2014) approach was expanded to include the calculation of the energy-orientated reliability indices. This is discussed in more detail in section 7.1.

#### **4.5. Standard substation configurations**

A substation configuration is defined by the busbar configuration (upstream and downstream busbars), transformer configuration and number of feeders connected to each busbar. More information about each is provided below.

##### **4.5.1. Busbar configurations**

The different busbar configurations considered are listed below.

- (a) Single busbar;
- (b) Single busbar with bypass busbar;
- (c) Single busbar with bus-section, where the bus-section consists of back-to-back isolators;

- (d) Single busbar with bus-section, where the bus-section consists of a breaker with an isolator on each side;
- (e) Single busbar with bus-section (as described in (d) above) and bypass busbar;
- (f) Double busbar, no bus-coupler (feeders can be linked to any one of the two busbars);
- (g) Double busbar, no bus-coupler, with bypass isolator;
- (h) Double busbar with bus-coupler (feeders can be linked to any one of two busbars and the busbars are connected via a bus-coupler);
- (i) Double busbar with bus-sections and bus-couplers (feeders can be linked to any one of two busbars and the sections of the busbars are connected via bus-couplers and bus-sections);
- (j) Breaker and a half.

For ease of reference, the different busbar configurations were numbered, e.g Type 1, Type 2, etc. The substation model is designed such that the user specifies a busbar type for both the upstream and the downstream busbar. This enables the user to identify numerous different substation configurations, by defining different combinations of upstream and downstream busbar classifications, such as Type 3 – Type 4, Type 1 – Type 3b etc.

Simplified single line diagrams of the Type 1 and Type 2 busbar configurations are shown in Figure 4-5. Descriptions with simplified single line diagrams of all the busbar types considered by Van der Merwe (2014) are given in Annex B. These diagrams do not represent the station electric diagrams, but are single line diagrams which indicate the electrical connectivity. Isolators with N/O indicated next to them are operated normally open. All other isolators are operated normally closed. All symbol definitions are provided in Annex A.

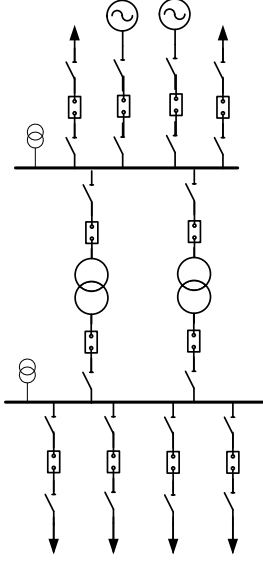
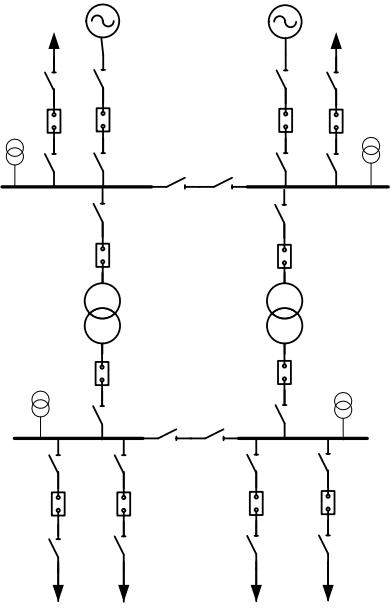
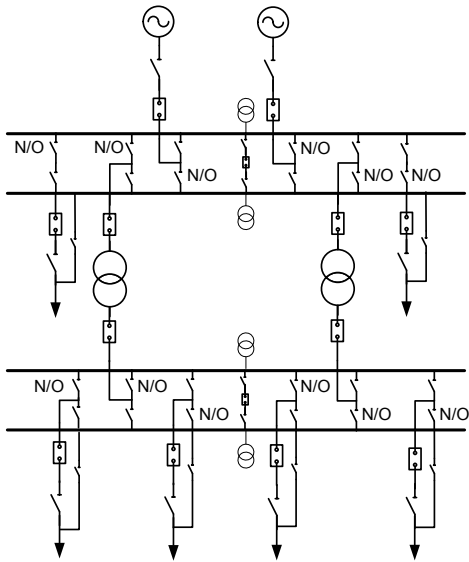
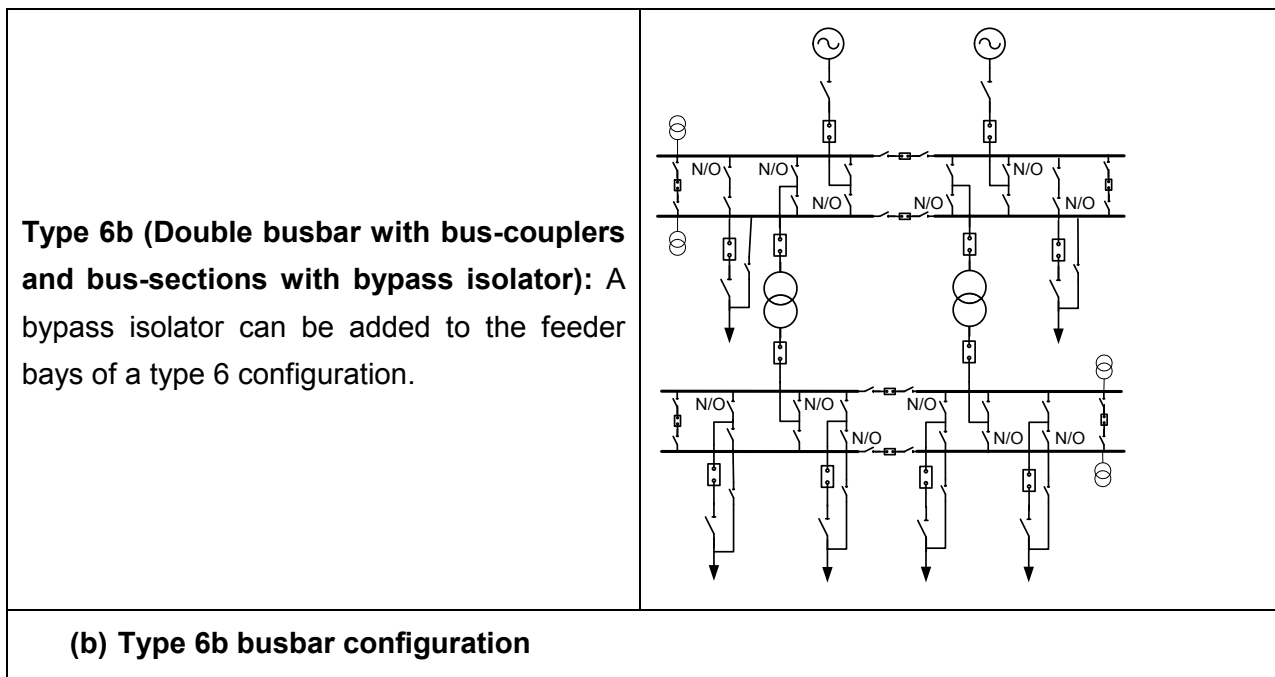
Description of busbar configuration	Single line diagram
<p><b>Type 1 (Single busbar):</b> A single busbar, without bus-sections or bus-couplers</p>	
<p><b>(a) Type 1 busbar configuration</b></p>	
<p><b>Type 2 (Single busbar with 2 x isolator bus-section):</b> A single busbar, with a bus-section. The bus-section consists of two isolators and no breaker.</p>	
<p><b>(b) Type 2 busbar configuration</b></p>	

Figure 4-5: Type 1 and Type 2 busbar configurations (Van der Merwe, 2014)

#### 4.5.2. Additional busbar configurations defined for this research

Two additional standard busbar configurations have been added to the busbar configurations used by Van der Merwe (2014) for this research. These two busbar configurations contain more components than any of the other components and are therefore expected to be more reliable than the configurations used by Van der Merwe (2014). These two more complex and expensive configurations are included in order to determine whether the additional cost required to achieve the value of losing less load or restoring customers more quickly is cost justified, and if so under what conditions (e.g. load size, customer type, etc.). These two busbar configurations are illustrated in Figure 4-6.

Description of busbar configuration	Single line diagram
<p><b>Type 5b (Double busbar with bus-coupler with bypass isolator):</b> A bypass isolator can be added to the feeder bays of a Type 5 busbar configuration.</p>	
<p><b>(a) Type 5b busbar configuration</b></p>	



**Figure 4-6: Type 5b and Type 6b busbar configurations**

The ten busbar configurations identified by Van der Merwe (2014) and the two additional busbar configurations result in 12 standard busbar configurations.

#### 4.5.3. Standard transformer configurations

Van der Merwe (2014) included the following standard transformer configurations in her simplified approach:

- (a) Single transformer: The downstream busbar is supplied by one transformer. Supply to all customers is interrupted if one transformer is out-of-service.
- (b) Double unfirm (non-firm) transformers: The downstream busbar is supplied by more than one transformer. Supply to some customers is interrupted if one transformer is out-of-service (considering average transformer loading).
- (c) Double firm transformers: The downstream busbar is supplied by more than one transformer. No supply is interrupted if one transformer is out-of-service.

The same three standard transformer configurations are considered for this research.

A substation can now be described by the transformer configuration and the upstream and downstream busbar configurations, for example:

- (a) Single Type 1 – Type 3: A substation with upstream busbar Type 1, downstream busbar Type 3 and a single transformer.

(b) Unfirm Type 3 – Type 4: A substation with upstream busbar Type 3, downstream busbar Type 4 and double unfirm transformers.

(c) Firm Type 4 – Type 5b: A substation with upstream busbar Type 4, downstream busbar Type 5b and double firm transformers.

Utilities often standardise on substation transformer sizes to minimise spares holding or to negotiate better prices with suppliers. The transformer sizes considered make a difference to the cost of the different substation configurations. For example, consider a substation designed for a peak load of 25 MVA. 1 x 25 MVA transformer is required to supply the full load and 2 x 25 MVA transformers are required to provide firm transformer capacity. If the utility only installs 20 MVA and 30 MVA transformers, then 1 x 30 MVA transformer is required to supply all load and 2 x 30 MVA transformers are required for firm capacity, which is more expensive than 1 x 25 MVA and 2 x 25 MVA transformers respectively.

For the purpose of this research, the following standard transformer sizes are considered:

- (a) 5 MVA
- (b) 10 MVA
- (c) 20 MVA
- (d) 40 MVA
- (e) 80 MVA
- (f) 160 MVA

#### **4.5.4. Number of feeders**

Van der Merwe (2014) explains that each line bay and transformer bay contains terminal equipment that can fail and needs to be maintained. These failures and maintenance activities could interrupt supply to either the entire busbar or parts thereof. Therefore, the number of bays connected to a busbar impacts the availability of the busbar to which it is connected.

The number of feeders is known to the network planner during the planning phase and therefore is considered as an input to the planning approach, and is not part of the optimal substation configuration decision-making process.

## 4.6. Failure rates, maintenance frequencies and outage durations

From the literature Van der Merwe (2014) compiled a list of failure rates, repair durations, maintenance frequencies and outage durations, used to illustrate her approach. These parameters are discussed briefly below.

### 4.6.1. Equipment failure rates

The assumed forced outage rates and repair durations per component, used by Van der Merwe (2014), are listed in Table 4-2. The same outage rates and repair durations were assumed for this study.

**Table 4-2: Substation component failure rates and repair durations (Van der Merwe, 2014)**

No	Component Description	Failure rate (Occ/a)	Repair duration (h)
1	High Voltage (HV) busbar	0.040	15
2	HV voltage transformer (VT)	0.004	24
3	HV breaker	0.020	60
4	HV isolator	0.002	12
5	HV current transformer (CT)	0.004	24
6	HV Surge arrestor	0.004	24
7	Transformer	0.120	100
8	Neutral electromagnetic coupled resistor with auxiliary power transformer (NECR/T)	0	0
9	Medium Voltage (MV) CT	0.002	7
10	MV Surge arrestor	0.002	7
11	MV VT	0.002	7
12	MV busbar	0.001	2
13	MV breaker	0.004	3
14	MV isolator	0.003	3

#### 4.6.2. Maintenance frequency and duration

The following high level assumptions were made by Van der Merwe (2014) regarding substation maintenance frequencies and duration:

- (a) Routine maintenance of the following equipment only requires a visual inspection, but no equipment outages: busbars, CTs, VTs and surge arrestors.
- (b) A maintenance cap of 1 outage per year and 12 hours over a 4 year maintenance cycle was assumed.

In the initial work, the maintenance duration assumed for isolators (8 hours) is longer than the maintenance duration for breakers (4 hours). Breakers however have more components to maintain and are therefore expected to take longer than isolators. The isolator maintenance duration has been adjusted to be 50% of the breaker maintenance duration, i.e. 2 hours. The maintenance frequency and duration per component assumed for this study are summarised in Table 4-3.

**Table 4-3: Planned maintenance frequency and duration for substation components**

No	Composite Description	Maintenance frequency (occ/a)	Maintenance duration (h)
1	HV busbar	0	0
2	HV VT	0	0
3	HV breaker	0.25	4
4	HV isolator	0.25	2
5	HV CT	0	0
6	HV Surge arrestor	0	0
7	Transformer module	0.25	2
8	NECR/T	Included in transformer module maintenance	Included in transformer module maintenance
9	MV CT	0	0
10	MV surge arrestor	0	0
11	MV VT	0	0
12	MV busbar	0	0

No	Composite Description	Maintenance frequency (occ/a)	Maintenance duration (h)
13	<b>MV breaker (outdoor)</b>	0.25	4
14	<b>MV isolator</b>	0.25	2
15	<b>Substation maintenance cap</b>	1	12/4*=3

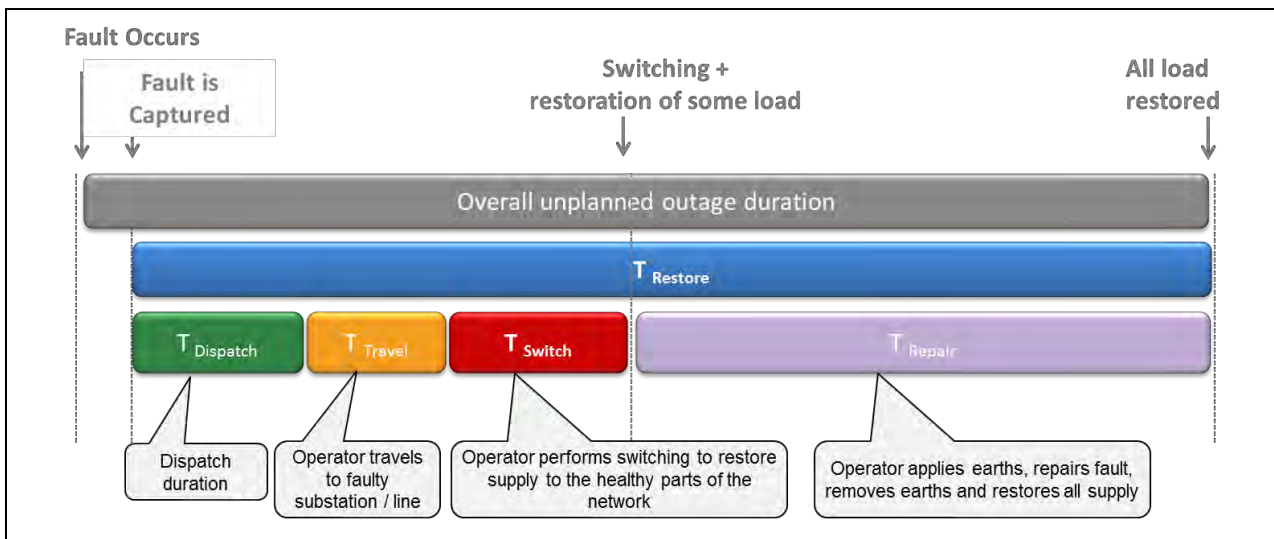
\* This is equivalent to a total outage duration of 12 hours over a four year maintenance cycle.

#### 4.6.3. Outage durations

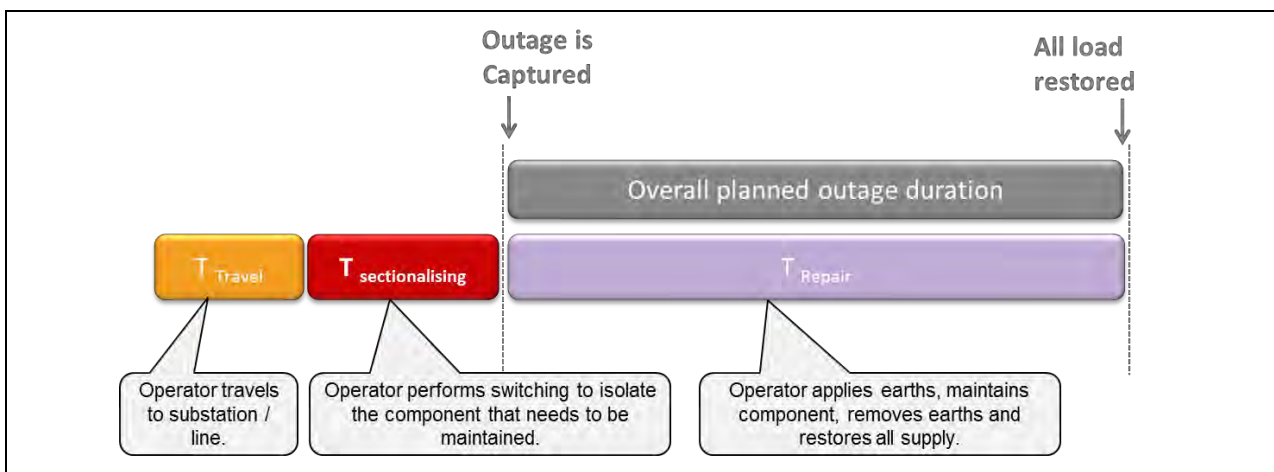
Van der Merwe (2014) defined the following outage elements in her research:

- (a) **T<sub>Dispatch</sub>**: The dispatch time is the time required by the control centre to acknowledge that there was a substation fault and dispatch an operator.
- (b) **T<sub>Travel</sub>**: This is the time required for the operator to travel to the substation/line. This duration therefore depends on the distance between the operator's office and the substation, and could be different for different areas of the network.
- (c) **T<sub>Switch</sub>**: The switch or sectionalising time is the time required by the operator to perform the necessary switching to restore supply to all healthy parts of the network.
- (d) **T<sub>Repair</sub>**: This is the time required to repair/replace the faulty equipment. It includes the time required to apply and remove earths.

These outage elements are illustrated in Figure 4-7 (unplanned outages) and Figure 4-8 (planned outages).



**Figure 4-7: Substation unplanned outage duration elements (Van der Merwe, 2014)**



**Figure 4-8: Substation planned outage duration elements (Van der Merwe, 2014)**

The outage duration assumptions for each element, proposed by Van der Merwe (2014), are listed in Table 4-4.

**Table 4-4: Outage duration assumptions (Van der Merwe, 2014)**

No	Outage duration component	Outage duration assumptions
1	Dispatch time	30 minutes
2	Travel time	60 minutes
3	Switch time	0 minutes*
4	Repair time	Component specific – see Table 4-2 and Table 4-3
5	Time to switch the normally open point	20 minutes

*\*The switch time is considered to be small compared to the travel time and repair time, and is therefore ignored.*

#### **4.7. Summary**

The research described in this section group the components in the substation into sub-systems and then calculates the reliability of the substation. No components are ignored, but the components are grouped to minimise the user inputs and simplify the model calculations. It significantly reduces the number of elements considered in the reliability calculation. This approach is the foundation for the substation cost calculation, described in section 6, where the substation is again grouped into sub-systems and only the sub-systems are considered in the cost calculation to minimise the user inputs and simplify the model calculations.

The simplified reliability calculation described in this section is also the foundation for calculating other reliability indices, such as the energy-orientated reliability indices, which is discussed in more detail in section 7.1.

This research compiled a comprehensive list of substation component failure rates, repair durations, maintenance frequencies and outages durations, which can be used to compare the reliability of different substation configurations.

Lastly, this research described standard substation configurations which can be compared with one another to determine the preferred substation configuration.

## 5. Standard substation configurations and design criteria

In order to identify the set of preferred substation configurations, the various substation configurations available to choose from need to be defined.

Building on the prior work, the standard busbar and transformer configurations used by Van der Merwe (2014) were considered as the basis set of available substation configurations (see section 4.5). Two additional busbar configurations were defined in section 4.5.2 for consideration in this research, resulting in 12 standard busbar configurations. Three standard transformer configurations were identified in section 4.5.3.

The standard substation configurations can be determined from the different combinations of standard upstream busbar configurations, downstream busbar configurations and transformer configurations. 432 different standard substation configurations result from the 12 standard busbar configurations on each of the upstream and downstream busbars and the three different transformer configurations (see Equation 8).

$$12 \times 12 \times 3 = 432$$

**Equation 8**

These are the configurations that the planner needs to consider in order to determine the optimal substation configuration.

Besides the busbar and transformer configuration, a substation is further defined by other design parameters, such as voltages. These design parameters, listed below, are known to the network planner during the planning phase and are considered as inputs into the planning approach:

- (a) Voltage levels of the upstream and downstream busbars;
- (b) Peak load, supplied from the upstream and downstream busbars respectively;
- (c) Number of load feeders, supplied from the upstream and downstream busbar respectively;

The number of source feeders is part of the optimal line configuration decision-making process. As explained in section 1.3, this is beyond the scope of this research. This research considers two options for different source line configurations, and the number of source feeders is also considered to be known to the planner during the planning stage.

The number of load feeders and load sizes are selected such that they represent a sample of the most likely design criteria for distribution networks. Regular points within the most likely

range were selected to ensure that the outcomes are not one-sided as a result of the input parameters selected.

The design parameters considered for this study are listed in Table 5-1.

**Table 5-1: Substation design parameters considered in the least life cycle cost comparison**

Design parameter	Values	Comment
Voltage level	132/66 kV (HV/HV); 132/22 kV (HV/MV); 33/11 kV (MV/MV)	
Number of source feeders	1 or 2	Source feeders supply only the upstream busbar. The downstream busbar is supplied by transformers only and not source feeders.
Number of load feeders	Upstream busbar: 0, 2 & 4 Downstream busbar: 2, 4, 6 & 8	
Peak load	5 – 10 MVA transformer range: 6.25, 7.5, 8.75 MVA. 10 – 20 MVA transformer range: 12.5, 15, 17.5 MVA. 20 – 40 MVA transformer range: 25, 30, 35 MVA. 40 – 80 MVA transformer range: 50, 60, 70 MVA. 80 – 160 MVA transformer range: 100, 120, 140 MVA.	The different peak loads are selected to consider 3 load points (i.e. 25%, 50% and 75%) within each transformer range, considering the standard transformer sizes discussed in section 4.5.3. For example, consider the two standard sizes 20 MVA and 40 MVA. The 50% load point between these two sizes are 30 MVA, while the 25% and 75% load points are 25 MVA and 35 MVA respectively.

The different combinations of substations that can be constructed from the values chosen for each of the design parameters listed in Table 5-1 are summarised in Table 5-2.

**Table 5-2: Substation design criteria considered in the least life cycle cost comparison**

Design criteria																			
Voltage	No. of source feeders	Transformer size:			5 - 10 MVA			10 - 20 MVA			20 - 40 MVA			40 - 80 MVA			80 - 160 MVA		
		No. of upstream load feeders	No. of downstream load feeders	Peak load (MVA)															
				6.25	7.5	8.75	12.5	15	17.5	25	30	35	50	60	70	100	120	140	
HV/HV	1	0	2	N/A	N/A	N/A	N/A	N/A	N/A	N/A	1	5	9	13	17	21	25	29	33
			4	N/A	N/A	N/A	N/A	N/A	N/A	N/A	2	6	10	14	18	22	26	30	34
			6	N/A	N/A	N/A	N/A	N/A	N/A	N/A	3	7	11	15	19	23	27	31	35
			8	N/A	N/A	N/A	N/A	N/A	N/A	N/A	4	8	12	16	20	24	28	32	36
		2	N/A	N/A	N/A	N/A	N/A	N/A	N/A	37	41	45	49	53	57	61	65	69	
		4	N/A	N/A	N/A	N/A	N/A	N/A	N/A	38	42	46	50	54	58	62	66	70	
		6	N/A	N/A	N/A	N/A	N/A	N/A	N/A	39	43	47	51	55	59	63	67	71	
		8	N/A	N/A	N/A	N/A	N/A	N/A	N/A	40	44	48	52	56	60	64	68	72	
		2	N/A	N/A	N/A	N/A	N/A	N/A	N/A	73	77	81	85	89	93	97	101	105	
		4	N/A	N/A	N/A	N/A	N/A	N/A	N/A	74	78	82	86	90	94	98	102	106	
		6	N/A	N/A	N/A	N/A	N/A	N/A	N/A	75	79	83	87	91	95	99	103	107	
		8	N/A	N/A	N/A	N/A	N/A	N/A	N/A	76	80	84	88	92	96	100	104	108	
	2	N/A	N/A	N/A	N/A	N/A	N/A	N/A	109	113	117	121	125	129	133	137	141		
	4	N/A	N/A	N/A	N/A	N/A	N/A	N/A	110	114	118	122	126	130	134	138	142		
	6	N/A	N/A	N/A	N/A	N/A	N/A	N/A	111	115	119	123	127	131	135	139	143		
	8	N/A	N/A	N/A	N/A	N/A	N/A	N/A	112	116	120	124	128	132	136	140	144		
	2	N/A	N/A	N/A	N/A	N/A	N/A	N/A	145	149	153	157	161	165	169	173	177		
	4	N/A	N/A	N/A	N/A	N/A	N/A	N/A	146	150	154	158	162	166	170	174	178		
	6	N/A	N/A	N/A	N/A	N/A	N/A	N/A	147	151	155	159	163	167	171	175	179		
	8	N/A	N/A	N/A	N/A	N/A	N/A	N/A	148	152	156	160	164	168	172	176	180		
	2	N/A	N/A	N/A	N/A	N/A	N/A	N/A	181	185	189	193	197	201	205	209	213		
	4	N/A	N/A	N/A	N/A	N/A	N/A	N/A	182	186	190	194	198	202	206	210	214		
	6	N/A	N/A	N/A	N/A	N/A	N/A	N/A	183	187	191	195	199	203	207	211	215		
	8	N/A	N/A	N/A	N/A	N/A	N/A	N/A	184	188	192	196	200	204	208	212	216		
HV/MV	1	0	2	217	221	225	229	233	237	241	245	249	253	257	261	265	210	214	
			4	218	222	226	230	234	238	242	246	250	254	258	262	N/A	N/A	N/A	
			6	219	223	227	231	235	239	243	247	251	255	259	263	N/A	N/A	N/A	
			8	220	224	228	232	236	240	244	248	252	256	260	264	N/A	N/A	N/A	
		2	265	269	273	277	281	285	289	293	297	301	305	309	N/A	N/A	N/A		
		4	266	270	274	278	282	286	290	294	298	302	306	310	N/A	N/A	N/A		
		6	267	271	275	279	283	287	291	295	299	303	307	311	N/A	N/A	N/A		
		8	268	272	276	280	284	288	292	296	300	304	308	312	N/A	N/A	N/A		
		2	313	317	321	325	329	333	337	341	345	349	353	357	N/A	N/A	N/A		
		4	314	318	322	326	330	334	338	342	346	350	354	358	N/A	N/A	N/A		
		6	315	319	323	327	331	335	339	343	347	351	355	359	N/A	N/A	N/A		
		8	316	320	324	328	332	336	340	344	348	352	356	360	N/A	N/A	N/A		
	2	361	365	369	373	377	381	385	389	393	397	401	405	N/A	N/A	N/A			
	4	362	366	370	374	378	382	386	390	394	398	402	406	N/A	N/A	N/A			
	6	363	367	371	375	379	383	387	391	395	399	403	407	N/A	N/A	N/A			
	8	364	368	372	376	380	384	388	392	396	400	404	408	N/A	N/A	N/A			
	2	409	413	417	421	425	429	433	437	441	445	449	453	N/A	N/A	N/A			
	4	410	414	418	422	426	430	434	438	442	446	450	454	N/A	N/A	N/A			
	6	411	415	419	423	427	431	435	439	443	447	451	455	N/A	N/A	N/A			
	8	412	416	420	424	428	432	436	440	444	448	452	456	N/A	N/A	N/A			
	2	457	461	465	469	473	477	481	485	489	493	497	501	N/A	N/A	N/A			
	4	458	462	466	470	474	478	482	486	490	494	498	502	N/A	N/A	N/A			
	6	459	463	467	471	475	479	483	487	491	495	499	503	N/A	N/A	N/A			
	8	460	464	468	472	476	480	484	488	492	496	500	504	N/A	N/A	N/A			
MV/MV	1	0	2	505	509	513	517	521	525	529	533	537	N/A	N/A	N/A	N/A	N/A		
			4	506	510	514	518	522	526	530	534	538	N/A	N/A	N/A	N/A	N/A		
			6	507	511	515	519	523	527	531	535	539	N/A	N/A	N/A	N/A	N/A		
			8	508	512	516	520	524	528	532	536	540	N/A	N/A	N/A	N/A	N/A		
		2	541	545	549	553	557	561	565	569	573	N/A	N/A	N/A	N/A	N/A			
		4	542	546	550	554	558	562	566	570	574	N/A	N/A	N/A	N/A	N/A			
		6	543	547	551	555	559	563	567	571	575	N/A	N/A	N/A	N/A	N/A			
		8	544	548	552	556	560	564	568	572	576	N/A	N/A	N/A	N/A	N/A			
		2	577	581	585	589	593	597	601	605	609	N/A	N/A	N/A	N/A	N/A			
		4	578	582	586	590	594	598	602	606	610	N/A	N/A	N/A	N/A	N/A			
		6	579	583	587	591	595	599	603	607	611	N/A	N/A	N/A	N/A	N/A			
		8	580	584	588	592	596	600	604	608	612	N/A	N/A	N/A	N/A	N/A			
	2	613	617	621	625	629	633	637	641	645	N/A	N/A	N/A	N/A	N/A				
	4	614	618	622	626	630	634	638	642	646	N/A	N/A	N/A	N/A	N/A				
	6	615	619	623	627	631	635	639	643	647	N/A	N/A	N/A	N/A	N/A				
	8	616	620	624	628	632	636	640	644	648	N/A	N/A	N/A	N/A	N/A				
	2	649	653	657	661	665	669	673	677	681	N/A	N/A	N/A	N/A	N/A				
	4	650	654	658	662	666	670	674	678	682	N/A	N/A	N/A	N/A	N/A				
	6	651	655	659	663	667	671	675	679	683	N/A	N/A	N/A	N/A	N/A				
	8	652	656	660	664	668	672	676	680	684	N/A	N/A	N/A	N/A	N/A				
	2	685	689	693	697	701	705	709	713	717	N/A	N/A	N/A	N/A	N/A				
	4	686	690	694	698	702	706	710	714	718	N/A	N/A	N/A	N/A	N/A				
	6	687	691	695	699	703	707	711	715	719	N/A	N/A	N/A	N/A	N/A				
	8	688	692	696	700	704	708	712	716	720	N/A	N/A	N/A	N/A	N/A				

Some options, marked N/A, are excluded from the analysis. These options are not deemed practical from a utility point of view. For example, it is assumed that an HV/HV substation will not be constructed for a load smaller than 20 MVA. Similarly an MV/MV substation will not supply a load bigger than 40 MVA.

For the purpose of this research a specific set of values selected for each of the four design parameters is referred to as one design criterion. It is clear from Table 5-2 that the design options result in 720 different design criteria. The number of different design criteria per voltage level are summarised in Table 5-3.

**Table 5-3: Number of different substation design criteria per voltage level**

No	Substation voltages	Number of different design criteria
1	HV/HV substations	216
2	HV/MV substations	288
3	MV/MV substations	216
<b>Total</b>		<b>720</b>

Each of these design criteria may result in a different preferred substation configuration. The preferred substation configuration therefore needs to be determined for each of the 720 different design criteria. The approach shown in Figure 3-1 therefore needs to be repeated 720 times, as illustrated in Figure 5-1.

If the different design criteria are combined with the 432 standard substation configurations (identified in section 4), it results in 311 040 different substation layouts.

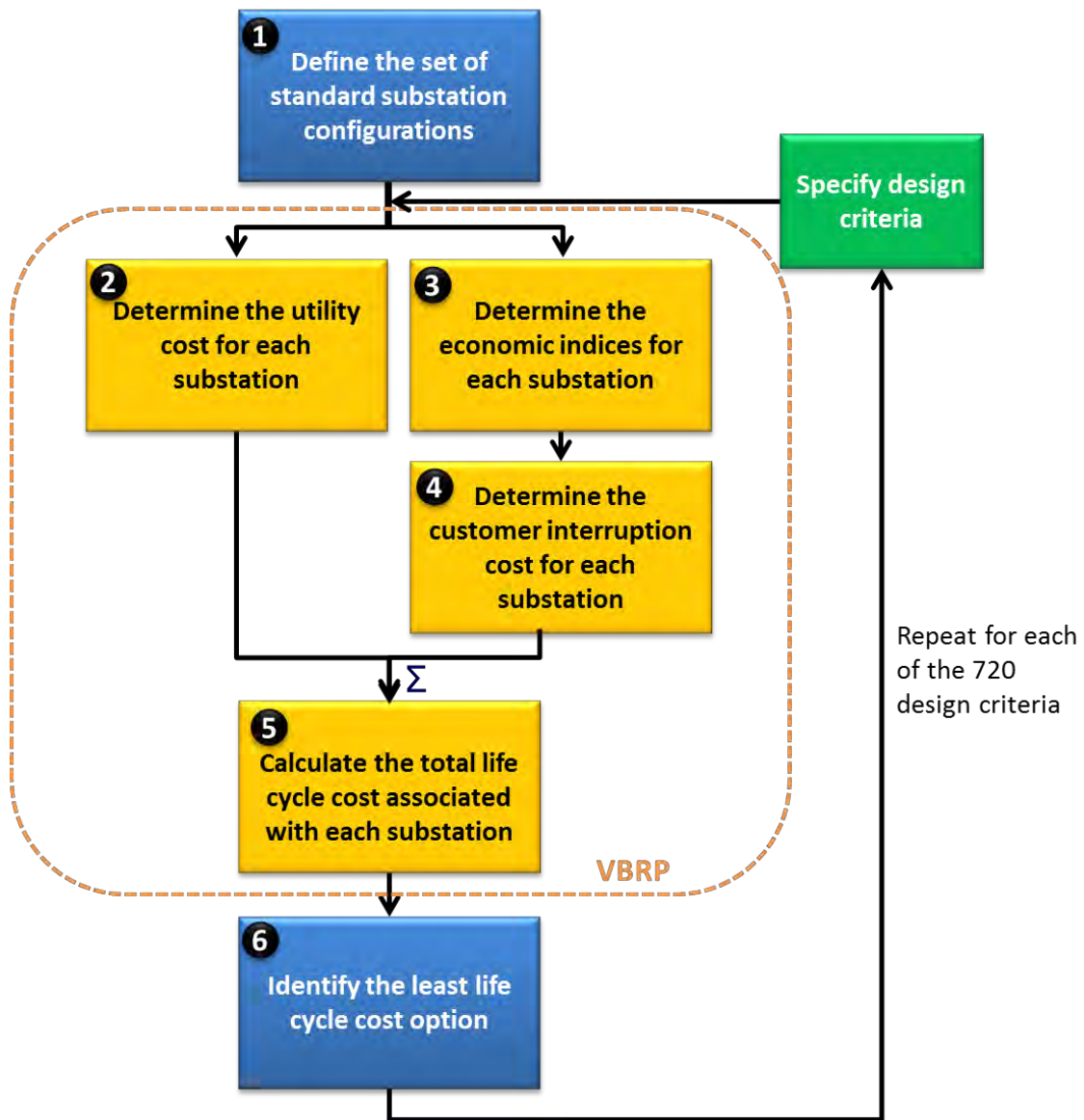


Figure 5-1: Approach to determining the preferred set of substation configurations for all design criteria

## 6. Substation cost estimation tool

The cost benefit calculation requires the utility life cycle cost associated with each of the different substation configurations. It is explained in section 5 that this study considers 311 040 different substations (720 different design criteria, combined with the 432 standard substation configurations). Based on the literature research performed on substation costs (see section 2.10), it is clear that finding costs for all the identified substation configurations is challenging for the following reasons:

- (a) No single publication was found which included all required substations components (for all relevant voltage levels).
- (b) Using costs from different publications is problematic since different cost elements are included in the costing of each (e.g. primary plant, secondary plant, construction, commissioning, etc.).
- (c) Different publications consider cost data from different currencies and base years. These costs then have to be converted to South African Rand and 2015 Rand value.

Due to these shortcomings, equipment costs were not sourced from literature, but a substation cost estimation tool was developed to determine the cost for each of the 311 040 different substations. This tool is embedded within the simplified reliability estimation model. Changes made to the cost estimation tool, such as the cost assumptions provided as input by the user, will therefore impact the preferred substation configurations identified by the simplified approach.

This substation cost estimation tool is described in more detail in the rest of this section.

### 6.1. Requirements

The objective was to develop a tool for preparing estimates of the utility substation life cycle costs based on conceptual design information. The tool is intended to be used as a preliminary cost estimation tool during the planning stage, and should not be used to estimate substation costs when more detailed design information is available. A more detailed cost-estimating approach is recommended once more detailed design information is available.

The following requirements were defined for this cost estimation tool:

- (a) The utility substation cost should include all life cycle costs, as discussed in section 2.10, i.e.:
  - (i) Acquisition cost;

- (ii) Operational cost (scheduled and unscheduled maintenance cost). The unscheduled maintenance cost excludes the impact of the outage on the customer;
  - (iii) Renewal cost.
- (b) All cost elements associated with the acquisition cost should be considered, including:
- (i) All associated power plant and control plant equipment;
  - (ii) Transport of equipment from the factory to the site;
  - (iii) Civil works;
  - (iv) Construction; and
  - (v) Commissioning.
- (c) It should require minimal, typical, design inputs, such as listed in Table 6-1.

**Table 6-1: Design variables used to determine the substation cost estimate**

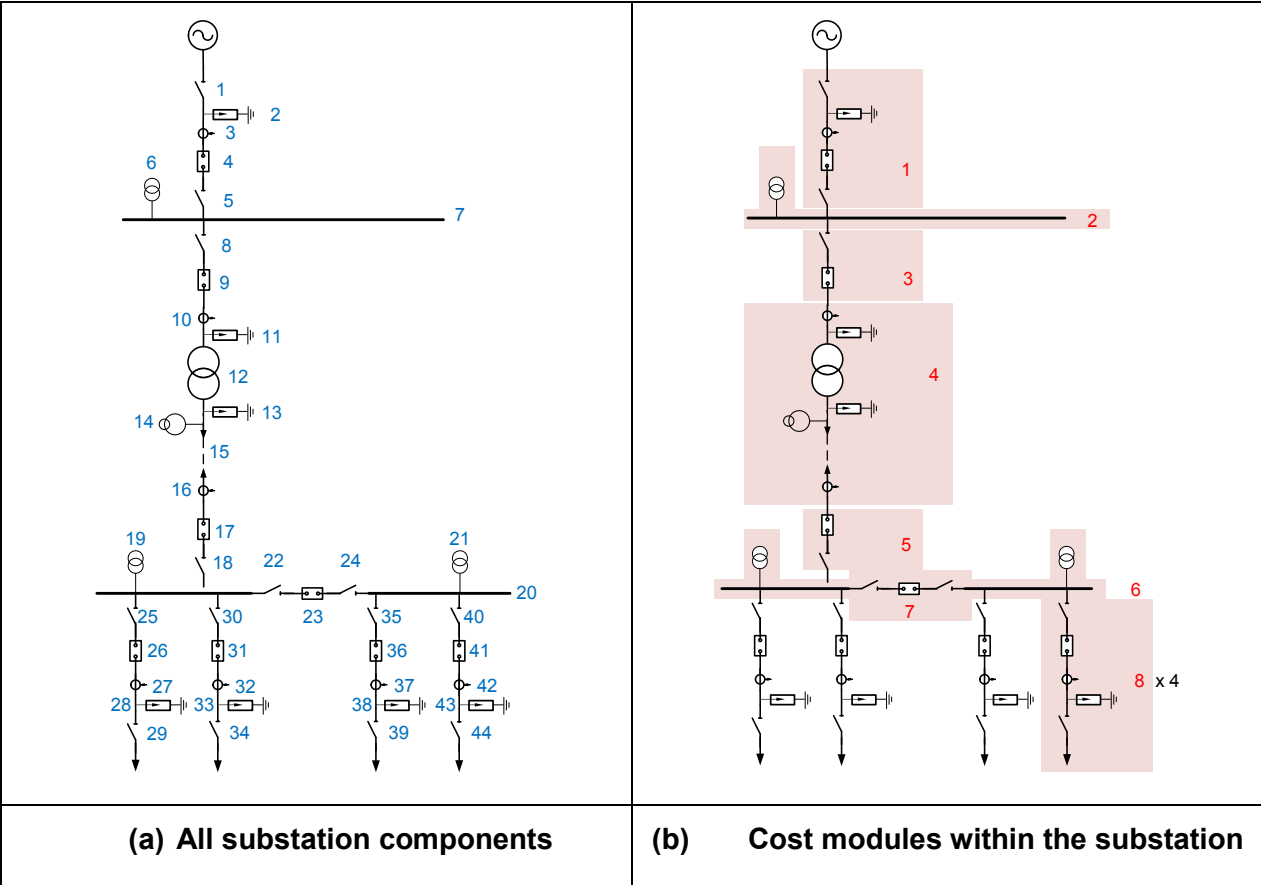
No	Design variable
1	Substation voltage levels
2	Busbar configuration (per voltage level)
3	Number of source feeders (per voltage level)
4	Number of load feeders (per voltage level)
5	Number of transformers
6	Transformer size

- (d) It should require minimum assumptions, e.g. cost per feeder bay, rather than cost of steelwork, civils, etc.

## 6.2. Approach

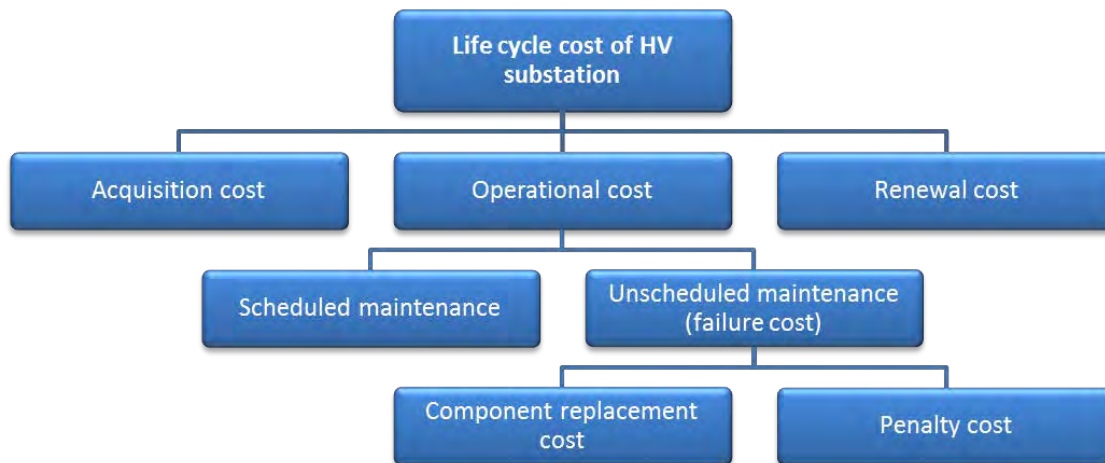
A modular approach was used, whereby the components of each substation are grouped into sub-systems, or modules, and only the sub-systems are considered in the cost calculation. This modular approach simplifies the calculations significantly and minimises the user inputs, without ignoring any components.

Consider the single transformer substation with one source feeder and four load feeders shown in Figure 6-1. This substation has 44 individual components. After grouping components into sub-systems or modules, there are only 8 modules to be considered in the cost calculation.



**Figure 6-1: Substation components grouped into sub-systems for the cost calculation**

The utility substation costs considered in the cost calculation are the total life cycle costs, as identified in section 2.10. These costs are summarised in the diagram in Figure 6-2.



**Figure 6-2: Cost breakdown of the total life cycle cost of an HV substation (adapted from Hinow & Mevissen, 2010)**

Each of these cost elements, and the assumptions for each, is discussed in the rest of this section.

### 6.2.1. Acquisition cost

As discussed in section 2.10.1, the acquisition cost includes the following costs:

- (a) Switchgear;
- (b) Common elements of site development; and
- (c) Land value.

#### 6.2.1.1. Switchgear

The switchgear includes all substation equipment as identified in Figure 6-1. It is important to note that each of the 44 components shown in Figure 6-1 (a) consists of various cost elements such as power plant equipment, control plant equipment, civil works, construction and commissioning. All these cost elements are included to derive the switchgear cost of each of the modules shown in Figure 6-1(b).

The following assumptions were made to derive the equipment costs:

- (a) All switchgear are air-insulated, outdoor switchgear;
- (b) All switchgear are insulated to 31 mm/kV;
- (c) All busbars are tubular busbars;

(d) The transport cost to site is based on a site approximately 300 km from the factory.

Considering the different standard busbar configurations identified in section 4, the cost modules identified in Figure 6-1 can look very different. The different modules considered in the cost estimation tool are summarised in Table 6-2.

**Table 6-2: Detail of the different cost modules in the cost estimation tool**

No	Cost module	Detail of different cost modules considered
1	Feeder bay	Feeder bay (1 busbar) Feeder bay (1 busbar with bypass) Feeder bay (2 busbars) Feeder bay (2 busbars with bypass) Feeder bay (breaker and a half)
2	Busbar	Single busbar (with single VT) Single busbar (with single VT) with bypass busbar Single busbar (with 2 x VTs) Single busbar (with 2 x VTs) with bypass busbar Double busbar (with 2 x VTs)
3	Transformer bay	Transformer bay (1 busbar) Transformer bay (1 busbar with bypass) Transformer bay (2 busbars) Transformer bay (2 busbars with bypass) Transformer bay (breaker and a half)
4	Transformer	With NECR/T (HV/MV and MV/MV transformers) Without NECR/T (HV/HV transformers)
5	Bus section	Bus section (2 x isolators) Bus section (2 x isolators & breaker)

The switchgear costs were collected from a South African electricity utility, at a specific time. Due to the proprietary nature and sensitivity of the equipment cost information, the costs are not shown as a South African Rand value, but rather as an index, normalised to the 11 kV feeder bay (1 busbar) cost. This indexed cost also provides some stability in the presence of inflation. The indexed costs for all relevant substation modules are shown in Table 6-3. Some

costs are indicated as N/A, since these costs are not applicable to the specific study, for example:

- (a) Breaker and a half is only considered for HV equipment in this study. Feeder bay, transformer bay and double busbar costs for breaker and a half are not shown for 11 kV, 22 kV and 33 kV.
- (b) In section 5 (see Table 5-2) it was explained that this study assumes a 132/66 kV transformer (i.e. an HV/HV transformer) will never be installed for a load smaller than 20 MVA, so no costs are shown for 132/66 kV 2.5 MVA, 5 MVA and 10 MVA transformers.

All these costs are input assumptions into the costing model and can be changed by the user.

**Table 6-3: Substation equipment cost assumptions**

No.	Cost module	11 kV	22 kV	33 kV	66 kV	132 kV
1	Feeder bay (1 busbar)	1.000	1.060	1.185	1.752	2.450
2	Feeder bay (1 busbar with bypass)	1.092	1.153	1.279	1.991	2.667
3	Feeder bay (2 busbars)	1.092	1.153	1.279	1.991	2.667
4	Feeder bay (2 busbars with bypass)	1.185	1.245	1.373	2.230	2.884
5	Feeder bay (breaker and a half)	N/A	N/A	N/A	2.429	3.228
6	Single busbar	0.123	0.143	0.178	0.276	0.345
7	Single busbar with bypass	0.184	0.215	0.266	0.414	0.517
8	Double busbar	0.245	0.286	0.355	0.551	0.689
9	Double busbar for breaker and a half	N/A	N/A	N/A	2.891	4.433
10	Busbar VT	0.130	0.152	0.180	0.315	0.607
11	Bus coupler	1.166	1.166	1.269	1.988	2.538
12	Bus section	1.166	1.166	1.269	1.988	2.538
13	Bus section (2 x isolators only)	0.920	0.920	0.985	1.614	1.851
14	Transformer bay (1 busbar)	0.554	0.556	0.621	0.916	1.381
15	Transformer bay (1 busbar with bypass)	0.647	0.649	0.714	1.155	1.598
16	Transformer bay (2 busbars)	0.647	0.649	0.714	1.155	1.598
17	Transformer bay (2 busbars with bypass)	0.739	0.741	0.808	1.394	1.816
18	Transformer bay (breaker and a half)	N/A	N/A	N/A	N/A	N/A
				<b>33/11 kV</b>		<b>132/22 kV</b>
19	Transformer (2.5 MVA)			4.002		6.653
20	Transformer (5 MVA)			5.588		7.559
21	Transformer (10 MVA)			7.959		8.666
22	Transformer (20 MVA)			9.742		9.850
23	Transformer (40 MVA)			12.654		13.006
24	Transformer (80 MVA)			N/A		22.727
25	Transformer (160 MVA)			N/A		N/A
						<b>132/66 kV</b>

See Note 1  
See Note 1  
See Note 2  
See Note 2

Note 1: The busbar costs shown are the costs associated with the length of busbar required for one feeder/transformer bay. Feeder bays and transformer bays can be connected back to back.

Note 2: The busbar costs shown are per feeder/transformer bay, and needs to be multiplied by the number of bays. Feeder bays and transformer bays cannot be connected back to back.

### **6.2.1.2. Land value**

It was mentioned in section 2.10.1.1 that the land cost can vary significantly from one area to the next and it is therefore impossible to estimate a cost that will be accurate for all new substation projects.

The land cost used by Howard (2011) was 0.94% of the switchgear cost, as discussed in section 2.10.1.1. For this study a land acquisition cost of 1% is assumed. This percentage is also an input for the costing model and can be changed by the user.

### **6.2.1.3. Common elements of site development**

In section 2.10.1.2 the common costs given by Howard (2011) were calculated as 58.9% of the switchgear cost. For the purposes of this study, the common costs are assumed to be 60% of the switchgear cost. This percentage is an input into the costing model and can be changed by the user.

### **6.2.2. O&M cost**

O&M cost from different literature sources are discussed in section 2.10.2. Considering these costs, an O&M cost of 1% per annum of switchgear cost was used for this study. Again, this percentage is an input assumption in the costing model and can be changed by the user.

The O&M cost includes future costs that were converted to a net present value, using a discount rate of 10%.

### **6.2.3. Renewal cost**

For the purpose of this study it is assumed that all substation equipment (including all switchgear and secondary plant) has the same expected life, and that this expected life is equal to the project life. The renewal cost during the project life is therefore assumed to be zero, since the renewal cost will only be incurred after the project life. The renewal cost was ignored in the model and is not a variable that can be changed by the user.

### **6.2.4. Substation useful life**

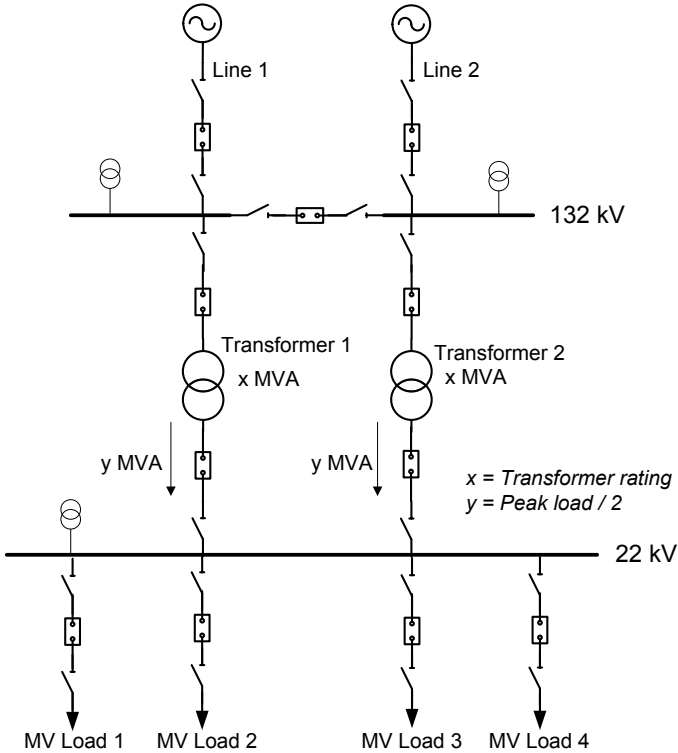
The O&M costs and customer interruption cost are provided per annum. In order to determine the total cost over the substation life, the useful life of the substation is required. In section 2.10.2 the substation useful life was discussed and it was concluded that great variability exists

in literature for this parameter. For the purpose of this study, a substation life of 30 years is assumed, as suggested by Kutlev et al. (2007) and Karlsson et al. (1997). The substation life is a variable in the model and has not been built into the approach as a constant. This input value can therefore be changed if the substation life is expected to be different or to test the sensitivity of this parameter.

### 6.3. Cost calculation example

The cost calculation is demonstrated for the substation layout in Figure 6-3. Assume a substation peak load of 30 MVA. Considering the standard transformer sizes listed in section 4.5.3, the 30 MVA peak load can be supplied by either:

- (a) 2 x 20 MVA transformers (unfirm transformer capacity), or
- (b) 2 x 40 MVA transformers (firm transformer capacity).



**Figure 6-3: Substation layout to demonstrate the cost calculation**

The cost calculation for the substation shown in Figure 6-3 is shown in Table 6-4. The cost calculation is performed for both the unfirm and firm transformer substation. The indexed costs, shown in Table 6-3, are used for the equipment costs.

If 2 x 20 MVA transformers are replaced by 2 x 40 MVA transformers, such that the transformers are firm for a load of 30 MVA, the substation cost increases from 74.22 to 86.28 (per unit, indexed to the base of the cost of an 11 kV feeder bay). The cost of selecting firm transformation instead of unfirm transformation is the difference between these two costs (i.e. 12.06).

**Table 6-4: Calculating the indexed cost of a specific substation configuration**

Substation bay	Indexed cost	Cost of unfirm transformer substation		Cost of firm transformer substation	
		Qty	Total cost	Qty	Total cost
132 kV feeder bays (1 busbar)	2.450	2	4.90	2	4.90
132 kV busbar	0.345	4	1.38	4	1.38
132 kV bus-section (breaker & isolators)	2.538	1	2.54	1	2.54
132 kV VT	0.607	2	1.21	2	1.21
132 kV transformer bays	1.381	2	2.76	2	2.76
Transformer (20 MVA)	9.850	2	19.70	0	-
Transformer (40 MVA)	13.006	0	-	2	26.01
22 kV transformer bays	0.556	2	1.11	2	1.11
22 kV feeder bays	1.060	4	4.24	4	4.24
22 kV busbar	0.143	6	0.86	6	0.86
22 kV VT	0.152	1	0.15	1	0.15
Total equipment cost			38.86		45.17
Common elements of site development (60%)			23.32		27.10
Land acquisition cost (1%)			0.39		0.45
Operations and maintenance cost (1%)			11.66		13.55
<b>Total substation cost</b>			<b>74.22</b>		<b>86.28</b>

**6.4. Summary**

The substation cost estimation tool can be used to determine the cost of the different substation configurations, based on conceptual design information, during the planning phase. The tool is intended to be used as preliminary cost-estimating tool and should not be used to estimate substation costs when more detailed design information is available.

The cost estimation tool includes all elements of the utility life cycle cost, as identified in section 2.10. The components of each substation are grouped into sub-systems, or modules. The user needs to specify the cost of each substation module and the cost calculation only considers the module costs in the cost calculation. This modular approach therefore doesn't ignore any components, but group them together in order to reduce the cost calculation.

Substation costs change on a continuous basis and the approach of a costing model ensures that customer costs can be updated regularly by updating the costs of the various building blocks of the substation.

This tool is embedded within the reliability estimation model. Changes made to the cost estimation tool, such as the cost assumptions, will affect the preferred substation configurations identified by the overall approach.

## 7. Customer interruption cost calculation

The customer interruption cost was discussed in section 2.9 as a crucial step in VBRP. It was explained that the customer interruption cost is calculated using (a) the energy-orientated indices and (b) the customer damage function.

(a) In section 4 a simplified approach to the reliability estimation of utility networks was reviewed. This approach is used to calculate the customer-focused reliability indices for different substation configurations. In order for this approach to be used in the value-based planning approach, it has to be expanded to include the calculation of the customer cost associated with different substation configurations. In section 7.1, the simplified approach is expanded to include the calculation of energy-orientated indices.

(b) In section 7.2, the simplified approach is further expanded to include the calculation of the customer interruption cost, considering the calculated energy-orientated indices.

### 7.1. Energy-orientated reliability indices

The simplified reliability approach developed by Van der Merwe (2014) and explained in section 4, calculates the customer-focused indices, such as SAIDI and SAIFI. In order to calculate the cost associated with outages, energy-orientated reliability indices are required. The existing simplified reliability approach had to be expanded to include the calculation of load- and energy-orientated outages.

#### 7.1.1. Calculating the reliability indices

The load- and energy-orientated outages are included by considering the percentage load not supplied in Equation 6 and Equation 7. The new calculation is shown in Equation 9, where the percentage of customers unsupplied in Equation 6 is replaced by the percentage of load unsupplied.

$$\text{Load interruption frequency}_j = \sum_{i=1}^n \#_i \times \lambda_i \times \%Load\_unsupplied_i \quad \text{Equation 9}$$

Where:

$\text{Load interruption frequency}_j$  = Number of interruptions experienced by a load supplied by busbar j

$\#_i$  = Number of components of type i

- $\lambda_i$  = Failure rate of component/module i (occ/a)
- $\%Load\_unsupplied_i$  = Percentage of load unsupplied if component i fails
- $n$  = Number of distinct components/modules

For the purpose of this study the percentage load unsupplied is calculated considering average load, as explained in section 7.1.3.1. The percentage load unsupplied, used in Equation 9, is calculated considering the load supplied from the interrupted feeders and the total load supplied from the busbar. For example, consider a substation that supplies 26 MVA from its downstream busbar via four load feeders. The load is distributed between these four feeders as shown in Table 7-1.

**Table 7-1: Calculating percentage load unsupplied**

Feeder description	Load supplied from feeder (MVA)	Percentage load unsupplied if supply to the feeder is interrupted	Percentage load unsupplied if supply to two of the feeders is interrupted
Feeder 1	5	19%	42%
Feeder 2	6	23%	
Feeder 3	7	27%	58%
Feeder 4	8	31%	

If supply to feeder 1 is interrupted, the percentage load unsupplied is calculated as shown in Equation 10. The percentage load unsupplied if supply to any of the other feeders is interrupted is also shown in Table 7-1.

$$\%Load\_unsupplied_1 = \frac{5}{26} = 19\% \qquad \text{Equation 10}$$

The same approach is used to calculate the percentage load unsupplied if supply to more than one feeder is interrupted. For example, if supply to feeder 1 and feeder 2 is interrupted, the percentage load unsupplied is calculated as shown in Equation 11. The percentage load unsupplied if supply to feeder 3 and feeder 4 is interrupted is also shown in Table 7-1.

$$\%Load\_unsupplied_{1\&2} = \frac{(5 + 6)}{26} = 42\% \quad \text{Equation 11}$$

Similarly to Equation 7, the duration of each interruption is added to Equation 9 to calculate the unavailability of supply experienced by each customer. The formula for the load unavailability is shown in Equation 12.

$$\begin{aligned} & \text{Load unavailability}_j \\ &= \sum_{i=1}^n \#_i \times \lambda_i \\ & \times (S_i \times \%Load\_unsupplied_{i_s} + R_i \times \%Load\_unsupplied_{i_r}) \end{aligned} \quad \text{Equation 12}$$

Where:

- $Load\ unavailability_j$  = Duration of interruptions experienced by a load supplied by busbar j (h)
- $\#_i$  = Number of components of type i
- $\lambda_i$  = Failure rate of component/module i (occ/a)
- $S_i$  = Time that elapse from the fault occurs until the operator can start with the fault repair, e.g. the time required to drive to site (h/occ)
- $R_i$  = Repair time of component/module i (h/occ)
- $\%Load\_unsupplied_{i_s}$  = Percentage load unsupplied, immediately after the protection has operated, if component i fails
- $\%Load\_unsupplied_{i_r}$  = Percentage load that remain unsupplied after switching, while the faulty component i is being repaired
- $n$  = Number of distinct components/modules

The load- and energy-based reliability indices are calculated by combining the size of the load interrupted with the frequency and duration of interruptions. The magnitude of the load interrupted combined with the frequency of interruptions is calculated using Equation 13.

$$kVA - Interruptions_j = \sum_{i=1}^n Load\ interruption\ frequency_i \times Load\ supplied_i \quad \text{Equation 13}$$

Where:

- kVA-Interruptions<sub>j</sub>* = kVA-interrupted due to the interruption of busbar j (kVA occ)
- Load interruption frequency<sub>i</sub>* = Number of interruptions experienced by a load feeder, *i*, supplied by busbar j (occ) (see Equation 9)
- Load supplied<sub>j</sub>* = Size of the load feeder, *i*, supplied by busbar j (kVA)
- n* = Number of distinct load feeders supplied from busbar j

The kVA-interruptions can be converted to kW-interruptions by including the power factor of the load, as shown in Equation 14.

$$kW - Interruptions_j = \sum_{i=1}^n Load\ interruption\ frequency_i \times Load\ supplied_i \times Power\ factor_i \quad \text{Equation 14}$$

Where:

- kW-Interruptions<sub>j</sub>* = kW-interruptions due to the interruption of busbar j (kW occ)
- Load interruption frequency<sub>i</sub>* = Number of interruptions experienced by a load feeder, *i*, supplied by busbar j (occ) (see Equation 9)
- Load supplied<sub>j</sub>* = Size of the load feeder, *i*, supplied by busbar j (kVA)
- Power factor<sub>j</sub>* = Power factor of the load feeder, *i*, supplied by busbar j (kVA)
- n* = Number of distinct load feeders supplied from busbar j

The energy not supplied is calculated considering the load unavailability (from Equation 12) and the load supplied from the interrupted feeders. This is shown in Equation 15.

$$\begin{aligned}
 & \text{Energy not supplied}_j \\
 &= \sum_{i=1}^n \text{Load unavailability}_i \times \text{Load supplied}_i \\
 & \times \text{Power factor}_i
 \end{aligned}
 \tag{Equation 15}$$

Where:

$\text{Energy not supplied}_i$  = Energy interrupted due to the unavailability of busbar j (kVAh)

$\text{Load unavailability}_i$  = Duration of interruptions experienced by a load feeder,  $i$ , supplied by busbar j (h) (see Equation 12)

$\text{Load supplied}_i$  = Size of the load feeder,  $i$ , supplied by busbar j (kVA)

$\text{Power factor}_j$  = Power factor of the load feeder,  $i$ , supplied by busbar j (kVA)

$n$  = Number of distinct load feeders supplied from busbar j

### 7.1.2. Load distribution

Equation 9, Equation 12, Equation 13, Equation 14 and Equation 15 require information on the size of each load feeder supplied in the network. In a utility network, this can amount to a significant number of inputs. If an assumption can be made about the load distribution across the different feeders supplied from a busbar, only the busbar load and the number of feeders are required and not the load supplied from each specific feeder. The number of feeders is already required to calculate the unavailability of the loads, so the only additional information required is the load supplied from the upstream and downstream busbar, i.e. two additional inputs per substation.

For the simplified approach, a homogenous load distribution was assumed, e.g. if a substation supplies 28 MW from four load feeders from the downstream busbar, it is assumed that each feeder supplies 7 MW. The accuracy lost using this approach is negligible. This is explained by the two examples below.

The example in Figure 7-1 shows an HV/MV substation which supplies 30 MVA via three load feeders from the MV busbar. Figure 7-1 (a) shows a homogeneous load distribution (i.e. each load supplies 10 MVA) and the unavailability experienced by each MV feeder is 1.12 hours. The total kVA-interruptions and energy not supplied are shown in Equation 16 and Equation 17 respectively.

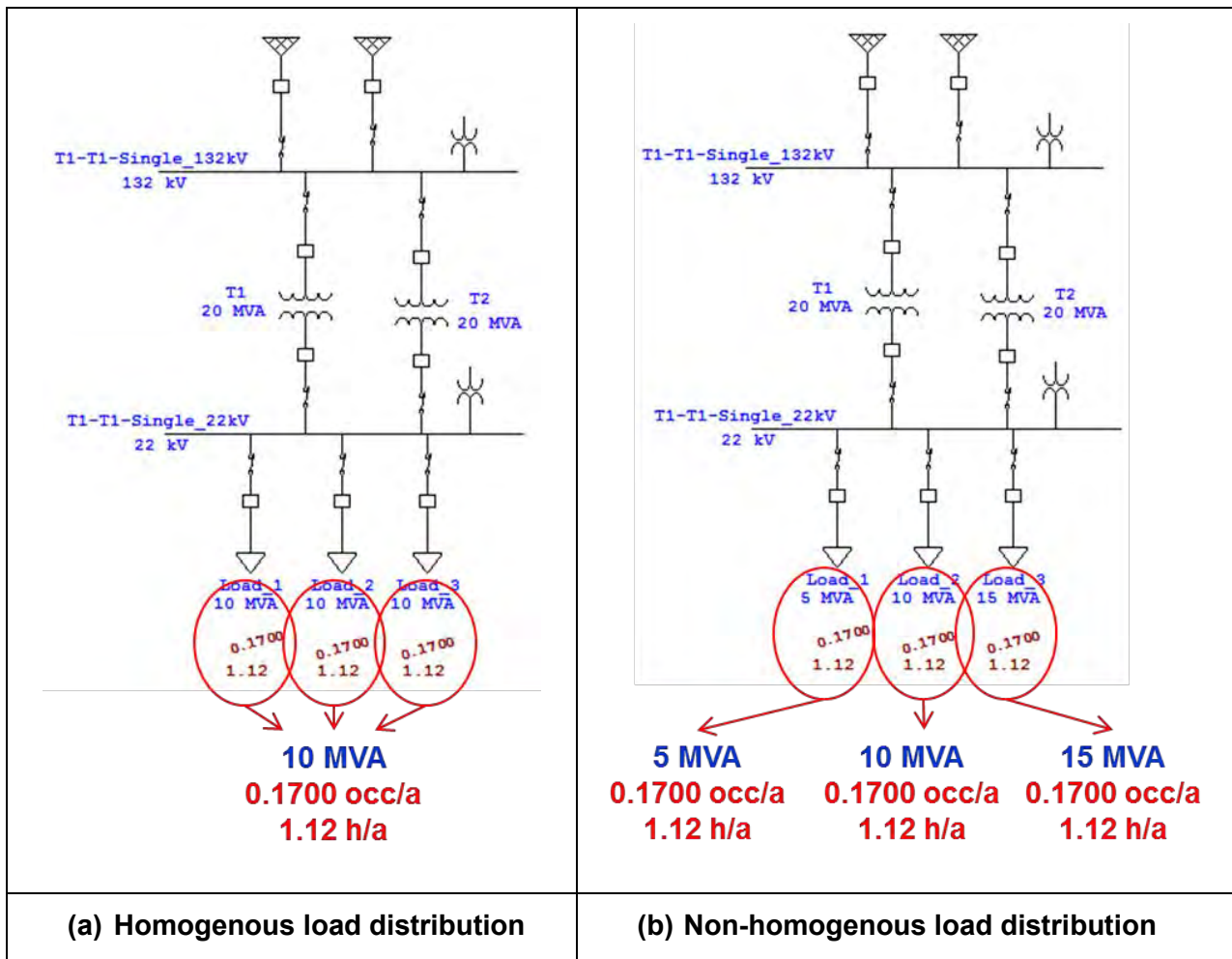


Figure 7-1: Substation with single MV busbar – used to illustrate the impact of the load distribution assumption

$kVA - Interruptions_j$

$$\begin{aligned}
 &= \sum_{i=1}^n \text{Load interruption frequency}_i \times \text{Load supplied}_i \\
 &= (0.17 \text{ occ} \times 10 \text{ MVA}) + (0.17 \text{ occ} \times 10 \text{ MVA}) + (0.17 \text{ occ} \times 10 \text{ MVA}) \quad \text{Equation 16} \\
 &= 0.17 \text{ occ} \times 30 \text{ MVA} \\
 &= 5.1 \text{ MVA occ}
 \end{aligned}$$

*Energy not supplied<sub>j</sub>*

$$\begin{aligned} &= \sum_{i=1}^n \text{Load unavailability}_i \times \text{Load supplied}_i \\ &= (1.12 \text{ h} \times 10 \text{ MVA}) + (1.12 \text{ h} \times 10 \text{ MVA}) (1.12 \text{ h} \times 10 \text{ MVA}) \\ &= 1.12 \text{ h} \times 30 \text{ MVA} \\ &= 33.6 \text{ MVAhours} \end{aligned}$$

**Equation 17**

Figure 7-1 (b) shows a non-homogeneous load distribution. The kVA-interruptions and total energy not supplied are shown in Equation 18 and Equation 19 respectively.

*kVA – Interruptions<sub>j</sub>*

$$\begin{aligned} &= \sum_{i=1}^n \text{Load interruption frequency}_i \times \text{Load supplied}_i \\ &= (0.17 \text{ occ} \times 10 \text{ MVA}) + (0.17 \text{ occ} \times 10 \text{ MVA}) (0.17 \text{ occ} \times 10 \text{ MVA}) \\ &= 0.17 \text{ occ} \times 30 \text{ MVA} \\ &= 5.1 \text{ MVA occ} \end{aligned}$$

**Equation 18**

*Energy not supplied<sub>j</sub>*

$$\begin{aligned} &= \sum_{i=1}^n \text{Load unavailability}_i \times \text{Load supplied}_i \\ &= (1.12 \text{ h} \times 5 \text{ MVA}) + (1.12 \text{ h} \times 10 \text{ MVA}) (1.12 \text{ h} \times 15 \text{ MVA}) \\ &= 1.12 \text{ h} \times 30 \text{ MVA} \\ &= 33.6 \text{ MVAhours} \end{aligned}$$

**Equation 19**

It is clear from this example that the load distribution makes no difference to the kVA-interruptions and energy not supplied.

A similar example is shown in Figure 7-2. The example in Figure 7-2 shows an HV/MV substation with a bus-section on the MV busbar. This substation also supplies 30 MVA via three load feeders from the MV busbar. Figure 7-2(a) shows a homogeneous load distribution (i.e. each load supplies 10 MVA). The total kVA-interruptions and energy not supplied are shown in Equation 20 and Equation 21 respectively.

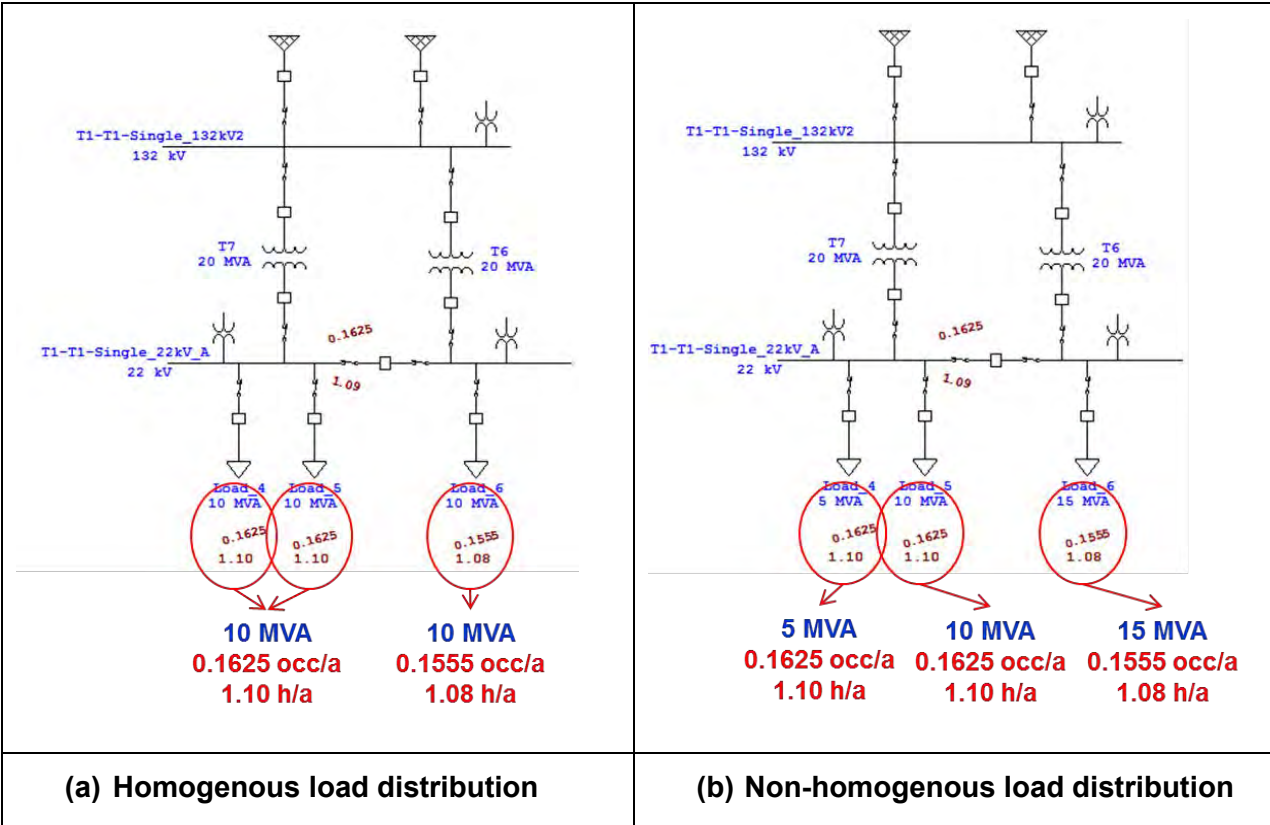


Figure 7-2: Substation with split MV busbar – used to illustrate the effect of the load distribution assumption

kVA Interruptions<sub>j</sub>

$$\begin{aligned}
 &= \sum_{i=1}^n \text{Load interruption frequency}_i \times \text{Load supplied}_i \\
 &= (0.1625 \text{ occ} \times 10 \text{ MVA}) + (0.1625 \text{ occ} \times 10 \text{ MVA}) + (0.1555 \text{ occ} \times 10 \text{ MVA}) \\
 &= 4.805 \text{ MVA occ}
 \end{aligned}$$

**Equation 20**

*Energy not supplied<sub>j</sub>*

$$\begin{aligned} &= \sum_{i=1}^n \text{Load unavailability}_i \times \text{Load supplied}_i \\ &= (1.10 \text{ h} \times 10 \text{ MVA}) + (1.10 \text{ h} \times 10 \text{ MVA}) + (1.08 \text{ h} \times 10 \text{ MVA}) \\ &= 32.8 \text{ MVAhours} \end{aligned} \quad \text{Equation 21}$$

Figure 7-3 (b) shows a non-homogeneous load distribution. The total kVA-interruptions and energy not supplied are shown in Equation 22 and Equation 23 respectively.

*kVA – Interruptions<sub>j</sub>*

$$\begin{aligned} &= \sum_{i=1}^n \text{Load interruption frequency}_i \times \text{Load supplied}_i \\ &= (0.1625 \text{ occ} \times 5 \text{ MVA}) + (0.1625 \text{ occ} \times 10 \text{ MVA}) + (0.1555 \text{ occ} \times 15 \text{ MVA}) \\ &= 4.770 \text{ MVA occ} \end{aligned} \quad \text{Equation 22}$$

Percentage error

$$\begin{aligned} &= (4.805/4.770) - 1 \\ &= 0.7\% \end{aligned}$$

*Energy not supplied<sub>j</sub>*

$$\begin{aligned} &= \sum_{i=1}^n \text{Load unavailability}_i \times \text{Load supplied}_i \\ &= (1.10 \text{ h} \times 5 \text{ MVA}) + (1.10 \text{ h} \times 10 \text{ MVA}) + (1.08 \text{ h} \times 15 \text{ MVA}) \\ &= 32.7 \text{ MVAhours} \end{aligned} \quad \text{Equation 23}$$

Percentage error

$$\begin{aligned} &= (32.8/32.7) - 1 \\ &= 0.3\% \end{aligned}$$

It is clear from this example that the load distribution makes a difference to the kVA-interruptions and energy not supplied. This is due to the fact that the MV busbar is not balanced, i.e. there are more feeders supplied from the one bus-section than the other bus-section. The homogeneous load distribution assumption results in an error of 0.7% for the kVA-interruptions and 0.3% for the energy not supplied. This error is deemed acceptable for the simplified approach, because it is within the same range of accuracy of estimates of the common substation costs.

The size of the error is a function of the difference between the actual feeder size and the average feeder size (considering the total busbar load divided by the number of feeders supplied from the busbar). As this difference increases, the error obtained with the homogeneous load distribution assumption will also increase. However, utilities try to balance the load between different load feeders as far as possible, therefore the homogeneous load distribution assumption is not expected to result in significant errors. The approximation of feeder load is therefore not essential.

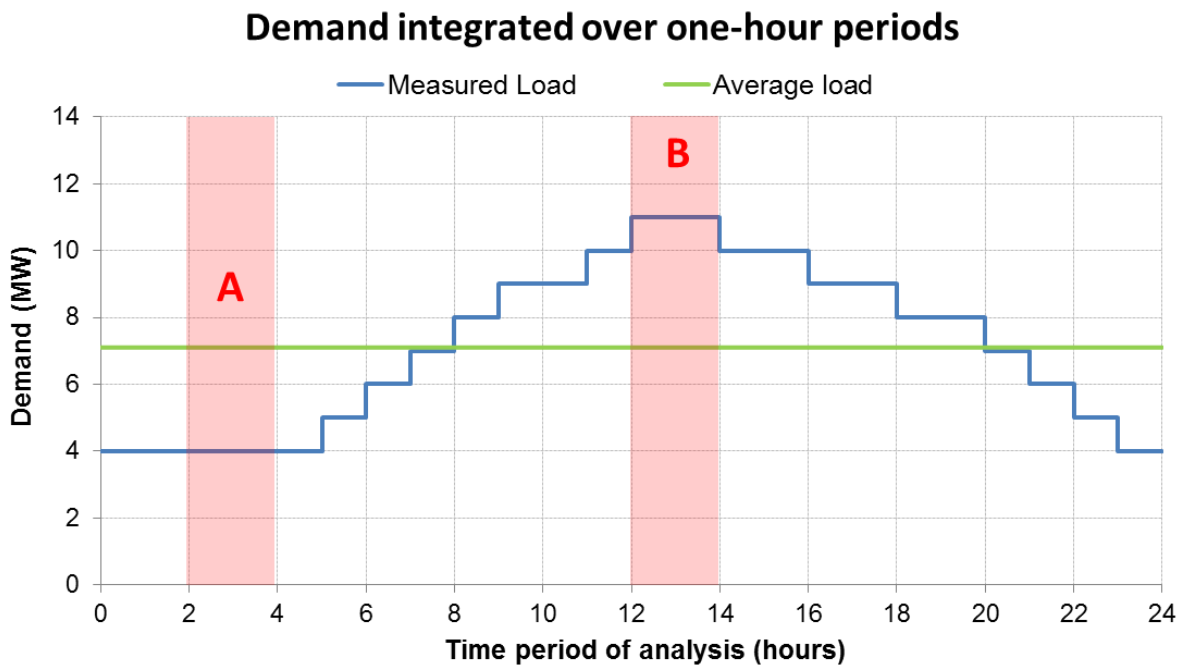
### **7.1.3. Load variation**

In section 2.12, the importance of the load-duration curve of each load point was explained when evaluating load- and energy-orientated indices. To consider the load-duration curve in the reliability calculations requires a significant amount of data on each load point. It also requires information on the probability of faults occurring at different times.

The load variation during unplanned and planned outages is discussed in more detail below.

#### **7.1.3.1. Unplanned outages**

Consider a load with load variation curve as shown in Figure 7-3. Two faults occur, each resulting in a two-hour outage. The one fault occurs during time period "A" and the other fault during time period "B". The energy that is interrupted during time period A is 8 MWh (4 MW x 2 hours), while the energy interrupted during time period B is 22 MWh (11 MW x 2 hours). The time at which the fault occurs therefore has a significant effect on the load- and energy-orientated indices.



**Figure 7-3: Variation of demand in hourly intervals for two specific time periods**

In order to reduce the number of inputs required, the simplified approach considers the average load in the calculation of the load- and energy-orientated indices. For the example shown above, the average load is 7 MW. A 2 hour outage will therefore result in 14 MWh (7 MW x 2 hours) interrupted.

The average load in MW is calculated from the substation peak load in MVA, load factor and power factor, which are inputs required from the user. This is shown in Equation 24.

$$\text{Average load (unplanned)} = \text{Peak load} \times \text{Load factor} \times \text{Power factor} \quad \text{Equation 24}$$

#### 7.1.3.2. Planned outages

Utilities often schedule planned outages during weekends, when the load is significantly lower, in order to reduce the impact on customers. It may therefore be necessary to consider a load lower than the average load for planned outages.

The simplified approach includes a parameter that can be used to scale the average load for planned outages. The load lost during planned outages is calculated from the substation peak

load, load factor, power factor and this scaling factor, as shown in Equation 25. All these inputs are provided by the user.

*Average load (planned)*

$$\begin{aligned} &= \textit{Average load (unplanned)} \times \textit{Planned scaling factor} \\ &= \textit{Peak load} \times \textit{Load factor} \times \textit{Power factor} \\ &\quad \times \textit{Planned scaling factor} \end{aligned}$$

**Equation 25**

**7.1.4. Load factor**

The load factor is required to calculate the average substation load, as discussed in section 7.1.3.1. In section 2.12 the load factors for different customer classes were discussed. In Table 2-10, the load factors for different residential township customers are shown. The load factors vary from 28% to 42%. In Table 2-11, the load factors for different industrial customers are shown. The average load factor for the group of customers is 65%.

For the purpose of this study, different load factors will be used for the different customer interruption duration costs. Three different customer interruption duration costs are considered in this study, i.e. R 5/kWh, R 75/kWh and R 150/kWh, as explained in section 7.2.2. The load factor assumed for each of these customer interruption duration costs are as follows:

- (a) A load factor of 28% will be used for township residential customers, which are customers with a low interruption cost. This load factor will be applied where a customer outage duration cost of R 5/kWh is used.
- (b) A load factor of 65% will be used for industrial customers, which are customers with a high interruption cost. This load factor will be applied where a customer outage duration cost of R 150/kWh is used.
- (c) The average of the above two load factors is 47%. A load factor of 47% will therefore be used for customers with an average interruption cost. This load factor will be applied where a customer outage duration cost of R 75/kWh is used.

The concept of a load scaling factor for planned outages was discussed in section 7.1.3.2. For this study a planned load scaling factor of 80% was assumed.

### **7.1.5. Power factor**

The power factor is required to calculate the average substation load, as discussed in section 7.1.3.1. For the purpose of this study a power factor of 0.95 will be assumed. This is an input into the approach and can be changed by the user.

## **7.2. Customer interruption cost**

In section 2.9 it was explained that the customer cost associated with a loss of supply is a major element in the evaluation of reliability worth. It was further explained that the customer cost component is calculated considering the energy-orientated indices and a customer damage function.

The ENS was explained in section 7.1. This section focusses on the customer damage function.

### **7.2.1. Customer damage function**

In section 2.9.4 it was summarised that the most important parameters in determining the customer interruption cost are:

- a) Load interrupted;
- b) Duration of the outage;
- c) Customer type/sector; and
- d) Whether advance warning was given.

For the purpose of this study, all these parameters will be considered when calculating the customer interruption cost. An additional parameter, the frequency of load interruptions will also be considered, to test the sensitivity of this parameter.

The customer damage function is therefore defined as shown in Equation 26, and such a function is defined for each customer sector.

*CIC*

$$= \sum_{i=0}^n (kW - Interruptions (unplanned)_j \times Cost\ of\ unplanned\ interruptions_j$$

**Equation 26**

$$+ENS (unplanned)_j \times Cost\ of\ unplanned\ interruption\ duration_j$$

$$+kW - Interruptions (planned)_j \times Cost\ of\ planned\ interruptions_j$$

$$+ENS (planned)_j \times Cost\ of\ planned\ interruption\ duration_j)$$

Where:

- CIC<sub>j</sub>* = Estimated annual cost of interruptions experienced by all customers supplied from busbar j (R)
- kW-Interruptions (unplanned)<sub>j</sub>* = kW-interruptions due to the interruption of feeder *i*, supplied from busbar j (kW occ) (see Equation 13) , as a result of an unplanned outage.
- kW-Interruptions (planned)<sub>j</sub>* = kW-interruptions due to the interruption of feeder *i*, supplied from busbar j (kW occ) (see Equation 13) , as a result of a planned outage.
- ENS (unplanned)<sub>j</sub>* = Energy interrupted on feeder *i*, due to the unplanned unavailability of busbar j (kWh) (see Equation 15).
- ENS (planned)<sub>j</sub>* = Energy interrupted on feeder *i*, due to the planned unavailability of busbar j (kWh) (see Equation 15).
- Cost of unplanned interruptions<sub>j</sub>* = The cost of unplanned interruptions of feeder *i*, as defined by the customer damage function (R/kW.occ)
- Cost of planned interruptions<sub>j</sub>* = The cost of planned interruptions of feeder *i*, as defined by the customer damage function (R/kW.occ)
- Cost of unplanned interruption durations<sub>j</sub>* = The cost of unplanned interruption durations of feeder *i*, as defined by the customer damage function (R/kWh)
- Cost of planned interruption durations<sub>j</sub>* = The cost of planned interruption durations of feeder *i*, as defined by the customer damage function (R/kWh)
- n* = Number of distinct load feeders supplied from busbar j

### 7.2.2. COUE rates

The type of customers to be supplied from the substation is considered to be known to the planner during the planning phase. The COUE rates associated with the specific type of customers are therefore an input into the decision-making process.

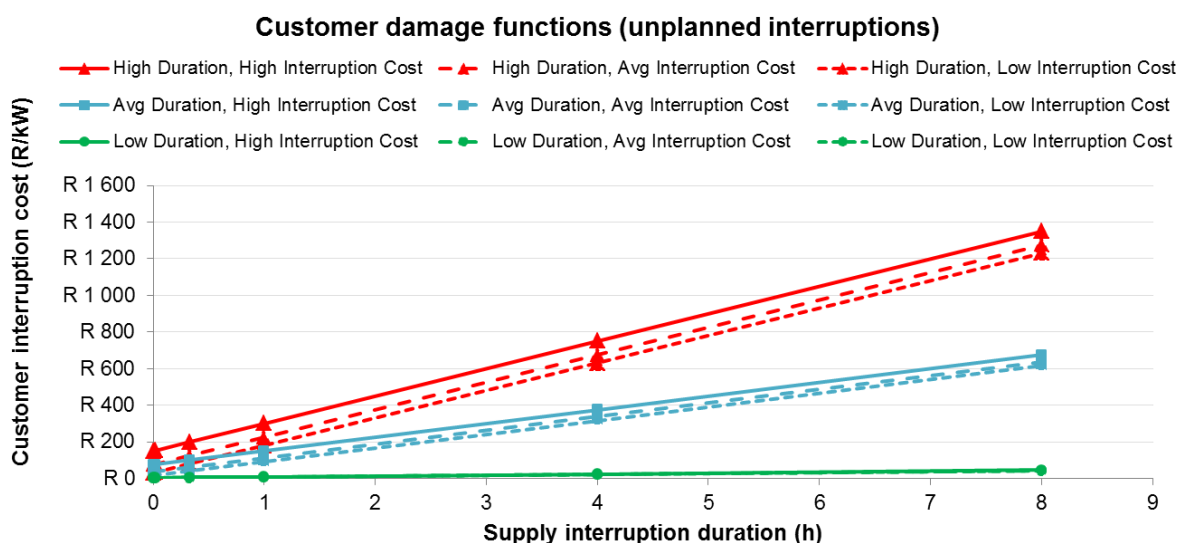
It was mentioned in section 2.9 that in South Africa no standardised set of COUE rates exists. Due to this shortcoming, this study will not consider predefined customer damage functions per customer type. Instead, different COUE rates will be analysed to determine the sensitivity of the optimal substation configuration to this parameter.

An average outage duration cost of R 75/kWh is considered for unplanned outages, as suggested by The Department of Minerals and Energy, Republic of South Africa (2006) (see section 2.9.2). Low and high COUE rate scenarios were considered, to determine if the set of preferred substation configurations will change when the COUE rate changes. Average COUE rates of R 5/kWh and R 150/kWh were considered for the low and high scenarios respectively.

Three different scenarios are considered for the interruption cost (R/interruption), as shown by the values for “x” in Table 7-2. The three different outage duration costs combined with the three different interruption frequency costs give nine different customer damage functions, as shown in Figure 7-4.

**Table 7-2: Customer damage functions for unplanned outages**

Description	Interruption cost (R/interruption)	Duration cost (R/kWh)	Values for x
Unplanned CDF 1	$x$	$x$	Where $x=5; 75; 150$
Unplanned CDF 2	$x/2$	$x$	
Unplanned CDF 3	$x/5$	$x$	



**Figure 7-4: Customer damage functions (unplanned interruptions) considered for the study**

From Table 2-6 it is clear that the interruption cost of planned outages are lower than that of unplanned outages, but by what factor we are not sure. From this table it is also clear that the cost of planned outages is not 0. The cost of planned outages is therefore between 0 and 100% of unplanned outage cost. Two different planned functions were considered for the analysis. These two points were selected to be more or less regular points within the most likely range (0 – 100%) to ensure that the outcomes are not one-sided as a result of the input parameters selected, therefore 30% and 60% were selected. These two functions are shown in Table 7-3. Each of these planned functions will be combined with the nine different unplanned functions. This results in 18 different customer damage functions that will be tested.

**Table 7-3: Customer damage functions for planned outages**

Description	Interruption cost (R/kW-interruption)	Duration cost (R/kWh)
Planned CDF 1	60% of unplanned	60% of unplanned
Planned CDF 2	30% of unplanned	30% of unplanned

It is important to note that the selected customer damage function is a linear function, offset with a specific interruption cost.

The 18 customer damage functions with load factors are listed in Table 7-4.

**Table 7-4: Customer damage functions**

CDF number	Unplanned function		Planned function		Load factor	Description
	Interruption cost (R/kW-interruption)	Duration cost (R/kWh)	Interruption cost (R/kW-interruption)	Duration cost (R/kWh)		
<b>CDF 1</b>	75.00	75.00	45.00	45.00	47%	Unplanned COUE = R75 /kWh Interruption frequency = 1 x interruption duration Planned = 60% of unplanned
<b>CDF 2</b>	25.00	75.00	15.00	45.00	47%	Unplanned COUE = R75 /kWh Interruption frequency = 0.33 x interruption duration Planned = 60% of unplanned
<b>CDF 3</b>	15.00	75.00	9.00	45.00	47%	Unplanned COUE = R75 /kWh Interruption frequency = 0.2 x interruption duration Planned = 60% of unplanned
<b>CDF 4</b>	75.00	75.00	22.50	22.50	47%	Unplanned COUE = R75 /kWh Interruption frequency = 1 x interruption duration Planned = 30% of unplanned
<b>CDF 5</b>	25.00	75.00	7.50	22.50	47%	Unplanned COUE = R75 /kWh Interruption frequency = 0.33 x interruption duration Planned = 30% of unplanned

CDF number	Unplanned function		Planned function		Load factor	Description
	Interruption cost (R/kW-interruption)	Duration cost (R/kWh)	Interruption cost (R/kW-interruption)	Duration cost (R/kWh)		
<b>CDF 6</b>	15.00	75.00	4.50	22.50	47%	Unplanned COUE = R75 /kWh Interruption frequency = 0.2 x interruption duration Planned = 30% of unplanned
<b>CDF 7</b>	5.00	5.00	3.00	3.00	28%	Unplanned COUE = R5 /kWh Interruption frequency = 1 x interruption duration Planned = 60% of unplanned
<b>CDF 8</b>	1.67	5.00	1.00	3.00	28%	Unplanned COUE = R5 /kWh Interruption frequency = 0.33 x interruption duration Planned = 60% of unplanned
<b>CDF 9</b>	1.00	5.00	0.60	3.00	28%	Unplanned COUE = R5 /kWh Interruption frequency = 0.2 x interruption duration Planned = 60% of unplanned
<b>CDF 10</b>	5.00	5.00	1.50	1.50	28%	Unplanned COUE = R5 /kWh Interruption frequency = 1 x interruption duration Planned = 30% of unplanned
<b>CDF 11</b>	1.67	5.00	0.50	1.50	28%	Unplanned COUE = R5 /kWh Interruption frequency = 0.33 x interruption duration Planned = 30% of unplanned

CDF number	Unplanned function		Planned function		Load factor	Description
	Interruption cost (R/kW-interruption)	Duration cost (R/kWh)	Interruption cost (R/kW-interruption)	Duration cost (R/kWh)		
<b>CDF 12</b>	1.00	5.00	0.30	1.50	28%	Unplanned COUE = R5 /kWh Interruption frequency = 0.2 x interruption duration Planned = 30% of unplanned
<b>CDF 13</b>	150.00	150.00	90.00	90.00	65%	Unplanned COUE = R150 /kWh Interruption frequency = 1 x interruption duration Planned = 60% of unplanned
<b>CDF 14</b>	50.00	150.00	30.00	90.00	65%	Unplanned COUE = R150 /kWh Interruption frequency = 0.33 x interruption duration Planned = 60% of unplanned
<b>CDF 15</b>	30.00	150.00	18.00	90.00	65%	Unplanned COUE = R150 /kWh Interruption frequency = 0.2 x interruption duration Planned = 60% of unplanned
<b>CDF 16</b>	150.00	150.00	45.00	45.00	65%	Unplanned COUE = R150 /kWh Interruption frequency = 1 x interruption duration Planned = 30% of unplanned

CDF number	Unplanned function		Planned function		Load factor	Description
	Interruption cost (R/kW-interruption)	Duration cost (R/kWh)	Interruption cost (R/kW-interruption)	Duration cost (R/kWh)		
CDF 17	50.00	150.00	15.00	45.00	65%	Unplanned COUE = R150 /kWh Interruption frequency = 0.33 x interruption duration Planned = 30% of unplanned
CDF 18	30.00	150.00	9.00	45.00	65%	Unplanned COUE = R150 /kWh Interruption frequency = 0.2 x interruption duration Planned = 30% of unplanned

### 7.2.3. Composite customer damage function

Equation 26 requires information on the customer damage function of each load feeder supplied from the substation. In a utility network, this can amount to a significant number of inputs. To minimise the inputs, the simplified approach considers a CCDF for each busbar.

In section 2.9.3 (see Equation 3) it was explained that a CCDF is calculated by weighting the energy utilisation ratio with the sector customer damage function (SCDF). The validity of this approach was investigated using specialized reliability software. ETAP was used for this purpose. Two examples are shown below. Both examples consider an HV/MV substation which supplies three load feeders from the MV busbar, with load sizes and customer damage functions as shown in Table 7-5. The calculated CCDF, using the average load size as a weighting factor, is also shown in Table 7-5.

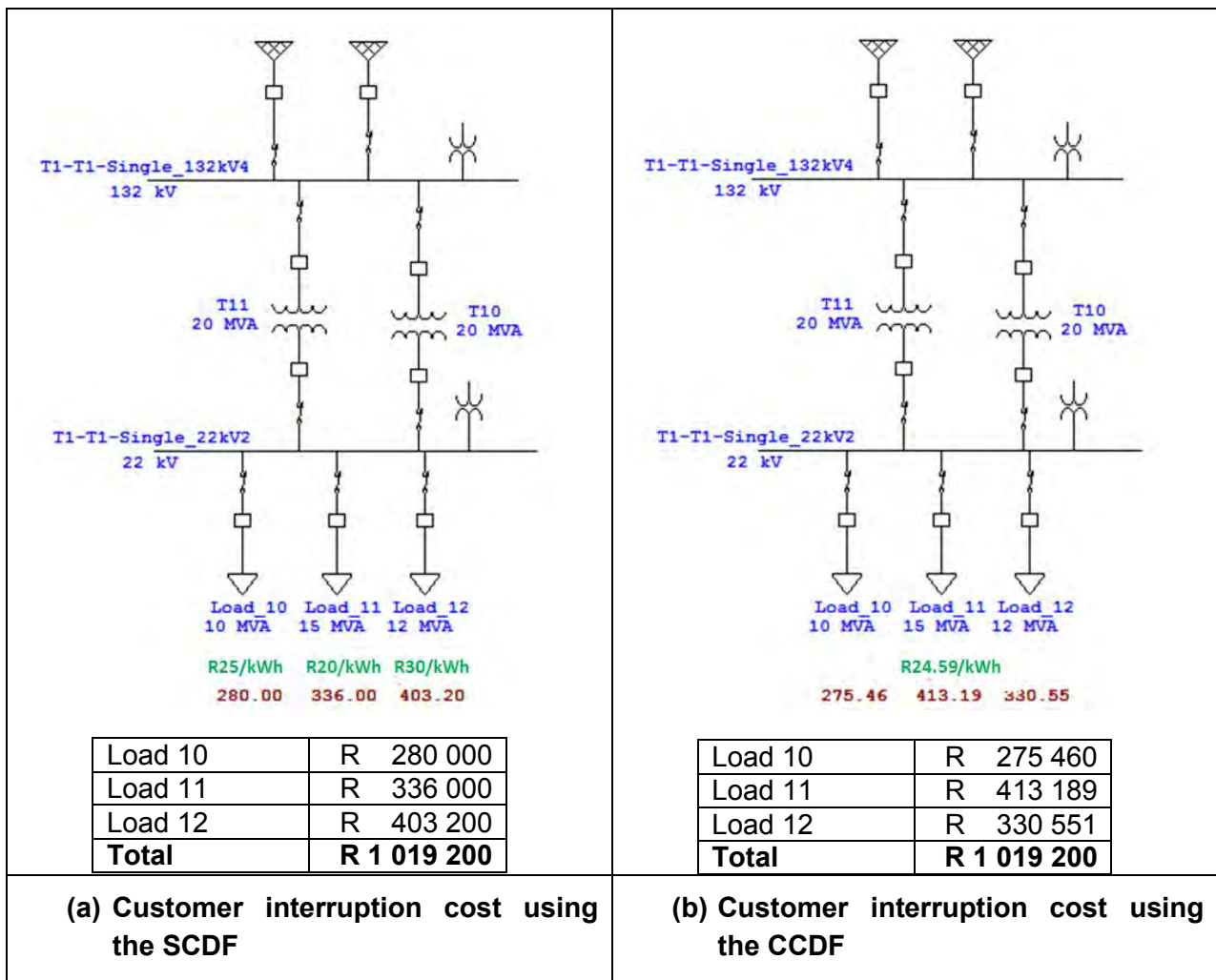
**Table 7-5: CCDF for three load feeders supplied from the same busbar**

Feeder No	Ave Load Size (MW)	Customer damage function	Substation Load (MW)	CCDF
Feeder 1	10	R 25/kWh	10+15+12=37	R 25/kWh x 10 000kW
Feeder 2	15	R 20/kWh		+ R 20/kWh x 15 000 kW
Feeder 3	12	R 30/kWh		+ R 30/kWh x 12 000 kW = R 910 000/h R 910 000/h / 37 000 kW <b>= R24.59/kWh</b>

Example 1:

The three feeders supplied from the downstream busbar are connected to the same busbar and are available for the same number of hours per year (considering only substation-originated outages and ignoring feeder-originated outages).

The ETAP results are shown in Figure 7-5. Figure 7-5 (a) shows the customer cost experienced per feeder, as well as the total customer cost (R1 019 200). In Figure 7-5 (b), the weighted average customer damage function, calculated in Table 7-5 was applied. The customer cost per feeder is different from that calculated in Figure 7-5 (a), but the total customer cost for all customers supplied from the MV busbar is also R1 019 200. The weighted average customer damage function therefore results in the same customer interruption cost as the feeder specific customer damage functions.

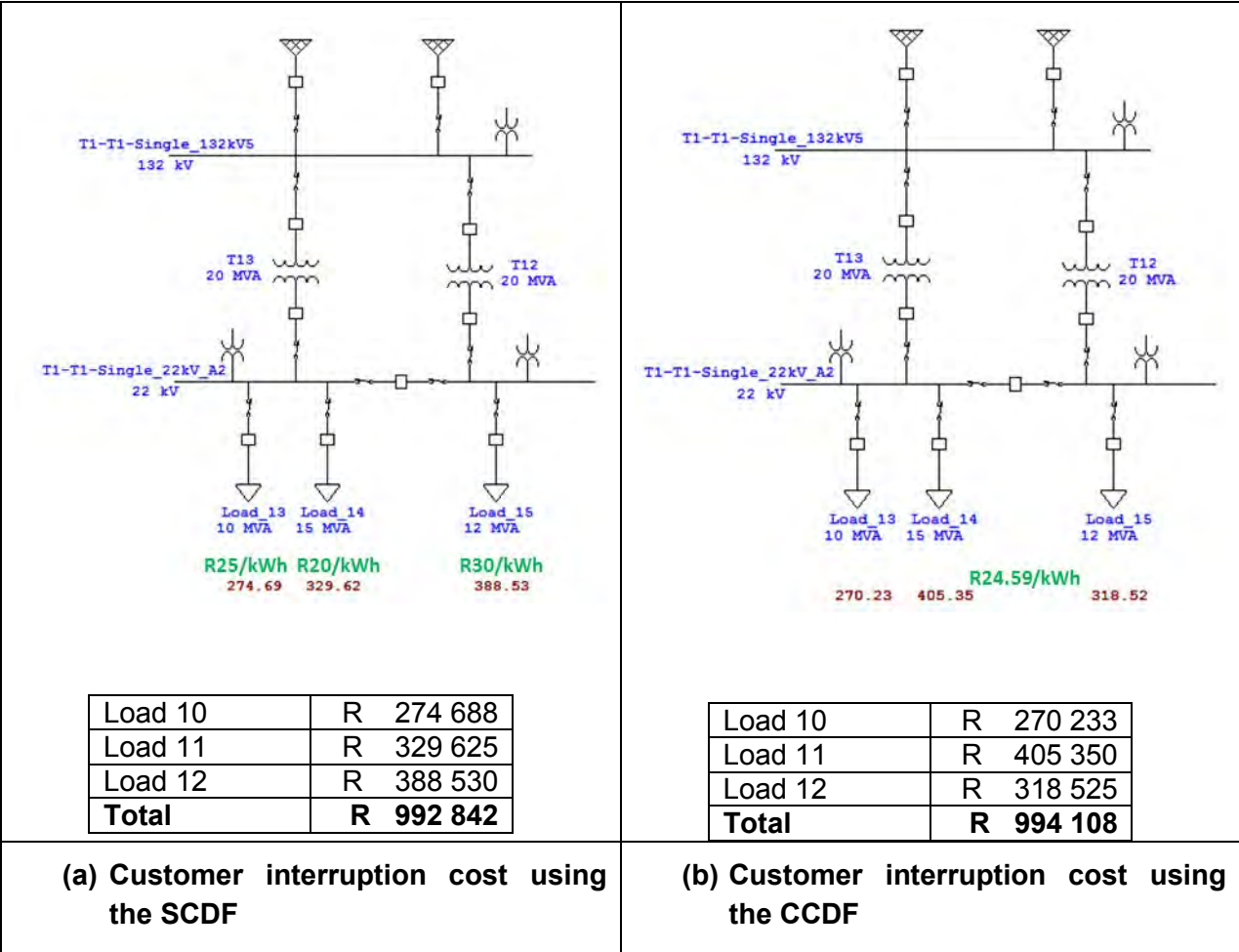


**Figure 7-5: Substation with single MV busbar used to illustrate the effect of using a CCDF**

Example 2:

In this example the three load feeders are supplied from a split MV busbar. Figure 7-6 (a) shows the customer cost experienced per feeder, as well as the total customer cost (R992 842). In Figure 7-6 (b), the weighted average customer damage function was applied. Now the total customer cost is different from that calculated in Figure 7-6 (a). The weighted average customer damage function does not result in the same customer interruption cost as the feeder specific customer damage functions. This is due to the fact that the MV busbar is not balanced, i.e. there are more feeders supplied from the one bus-section than the other bus-section resulting in the unavailability of the two bus-sections being different. This difference in unavailability causes the error when using the CCDF as opposed to the SCDF. The weighted

average customer damage function assumption results in an error of 0.13%. This error is deemed acceptable for the simplified approach, because it is within the same range of accuracy of estimates of the common substation costs.



**Figure 7-6: Substation with split MV busbar – used to illustrate the effect of using a CCDF**

**7.3. Summary of identified methodology**

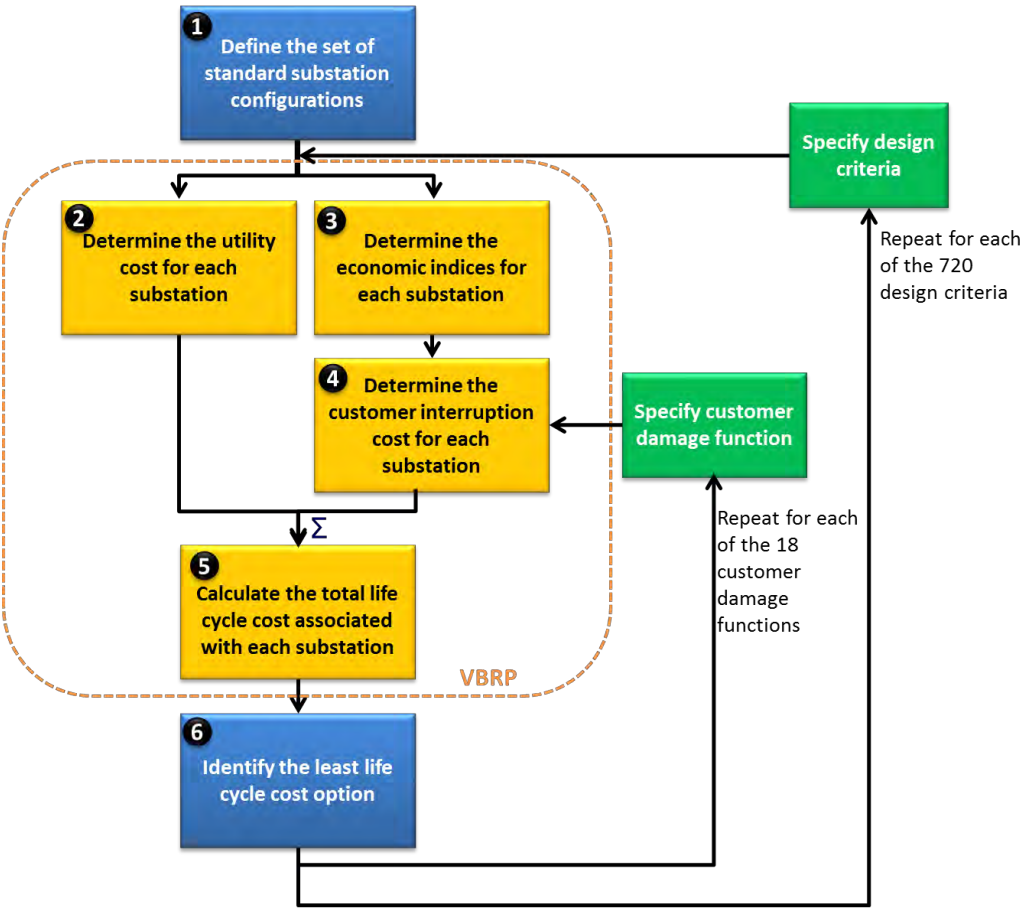
The customer interruption cost is calculated using a simplified approach to reliability modelling. This simplified approach is sufficiently comprehensive to ensure that errors are not one-sided, while at the same time minimising the number of calculations of the reliability evaluation.

Since no standardised set of COUE rates exists in South Africa, the study will not consider predefined customer damage functions per customer type. Instead, different customer damage functions will be analysed to determine the sensitivity of the optimal substation configuration to this parameter. 18 customer damage functions have been defined for this purpose.

A CCDF, using the average load size as a weighting factor, can be used to calculate the customer interruption cost at each busbar in the substation.

In section 2.10 of the literature review it was indicated that all future costs should be converted to a net present value. The COUE rates considered for this research are however not based on predefined COUE rates per customer type, but arbitrarily chosen values. No additional calculation was performed to convert these values to a net present value.

Each of the customer damage functions may result in a different preferred substation configuration, given the same design criteria. The preferred substation configuration therefore needs to be determined for each of the 18 customer damage functions. This means that the approach shown in Figure 5-1 needs to be repeated 18 times, as illustrated in Figure 7-7.



**Figure 7-7: Approach to determining the preferred set of substation configurations for all design criteria and customer damage functions**

## 8. Total life cycle cost calculation

This section discusses the total life cycle cost calculation, and how to identify the lowest life cycle cost option:

- (a) The total life cycle cost calculation is explained in section 8.1.
- (b) The process used to identify the least life cycle cost option, for the given design criterion and customer damage function, is discussed in 8.2.
- (c) The time required to perform the cost comparison for all different design criteria and customer damage functions is explained in section 8.3.

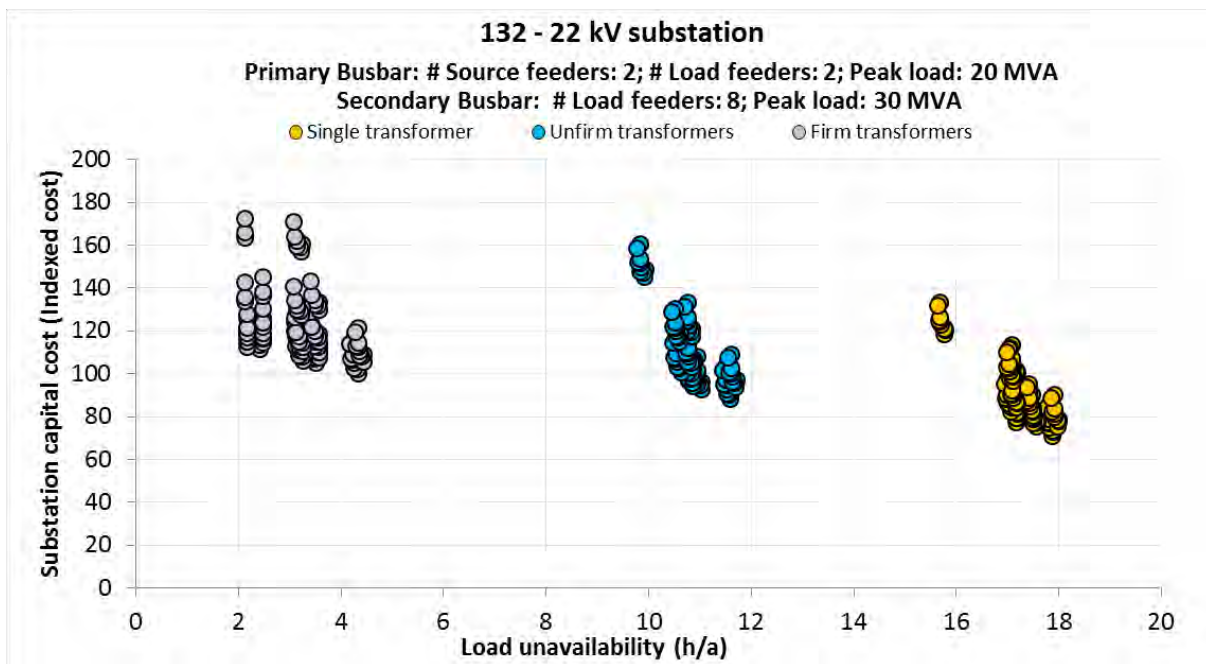
### 8.1. Cost calculation

The simplified reliability approach was programmed into MS Excel and used to calculate the economic indices and customer interruption cost, as explained in section 7, and the total utility cost, using the cost estimation tool described in section 6.

An example is shown below. For this example the design criteria listed in Table 8-1 were used. The load unavailability vs. life cycle cost for the 432 standard substation configurations is shown in Figure 8-1. The load unavailability shown is that of the downstream busbar of each substation. The interruption frequency is not shown. The cost shown is the indexed cost, as explained in section 6.2.1.1. The groupings of results in Figure 8-1 are the outcomes for single transformer substations, unfirm transformer substations and firm transformer substations, respectively. The steps between the groupings are a function of failure rates, maintenance frequencies, outage durations, average load supplied from the downstream busbar and percentage overload allowed on the transformer.

**Table 8-1: Design criteria for the substation life cycle cost comparison**

Parameter	Upstream busbar	Downstream busbar
Voltage	132 kV	22 kV
Number of source feeders	2	0
Number of load feeders	2	8
Peak load	20 MVA	30 MVA



**Figure 8-1: Substation capital cost vs. unavailability (h/a)**

The next step is to convert the load interruption frequency and load unavailability into a customer cost. First the load interruption frequency and load unavailability is converted to kW-interruptions and energy not supplied, by considering the average load supplied and the power factor (as per Equation 14 and Equation 15 in section 7.1.1). The customer interruption cost is then calculated by adding the effect of the customer damage function. This calculation is shown in Equation 26 (see section 7.2.1), where the cost of interruptions and cost of interruption duration were assumed as shown in Equation 27.

$$COUE \text{ Unplanned} = R20 \times kW - \text{interruptions} + R30 \times \text{Energy not supplied}$$

**Equation 27**

$$COUE \text{ Planned} = R10 \times kW - \text{interruptions} + R15 \times \text{Energy not supplied}$$

The total customer interruption cost is calculated by adding the COUE planned and COUE unplanned, and then converting this cost to a NPV, considering a discount rate of 10%. The total customer interruption cost is then converted to an indexed value, normalised to the same value used to index the substation capital cost.

The total substation life cycle cost is now calculated by adding the indexed utility life cycle cost and the indexed total customer interruption cost (COUE planned and COUE unplanned) for each substation configuration. The results for three different substation configurations are shown in Table 8-2.

**Table 8-2: Total life cycle cost calculation for three different substation configurations**

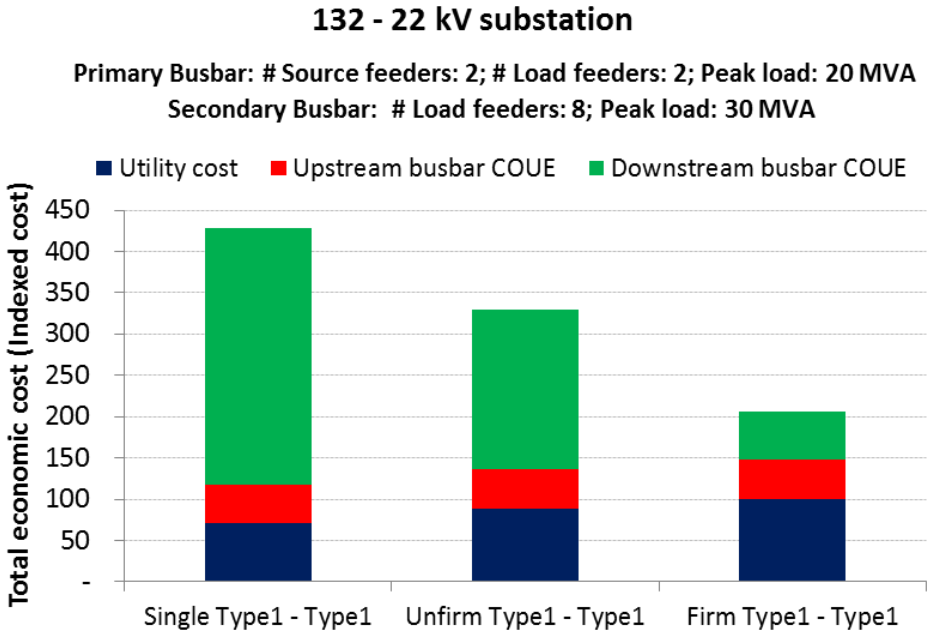
No	Parameter	Substation cost (indexed)	Index description	Load interruption frequency (occ/a)	Load interruption duration (h/a)	Customer interruption cost (indexed)	Total life cycle cost (indexed)
1	Type 1 – Type 1 with single transformer	70.66	Upstream Unplanned	0.15	2.25	29.10	428.50
			Upstream Planned	1	3	18.16	
			Downstream Unplanned	0.35	14.89	280.85	
			Downstream Planned	1	3	29.72	
2	Type 1 – Type 1 with unfirm transformation (2 x 20 MVA transformers)	88.08	Upstream Unplanned	0.18	2.30	29.98	329.67
			Upstream Planned	1	3	18.16	
			Downstream Unplanned	0.32	8.60	163.72	
			Downstream Planned	1	3	29.72	
3	Type 1 – Type 1 with firm transformation (2 x 40 MVA transformers)	100.14	Upstream Unplanned	0.18	2.30	29.98	205.82
			Upstream Planned	1	3	18.16	
			Downstream Unplanned	0.25	1.33	27.82	
			Downstream Planned	1	3	29.72	

**8.2. Identify the least life cycle cost option**

The total life cycle costs for all substation configurations can now be compared to determine the substation configuration with the least life cycle cost. This is illustrated in Figure 8-2 for the same three substation configurations considered in Table 8-2 above:

- (a) Type 1 – Type 1 with single transformer;
- (b) Type 1 – Type 1 with unfirm transformation (2 x 20 MVA transformers);
- (c) Type 1 – Type 1 with firm transformation (2 x 40 MVA transformers).

This figure separates the utility cost, upstream busbar - and downstream busbar customer interruption cost. It is clear from this figure that the single transformer substation is the least cost option for the utility, but the firm transformer substation configuration has the least total economic life cycle cost. The firm transformer substation is preferred, since it minimises the total life cycle cost of the utility and the customer.



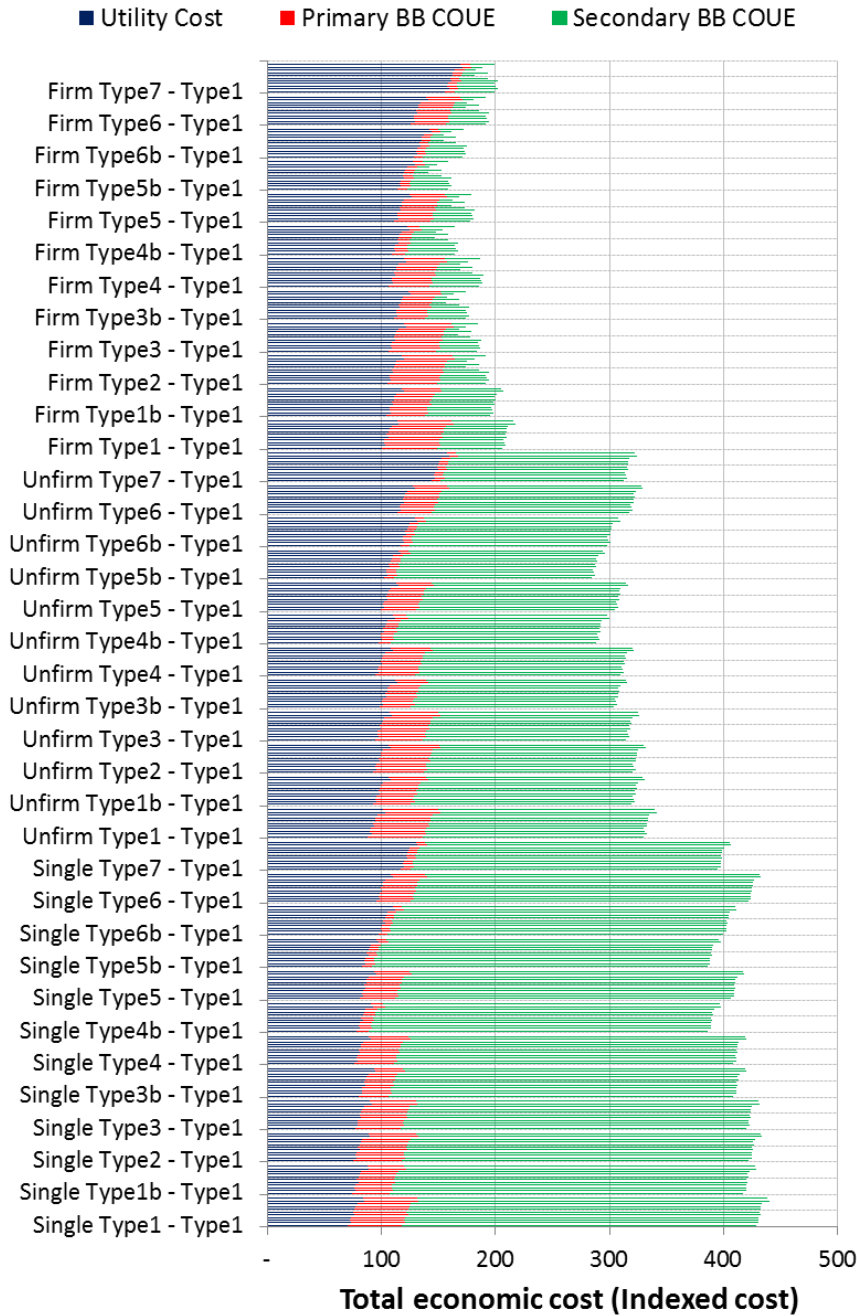
**Figure 8-2: Comparison of the total economic life cycle cost of three substations**

The same cost comparison is shown for all 432 different substation configurations in Figure 8-3. The total cost in this figure represents the blue line in Figure 2-1 and Figure 2-7 and clearly illustrates the minimal cost aimed at by the VBRP. The ten substations with the lowest life cycle cost are listed in Table 8-3. Substation no. 1 (Firm Type 5b – Type 4b) is the preferred substation configuration for the given design criteria.

### 132 - 22 kV substation

Primary Busbar: # Source feeders: 2; # Load feeders: 2; Peak load: 20 MVA

Secondary Busbar: # Load feeders: 8; Peak load: 30 MVA



**Figure 8-3: Comparison of the total economic life cycle cost of the 432 standard substation configurations<sup>3</sup>**

<sup>3</sup> Not all labels shown on y-axis. Only every 12<sup>th</sup> label is shown due to limited space.

**Table 8-3: Preferred substation configurations for given design criteria**

No	Parameter	Indexed cost
1	Firm Type5b - Type4b	141.3
2	Firm Type5b - Type5b	142.1
3	Firm Type4b - Type4b	147.0
4	Firm Type4b - Type5b	147.9
5	Firm Type5b – Type6b	148.3
6	Firm Type5b – Type4	152.6
7	Firm Type5b – Type5	152.7
8	Firm Type4b – Type6b	154.1
9	Firm Type6b - Type4b	154.1
10	Firm Type6b - Type5b	155.0

This model was used to compare the 432 different substation configurations for each of the 720 different design criteria and 18 different customer damage functions. The cost comparison of the 432 substations was thus performed 12 960 times. This requires 5 598 720 (432 x 12 960) life cycle cost calculations.

A single design criterion is specified by the first five dimensions in Table 8-4, with the possible range of values for each parameter, or dimension, as shown in the table. The customer damage function represents a sixth dimension. A specific customer damage function combined with a design criterion is referred to as a “scenario”. When any value in any of the sixth dimensions change, this represents another “scenario”.

**Table 8-4: Six dimensions and the range of values considered in each dimension**

No	Dimension	Range of values	Number of values in the range
1	Voltage	HV/HV; HV/MV; MV/MV	3
2	Number of source feeders	1; 2	2

No	Dimension	Range of values	Number of values in the range
3	Number of load feeders supplied from upstream busbar	0; 2; 4	3
4	Number of load feeders supplied from downstream busbar	2; 4; 6; 8	4
5	Load supplied from busbar (MVA)	6.25; 7.5; 8.25 (only HV/MV & MV/MV) 12.5; 15; 17.5 (only HV/MV & MV/MV) 25; 30; 35 50; 60; 70 (only HV/HV & HV/MV) 100; 120; 140 (only HV/HV)	15
6	Customer interruption cost	CDF 1 – 18 (see Table 7-4)	18

### 8.3. Time required for the analysis

The approach was programmed into an MS Excel model. An overview of this MS Excel model is given in Annex G.

The time required to perform the comparison of the 432 different substation configurations for one given design criteria and customer damage function is approximately 2 seconds. The process of running through 720 different design criteria was automated in MS Excel. The time required to run through all the design criteria, for one given customer damage function, is summarised in Table 8-5. These times were recorded using Excel 2010 (32 bit) on a machine with the following specifications: Intel core i5-3360M CPU 2.8 GHz, 8 GB RAM, 64 bit operating system.

**Table 8-5: Time required to run different design criteria for one customer damage function**

Substation voltage	Number of different design criteria	Average time required per customer damage function
MV/MV substations	216	7 minutes
HV/MV substations	288	13 minutes
HV/HV substations	216	7 minutes

This analysis was repeated for each of the 18 different customer damage functions. The total times required to run all the customer damage functions are summarised in Table 8-6.

**Table 8-6: Time required to run through different customer damage functions for all design criteria**

Substation voltage	Number of different design criteria	Average time required for all design criteria	Customer damage functions	Total time required for all customer damage functions
MV/MV substations	216	7 minutes	18	2 hours 17 minutes
HV/MV substations	288	13 minutes	18	4 hours 9 minutes
HV/HV substations	216	7 minutes	18	2 hours 20 minutes
<b>Total time for 18 customer damage functions</b>				<b>8 hours 46 minutes</b>
<b>Average time for 1 customer damage function</b>				<b>29 minutes</b>

The time required to run the model for all voltage levels and all customer damage functions is more than 8 hours. With a faster (typical industry standard) machine the running time would be dramatically reduced. Further, since the full model only needs to be run occasionally (as prices change or new substation configurations are developed) the running time is not significant, and does not justify the extra time required to simplify its use.

## 9. Results

This section discusses the optimal substation configurations for the various design criteria and customer damage functions calculated for the given set of assumptions. It then identifies a preferred set of substation configurations that minimises the total life cycle cost. These results are discussed in more detail in the following sections:

- (a) In section 9.1 some general observations from the results are discussed.
- (b) In section 9.2 the approach of clustering the results is explained.
- (c) In Section 9.3 the preferred substation configurations are presented.

### 9.1. Observations from the optimal substation configuration

The life cycle cost comparison was performed for each of the design criteria and customer damage functions discussed in section 5 (see Table 5-1) and section 7.2 respectively.

The optimal substation configuration for a 132/22 kV substation with customer damage function 1 (see Table 7-4) is shown in Figure 9-1. The optimal substation configuration is indicated by a key, e.g. S\_2-3b, which is interpreted as follows:

- (a) The first letter indicates the type of transformer capacity:
  - (i) S – Single transformer;
  - (ii) U – Unfirm transformation; and
  - (iii) F – Firm transformation
- (b) The first numeric (after the underscore) indicates the type of upstream busbar configuration. The bypass busbar configurations are indicated with a “b” after the numeric.
- (c) The second numeric indicates the type of downstream busbar configuration. Again the bypass configurations are indicated with a “b” after the numeric.
- (d) For example, the key “S\_2-3b” describes a substation with a single transformer, a Type 2 upstream busbar configuration and a Type 3b downstream busbar configuration.

The different optimal configurations are colour-coded, such that it is easy to identify at which point the optimal configuration changes from one type to another.

No. of source feeders	No. of upstream load feeders	No. of down-stream load feeders	Busbar peak load (MVA)								
			6.25	7.5	8.75	12.5	15	17.5	25	30	35
Transformer size:			5 – 10 MVA			10 – 20 MVA			20 – 40 MVA		
1	0	2	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b
1	0	4	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b
1	0	6	F_4b-1	F_4b-1	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b
1	0	8	F_4b-1	F_4b-1	F_4b-1	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b
1	2	2	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b
1	2	4	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b
1	2	6	F_4b-1	F_4b-1	F_4b-4b	F_4b-4b	F_4b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b
1	2	8	F_4b-1	F_4b-1	F_4b-1	F_4b-4b	F_4b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b
1	4	2	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b
1	4	4	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b
1	4	6	F_4b-1	F_4b-1	F_4b-4b	F_4b-4b	F_4b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b
1	4	8	F_4b-1	F_4b-1	F_4b-1	F_4b-4b	F_4b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b
2	0	2	F_1-1	F_1-1	F_4-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b
2	0	4	F_1-1	F_1-1	F_1-1	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b
2	0	6	F_1-1	F_1-1	F_1-1	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b
2	0	8	F_1-1	F_1-1	F_1-1	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b
2	2	2	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_5b-4b	F_5b-4b	F_5b-4b
2	2	4	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_5b-4b	F_5b-4b	F_5b-4b
2	2	6	F_4b-1	F_4b-1	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_5b-4b	F_5b-4b	F_5b-4b
2	2	8	F_4b-1	F_4b-1	F_4b-1	F_4b-4b	F_4b-4b	F_4b-4b	F_5b-4b	F_5b-4b	F_5b-4b
2	4	2	F_3-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b
2	4	4	F_1-1	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b
2	4	6	F_1-1	F_4b-1	F_4b-4b	F_4b-4b	F_4b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b
2	4	8	F_1-1	F_4b-1	F_4b-1	F_4b-4b	F_4b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b

**Figure 9-1: Optimal substation configurations for a 132/22 kV substation with CDF 1**

A table with the preferred substation configurations, like the one shown in Figure 9-1, was produced for each voltage level (HV-HV, HV-MV and MV-MV) and each of the 18 customer damage functions, i.e. 54 tables were produced. As examples, the tables with the optimal substation configuration for a 132/22 kV substation with CDF 2 & CDF 3 (see Table 7-4) are shown in Figure 9-2 and Figure 9-3 respectively.



It is clear from these three tables that:

- (a) The optimal substation configurations are in various instances the same irrespective of the interruption frequency cost applied. For example, the optimal configuration for a single source substation, no load supplied from the upstream busbar and a peak load of 12.5 MVA supplied from the secondary busbar is always F\_4b-4b (see yellow block “1” in Figure 9-4 (a) – (c)).

The results for all possible values in the customer damage functions range, considering all possible values for the other dimensions, were analysed and a similar observation was made when changing the interruption frequency cost. It can therefore be concluded that the interruption frequency cost does not have a significant effect on the optimal substation configuration.

- (b) Following the same approach as in (a) above, it was also observed that the planned interruption cost does not have a significant effect on the optimal substation configuration.

- (c) It was further observed that the optimal substation configurations are often the same for a specific transformer group (e.g. 5 – 10 MVA, or 10 – 20 MVA), but in some instances it changes when changing the peak load supplied within a specific transformer group. Consider for example the optimal configuration for a single source substation with two load feeders supplied from the upstream busbar (see yellow block “2” in Figure 9-4 (a)). The optimal configuration changes as the load changes from 12.5 MVA to 15 MVA. The same is observed for a double source substation with two load feeders supplied from the upstream busbar (see yellow block “3” in Figure 9-4 (a)), but now the optimal configuration only changes when the peak load changes from 15 MVA to 17.5 MVA.

The substation peak load will not stay constant during the project life over which the life cycle cost is analysed. The peak load can, for example, be 12 MVA when the substation is commissioned and increase to 18 MVA over the project life of 30 years. It is therefore difficult to predict whether the average peak load over the project life is 12.5 MVA or 15 MVA.

No. of source feeders	No. of upstream load feeders	No. of downstream load feeders	Busbar peak load (MVA)		
			12.5	15	17.5
Transformer size: 10 – 20 MVA					
1	0	2	F_4b-4b	F_4b-4b	F_4b-4b
1	0	4	F_4b-4b	F_4b-4b	F_4b-4b
1	0	6	F_4b-4b	F_4b-4b	F_4b-4b
1	0	8	F_4b-4b	F_4b-4b	F_4b-4b
1	2	2	F_4b-4b	F_5b-4b	F_5b-4b
1	2	4	F_4b-4b	F_5b-4b	F_5b-4b
1	2	6	F_4b-4b	F_5b-4b	F_5b-4b
1	2	8	F_4b-4b	F_5b-4b	F_5b-4b
1	4	2	F_4b-4b	F_5b-4b	F_5b-4b
1	4	4	F_4b-4b	F_5b-4b	F_5b-4b
1	4	6	F_4b-4b	F_5b-4b	F_5b-4b
1	4	8	F_4b-4b	F_5b-4b	F_5b-4b
2	0	2	F_3-4b	F_3-4b	F_3-4b
2	0	4	F_3-4b	F_3-4b	F_3-4b
2	0	6	F_3-4b	F_3-4b	F_3-4b
2	0	8	F_3-4b	F_3-4b	F_3-4b
2	2	2	F_4b-4b	F_5b-4b	F_5b-4b
2	2	4	F_4b-4b	F_5b-4b	F_5b-4b
2	2	6	F_4b-4b	F_5b-4b	F_5b-4b
2	2	8	F_4b-4b	F_5b-4b	F_5b-4b
2	4	2	F_4b-4b	F_5b-4b	F_5b-4b
2	4	4	F_4b-4b	F_5b-4b	F_5b-4b
2	4	6	F_4b-4b	F_5b-4b	F_5b-4b
2	4	8	F_4b-4b	F_5b-4b	F_5b-4b

No. of source feeders	No. of upstream load feeders	No. of downstream load feeders	Busbar peak load (MVA)		
			12.5	15	17.5
Transformer size: 10 – 20 MVA					
1	0	2	F_4b-4b	F_4b-4b	F_4b-4b
1	0	4	F_4b-4b	F_4b-4b	F_4b-4b
1	0	6	F_4b-4b	F_4b-4b	F_4b-4b
1	0	8	F_4b-4b	F_4b-4b	F_4b-4b
1	2	2	F_4b-4b	F_4b-4b	F_4b-4b
1	2	4	F_4b-4b	F_4b-4b	F_4b-4b
1	2	6	F_4b-4b	F_4b-4b	F_4b-4b
1	2	8	F_4b-4b	F_4b-4b	F_4b-4b
1	4	2	F_4b-4b	F_4b-4b	F_5b-4b
1	4	4	F_4b-4b	F_4b-4b	F_5b-4b
1	4	6	F_4b-4b	F_4b-4b	F_5b-4b
1	4	8	F_4b-4b	F_4b-4b	F_5b-4b
2	0	2	F_4-4b	F_3-4b	F_3-4b
2	0	4	F_4-4b	F_3-4b	F_3-4b
2	0	6	F_4-4b	F_3-4b	F_3-4b
2	0	8	F_4-4b	F_3-4b	F_3-4b
2	2	2	F_4b-4b	F_4b-4b	F_4b-4b
2	2	4	F_4b-4b	F_4b-4b	F_4b-4b
2	2	6	F_4b-4b	F_4b-4b	F_4b-4b
2	2	8	F_4b-4b	F_4b-4b	F_4b-4b
2	4	2	F_4b-4b	F_4b-4b	F_5b-4b
2	4	4	F_4b-4b	F_4b-4b	F_5b-4b
2	4	6	F_4b-4b	F_4b-4b	F_5b-4b
2	4	8	F_4b-4b	F_4b-4b	F_5b-4b

No. of source feeders	No. of upstream load feeders	No. of downstream load feeders	Busbar peak load (MVA)		
			12.5	15	17.5
Transformer size: 10 – 20 MVA					
1	0	2	F_4b-4b	F_4b-4b	F_4b-4b
1	0	4	F_4b-4b	F_4b-4b	F_4b-4b
1	0	6	F_4b-4b	F_4b-4b	F_4b-4b
1	0	8	F_4b-4b	F_4b-4b	F_4b-4b
1	2	2	F_4b-4b	F_4b-4b	F_4b-4b
1	2	4	F_4b-4b	F_4b-4b	F_4b-4b
1	2	6	F_4b-4b	F_4b-4b	F_4b-4b
1	2	8	F_4b-4b	F_4b-4b	F_4b-4b
1	4	2	F_4b-4b	F_4b-4b	F_5b-4b
1	4	4	F_4b-4b	F_4b-4b	F_5b-4b
1	4	6	F_4b-4b	F_4b-4b	F_5b-4b
1	4	8	F_4b-4b	F_4b-4b	F_5b-4b
2	0	2	F_4-4b	F_3-4b	F_3-4b
2	0	4	F_4-4b	F_3-4b	F_3-4b
2	0	6	F_4-4b	F_3-4b	F_3-4b
2	0	8	F_4-4b	F_3-4b	F_3-4b
2	2	2	F_4b-4b	F_4b-4b	F_4b-4b
2	2	4	F_4b-4b	F_4b-4b	F_4b-4b
2	2	6	F_4b-4b	F_4b-4b	F_4b-4b
2	2	8	F_4b-4b	F_4b-4b	F_4b-4b
2	4	2	F_4b-4b	F_4b-4b	F_5b-4b
2	4	4	F_4b-4b	F_4b-4b	F_5b-4b
2	4	6	F_4b-4b	F_4b-4b	F_5b-4b
2	4	8	F_4b-4b	F_4b-4b	F_5b-4b

(a) From Figure 9-1 (CDF 1)

(b) From Figure 9-2 (CDF 2)

(c) From Figure 9-3 (CDF 3)

**Figure 9-4: Identifying similarities in the optimal substation configuration**

In addition, the following observations were made:

- (a) The unplanned interruption duration cost has a significant effect on the optimal substation configuration. This is illustrated in Figure 9-5 for an HV/HV substation with a load of 20 – 40 MVA.

The optimal substation configuration for a CDF 1 is F\_4b-4b (see Figure 9-5 (a)). The optimal configuration for CDF 7 is predominantly S\_1-1 (see Figure 9-5 (b)). The optimal configuration for CDF 13 is predominantly F\_4b-5b (see Figure 9-5 (c)).

No. of source feeders	No. of upstream load feeders	No. of downstream load feeders	Busbar peak load (MVA)		
			25	30	35
Transformer size: 20 – 40 MVA					
1	0	2	F_4b-4b	F_4b-4b	F_4b-4b
1	0	4	F_4b-4b	F_4b-4b	F_4b-4b
1	0	6	F_4b-4b	F_4b-4b	F_4b-5b
1	0	8	F_4b-4b	F_4b-5b	F_4b-5b

(a) From Figure E-3 (CDF 1)

No. of source feeders	No. of upstream load feeders	No. of downstream load feeders			
			25	30	35
Transformer size:			20 – 40 MVA		
1	0	2	S_1-1	S_1-1	S_1-1
1	0	4	S_1-1	S_1-1	S_1-1
1	0	6	S_1-1	S_1-1	S_1-1
1	0	8	S_1-1	S_1-1	S_1-1

**(b) From Figure E-6 (CDF 7)**

No. of source feeders	No. of upstream load feeders	No. of downstream load feeders			
			25	30	35
Transformer size:			20 – 40 MVA		
1	0	2	F_4b-5b	F_4b-5b	F_4b-5b
1	0	4	F_4b-5b	F_4b-5b	F_4b-5b
1	0	6	F_4b-5b	F_4b-5b	F_4b-5b
1	0	8	F_4b-5b	F_4b-5b	F_4b-5b

**(c) From Figure E-9 (CDF 13)**

**Figure 9-5: Illustrating the impact of unplanned interruption duration cost on the optimal substation configuration (HV/HV substation)**

(b) The voltage level has a significant effect on the optimal substation configuration. This is illustrated in Figure 9-6 and Figure 9-7.

In Figure 9-6 the results for MV/MV and HV/MV (CDF 1, load 10 - 20 MVA) is shown. The optimal configuration for an MV/MV substation is F\_4-4b (see yellow block in Figure 9-6 (a)). The optimal configuration for an HV/MV substation is F\_3-4b (see yellow block in Figure 9-6 (b)).

In Figure 9-7 the results for HV/MV and HV/HV (CDF 13, load 20 - 40 MVA) is shown. The optimal configuration for an HV/HV substation is F\_5b-5b or F\_5b-6b, depending on the number of downstream feeders (see yellow block in Figure 9-7 (a)). The optimal configuration for an HV/MV substation is F\_4b-4b or F\_4b-5b, depending on the number of downstream feeders (see yellow block in Figure 9-7 (b)).

No. of source feeders	No. of upstream load feeders	No. of downstream load feeders	Busbar peak load (MVA)		
			12.5	15	17.5
Transformer size:			10 – 20 MVA		
1	0	2	F_4b-4b	F_4b-4b	F_4b-4b
1	0	4	F_4b-4b	F_4b-4b	F_4b-4b
1	0	6	F_4b-4b	F_4b-4b	F_4b-4b
1	0	8	F_4b-4b	F_4b-4b	F_4b-4b
1	2	2	F_5b-4b	F_5b-4b	F_5b-4b
1	2	4	F_5b-4b	F_5b-4b	F_5b-4b
1	2	6	F_5b-4b	F_5b-4b	F_5b-4b
1	2	8	F_5b-4b	F_5b-4b	F_5b-4b
1	4	2	F_5b-4b	F_5b-4b	F_5b-4b
1	4	4	F_5b-4b	F_5b-4b	F_5b-4b
1	4	6	F_5b-4b	F_5b-4b	F_5b-4b
1	4	8	F_5b-4b	F_5b-4b	F_5b-4b
2	0	2	F_4-4b	F_4-4b	F_4-4b
2	0	4	F_4-4b	F_4-4b	F_4-4b
2	0	6	F_4-4b	F_4-4b	F_4-4b
2	0	8	F_4-4b	F_4-4b	F_4-4b
2	2	2	F_4b-4b	F_4b-4b	F_4b-4b
2	2	4	F_4b-4b	F_4b-4b	F_4b-4b
2	2	6	F_4b-4b	F_4b-4b	F_4b-4b
2	2	8	F_4b-4b	F_4b-4b	F_4b-4b
2	4	2	F_4b-4b	F_4b-4b	F_4b-4b
2	4	4	F_4b-4b	F_4b-4b	F_4b-4b
2	4	6	F_4b-4b	F_4b-4b	F_4b-4b
2	4	8	F_4b-4b	F_4b-4b	F_4b-4b

No. of source feeders	No. of upstream load feeders	No. of downstream load feeders	Busbar peak load (MVA)		
			12.5	15	17.5
Transformer size:			10 – 20 MVA		
1	0	2	F_4b-4b	F_4b-4b	F_4b-4b
1	0	4	F_4b-4b	F_4b-4b	F_4b-4b
1	0	6	F_4b-4b	F_4b-4b	F_4b-4b
1	0	8	F_4b-4b	F_4b-4b	F_4b-4b
1	2	2	F_4b-4b	F_5b-4b	F_5b-4b
1	2	4	F_4b-4b	F_5b-4b	F_5b-4b
1	2	6	F_4b-4b	F_5b-4b	F_5b-4b
1	2	8	F_4b-4b	F_5b-4b	F_5b-4b
1	4	2	F_4b-4b	F_5b-4b	F_5b-4b
1	4	4	F_4b-4b	F_5b-4b	F_5b-4b
1	4	6	F_4b-4b	F_5b-4b	F_5b-4b
1	4	8	F_4b-4b	F_5b-4b	F_5b-4b
2	0	2	F_3-4b	F_3-4b	F_3-4b
2	0	4	F_3-4b	F_3-4b	F_3-4b
2	0	6	F_3-4b	F_3-4b	F_3-4b
2	0	8	F_3-4b	F_3-4b	F_3-4b
2	2	2	F_4b-4b	F_4b-4b	F_5b-4b
2	2	4	F_4b-4b	F_4b-4b	F_5b-4b
2	2	6	F_4b-4b	F_4b-4b	F_5b-4b
2	2	8	F_4b-4b	F_4b-4b	F_5b-4b
2	4	2	F_4b-4b	F_5b-4b	F_5b-4b
2	4	4	F_4b-4b	F_5b-4b	F_5b-4b
2	4	6	F_4b-4b	F_5b-4b	F_5b-4b
2	4	8	F_4b-4b	F_5b-4b	F_5b-4b

(a) From Figure E-1 (MV/MV; CDF 1)      (b) From Figure E-2 (HV/MV; CDF 1)

Figure 9-6: Illustrating the impact of voltage level on the optimal substation configuration

No. of source feeders	No. of upstream load feeders	No. of downstream load feeders	Busbar peak load (MVA)		
			50	60	70
Transformer size:			40-80 MVA		
1	0	2	F_5b-5b	F_5b-5b	F_5b-5b
1	0	4	F_5b-5b	F_5b-5b	F_5b-5b
1	0	6	F_5b-5b	F_5b-5b	F_5b-5b
1	0	8	F_5b-5b	F_5b-5b	F_5b-5b
1	2	2	F_5b-5b	F_5b-5b	F_5b-5b
1	2	4	F_5b-5b	F_5b-5b	F_5b-5b
1	2	6	F_5b-5b	F_5b-5b	F_5b-5b
1	2	8	F_5b-5b	F_5b-5b	F_5b-5b
1	4	2	F_5b-5b	F_5b-5b	F_5b-5b
1	4	4	F_5b-5b	F_5b-5b	F_5b-5b
1	4	6	F_5b-5b	F_5b-5b	F_5b-5b
1	4	8	F_5b-5b	F_5b-5b	F_5b-5b
2	0	2	F_3-5b	F_3-5b	F_3-5b
2	0	4	F_3-5b	F_3-5b	F_3-5b
2	0	6	F_3-5b	F_3-5b	F_3-5b
2	0	8	F_3-5b	F_3-5b	F_3-5b
2	2	2	F_5b-5b	F_5b-5b	F_5b-5b
2	2	4	F_5b-5b	F_5b-5b	F_5b-5b
2	2	6	F_5b-5b	F_5b-5b	F_5b-5b
2	2	8	F_5b-5b	F_5b-5b	F_5b-5b
2	4	2	F_5b-5b	F_5b-5b	F_5b-5b
2	4	4	F_5b-5b	F_5b-5b	F_5b-5b
2	4	6	F_5b-5b	F_5b-5b	F_5b-5b
2	4	8	F_5b-5b	F_5b-5b	F_5b-5b

No. of source feeders	No. of upstream load feeders	No. of downstream load feeders	Busbar peak load (MVA)		
			25	30	35
Transformer size:			20 – 40 MVA		
1	0	2	F_4b-4b	F_4b-4b	F_4b-4b
1	0	4	F_4b-4b	F_4b-4b	F_4b-4b
1	0	6	F_4b-4b	F_4b-5b	F_4b-5b
1	0	8	F_4b-5b	F_4b-5b	F_4b-5b
1	2	2	F_5b-4b	F_5b-4b	F_5b-4b
1	2	4	F_5b-4b	F_5b-4b	F_5b-4b
1	2	6	F_5b-4b	F_5b-5b	F_5b-5b
1	2	8	F_5b-5b	F_5b-5b	F_5b-5b
1	4	2	F_5b-4b	F_5b-4b	F_5b-4b
1	4	4	F_5b-4b	F_5b-4b	F_5b-4b
1	4	6	F_5b-4b	F_5b-5b	F_5b-5b
1	4	8	F_5b-5b	F_5b-5b	F_5b-5b
2	0	2	F_3-4b	F_3-4b	F_3-4b
2	0	4	F_3-4b	F_3-4b	F_3-4b
2	0	6	F_3-4b	F_3-5b	F_3-5b
2	0	8	F_3-5b	F_3-5b	F_3-5b
2	2	2	F_5b-4b	F_5b-4b	F_5b-4b
2	2	4	F_5b-4b	F_5b-4b	F_5b-4b
2	2	6	F_5b-4b	F_5b-5b	F_5b-5b
2	2	8	F_5b-5b	F_5b-5b	F_5b-5b
2	4	2	F_5b-4b	F_5b-4b	F_5b-4b
2	4	4	F_5b-4b	F_5b-4b	F_5b-4b
2	4	6	F_5b-4b	F_5b-5b	F_5b-5b
2	4	8	F_5b-5b	F_5b-5b	F_5b-5b

(a) From Figure E-9 (HV/HV; CDF 13)      (b) From Figure E-8 (HV/MV; CDF 13)

Figure 9-7: Illustrating the impact of voltage level on the optimal substation configuration

- (c) The number of source and load feeders has an effect on the optimal substation configuration, but the result is not as sensitive to these parameters as it is to the voltage level and unplanned interruption duration cost. This is illustrated in Figure 9-8 for an HV/HV substation with CDF 13.

Consider a substation with a load of 20 – 40 MVA and 0 upstream load feeders. The optimal substation configuration is F\_4b-5b, irrespective of the number of downstream load feeders (see yellow block “1a” in Figure 9-8). Similarly, for a substation with 2 or 4 upstream load feeders, the optimal substation configuration is F\_5b-5b, irrespective of the number of downstream load feeders (see yellow block “1b” and “1c” in Figure 9-8). Now consider a substation with load 80 – 160 MVA and 0 upstream feeders (see red block “2a” in Figure 9-8). The optimal configuration is F\_5b-5b irrespective of whether there are 2 or 4 downstream feeders, but it changes to F\_5b-6b if there are 6 downstream load feeders. It remains F\_5b-6b for 8 load feeders. Hence in some cases the number of downstream load feeders make a difference, but often it does not make a difference.

Analysing the impact of the number of upstream load feeders, the yellow blocks “1a” and “1b” in Figure 9-8 shows that the optimal configuration for a 20 – 40 MVA substation changes when moving from 0 to 2 upstream load feeders, but remains the same for 2 or 4 upstream load feeders (see yellow blocks “1b” and “1c” in Figure 9-8). The red blocks “2a” and “2b” in Figure 9-8 shows that the optimal configuration for a 80 – 160 MVA substation remains the same when moving from 0 to 2 upstream load feeders, but changes for 2 or 4 upstream load feeders (see red blocks “2b” and “2c” in Figure 9-8). Again the number of upstream load feeders make a difference in some cases, but often it does not make a difference.

No. of source feeders	No. of upstream load feeders	No. of downstream load feeders	Busbar peak load (MVA)								
			25	30	35	50	60	70	100	120	140
Transformer size:			20 – 40 MVA			40-80 MVA			80-160 MVA		
1	0	2	F 4b-5b	F 4b-5b	F 4b-5b	F 5b-5b	F 5b-5b	F 5b-5b	F 5b-5b	F 5b-5b	F 5b-5b
1	0	4	F 4b-5b	F 4b-5b	F 4b-5b	F 5b-5b	F 5b-5b	F 5b-5b	F 5b-5b	F 5b-5b	F 5b-5b
1	0	6	F 4b-5b	F 4b-5b	F 4b-5b	F 5b-5b	F 5b-5b	F 5b-5b	F 5b-5b	F 5b-5b	F 5b-5b
1	0	8	F 4b-5b	F 4b-5b	F 4b-5b	F 5b-5b	F 5b-5b	F 5b-5b	F 5b-5b	F 5b-5b	F 5b-5b
1	2	2	F 5b-5b	F 5b-5b	F 5b-5b	F 5b-5b	F 5b-5b	F 5b-5b	F 5b-5b	F 5b-5b	F 5b-5b
1	2	4	F 5b-5b	F 5b-5b	F 5b-5b	F 5b-5b	F 5b-5b	F 5b-5b	F 5b-5b	F 5b-5b	F 5b-5b
1	2	6	F 5b-5b	F 5b-5b	F 5b-5b	F 5b-5b	F 5b-5b	F 5b-5b	F 5b-5b	F 5b-5b	F 5b-5b
1	2	8	F 5b-5b	F 5b-5b	F 5b-5b	F 5b-5b	F 5b-5b	F 5b-5b	F 5b-5b	F 5b-5b	F 5b-5b
1	4	2	F 5b-5b	F 5b-5b	F 5b-5b	F 5b-5b	F 5b-5b	F 5b-5b	F 5b-5b	F 5b-5b	F 5b-5b
1	4	4	F 5b-5b	F 5b-5b	F 5b-5b	F 5b-5b	F 5b-5b	F 5b-5b	F 5b-5b	F 5b-5b	F 5b-5b
1	4	6	F 5b-5b	F 5b-5b	F 5b-5b	F 5b-5b	F 5b-5b	F 5b-5b	F 5b-5b	F 5b-5b	F 5b-5b
1	4	8	F 5b-5b	F 5b-5b	F 5b-5b	F 5b-5b	F 5b-5b	F 5b-5b	F 5b-5b	F 5b-5b	F 5b-5b
2	0	2	F 3-5b	F 3-5b	F 3-5b	F 3-5b	F 3-5b	F 3-5b	F 3-5b	F 3-5b	F 3-5b
2	0	4	F 3-5b	F 3-5b	F 3-5b	F 3-5b	F 3-5b	F 3-5b	F 3-5b	F 3-5b	F 3-5b
2	0	6	F 3-5b	F 3-5b	F 3-5b	F 3-5b	F 3-5b	F 3-5b	F 3-5b	F 3-5b	F 3-5b
2	0	8	F 3-5b	F 3-5b	F 3-5b	F 3-5b	F 3-5b	F 3-5b	F 3-5b	F 3-5b	F 3-5b
2	2	2	F 5b-5b	F 5b-5b	F 5b-5b	F 5b-5b	F 5b-5b	F 5b-5b	F 5b-5b	F 5b-5b	F 5b-5b
2	2	4	F 5b-5b	F 5b-5b	F 5b-5b	F 5b-5b	F 5b-5b	F 5b-5b	F 5b-5b	F 5b-5b	F 5b-5b
2	2	6	F 5b-5b	F 5b-5b	F 5b-5b	F 5b-5b	F 5b-5b	F 5b-5b	F 5b-5b	F 5b-5b	F 5b-5b
2	2	8	F 5b-5b	F 5b-5b	F 5b-5b	F 5b-5b	F 5b-5b	F 5b-5b	F 5b-5b	F 5b-5b	F 5b-5b
2	4	2	F 5b-5b	F 5b-5b	F 5b-5b	F 5b-5b	F 5b-5b	F 5b-5b	F 5b-5b	F 5b-5b	F 5b-5b
2	4	4	F 5b-5b	F 5b-5b	F 5b-5b	F 5b-5b	F 5b-5b	F 5b-5b	F 5b-5b	F 5b-5b	F 5b-5b
2	4	6	F 5b-5b	F 5b-5b	F 5b-5b	F 5b-5b	F 5b-5b	F 5b-5b	F 5b-5b	F 5b-5b	F 5b-5b
2	4	8	F 5b-5b	F 5b-5b	F 5b-5b	F 5b-5b	F 5b-5b	F 5b-5b	F 5b-5b	F 5b-5b	F 5b-5b

**Figure 9-8: Illustrating the impact of number of source and load feeders on the optimal substation configuration (HV/HV substation, CDF 13)**

The tables with the optimal substation configurations for the three voltage levels (HV-HV, HV-MV and MV-MV) and three of the customer damage functions (Function 1, 7 and 13) are shown in Annex E.

## 9.2. Clustering the results of different design criteria

From section 9.1 it is clear that some of the design parameters, or dimensions as referred to in section 8.2, does not have a significant impact on the optimal substation configuration, i.e. changing the value within a specific dimension does not result in a different outcome. Considering the 720 design criteria and the 18 customer damage functions, the approach explained will give the optimal configuration for 12 960 different combinations of design criteria and customer damage functions. For some of these combinations, the optimal configurations may be the same. It could therefore be possible to group some of the results in order to minimise the number of optimal substation configurations. The optimal configurations across different values within a specific dimension was therefore clustered in order to find a robust low-cost configuration that limits the cost penalty of any other optimal configuration to a small value.

### 9.2.1. Criteria for clustering

From the observations made in section 9.1, the following clusters were defined (see Table 9-1):

- (a) All customer damage functions with the same customer outage duration cost;
- (b) All peak loads within a transformer group;
- (c) Number of load feeders supplied from the upstream busbar;
  - (i) 0 load feeders supplied from the upstream busbar;
  - (ii) >0 load feeders supplied from the upstream busbar;
- (d) Number of load feeders supplied from the downstream busbar;
  - (iii) 1 – 2 load feeders supplied from the downstream busbar;
  - (iv) 3 – 8 load feeders supplied from the downstream busbar;

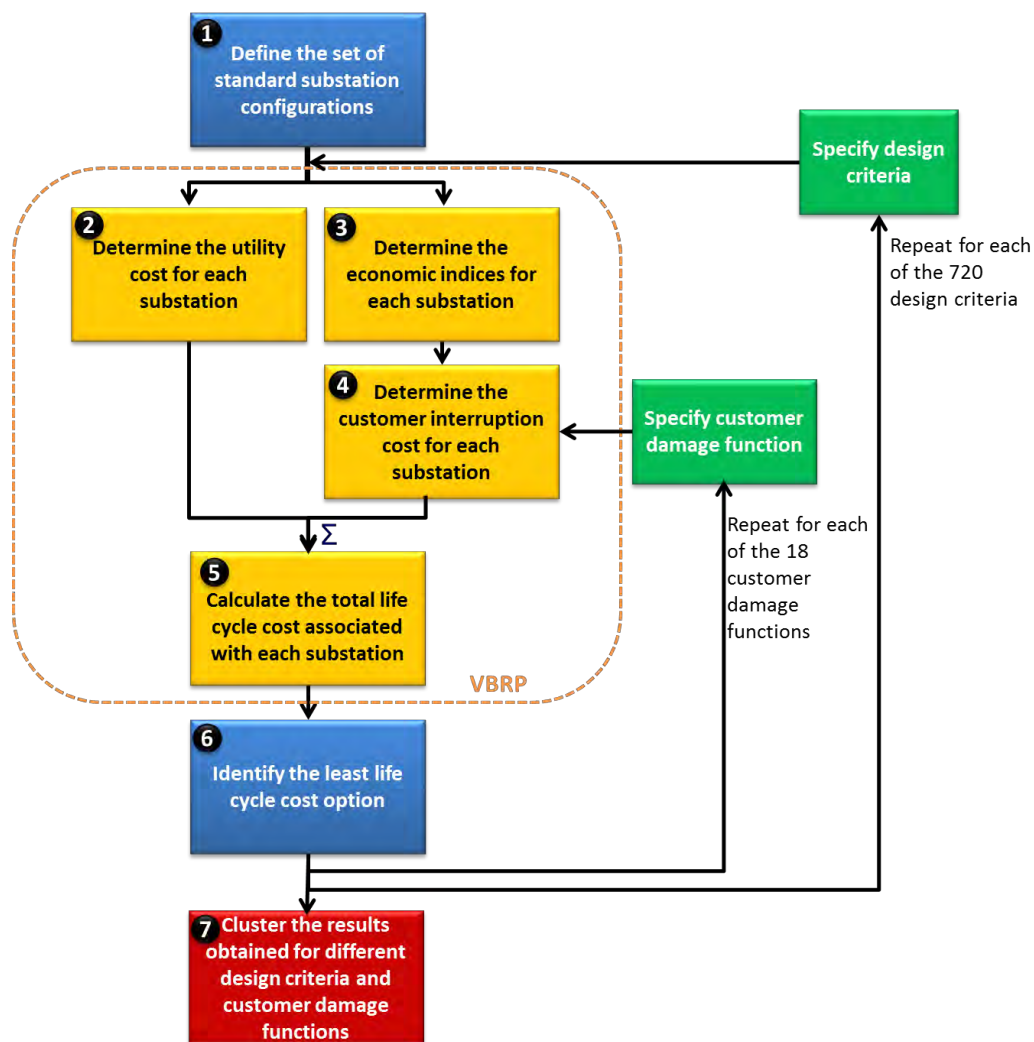
Before clustering an optimal configuration was calculated for 12 960 scenarios. After clustering a preferred configuration is given for only 240 scenarios.

**Table 9-1: Six dimensions and the range of values considered in each of the six dimensions**

No	Dimension	Range of values	Number of values in the range	
			Before clustering	After clustering
1	Voltage	HV/HV; HV/MV; MV/MV	3	3
2	Number of source feeders	1; 2	2	2
3	Number of load feeders supplied from upstream busbar	Cluster 1: 0 Cluster 2: 2; 4 (>0)	3	2
4	Number of load feeders supplied from downstream busbar	Cluster 1: 2; 4; (1-4) Cluster 2: 6; 8 (>4)	4	2

No	Dimension	Range of values	Number of values in the range	
			Before clustering	After clustering
5	Load supplied from busbar (MVA)	Cluster 1: 6.25; 7.5; 8.25 (only HV/MV & MV/MV) Cluster 2: 12.5; 15; 17.5 (only HV/MV & MV/MV) Cluster 3: 25; 30; 35 Cluster 4: 50; 60; 70 (only HV/HV & HV/MV) Cluster 5: 100; 120; 140 (only HV/HV)	15	5
6	Customer interruption cost	Cluster 1: CDF 1 – 6 (see Table 7-4) Cluster 2: CDF 7 – 12 (see Table 7-4) Cluster 3: CDF 13 – 18 (see Table 7-4)	18	3

This step of clustering is added to the approach shown in Figure 7-7, and the complete process is shown in Figure 9-9.



**Figure 9-9: Approach to determining the preferred set of substation configurations for all design criteria and customer damage functions, including the clustering of the results**

### 9.2.2. Determining the preferred configuration for a cluster

The preferred substation configuration within a cluster was determined as follows:

- (a) For each scenario within a cluster, a “score” is calculated for each of the 432 substation configurations. This score is derived from the indexed life cycle cost. The cheapest substation configuration is assigned a score of 1, and the scores of each of the other 431 substation configurations is derived by dividing its indexed cost with that of the lowest life cycle cost option. This is illustrated for 10 substation configurations in Table 9-2.

**Table 9-2: Determining the score for each substation configuration**

No	Substation configuration	Indexed cost	“Score”
1	Configuration 1	154.8	$154.8 / 154.8 = 1.0000$
2	Configuration 2	155.7	$155.7 / 154.8 = 1.0058$
3	Configuration 3	157.7	$157.7 / 154.8 = 1.0187$
4	Configuration 4	157.8	$157.8 / 154.8 = 1.0194$
5	Configuration 5	160.7	$160.7 / 154.8 = 1.0381$
6	Configuration 6	161.5	$161.5 / 154.8 = 1.0433$
7	Configuration 7	161.9	$161.9 / 154.8 = 1.0459$
8	Configuration 8	163.3	$163.3 / 154.8 = 1.0549$
9	Configuration 9	163.5	$163.5 / 154.8 = 1.0562$
10	Configuration 10	163.7	$163.7 / 154.8 = 1.0575$

- (b) This process is then repeated for all other design criteria (or scenarios) within the same cluster. This means that a value in anyone of the six dimensions is changed to another value that falls within the identified cluster, e.g. changing the load size from 25 MVA to 35 MVA, or changing the number of downstream load feeders from 6 to 8. Each time the design criterion is changed this represents another “scenario”.
- (c) For each substation configuration the scores across all scenarios within a specific cluster are then added. The configuration with the lowest score is the preferred substation configuration for the identified cluster. This is illustrated in Table 9-3, where the optimal substation configuration for each scenario is highlighted in yellow. The scores from all scenarios in the cluster are added and the configuration with the lowest total is the preferred substation configuration for the cluster.

It is important to note that, using this approach, it is possible that a configuration that is not the optimal configuration for any scenario can be the preferred configuration for the cluster. This is illustrated by the example in Table 9-3, where Configuration 9 is not the optimal configuration for any of the six scenarios, but it is the preferred configuration for the cluster. This means that the summation of the life cycle cost over the scenarios within a cluster had to be done for all

configurations, not just the 10 optimal configurations for a specific scenario. However only 10 configurations are used in the example in order to simplify the explanation.

The process of clustering the results changes the optimal configuration to the preferred configuration.

**Table 9-3: Determining the preferred substation configuration for a cluster by adding the scores for all scenarios**

No	Substation configuration	"Score"						Total
		Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5	Scenario 6	
1	Configuration 1	1.0000	1.0647	1.0585	1.0506	1.0269	1.1059	6.3066
2	Configuration 2	1.0058	1.0670	1.0697	1.0590	1.0317	1.0991	6.3324
3	Configuration 3	1.0187	1.0000	1.0732	1.0648	1.0548	1.0924	6.3039
4	Configuration 4	1.0194	1.0068	1.0766	1.0772	1.0643	1.0776	6.3220
5	Configuration 5	1.0381	1.0208	1.0000	1.0818	1.0712	1.0696	6.2815
6	Configuration 6	1.0433	1.0224	1.0078	1.0863	1.0848	1.0590	6.3037
7	Configuration 7	1.0459	1.0423	1.0228	1.0000	1.0904	1.0348	6.2361
8	Configuration 8	1.0549	1.0485	1.0255	1.0088	1.0961	1.0290	6.2628
9	Configuration 9	1.0562	1.0521	1.0464	1.0249	1.0098	1.0109	6.2003
10	Configuration 10	1.0575	1.0623	1.0537	1.0286	1.0000	1.0000	6.2021
<b>Optimal configuration</b>		<b>Config 1</b>	<b>Config 3</b>	<b>Config 5</b>	<b>Config 7</b>	<b>Config 10</b>	<b>Config 10</b>	<b>Config 9</b>

This process of clustering the results is illustrated for an HV/MV substation with a customer outage duration cost of R75/kWh. All optimal configurations, before any clustering, are shown in Figure 9-10 (The CDF referred to is the CDF as described in Table 7-3).



No. of source feeders	No. of upstream load feeders	No. of downstream load feeders	Busbar peak load (MVA)												
			6.25	7.5	8.75	12.5	15	17.5	25	30	35	50	60	70	
Transformer size:			5 – 10 MVA			10 – 20 MVA			20 – 40 MVA			40-80 MVA			
1	0	2	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b
1	0	4	F_4b-1	F_4b-1	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b
1	0	6	F_4b-1	F_4b-1	F_4b-1	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b
1	0	8	F_4b-1	F_4b-1	F_4b-1	F_4b-1	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b
1	2	2	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b
1	2	4	F_4b-1	F_4b-1	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b
1	2	6	F_4b-1	F_4b-1	F_4b-1	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b
1	2	8	F_4b-1	F_4b-1	F_4b-1	F_4b-1	F_4b-4b	F_4b-4b	F_4b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b
1	4	2	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b
1	4	4	F_4b-1	F_4b-1	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b
1	4	6	F_4b-1	F_4b-1	F_4b-1	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b
1	4	8	F_4b-1	F_4b-1	F_4b-1	F_4b-1	F_4b-4b	F_4b-4b	F_4b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b
2	0	2	F_1-1	F_1-1	F_1-1	F_2-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b
2	0	4	F_1-1	F_1-1	F_1-1	F_2-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b
2	0	6	F_1-1	F_1-1	F_1-1	F_2-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b
2	0	8	F_1-1	F_1-1	F_1-1	F_1-1	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b
2	2	2	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b
2	2	4	F_4b-1	F_4b-1	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b
2	2	6	F_4b-1	F_4b-1	F_4b-1	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b
2	2	8	F_4b-1	F_4b-1	F_4b-1	F_4b-1	F_4b-4b	F_4b-4b	F_4b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b
2	4	2	F_1-1	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b
2	4	4	F_1-1	F_4b-1	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b
2	4	6	F_1-1	F_4b-1	F_4b-1	F_4b-4b	F_4b-4b	F_4b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b
2	4	8	F_1-1	F_4b-1	F_4b-1	F_4b-1	F_4b-4b	F_4b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b

**Figure 9-11: Results clustered across different CDFs (with the same customer outage duration cost)**

The next step is to cluster the results across different peak loads, within a specific transformer group. The result is shown in Figure 9-12. This selects the substation configuration that affords a compromise across the possible power levels.

No. of source feeders	No. of upstream load feeders	No. of downstream load feeders	Busbar peak load (MVA)											
			6.25	7.5	8.75	12.5	15	17.5	25	30	35	50	60	70
Transformer size:			5 – 10 MVA			10 – 20 MVA			20 – 40 MVA			40-80 MVA		
1	0	2	F_4b-4b			F_4b-4b			F_4b-4b			F_4b-4b		
1	0	4	F_4b-1			F_4b-4b			F_4b-4b			F_4b-4b		
1	0	6	F_4b-1			F_4b-4b			F_4b-4b			F_4b-4b		
1	0	8	F_4b-1			F_4b-4b			F_4b-4b			F_4b-4b		
1	2	2	F_4b-4b			F_4b-4b			F_5b-4b			F_5b-4b		
1	2	4	F_4b-1			F_4b-4b			F_5b-4b			F_5b-4b		
1	2	6	F_4b-1			F_4b-4b			F_5b-4b			F_5b-4b		
1	2	8	F_4b-1			F_4b-4b			F_5b-4b			F_5b-4b		
1	4	2	F_4b-4b			F_4b-4b			F_5b-4b			F_5b-4b		
1	4	4	F_4b-1			F_4b-4b			F_5b-4b			F_5b-4b		
1	4	6	F_4b-1			F_4b-4b			F_5b-4b			F_5b-4b		
1	4	8	F_4b-1			F_4b-4b			F_5b-4b			F_5b-4b		
2	0	2	F_1-1			F_3-4b			F_3-4b			F_3-4b		
2	0	4	F_1-1			F_3-4b			F_3-4b			F_3-4b		
2	0	6	F_1-1			F_3-4b			F_3-4b			F_3-4b		
2	0	8	F_1-1			F_3-4b			F_3-4b			F_3-4b		
2	2	2	F_4b-4b			F_4b-4b			F_5b-4b			F_5b-4b		
2	2	4	F_4b-1			F_4b-4b			F_5b-4b			F_5b-4b		
2	2	6	F_4b-1			F_4b-4b			F_5b-4b			F_5b-4b		
2	2	8	F_4b-1			F_4b-4b			F_5b-4b			F_5b-4b		
2	4	2	F_4b-4b			F_4b-4b			F_5b-4b			F_5b-4b		
2	4	4	F_4b-1			F_4b-4b			F_5b-4b			F_5b-4b		
2	4	6	F_4b-1			F_4b-4b			F_5b-4b			F_5b-4b		
2	4	8	F_4b-1			F_4b-4b			F_5b-4b			F_5b-4b		

**Figure 9-12: Results clustered across different peak loads (within a specific transformer size group)**

The last step is to cluster the results across different number of load feeders supplied. The result is shown in Figure 9-13.

No. of source feeders	No. of upstream load feeders	No. of downstream load feeders	Busbar peak load (MVA)											
			6.25	7.5	8.75	12.5	15	17.5	25	30	35	50	60	70
Transformer size:			5 – 10 MVA			10 – 20 MVA			20 – 40 MVA			40-80 MVA		
1	0	2	F_4b-4b			F_4b-4b			F_4b-4b			F_4b-4b		
1	0	>2	F_4b-1			F_4b-4b			F_4b-4b			F_4b-4b		
1	>0	2	F_4b-4b			F_4b-4b			F_5b-4b			F_5b-4b		
1	>0	>2	F_4b-1			F_4b-4b			F_5b-4b			F_5b-4b		
2	0	2	F_1-1			F_3-4b			F_3-4b			F_3-4b		
2	0	>2	F_1-1			F_3-4b			F_3-4b			F_3-4b		
2	>0	2	F_4b-4b			F_4b-4b			F_5b-4b			F_5b-4b		
2	>0	>2	F_4b-1			F_4b-4b			F_5b-4b			F_5b-4b		

**Figure 9-13: Results after clustering across different number of load feeders supplied**

The process of clustering, as explained above, minimises the number of preferred substation configurations.

A process of manual clustering was used in this research. After using this manual technique it became clear that a statistical clustering technique can be used, which consider the penalty cost between the optimal configuration and the preferred configuration, to determine whether clustering of two values within a dimension is acceptable. This statistical clustering technique can then be used to automate the clustering in the Ms Excel Model. This is an area for further research.

### 9.3. Preferred configurations for different design criteria

The method used to determine the preferred substation configuration for each design criterion and to cluster the results, as explained in section 9.2, was used to determine the preferred substation configuration for the different voltage levels and customer outage duration costs. The results are presented in this section:

- (a) The preferred substation configurations for a customer interruption duration cost of R 75/kWh are shown in section 9.3.1.
- (b) The preferred substation configurations for a customer interruption duration cost of R 5/kWh are shown in section 9.3.2.
- (c) The preferred substation configurations for a customer interruption duration cost of R 150/kWh are shown in section 9.3.3.

A summary of the preferred substation configurations per voltage level and customer outage duration cost is shown in Table 9-4. Schematic diagrams of these preferred substation configurations are shown in Annex F.

The following can be concluded from Table 9-4 and the preferred configurations in section 9.3.1, section 9.3.2 and section 9.3.3:

- (a) The preferred substation configuration for a load with customer interruption duration cost of R75/kWh or more is always a substation with firm transformer capacity, irrespective of the voltage and/or other design parameters.
- (b) A load with a customer interruption duration cost of R5/kWh never justifies a substation with more than one transformer, irrespective of the voltage and/or other design parameters.
- (c) A substation load of less than 80 MVA and customer interruption duration cost of R5/kWh does not justify any redundancy and therefore a single transformer, single busbar substation is always preferred, irrespective of the voltage and/or other design parameters.
- (d) A substation with a customer interruption duration cost of R75/kWh or more and a load of more than 10 MVA always justifies a double busbar with bypass isolators on the downstream side of the substation, irrespective of the voltage and/or other design parameters.

In addition to the voltage level and COUE, a substation designer needs to consider the size of the load supplied as well as the number of source feeders and number of load feeders supplied from each busbar to choose between the recommended configurations. These specific configurations are shown in Figure 9-14 (section 9.3.1), Figure 9-15 (section 9.3.2) and Figure 9-16 (section 9.3.3) respectively.

**Table 9-4: Summary of the preferred substation configurations per voltage level and outage duration cost**

<b>Substation voltage</b>	<b>COUE rate = R75/kWh</b>	<b>COUE rate = R5/kWh</b>	<b>COUE = R150/kWh</b>	<b>Total number of different substation configurations</b>
MV/MV substations	1) F_1-1 2) F_3-4b 3) F_4b-4b 4) F_5b-4b 5) F_4-4b	1) S_1-1	1) F_4b-4b 2) F_5b-4b 3) F_4-4b 4) F_3-4b	1) S_1-1 2) F_1-1 3) F_4b-4b 4) F_5b-4b 5) F_3-4b 6) F_4-4b
HV/MV substations	1) F_1-1 2) F_3-4b 3) F_4b-4b 4) F_5b-4b 5) F_4b-1	1) S_1-1	1) F_4b-4b 2) F_5b-4b 3) F_3-4b 4) F_3-5b 5) F_5b-5b	1) S_1-1 2) F_1-1 3) F_4b-1 4) F_4b-4b 5) F_5b-4b 6) F_3-4b 7) F_3-5b 8) F_5b-5b
HV/HV substations	1) F_3-4b 2) F_4b-4b 3) F_5b-4b 4) F_4b-5b 5) F_5b-5b 6) F_3-5b	1) S_1-1 2) S_1-1b 3) S_4b-1b 4) S_4b-1	1) F_4b-5b 2) F_5b-5b 3) F_3-5b 4) F_3-6b 5) F_5b-6b 6) F_6b-5b 7) F_6b-6b	1) S_1-1 2) S_1-1b 3) S_4b-1b 4) S_4b-1 5) F_4b-4b 6) F_4b-5b 7) F_5b-4b 8) F_5b-5b 9) F_3-4b 10) F_3-5b 11) F_3-6b 12) F_5b-6b 13) F_6b-5b 14) F_6b-6b

Substation voltage	COUE rate = R75/kWh	COUE rate = R5/kWh	COUE = R150/kWh	Total number of different substation configurations
All voltages	1) F_1-1 2) F_4b-4b 3) F_5b-4b 4) F_3-4b 5) F_4-4b 6) F_4b-1 7) F_4b-5b 8) F_5b-5b 9) F_3-5b	1) S_1-1 2) S_1-1b 3) S_4b-1b 4) S_4b-1	1) F_4b-4b 2) F_5b-4b 3) F_4-4b 4) F_3-4b 5) F_3-5b 6) F_5b-5b 7) F_4b-5b 8) F_3-6b 9) F_5b-6b 10) F_6b-5b 11) F_6b-6b	1) S_1-1 2) S_1-1b 3) S_4b-1b 4) S_4b-1 5) F_1-1 6) F_4b-4b 7) F_5b-4b 8) F_3-4b 9) F_4-4b 10) F_4b-1 11) F_4b-5b 12) F_5b-5b 13) F_3-5b 14) F_3-6b 15) F_5b-6b 16) F_6b-5b 17) F_6b-6b

A summary of the number of distinct different substation configurations per voltage level and customer damage function is given in Table 9-5. This table shows that there are 17 different preferred substation configurations, considering all three voltage levels and the three selected COUE rates.

**Table 9-5: Number of different substation configurations per voltage level and COUE rate**

Substation voltage	COUE rate = R75/kWh	COUE rate = R5/kWh	COUE = R150/kWh	Total number of different substation configurations
MV/MV substations	5	1	4	6
HV/MV substations	5	1	5	8
HV/HV substations	6	4	7	14
<b>All voltages</b>	<b>9</b>	<b>4</b>	<b>11</b>	<b>17</b>

### 9.3.1. Preferred substation configurations for a COUE rate of R 75/kWh

The preferred substation configurations for a COUE rate of R 75/kWh are shown in Figure 9-14.

No. of source feeders	No. of upstream load feeders	No. of down-stream load feeders	Busbar peak load (MVA)								
			6.25	7.5	8.75	12.5	15	17.5	25	30	35
Transformer size:			5 – 10 MVA			10 – 20 MVA			20 – 40 MVA		
1	0	2	F_1-1			F_4b-4b			F_4b-4b		
1	0	>2	F_1-1			F_4b-4b			F_4b-4b		
1	>0	2	F_1-1			F_4b-4b			F_5b-4b		
1	>0	>2	F_1-1			F_4b-4b			F_5b-4b		
2	0	2	F_1-1			F_4-4b			F_3-4b		
2	0	>2	F_1-1			F_4-4b			F_3-4b		
2	>0	2	F_1-1			F_4b-4b			F_4b-4b		
2	>0	>2	F_1-1			F_4b-4b			F_4b-4b		

**(a) MV/MV substation**

No. of source feeders	No. of upstream load feeders	No. of down-stream load feeders	Busbar peak load (MVA)											
			6.25	7.5	8.75	12.5	15	17.5	25	30	35	50	60	70
Transformer size:			5 – 10 MVA			10 – 20 MVA			20 – 40 MVA			40-80 MVA		
1	0	2	F_4b-4b			F_4b-4b			F_4b-4b			F_4b-4b		
1	0	>2	F_4b-1			F_4b-4b			F_4b-4b			F_4b-4b		
1	>0	2	F_4b-4b			F_4b-4b			F_5b-4b			F_5b-4b		
1	>0	>2	F_4b-1			F_4b-4b			F_5b-4b			F_5b-4b		
2	0	2	F_1-1			F_3-4b			F_3-4b			F_3-4b		
2	0	>2	F_1-1			F_3-4b			F_3-4b			F_3-4b		
2	>0	2	F_4b-4b			F_4b-4b			F_5b-4b			F_5b-4b		
2	>0	>2	F_4b-1			F_4b-4b			F_5b-4b			F_5b-4b		

**(b) HV/MV substation**

No. of source feeders	No. of upstream load feeders	No. of down-stream load feeders	Busbar peak load (MVA)								
			25	30	35	50	60	70	100	120	140
Transformer size:			20 – 40 MVA			40-80 MVA			80-160 MVA		
1	0	2	F_4b-4b			F_4b-4b			F_4b-5b		
1	0	>2	F_4b-4b			F_4b-5b			F_4b-5b		
1	>0	2	F_5b-4b			F_5b-4b			F_5b-5b		
1	>0	>2	F_5b-4b			F_5b-5b			F_5b-5b		
2	0	2	F_3-4b			F_3-4b			F_3-5b		
2	0	>2	F_3-4b			F_3-5b			F_3-5b		
2	>0	2	F_5b-4b			F_5b-4b			F_5b-5b		
2	>0	>2	F_5b-4b			F_5b-5b			F_5b-5b		

**(c) HV/HV substation**

Figure 9-14: Preferred substation configurations for a COUE rate of R 75/kWh

### 9.3.2. Preferred substation configurations for a COUE rate of R 5/kWh

The preferred substation configurations for a COUE rate of R 5/kWh are shown in Figure 9-15.

No. of source feeders	No. of upstream load feeders	No. of down-stream load feeders	Busbar peak load (MVA)								
			6.25	7.5	8.75	12.5	15	17.5	25	30	35
Transformer size:			5 – 10 MVA			10 – 20 MVA			20 – 40 MVA		
1	0	2	S_1-1			S_1-1			S_1-1		
1	0	>2	S_1-1			S_1-1			S_1-1		
1	>0	2	S_1-1			S_1-1			S_1-1		
1	>0	>2	S_1-1			S_1-1			S_1-1		
2	0	2	S_1-1			S_1-1			S_1-1		
2	0	>2	S_1-1			S_1-1			S_1-1		
2	>0	2	S_1-1			S_1-1			S_1-1		
2	>0	>2	S_1-1			S_1-1			S_1-1		

**(a) MV/MV substation**

No. of source feeders	No. of upstream load feeders	No. of down-stream load feeders	Busbar peak load (MVA)											
			6.25	7.5	8.75	12.5	15	17.5	25	30	35	50	60	70
Transformer size:			5 – 10 MVA			10 – 20 MVA			20 – 40 MVA			40-80 MVA		
1	0	2	S_1-1			S_1-1			S_1-1			S_1-1		
1	0	>2	S_1-1			S_1-1			S_1-1			S_1-1		
1	>0	2	S_1-1			S_1-1			S_1-1			S_1-1		
1	>0	>2	S_1-1			S_1-1			S_1-1			S_1-1		
2	0	2	S_1-1			S_1-1			S_1-1			S_1-1		
2	0	>2	S_1-1			S_1-1			S_1-1			S_1-1		
2	>0	2	S_1-1			S_1-1			S_1-1			S_1-1		
2	>0	>2	S_1-1			S_1-1			S_1-1			S_1-1		

**(b) HV/MV substation**

No. of source feeders	No. of upstream load feeders	No. of down-stream load feeders	Busbar peak load (MVA)								
			25	30	35	50	60	70	100	120	140
Transformer size:			20 – 40 MVA			40-80 MVA			80-160 MVA		
1	0	2	S_1-1			S_1-1			S_1-1b		
1	0	>2	S_1-1			S_1-1			S_1-1		
1	>0	2	S_1-1			S_1-1			S_4b-1b		
1	>0	>2	S_1-1			S_1-1			S_4b-1		
2	0	2	S_1-1			S_1-1			S_1-1b		
2	0	>2	S_1-1			S_1-1			S_1-1		
2	>0	2	S_1-1			S_1-1			S_1-1b		
2	>0	>2	S_1-1			S_1-1			S_1-1		

**(c) HV/HV substation**

Figure 9-15: Preferred substation configurations for a COUE rate of R 5/kWh

### 9.3.3. Preferred substation configurations for a COUE rate of R 150/kWh

The preferred substation configurations for a COUE rate of R150/kWh are shown in Figure 9-16.

No. of source feeders	No. of upstream load feeders	No. of down-stream load feeders	Busbar peak load (MVA)								
			6.25	7.5	8.75	12.5	15	17.5	25	30	35
Transformer size:			5 – 10 MVA			10 – 20 MVA			20 – 40 MVA		
1	0	2	F_4b-4b			F_4b-4b			F_4b-4b		
1	0	>2	F_4b-4b			F_4b-4b			F_4b-4b		
1	>0	2	F_5b-4b			F_5b-4b			F_5b-4b		
1	>0	>2	F_5b-4b			F_5b-4b			F_5b-4b		
2	0	2	F_4-4b			F_3-4b			F_3-4b		
2	0	>2	F_4-4b			F_3-4b			F_3-4b		
2	>0	2	F_4b-4b			F_5b-4b			F_5b-4b		
2	>0	>2	F_4b-4b			F_5b-4b			F_5b-4b		

**(a) MV/MV substation**

No. of source feeders	No. of upstream load feeders	No. of down-stream load feeders	Busbar peak load (MVA)											
			6.25	7.5	8.75	12.5	15	17.5	25	30	35	50	60	70
Transformer size:			5 – 10 MVA			10 – 20 MVA			20 – 40 MVA			40-80 MVA		
1	0	2	F_4b-4b			F_4b-4b			F_4b-4b			F_5b-4b		
1	0	>2	F_4b-4b			F_4b-4b			F_4b-4b			F_5b-5b		
1	>0	2	F_5b-4b			F_5b-4b			F_5b-4b			F_5b-4b		
1	>0	>2	F_5b-4b			F_5b-4b			F_5b-4b			F_5b-5b		
2	0	2	F_3-4b			F_3-4b			F_3-4b			F_3-4b		
2	0	>2	F_3-4b			F_3-4b			F_3-4b			F_3-5b		
2	>0	2	F_5b-4b			F_5b-4b			F_5b-4b			F_5b-4b		
2	>0	>2	F_5b-4b			F_5b-4b			F_5b-4b			F_5b-5b		

**(b) HV/MV substation**

No. of source feeders	No. of upstream load feeders	No. of down-stream load feeders	Busbar peak load (MVA)								
			25	30	35	50	60	70	100	120	140
Transformer size:			20 – 40 MVA			40-80 MVA			80-160 MVA		
1	0	2	F_4b-5b			F_5b-5b			F_5b-5b		
1	0	>2	F_4b-5b			F_5b-5b			F_5b-6b		
1	>0	2	F_5b-5b			F_5b-5b			F_5b-5b		
1	>0	>2	F_5b-5b			F_5b-5b			F_5b-6b		
2	0	2	F_3-5b			F_3-5b			F_3-5b		
2	0	>2	F_3-5b			F_3-5b			F_3-6b		
2	>0	2	F_5b-5b			F_5b-5b			F_6b-5b		
2	>0	>2	F_5b-5b			F_5b-5b			F_6b-6b		

**(c) HV/HV substation**

Figure 9-16: Preferred substation configurations for a COUE rate of R 150/kWh

## 9.4. Summary

The following can be concluded regarding the parameters that have the biggest effect on the preferred substation configuration:

- (a) Neither the interruption frequency cost nor the planned interruption cost has a significant effect on the preferred substation configuration.
- (b) The unplanned interruption duration cost, the transformer size and the voltage level have a significant effect on the preferred substation configuration.
- (c) The number of source and load feeders has an effect on the optimal substation configuration, but the results are not as sensitive to these parameters as they are to the voltage level and unplanned interruption duration cost.

Considering the above, the preferred substation configuration is specified considering the following five substation parameters:

- (a) The substation voltage levels;
- (b) The customer unplanned interruption duration cost, in R/kWh;
- (c) The load size, supplied from the downstream busbar;
- (d) Number of source feeders; and
- (e) Number of load feeders supplied from the upstream and downstream busbars.

Therefore the utility planning engineer needs to provide only these five parameters in order to determine which substation configuration is the preferred configuration.

A process of manual clustering was used in this research. After using this manual technique it became clear that a statistical clustering technique can be used to automate the clustering in the Ms Excel Model. This is an area for further research.

## 10. Testing the outcomes of the approach

The following testing was performed to verify the simplified approach used to determine the set of preferred substation configurations that minimize the total life cycle cost:

- (a) Section 10.1: Verify the simplified reliability calculation for all new standard busbar configurations introduced for this study.
- (b) Section 10.2: Verify the simplified customer interruption cost calculation.
- (c) Section 10.3: Test the validity of the results with different upstream busbar loads.

Existing reliability modelling software was used to verify the simplified reliability calculation for the two new busbar configurations (introduced in section 4.5.2) and to verify the simplified customer interruption cost calculation.

Various reliability modelling software packages are available on the market to perform reliability and cost of unserved energy analysis, e.g. PowerFactory, PSS/E, ETAP, SUBREL, NEPLAN, etc. Van der Merwe (2014) used ETAP for the verification of the simplified substation approach.

The same software was used for the verification of the two additional busbar configurations and the simplified customer interruption cost calculation. The student version of the ETAP license allows a maximum of 25 busbars per project. The number of feeders considered in the different test cases was therefore limited by this constraint. This was specifically limiting in the Type 5b – Type 5b and Type 6b – Type 6b substation configurations, where two additional busbars are required per feeder for the bypass configuration. The maximum number of feeders that could be included for a Type 6b – Type 6b substation (with two transformers) was 7 feeders.

The following conventions were applied to the ETAP models:

- (a) The line isolators have zero failure rate, since the failures of these isolators are included in the line calculations and not the substation calculations.
- (b) A response time of 1.5 hours was assumed for all components. This represents the sum of the dispatch time (30 minutes) and travel time (60 minutes) used in the simplified reliability model.
- (c) The failure rates and repair durations are as used in the simplified reliability calculations (see Table 4-2 in section 4.6.1).

- (d) Only the effect of unplanned failures was considered. The planned component was ignored, to simplify the verification.
- (e) There is bus zone protection on all HV and MV busbars.
- (f) A power factor of 1 was assumed.

### **10.1. Verification of the simplified reliability calculation**

The simplified reliability estimation approach was tested by Van der Merwe (2014) for the standard configurations used in her study. As discussed in section 4.5.2, two new standard busbar configurations were introduced for this research. The unavailability results calculated by the simplified approach were tested for these two configurations to ensure that the simplified reliability estimation approach is valid for all substation configurations.

The reliability values obtained using ETAP are shown in the ETAP diagrams in Annex C. The feeder and transformer switching arrangement often makes a difference to the calculated reliability in ETAP. In order to verify the results for different switching arrangements, more than one switching arrangement was tested for some configurations. The ETAP result is then calculated by considering the average of all results obtained from the different switching configurations. All different switching configurations tested are shown in Annex C.

It is evident from the results in Annex C that the simplified approach is a good approximation of the ETAP result. This is due to fact that the simplified approach:

- (a) considers the failure and specific outage duration of each component in the substation;
- (b) differentiates between the impact on customers and outage duration before switching and after switching;

There will however be a larger error between the simplified approach and the ETAP result if the ETAP substation has a different switching arrangement than what is assumed in the simplified approach. For example, if the substation has a single busbar with a bus-section and six load feeders, the simplified approach assumes three feeders are connected to each bus-section. If all six feeders are now connected to the same bus-section in ETAP, the error between the simplified result and the ETAP result will be larger.

### 10.1.1. Busbar Type 5b

The busbar type 5b configuration was tested using an HV/MV substation with firm transformer capacity. Three substation configurations were chosen to verify the simplified calculation for the Type 5b busbar configuration, with configurations as summarised in Table 10-1.

**Table 10-1: Substation configurations used to verify the simplified Type5b busbar calculation**

No	Upstream busbar	Downstream busbar	No of source feeders	No of load feeders (upstream busbar)	No of load feeders (downstream busbar)
1	Type 5b	Type 5b	1	4	2
2	Type 5b	Type 5b	2	4	2
3	Type 5b	Type 5b	2	3	4

The errors between the simplified model and the ETAP simulation are summarised in Table 10-2. A negative error means the frequency/ duration calculated with the simplified approach is lower than the ETAP simulation.

**Table 10-2: Error between simplified reliability and ETAP results for a Type 5b – Type 5b busbar configuration**

No (see Table 10-1)	Percentage difference				ETAP snapshot of the results (See Annex C)
	Upstream busbar		Downstream busbar		
	Load point interruption frequency (occ/a)	Load point interruption duration (h/a)	Load point interruption frequency (occ/a)	Load point interruption duration (h/a)	
1	-5.2%	-1.4%	0%	0%	Figure C-1
2	0%	0%	0%	0%	Figure C-2
3	-2.5%	-2.4%	0%	0%	Figure C-3

It is clear from Table 10-2 that the results obtained with the simplified approach correspond with the results in ETAP and the biggest error between these two approaches is 5.2%.

### 10.1.2. Busbar Type 6b

The busbar type 6b configuration was tested using an HV/MV substation with firm transformation. Three substation configurations were chosen to verify the simplified calculation for the Type 6b busbar configuration, with configurations as summarised in Table 10-3.

**Table 10-3: Substation configurations used to verify the simplified Type6b busbar calculation**

No	Upstream busbar	Downstream busbar	No of source feeders	No of load feeders (upstream busbar)	No of load feeders (downstream busbar)
1	Type 6b	Type 6b	1	2	2
2	Type 6b	Type 6b	2	2	2
3	Type 6b	Type 6b	2	3	4

The errors between the simplified model and the ETAP simulation are summarised in Table 10-4. The results differ depending on whether the load feeders or transformer feeders are connected to the incoming line feeders. Different combinations for the connectivity of the feeders are therefore shown. A negative error means the frequency/ duration calculated with the simplified approach is lower than the ETAP simulation.

**Table 10-4: Error between Simplified reliability and ETAP results for a Type 6b – Type 6b busbar configuration**

No (see Table 10-3)	Percentage difference				ETAP snapshot of the results (See Annex C)
	Upstream busbar		Downstream busbar		
	Load point interruption frequency (occ/a)	Load point interruption duration (h/a)	Load point interruption frequency (occ/a)	Load point interruption duration (h/a)	
1	-4.9%	-4.5%	0.8%	-4.9%	Figure C-4
2	0%	0%	4.7%	4.1%	Figure C-5
3	-1.7%	-1.6%	0%	0%	Figure C-6

It is clear from Table 10-4 that the results obtained with the simplified approach correspond with the results in ETAP and the biggest error between these two approaches is 4.9%.

## 10.2. Verification of the customer interruption cost calculation

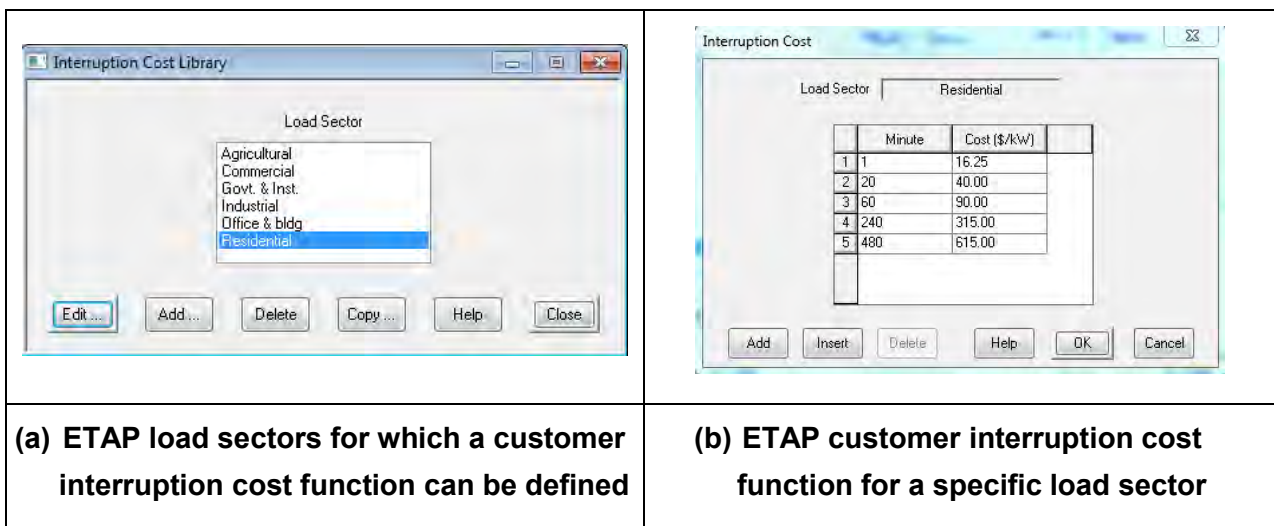
The energy not supplied and customer interruption cost calculation is fairly straight forward if the interruption frequency and interruption duration of each load are known. These formulae were shown in Equation 15 and Equation 26.

The ETAP software can also be used to calculate the energy not supplied and customer interruption cost associated with the expected outage duration per year. ETAP allows a customer interruption cost function to be specified for different load sectors, as shown in Figure 10-1 (a). The cost function is defined by specifying costs for different outage durations, as shown in Figure 10-1 (b). ETAP does not allow a cost to be specified for different interruption frequencies.

For the purpose of testing, all loads were defined as residential loads, and the customer interruption cost “Function 6” in Table 7-4 was used, i.e.

$$COUE \text{ Unplanned} = R15 \times kW \text{ interruptions} + R75 \times \text{Energy not supplied} \quad \text{Equation 28}$$

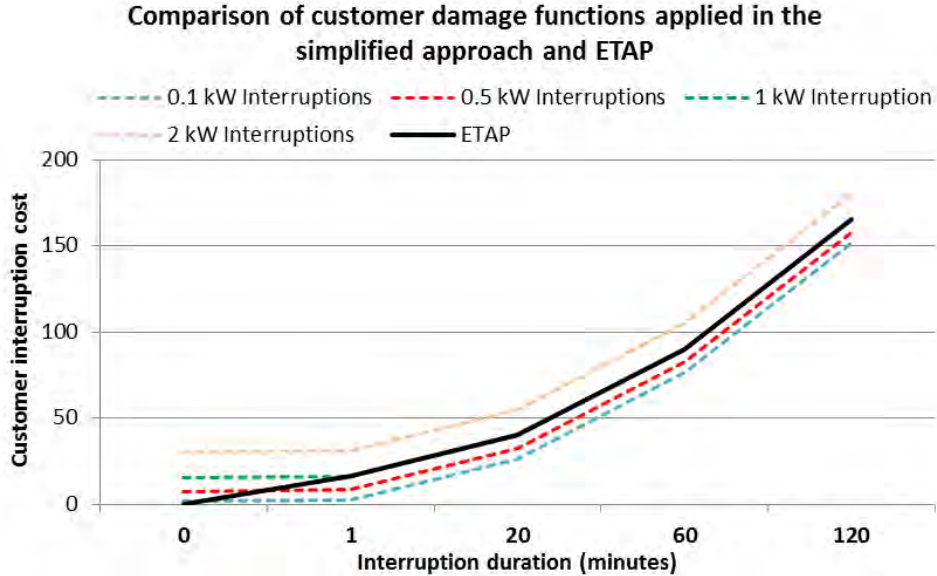
The cost function as specified in ETAP for the purposes of verification is shown in Figure 10-1 (b).



**Figure 10-1: ETAP customer interruption cost input parameters**

Since ETAP does not allow a cost to be specified for different interruption frequencies, the customer damage function applied in the two approaches are not 100% the same for all

interruption frequencies and durations. A comparison of the customer damage function applied in the simplified approach and in ETAP is shown in Figure 10-2. This comparison shows a lower customer interruption cost in ETAP for interruptions more than 1 kW-interruptions per annum, while ETAP has a higher customer interruption cost for interruptions less than 1 kW-interruptions per annum.



**Figure 10-2: Comparison of the customer damage functions applied in the simplified approach and ETAP**

Different busbar configurations were selected for the upstream and downstream busbars, such that each of the 12 standard busbar configurations is tested at least once. The substation configurations used for the testing are listed in Table 10-5.

**Table 10-5: Substation configurations used to verify the customer interruption cost calculation**

No	Upstream busbar	Downstream busbar	No of source feeders	No of load feeders supplied from upstream busbar	No of load feeders supplied from downstream busbar
1	Type 4	Type 1b	2	4	4
2	Type 4b	Type 1	2	4	4
3	Type 5	Type 2	2	4	4

No	Upstream busbar	Downstream busbar	No of source feeders	No of load feeders supplied from upstream busbar	No of load feeders supplied from downstream busbar
4	Type 5b	Type 2	2	4	4
5	Type 6	Type 3b	2	4	4
6	Type 6b	Type 3	2	4	4
7	Type 7	Type 1	2	4	4

The reliability values obtained using ETAP are shown in the ETAP diagrams in Annex D. The errors between the simplified model and the ETAP simulation are summarised in Table 10-6.

**Table 10-6: Error between simplified reliability and ETAP results for energy not supplied and customer interruption cost**

No (see Table 10-5)	Percentage difference							
	Upstream busbar				Downstream busbar			
	Interruption frequency (occ/a)	Interruption duration (h/a)	ENS (MWh/a)	Interruption Cost (R/a)	Interruption frequency (occ/a)	Interruption duration (h/a)	ENS (MWh/a)	Interruption Cost (R/a)
1	0%	0%	0%	-0.4%	0%	0%	0%	-1.5%
2	0%	0.7%	0.7%	-1.1%	0%	0%	0%	-1.5%
3	0%	0%	0%	-0.3%	0%	0%	0%	-1.0%
4	0%	0%	0%	-1.7%	0%	0%	0%	-1.0%
5	0%	0%	0%	-0.2%	0%	0.1%	0%	-0.6%
6	0%	0%	0%	-1.7%	0%	0%	0%	-0.4%
7	0%	0%	0%	-1.0%	0%	0%	0%	-0.5%

The ENS for each of the different substation configurations matches the ENS as calculated in ETAP, but there are differences in the interruption costs. This error is due to the difference in customer damage functions applied, as shown in Figure 10-2, and not shortcomings in the simplified approach. The biggest error between the ETAP and simplified interruption cost

calculation was 1.5%, which is deemed acceptable since it is within the same range of accuracy of estimates of the common substation costs.

### 10.3. Validity of the results when changing the load supplied from the upstream busbar

The preferred substation configurations shown in section 9.3 are for substations of which the load on the upstream busbar is equal to the load on the downstream busbar. The load on the upstream busbar can however be less or even more than the load supplied from the downstream busbar. The following scenarios were tested to determine how the preferred set of configurations will change if the load on the upstream busbar is different from the load on the downstream busbar:

- (a) The load supplied from the upstream busbar is 50% less than the load supplied from the downstream busbar.
- (b) The load supplied from the upstream busbar is 50% more than the load supplied from the downstream busbar.

The analysis took just less than 18 hours to complete for all 3 voltage levels and all 18 customer damage functions. The results for all design criteria of an HV/MV substation, considering a customer interruption duration cost of R75/kWh, are shown in Figure 10-3.

COUE=R75															
No. of source feeders	No. of upstream load feeders	No. of downstream load feeders	Busbar peak load (MVA)												
			6.25	7.5	8.75	12.5	15	17.5	25	30	35	50	60	70	
Transformer size:			5 – 10 MVA				10 – 20 MVA			20 – 40 MVA			40-80 MVA		
1	0	2	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_5b-4b	F_5b-4b
1	0	4	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-5b	F_5b-5b	F_5b-5b
1	0	6	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-5b	F_5b-5b	F_5b-5b
1	0	8	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-5b	F_4b-5b	F_4b-5b	F_5b-5b	F_5b-5b
1	2	2	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b
1	2	4	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-5b	F_5b-5b	F_5b-5b
1	2	6	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-5b	F_5b-5b	F_5b-5b
1	2	8	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b
1	4	2	F_4b-4b	F_4b-4b	F_4b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b
1	4	4	F_4b-4b	F_4b-4b	F_4b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-5b	F_5b-5b	F_5b-5b
1	4	6	F_4b-4b	F_4b-4b	F_4b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-5b	F_5b-5b	F_5b-5b
1	4	8	F_4b-4b	F_4b-4b	F_4b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b
2	0	2	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b
2	0	4	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-5b	F_3-5b	F_3-5b
2	0	6	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-5b	F_3-5b	F_3-5b
2	0	8	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-5b	F_3-5b	F_3-5b	F_3-5b	F_3-5b
2	2	2	F_4b-4b	F_4b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b
2	2	4	F_4b-4b	F_4b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-5b	F_5b-5b	F_5b-5b
2	2	6	F_4b-4b	F_4b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-5b	F_5b-5b	F_5b-5b
2	2	8	F_4b-4b	F_4b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b
2	4	2	F_3-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b
2	4	4	F_3-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b
2	4	6	F_3-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b
2	4	8	F_3-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b

**(a) Upstream busbar load = 50% downstream busbar load**



function. It can therefore be concluded that the load supplied from the primary busbar does not have a significant effect on the preferred substation configuration.

However, it should be noted that whether there is load supplied from the upstream busbar or not does affect the optimal substation configuration. This is clear from Figure 10-3 where the optimal substation configurations for the scenario with no load supplied from the upstream busbar are very different from the scenarios where there are two or four loads supplied from the upstream busbar.

### 10.4. Effect of changing the utility cost

The effect of the utility cost on the preferred substation configurations were tested by doubling the utility cost. For example, if a specific substation configuration has an indexed utility cost of 5 and an indexed customer interruption cost of 3, the total indexed cost is 8. For this exercise the utility cost was doubled, i.e. changed to 10, hence the total indexed cost is now 13. The analysis took just less than 9 hours to complete for all 3 voltage levels and all 18 customer damage functions. The results for all design criteria of an HV/MV substation, considering a customer interruption duration cost of R75/kWh, are shown in Figure 10-4. Also shown in Figure 10-4 are the results when:

(b) Doubling the utility cost

(c) Reducing the COUE by 50%, i.e. from R75/kWh to R37.50/kWh

COUE = R75			Planned = 0.6												
No. of source feeders	No. of upstream load feeders	No. of down-stream load feeders	Busbar peak load (MVA)												
			6.25	7.5	8.75	12.5	15	17.5	25	30	35	50	60	70	
Transformer size:			5 – 10 MVA			10 – 20 MVA			20 – 40 MVA			40-80 MVA			
1	0	2	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b
1	0	4	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b
1	0	6	F_4b-1	F_4b-1	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b
1	0	8	F_4b-1	F_4b-1	F_4b-1	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-5b
1	2	2	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b
1	2	4	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b
1	2	6	F_4b-1	F_4b-1	F_4b-4b	F_4b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b
1	2	8	F_4b-1	F_4b-1	F_4b-1	F_4b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-5b
1	4	2	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b
1	4	4	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b
1	4	6	F_4b-1	F_4b-1	F_4b-4b	F_4b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b
1	4	8	F_4b-1	F_4b-1	F_4b-1	F_4b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-5b
2	0	2	F_1-1	F_1-1	F_4-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b
2	0	4	F_1-1	F_1-1	F_1-1	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b
2	0	6	F_1-1	F_1-1	F_1-1	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b
2	0	8	F_1-1	F_1-1	F_1-1	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-5b
2	2	2	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b
2	2	4	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b
2	2	6	F_4b-1	F_4b-1	F_4b-4b	F_4b-4b	F_4b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b
2	2	8	F_4b-1	F_4b-1	F_4b-1	F_4b-4b	F_4b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-5b
2	4	2	F_3-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b
2	4	4	F_1-1	F_4b-4b	F_4b-4b	F_4b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b
2	4	6	F_1-1	F_4b-1	F_4b-4b	F_4b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b
2	4	8	F_1-1	F_4b-1	F_4b-1	F_4b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-5b

**(a) Base utility cost**

COUE = R75			Frequency = 1			Planned = 0.6			Busbar peak load (MVA)												
No. of source feeders	No. of upstream load feeders	No. of down-stream load feeders	Busbar peak load (MVA)																		
			6.25	7.5	8.75	12.5	15	17.5	25	30	35	50	60	70							
Transformer size:			5 – 10 MVA			10 – 20 MVA			20 – 40 MVA			40-80 MVA									
1	0	2	S_1-1	S_1-1	F_1-1	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b					
1	0	4	S_1-1	S_1-1	F_1-1	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b					
1	0	6	S_1-1	S_1-1	F_1-1	F_4b-1	F_4b-1	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b					
1	0	8	S_1-1	S_1-1	F_1-1	F_4b-1	F_4b-1	F_4b-1	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b					
1	2	2	S_4b-1	S_4b-1	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b					
1	2	4	S_4b-1	S_4b-1	F_4b-1	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b					
1	2	6	S_4b-1	S_4b-1	F_4b-1	F_4b-1	F_4b-1	F_4b-4b	F_4b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b					
1	2	8	S_4b-1	S_4b-1	F_4b-1	F_4b-1	F_4b-1	F_4b-1	F_4b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b					
1	4	2	S_1-1	F_1-1	F_1-1	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b					
1	4	4	S_1-1	F_1-1	F_1-1	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b					
1	4	6	S_1-1	F_1-1	F_1-1	F_4b-1	F_4b-1	F_4b-4b	F_4b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b					
1	4	8	S_1-1	F_1-1	F_1-1	F_4b-1	F_4b-1	F_4b-1	F_4b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b					
2	0	2	S_1-1	F_1-1	F_1-1	F_1-1	F_1-1	F_4-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b					
2	0	4	S_1-1	F_1-1	F_1-1	F_1-1	F_1-1	F_1-1	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b					
2	0	6	S_1-1	F_1-1	F_1-1	F_1-1	F_1-1	F_1-1	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b					
2	0	8	S_1-1	F_1-1	F_1-1	F_1-1	F_1-1	F_1-1	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b					
2	2	2	S_1-1	F_1-1	F_1-1	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b					
2	2	4	S_1-1	F_1-1	F_1-1	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b					
2	2	6	S_1-1	F_1-1	F_1-1	F_4b-1	F_4b-1	F_4b-4b	F_4b-4b	F_4b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b					
2	2	8	S_1-1	F_1-1	F_1-1	F_4b-1	F_4b-1	F_4b-1	F_4b-4b	F_4b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b					
2	4	2	S_1-1	F_1-1	F_1-1	F_3-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b					
2	4	4	S_1-1	F_1-1	F_1-1	F_1-1	F_4b-4b	F_4b-4b	F_4b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b					
2	4	6	S_1-1	F_1-1	F_1-1	F_1-1	F_4b-1	F_4b-1	F_4b-4b	F_4b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b					
2	4	8	S_1-1	F_1-1	F_1-1	F_1-1	F_4b-1	F_4b-1	F_4b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b					

**(b) Utility cost x 2**

COUE = R38			Frequency = 1			Planned = 0.6			Busbar peak load (MVA)												
No. of source feeders	No. of upstream load feeders	No. of down-stream load feeders	Busbar peak load (MVA)																		
			6.25	7.5	8.75	12.5	15	17.5	25	30	35	50	60	70							
Transformer size:			5 – 10 MVA			10 – 20 MVA			20 – 40 MVA			40-80 MVA									
1	0	2	S_1-1	S_1-1	F_1-1	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b					
1	0	4	S_1-1	S_1-1	F_1-1	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b					
1	0	6	S_1-1	S_1-1	F_1-1	F_4b-1	F_4b-1	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b					
1	0	8	S_1-1	S_1-1	F_1-1	F_4b-1	F_4b-1	F_4b-1	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b					
1	2	2	S_4b-1	S_4b-1	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b					
1	2	4	S_4b-1	S_4b-1	F_4b-1	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b					
1	2	6	S_4b-1	S_4b-1	F_4b-1	F_4b-1	F_4b-1	F_4b-4b	F_4b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b					
1	2	8	S_4b-1	S_4b-1	F_4b-1	F_4b-1	F_4b-1	F_4b-1	F_4b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b					
1	4	2	S_1-1	F_1-1	F_1-1	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b					
1	4	4	S_1-1	F_1-1	F_1-1	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b					
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1	4	8	S_1-1	F_1-1	F_1-1	F_4b-1	F_4b-1	F_4b-1	F_4b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b					
2	0	2	S_1-1	F_1-1	F_1-1	F_1-1	F_1-1	F_4-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b					
2	0	4	S_1-1	F_1-1	F_1-1	F_1-1	F_1-1	F_1-1	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b					
2	0	6	S_1-1	F_1-1	F_1-1	F_1-1	F_1-1	F_1-1	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b					
2	0	8	S_1-1	F_1-1	F_1-1	F_1-1	F_1-1	F_1-1	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b					
2	2	2	S_1-1	F_1-1	F_1-1	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b					
2	2	4	S_1-1	F_1-1	F_1-1	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b					
2	2	6	S_1-1	F_1-1	F_1-1	F_4b-1	F_4b-1	F_4b-4b	F_4b-4b	F_4b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b					
2	2	8	S_1-1	F_1-1	F_1-1	F_4b-1	F_4b-1	F_4b-1	F_4b-4b	F_4b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b					
2	4	2	S_1-1	F_1-1	F_1-1	F_3-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b					
2	4	4	S_1-1	F_1-1	F_1-1	F_1-1	F_4b-4b	F_4b-4b	F_4b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b					
2	4	6	S_1-1	F_1-1	F_1-1	F_1-1	F_4b-1	F_4b-1	F_4b-4b	F_4b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b					
2	4	8	S_1-1	F_1-1	F_1-1	F_1-1	F_4b-1	F_4b-1	F_4b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b					

**(c) COUE x 50%**

**Figure 10-4: Preferred substation configurations when changing the utility cost**

It is clear from Figure 10-4 that changing the utility cost has the same impact as changing the customer interruption cost, i.e. doubling the utility cost yields the same result as reducing COUE by 50%. The outcome is therefore just as sensitive to utility cost as it is to COUE. It

should however be noted that the possible range of values for utility cost is not as wide as the range for COUE. This research considers a range of COUE values from R5/kWh to R150/kWh, which means the highest COUE value is 30 times the lowest COUE value. The utility cost, however, could possibly be twice or maybe three times as much as the assumed values, but never 30 times higher. The lowest and highest possible utility cost values will therefore produce similar preferred configurations, while changing the COUE value will produce options that vary from single busbar, single transformer substations to double busbar, double transformer substations.

## **10.5. Summary**

The simplified reliability estimation for the two new busbar configurations introduced for this research was validated using ETAP. The biggest error between the ETAP and simplified results was 5.2%.

The simplified interruption cost calculation was validated using ETAP. The biggest error between the ETAP and simplified results was 1.5% for a sample of configurations, which is due to the difference in customer damage functions applied and not shortcomings in the simplified approach.

This section also tested the validity of the results when changing the load supplied from the upstream busbar. It was found that the load supplied from the primary busbar does not have a significant effect on the preferred substation configuration.

Lastly, the effect of changing the utility cost was tested by increasing the utility cost by 100%. It was found that changing the utility cost has the same effect as an inverse change in the COUE rate.

## 11. Discussion and conclusions

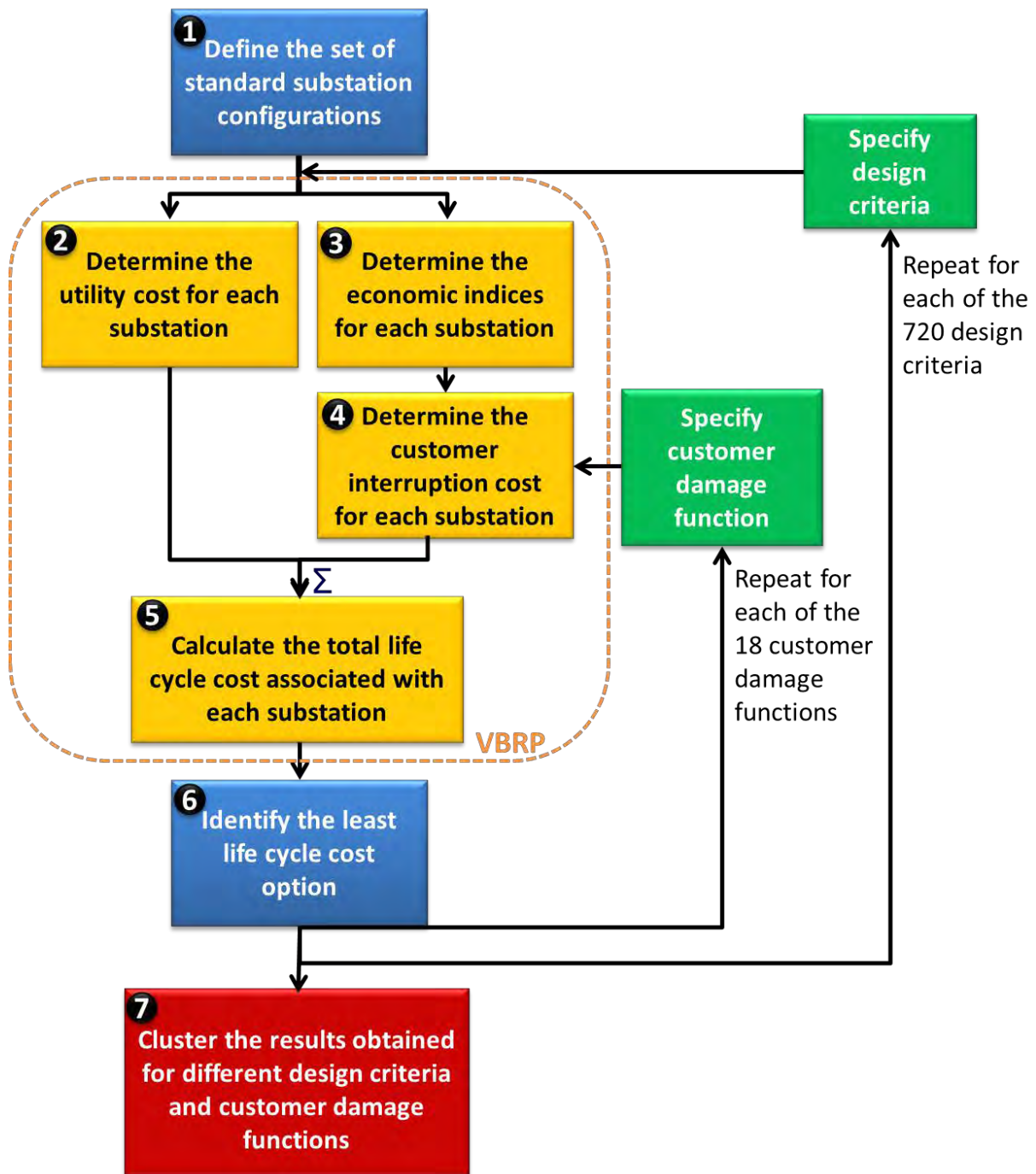
This research developed an analytical simplified substation life cycle costing approach, based on the VBRP approach. This simplified approach is capable of informing the preferred set of substation configurations for a given set of input assumptions. It can further be used to indicate the effect on the preferred substation configurations when specific input assumptions are changed, such as equipment failure rates or substation costs.

A simplified analytical approach is considered which uses deterministic reliability assessment to determine the load-based and economic performance indicators for different substation layouts. This analytical approach builds onto the simplified reliability estimation approach developed by Van der Merwe (2014). The outcome of this approach is the customer interruption cost over the life of the substation.

A cost estimation tool was developed to determine the utility cost for the various substation configurations. The purpose of this tool is to prepare preliminary estimates of substation life cycle costs during the planning stage, based on conceptual design information. The outcome of this cost estimation tool is the utility cost over the life of the substation.

The approach used, for both the utility and customer costs, simplifies the detail of each substation by grouping the components into sub-systems and only considers the sub-systems in the cost and reliability calculations. This modular approach therefore doesn't ignore any components, but groups them together in order to minimise the user inputs and simplify the calculations. This reduces the number of components considered in the calculation significantly. The result will therefore be less accurate than for a detailed model, but due to the composite models considered, the errors are not one-sided.

The approach was programmed into an MS Excel model and used to determine the set of preferred substation configurations by comparing 432 different substation configurations for 720 different design criteria and 18 different customer damage functions. This approach is shown in Figure 11-1. The model requires less than 30 minutes to compare the life cycle cost of 432 substations for 720 different design criteria, given a specific customer damage function.



**Figure 11-1: Approach to determining the preferred set of substation configurations for all design criteria and customer damage functions, including the clustering of the results**

The different design criteria selected for the analysis (i.e. number of load feeders and load sizes) were selected such that they represent a reasonable sample of the most likely design

criteria for distribution networks. Regular points within the most likely range were selected to ensure that the outcomes are not one-sided as a result of the input parameters selected. The approach is therefore statistically likely to give good results.

Although there is a high level of complexity involved in the simplified approach, this complexity is programmed into analytical software once, and the utility engineer only needs to enter the different substation configurations that need to be compared and the assumptions such as failure models, substation cost assumptions, load factor, customer interruption cost, etc. The approach is repeatable and can be updated with relatively little effort as the network evolves and input parameters or assumptions, such as expected failure rates, protection philosophies, and costs, change.

The results presented in this research only give the preferred set of substation configurations, but does not refer to the preferred switching station layouts. The different configurations that need to be compared are inputs into the approach and can therefore be changed by the user. As a result, the same approach and model can be used to determine the set of preferred switching station layouts. Similarly, the same approach and model can be used to determine the preferred configuration of substations with more than two voltage levels, e.g. 132/66/22 kV substations.

The same approach of using sub-systems in the VBRP approach can be used to determine the preferred set of line configurations. This will require the standard set of line configurations to be identified, as well as additional assumptions for parameters such as line outage durations and maintenance durations.

The section below provides answers to the specific research questions identified at the start of the research.

### **11.1. Answers to specific research questions**

The first two research questions were already answered by the literature review and these answers are provided in section 2.13

- (a) What are the benefits of a more reliable substation configuration?
- (b) What is an acceptable target for substation reliability?

The research questions answered through this research are discussed below.

### **What criteria need to be considered when determining the optimal substation configuration?**

This question was partly answered by the literature review (see section 2.13) which highlighted the following to be considered when determining the optimal substation configuration:

- (a) The cost to the utility, which consists of the capital cost and O&M cost. Other utility costs, such as loss in revenue due to unsupplied loads, are small compared to the other costs and can therefore be ignored.
- (b) The interruption cost to the customers, which is influenced by the customer type (i.e. industrial, commercial, residential, etc.), load interrupted, duration of the interruptions and whether advance warning was given.

The literature did not provide answers on which substation parameters have the biggest influence on the utility and customer costs. In section 9.4 the following was concluded regarding the parameters that have the biggest influence on the preferred substation configuration:

- (a) The customer unplanned interruption duration cost, in R/kWh;
- (b) The substation voltage levels;
- (c) The load size, supplied from the downstream busbar;
- (d) Number of source feeders; and
- (e) Number of load feeders supplied from the upstream and downstream busbars.

The following parameters do not have a significant effect and can be ignored:

- (a) The customer planned interruption cost; and
- (b) The customer unplanned interruption frequency cost (R/kWh occ).

### **Can a set of preferred substation layouts be defined for a given set of failure rates and equipment cost?**

The results in section 9 show that a set of preferred substation layouts can be identified. This preferred set of configurations is dependent on the input parameters, such as failure rates and equipment costs. If the input parameters change, the preferred substation configurations could change and/or the point (i.e. COUE rate) at which one substation is preferred above another could change.

The number of substations in the set is also influenced by the extent of clustering that is done. The number of substations can be minimised by doing more clustering of the results.

In section 4.5.2 two additional standard busbar configurations, i.e. busbars 5b and 6b, were introduced for this research to determine whether these more expensive substations can be cost justified, and if so under what conditions (e.g. load size, customer type, etc.). From section 9.3, the type 5b busbar configuration is cost justified under the conditions shown in Figure 11-2 (for MV busbars) and Figure 11-3 (for HV busbars).

## Type 5b

### Upstream MV busbar

- |  |           |  |           |   |
|--|-----------|--|-----------|---|
| <ul style="list-style-type: none"> <li><input checked="" type="checkbox"/> COUE &gt; R75/kWh, and</li> <li><input checked="" type="checkbox"/> Load &gt; 20 MVA, and</li> <li><input checked="" type="checkbox"/> No. upstream load feeders &gt; 0, and</li> <li><input checked="" type="checkbox"/> No. source feeders = 1</li> </ul> | <b>OR</b> | <ul style="list-style-type: none"> <li><input checked="" type="checkbox"/> COUE &gt; R150/kWh, and</li> <li><input checked="" type="checkbox"/> No. upstream load feeders &gt; 0, and</li> <li><input checked="" type="checkbox"/> No. source feeders = 1</li> </ul> | <b>OR</b> | <ul style="list-style-type: none"> <li><input checked="" type="checkbox"/> COUE &gt; R150/kWh, and</li> <li><input checked="" type="checkbox"/> Load &gt; 10 MVA, and</li> <li><input checked="" type="checkbox"/> No. upstream load feeders &gt; 0, and</li> </ul> |
|--|-----------|--|-----------|---|
- 

### Downstream MV busbar

- COUE > R150/kWh, and
- Load > 40 MVA, and
- No. downstream load feeders > 2

**Figure 11-2: Conditions to justify a Type 5b MV busbar**

## Type 5b

### Upstream HV busbar

- |  |           |   |           |   |
|--|-----------|---|-----------|---|
| <ul style="list-style-type: none"> <li><input checked="" type="checkbox"/> COUE ≥ R75/kWh, and</li> <li><input checked="" type="checkbox"/> Load &gt; 20 MVA, and</li> <li><input checked="" type="checkbox"/> No. upstream load feeders &gt; 0</li> </ul> | <b>OR</b> | <ul style="list-style-type: none"> <li><input checked="" type="checkbox"/> COUE ≥ R150/kWh, and</li> <li><input checked="" type="checkbox"/> No. upstream load feeders &gt; 0, and</li> </ul> | <b>OR</b> | <ul style="list-style-type: none"> <li><input checked="" type="checkbox"/> COUE ≥ R150/kWh, and</li> <li><input checked="" type="checkbox"/> Load &gt; 40 MVA, and</li> <li><input checked="" type="checkbox"/> No. source feeders = 1</li> </ul> |
|--|-----------|---|-----------|---|
- 

### Downstream HV busbar

- |  |           |   |           |   |
|--|-----------|---|-----------|---|
| <ul style="list-style-type: none"> <li><input checked="" type="checkbox"/> COUE ≥ R75/kWh, and</li> <li><input checked="" type="checkbox"/> Load &gt; 40 MVA, and</li> <li><input checked="" type="checkbox"/> No. downstream load feeders &gt; 2</li> </ul> | <b>OR</b> | <ul style="list-style-type: none"> <li><input checked="" type="checkbox"/> COUE ≥ R75/kWh, and</li> <li><input checked="" type="checkbox"/> Load &gt; 80 MVA</li> </ul> | <b>OR</b> | <ul style="list-style-type: none"> <li><input checked="" type="checkbox"/> COUE ≥ R150/kWh</li> </ul> |
|--|-----------|---|-----------|---|

**Figure 11-3: Conditions to justify a Type 5b HV busbar**

The type 6b busbar configuration is cost justified if all conditions in Figure 11-4 are satisfied.

## **Type 6b**

<u>Upstream busbar</u>	<u>Downstream busbar</u>
<input checked="" type="checkbox"/> COUE $\geq$ R150/kWh, and	<input checked="" type="checkbox"/> COUE $\geq$ R150/kWh, and
<input checked="" type="checkbox"/> Load $>$ 80 MVA, and	<input checked="" type="checkbox"/> Load $>$ 80 MVA, and
<input checked="" type="checkbox"/> No. upstream load feeders $>$ 0, and	<input checked="" type="checkbox"/> No. downstream load feeders $>$ 2
<input checked="" type="checkbox"/> No. source feeders $>$ 1	

**Figure 11-4: Conditions to justify a Type 6b busbar**

### **For which parameters are the preferred substation layouts most sensitive?**

In section 9 it was highlighted that the customer interruption cost is one of the most important parameters when determining the preferred substation layout. This is aligned with the literature research in section 2.9 where it was mentioned that the VBRP is only as good as the customer interruption cost estimates that serve as a primary input into the analysis (Schellenberg et al. 2014).

This is particularly problematic in South Africa, where no standard set of COUE rates exists (refer to section 2.9.2). It is therefore essential that a set of COUE rates is defined for the different customer sectors in order to enable the use of the VBRP approach in the planning of the distribution and transmission networks.

Other parameters for which the preferred layout is sensitive are:

- (a) Utility cost
- (b) Voltage level
- (c) Load size

The preferred layout also changes depending on the number of source and load feeders, but it is less sensitive for this parameter compared to the parameters listed above.

## 11.2. Conclusions

The approach developed through this research can be used to calculate the preferred set of substation configurations using a utility's specific assumptions for parameters such as failure rates, customer damage functions, etc. The approach was programmed into MS Excel and requires less than 30 minutes to compare the life cycle cost of 432 substations for 720 different design criteria, given a specific customer damage function.

This process only needs to be repeated when the underlying assumptions change. The outcomes of this approach provides power system network planners with a consistent framework to select the preferred substation configuration, with much less effort compared with that required to construct detailed network models using specialised power system reliability modelling software.

Considering the specific assumptions used in this research for parameters such as failure rates, outage durations, etc., the preferred substation configurations can be summarised as shown in Figure 11-5.

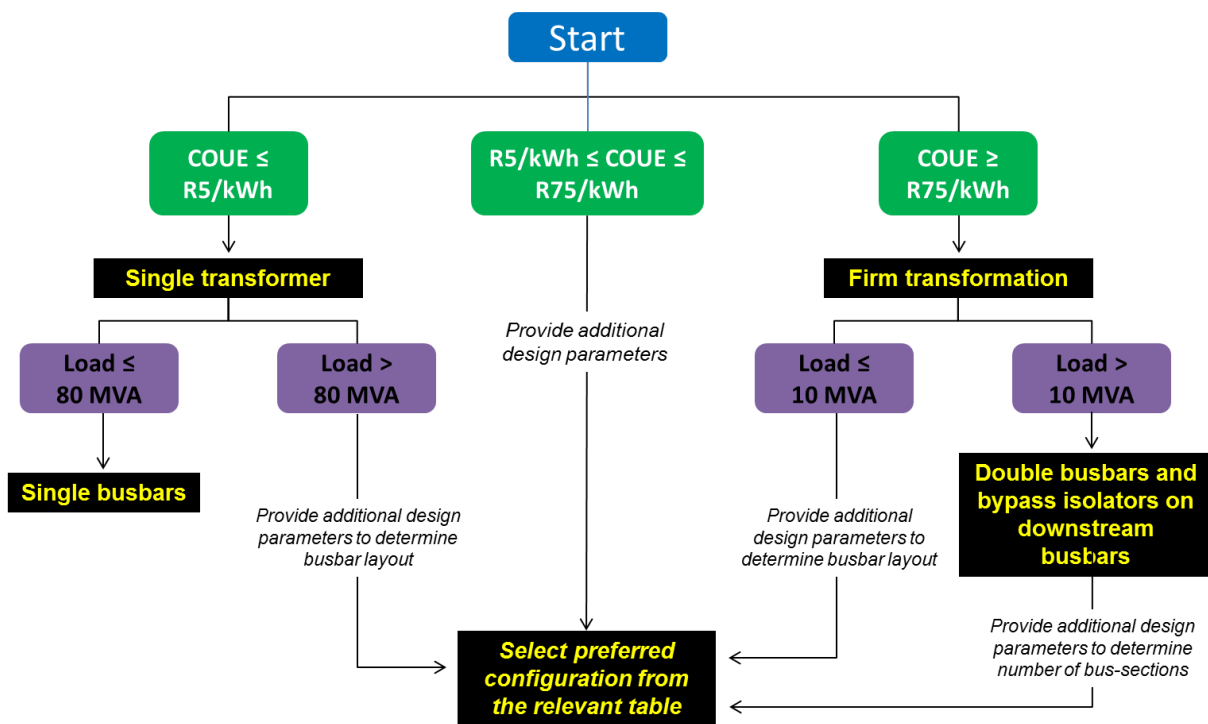


Figure 11-5: High level summary of the preferred substation configurations

The research has shown that the preferred substation configurations are extremely sensitive to the customer damage function. This highlights the importance of using accurate customer

interruption costs during the planning process, which must be a matter of concern in South Africa, where no standard set of customer interruption costs exists.

### **11.3. Research innovations**

The following was achieved through this research:

- (a) This research builds on the simplified reliability estimation approach developed by Van der Merwe (2014) by adding the customer cost associated with outages.
- (b) A cost estimation tool was developed. This tool is capable of preparing preliminary estimates of the utility life cycle costs of each substation during the planning stage, based on conceptual design information. The approach used simplifies the detail of each substation by grouping the components into sub-systems and only considers the sub-systems in the cost calculations. This modular approach minimises the user inputs without ignoring any components. This reduces significantly the number of components considered in the calculation.
- (c) The outcome of the approach is the preferred set of substation configurations. The inputs identified 432 possible configurations for 720 different design criteria and the approach reduced this to 17 preferred configurations, each to be used for different design parameters.
- (d) The research developed the robustness of the decision making.
- (e) A large problem has been reduced to workable dimensions, not only in running time but especially for the collection and input of data.

The following areas could be improved by further research:

- (a) The type of switchgear, i.e. indoor vs. outdoor, could be included in the decision-making process. This can also be extended to other components, such as GIS vs. AIS, or any other variations that may characterise a particular utility.
- (b) The optimal source line configuration could be included in the decision-making process, i.e. one vs. two source feeders and/or loop-in-loop-out vs. T-lines. This will guide the utility planner whether a second line or a loop-in-loop-out configuration can be cost-justified.
- (c) The input data could be changed to determine the preferred switching stations for utilities characterised by switching stations..

- (d) A full probabilistic approach could be investigated if useable data becomes available.
- (e) The research has shown that the preferred substation configurations are extremely sensitive to the customer damage function. Accurate customer damage functions are a broad area for further research.
- (f) This research has shown that single transformer substations has the lowest life cycle cost for customers with a COUE of R5/kWh, while firm transformation has the lowest life cycle cost for customers with a COUE of R75/kWh. The COUE cross-over point from single transformer substations to substations with firm transformation has however not been identified by this research. This represents an area for further research.
- (g) The process of clustering can be simplified by implementing a process of statistical clustering in the Ms Excel Model.

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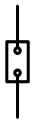

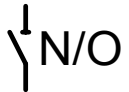
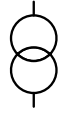
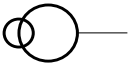





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## Annex A      Electric symbol definition

The following symbols are used in this document:

No	Symbol	Description
1		Non-metalclad breaker
2		Isolator
3		Normally open isolator
4		Substation transformer
5		NECR/T
6		Surge arrestor
7		Voltage transformer
8		Current Transformer
9		Source
10		Load

## Annex B      Standard busbar configurations

The different busbar configurations, with descriptions and simplified single line diagrams, of all the busbar types considered by Van der Merwe (2014) are shown below. These diagrams do not represent the station electric diagrams, but are single line diagrams which indicate the electrical connectivity. Isolators with N/O indicated next to them are operated normally open. All other isolators are operated normally closed. All symbol definitions are provided in Annex A.

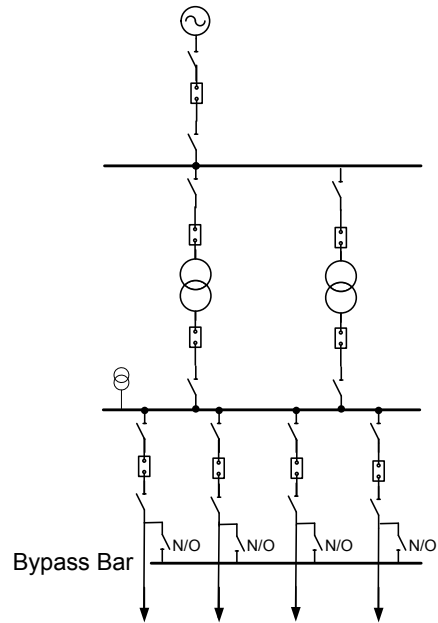
Description of busbar configuration	Single line diagram
<p><b>Type 1 (Single busbar):</b> A single busbar, without bus-sections or bus-couplers</p>	
<p><b>(a) Type 1 busbar configuration</b></p>	

**Type 1b (Single busbar with bypass):** A bypass busbar, also referred to as a hospital bar, is often used to improve the reliability of supply. A single busbar with a hospital bar is shown on the downstream busbar of the substation. The bypass configuration only applies to non-metalclad switchgear.

With this configuration, all objects (feeders and transformers) are connected to one busbar. If the feeder breaker needs to be taken out-of-service, due to a planned or unplanned outage, the following changes are made in order to maintain supply:

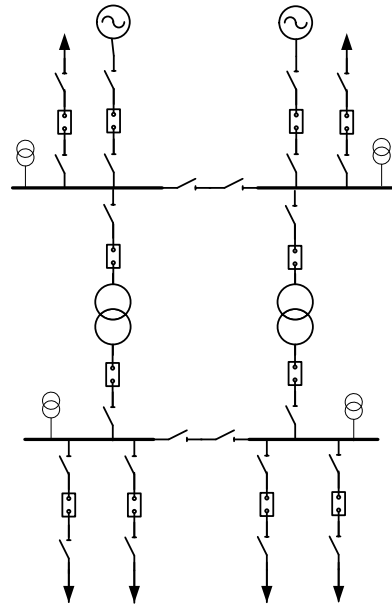
- a) The feeder of which the breaker needs to be taken out-of-service is connected to the hospital bar.
- b) The isolators on both sides of the feeder breaker are opened in order to take the breaker out-of-service for repair/maintenance.
- c) One of the other feeders is switched to both busbars in order to supply the hospital bar.

A hospital bar therefore minimises the interruption duration due to outage(s) of the feeder breaker(s).



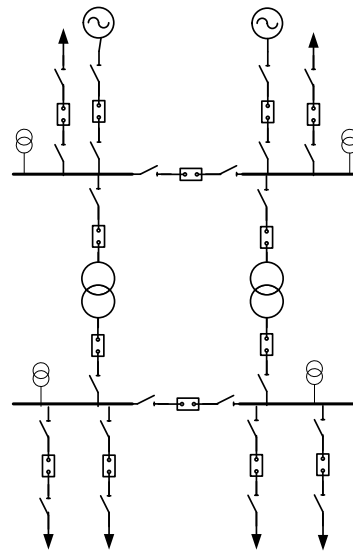
**(b) Type 1b busbar configuration (illustrated on the downstream side only)**

**Type 2 (Single busbar with 2 x isolator bus-section):** A single busbar, with a bus-section. The bus-section consists of two isolators and no breaker.



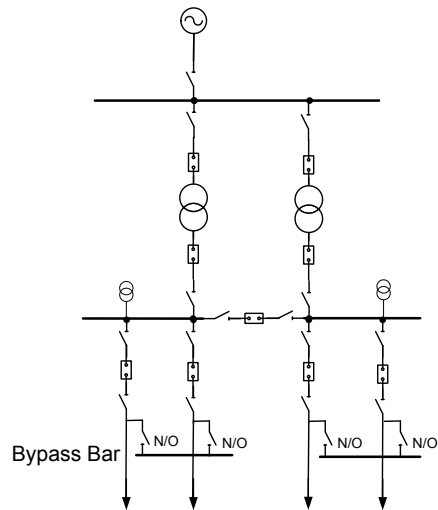
**(c) Type 2 busbar configuration**

**Type 3 (Single busbar with bus-section breaker):** A single busbar, with a bus-section. The bus-section consists of two isolators and a breaker.



**(d) Type 3 busbar configuration**

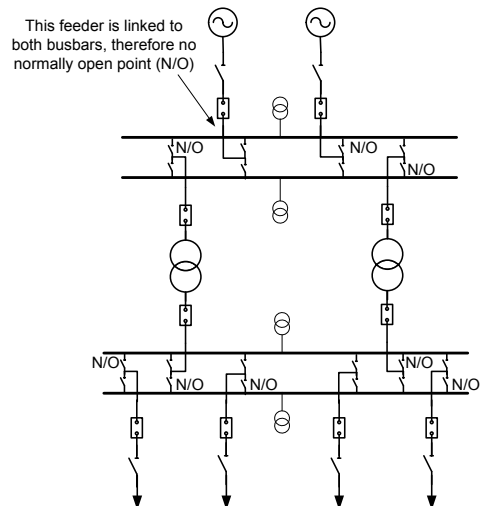
**Type 3b (Single busbar with bus-section breaker and bypass busbar):** A bypass busbar can be added to a Type 3 busbar configuration. Similar to the type 1 with bypass busbar configuration, this bypass busbar has the benefit that supply can be maintained if a feeder breaker is taken out-of-service. The layout of Type 3 with a bypass busbar configuration is shown for the downstream busbar.



**(e) Type 3b busbar configuration (illustrated on downstream side only)**

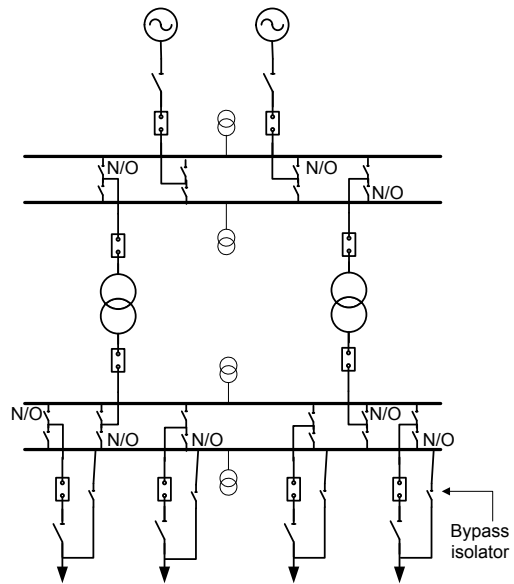
**Type 4 (Double busbar):** A double busbar, without a bus-coupler.

All feeders and transformers have two busbar isolators, one connected to each busbar. One of the two busbar isolators of each feeder/transformer is operated normally open (N/O). One of the feeders is linked to both busbars, in order to link the two busbars. There is no bus-coupler.



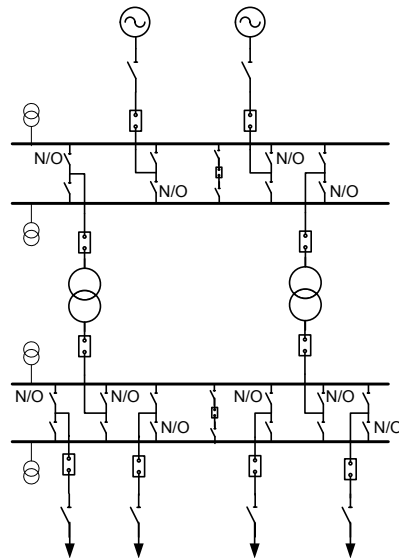
**(f) Type 4 busbar configuration**

**Type 4b (Double busbar with bypass isolator):** A bypass isolator can be added to the feeder bays of a type 4 configuration.



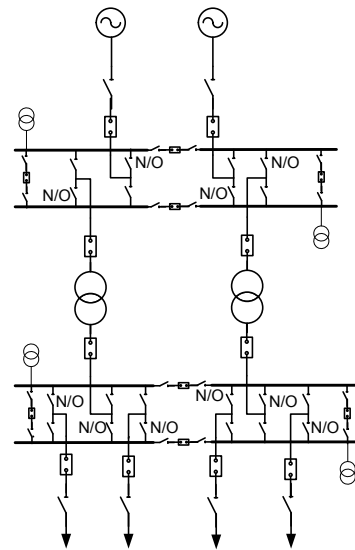
**(g) Type 4b busbar configuration (illustrated on downstream side only)**

**Type 5 (Double busbar with bus-coupler):** A double busbar, with a bus-coupler. All feeders and transformers have isolators connected to each busbar. One busbar isolator of each feeder and transformer is operated normally open. The bus-coupler breaker and isolators are operated normally closed.



**(h) Type 5 busbar configuration**

**Type 6 (Double busbar with bus-couplers and bus-sections):** A double busbar, with two bus-couplers and two bus-sections. All feeders and transformers have isolators connected to each busbar. One busbar isolator of each feeder and transformer is operated normally open.

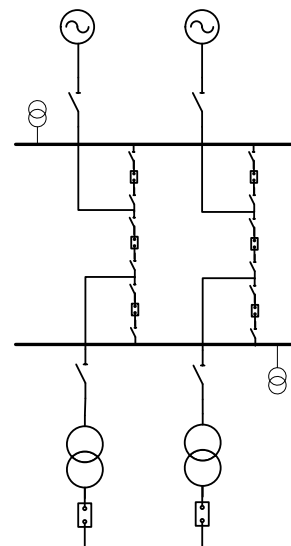


**(i) Type 6 busbar configuration**

**Type 7 (Breaker and a half configuration):** This configuration has double busbars and for every two feeders, one spare breaker is provided. Two feeders are fed from two different buses through their associated breakers and these two feeders are coupled by a third breaker which is called the tie breaker. Normally all the three breakers are closed.

During failure of any feeder breaker, the power is fed through the breaker of the second feeder and tie breaker, therefore each feeder breaker has to be rated to feed both the feeders.

The breaker and a half configuration is shown for an upstream busbar.



**(j) Type 7 busbar configuration (breaker and a half)**

**Figure B-1: Busbar configurations (Van der Merwe, 2014)**

## Annex C      Verification of simplified reliability results

This section shows the ETAP results for verification of the simplified reliability results, as summarised in section 10.1. A summary of the substation configuration with a cross-reference to the relevant figure is given in Table C-1. This is followed by ETAP snapshots of the results, with a table comparing the simplified results with the ETAP result and the percentage difference between the two.

**Table C-1: Summary of ETAP results shown for the verification of the simplified reliability calculation**

No	Description	ETAP snapshot
1	Firm Type 5b – Type 5b, 1 x source feeder, 4 x upstream load feeders, 2 x downstream load feeders.	Figure C-1
2	Firm Type 5b – Type 5b, 2 x source feeders, 4 x upstream load feeders, 2 x downstream load feeders.	Figure C-2
3a	Firm Type 5b – Type 5b, 2 x source feeders, 3 x upstream load feeders, 2 x downstream load feeders – majority of upstream feeders connected to the <b>same</b> busbar as the by-pass isolators.	Figure C-3
3b	Firm Type 5b – Type 5b, 2 x source feeders, 3 x upstream load feeders, 2 x downstream load feeders – majority of upstream feeders connected to the <b>opposite</b> busbar as the by-pass isolators.	
4a	Firm Type 6b – Type 6b, 1 x source feeder, 2 x upstream load feeders, 2 x downstream load feeders. Source feeder connected to the <b>same</b> busbar as the load feeders (connected to the <b>opposite</b> busbar as the by-pass isolators).	Figure C-4
4b	Firm Type 6b – Type 6b, 1 x source feeder, 2 x upstream load feeders, 2 x downstream load feeders. Source feeder connected to the <b>opposite</b> busbar as the load feeders (connected to the <b>same</b> busbar as the by-pass isolators).	

No	Description	ETAP snapshot
4c	Firm Type 6b – Type 6b, 1 x source feeder, 2 x upstream load feeders, 2 x downstream load feeders. Source feeder connected to the <b>same</b> busbar as the load feeders (connected to the <b>same</b> busbar as the by-pass isolators).	
4d	Firm Type 6b – Type 6b, 1 x source feeder, 2 x upstream load feeders, 2 x downstream load feeders. Source feeder connected to the <b>opposite</b> busbar as the load feeders (connected to the <b>opposite</b> busbar as the by-pass isolators).	
5a	Firm Type 6b – Type 6b, 2 x source feeders, 2 x upstream load feeders, 2 x downstream load feeders. Upstream load feeders connected to the <b>same</b> busbar as the source feeders.	Figure C-5
5b	Firm Type 6b – Type 6b, 2 x source feeders, 2 x upstream load feeders, 2 x downstream load feeders. Upstream load feeders connected to the <b>opposite</b> busbar as the source feeders.	
6a	Firm Type 6b – Type 6b, 2 x source feeders, 3 x upstream load feeders, 2 x downstream load feeders. Upstream load feeders connected to the <b>same</b> busbar as the by-pass isolators.	Figure C-6
6b	Firm Type 6b – Type 6b, 2 x source feeders, 3 x upstream load feeders, 2 x downstream load feeders. Upstream load feeders connected to the <b>opposite</b> busbar as the by-pass isolators.	

The results for a firm Type 5b – Type 5b substation with 1 x source feeder, 4 x upstream load feeders and 2 x downstream load feeders are shown in Figure C-1.

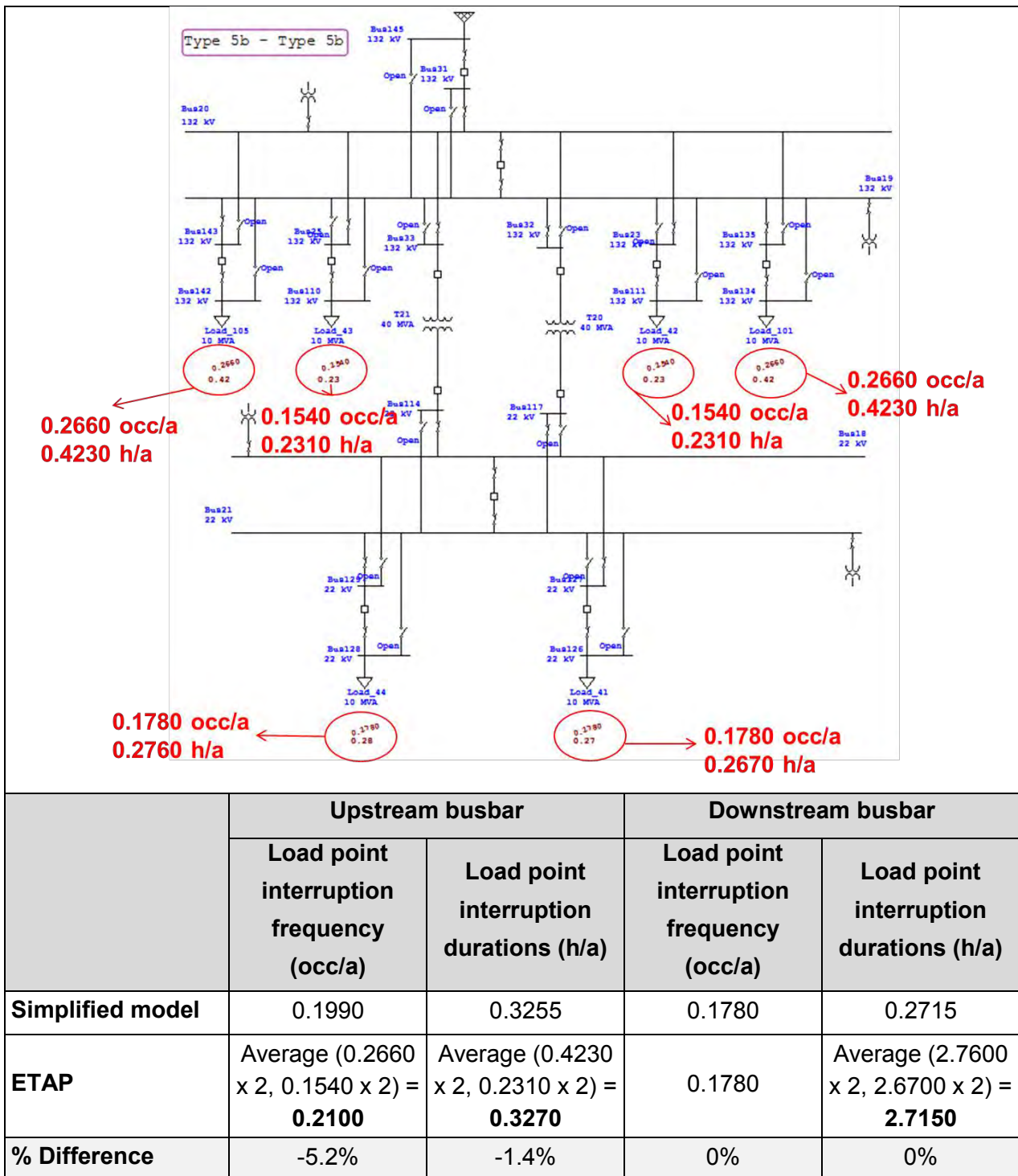


Figure C-1: ETAP unavailability results for a Type 5b – Type 5b substation with one source feeder

The results for a firm Type 5b – Type 5b substation with 2 x source feeders, 4 x upstream load feeders and 2 x downstream load feeders are shown in Figure C-2.

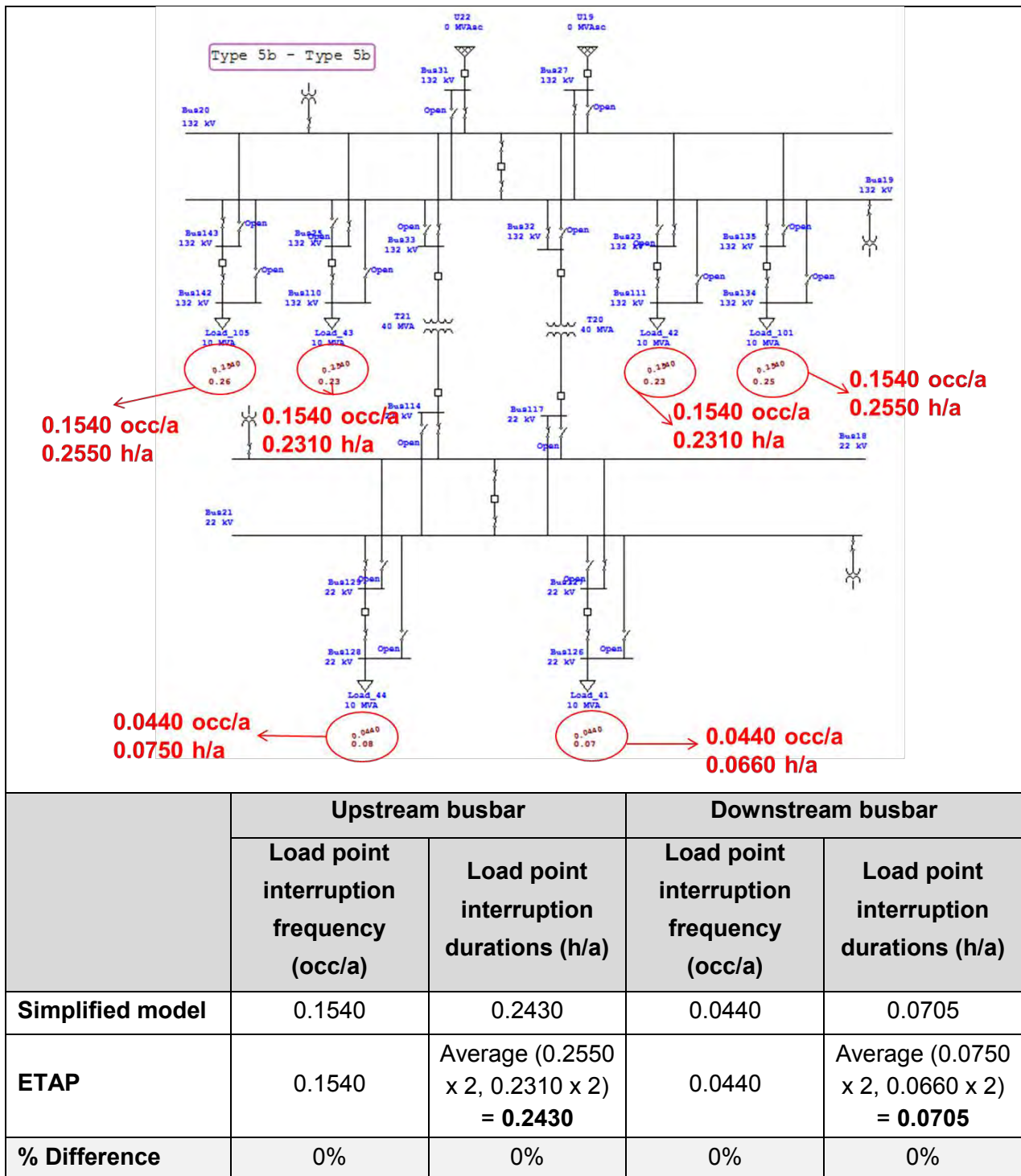
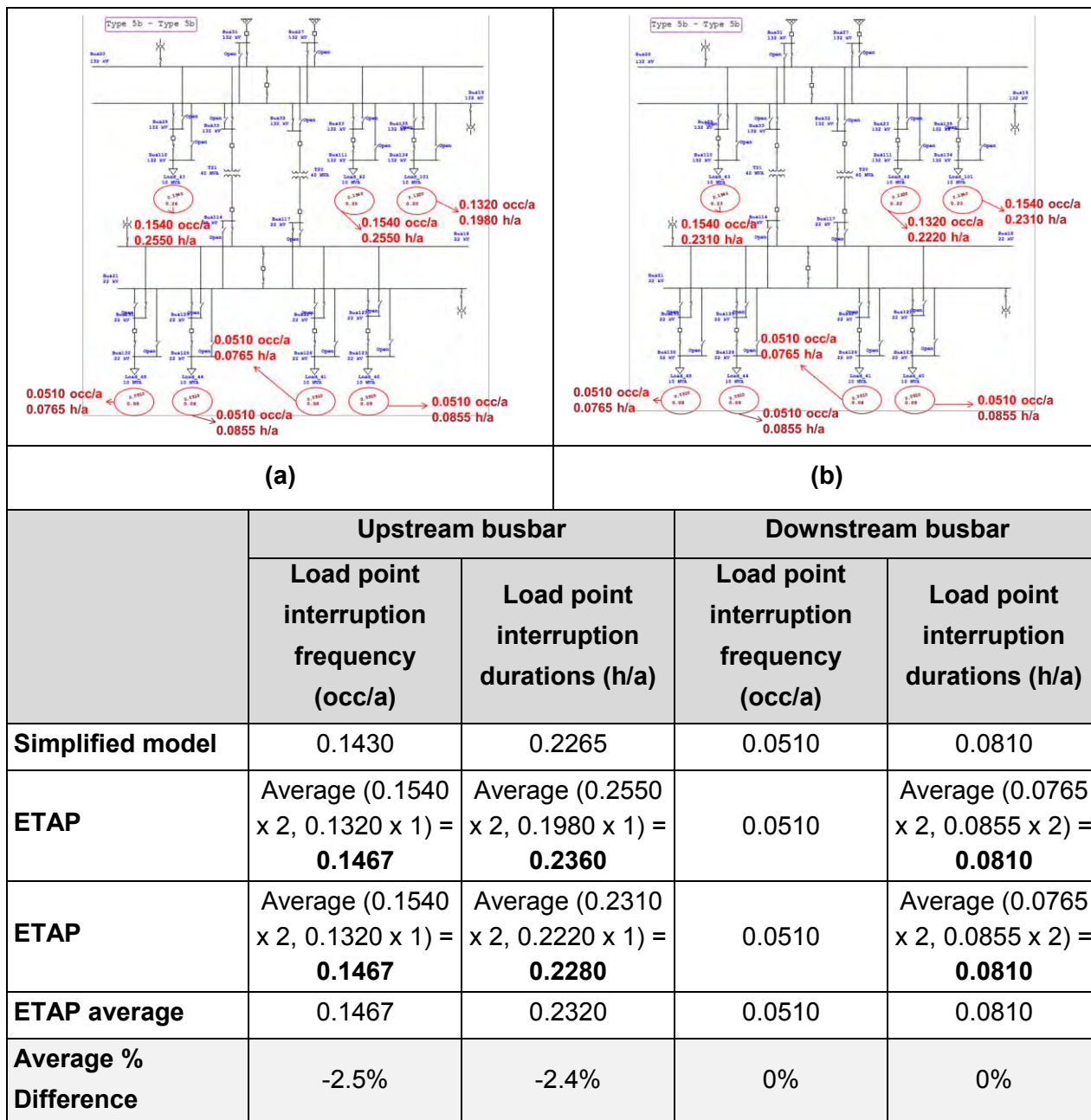


Figure C-2: ETAP unavailability results for a Type 5b – Type 5b substation with two source feeders and an even number of load feeders

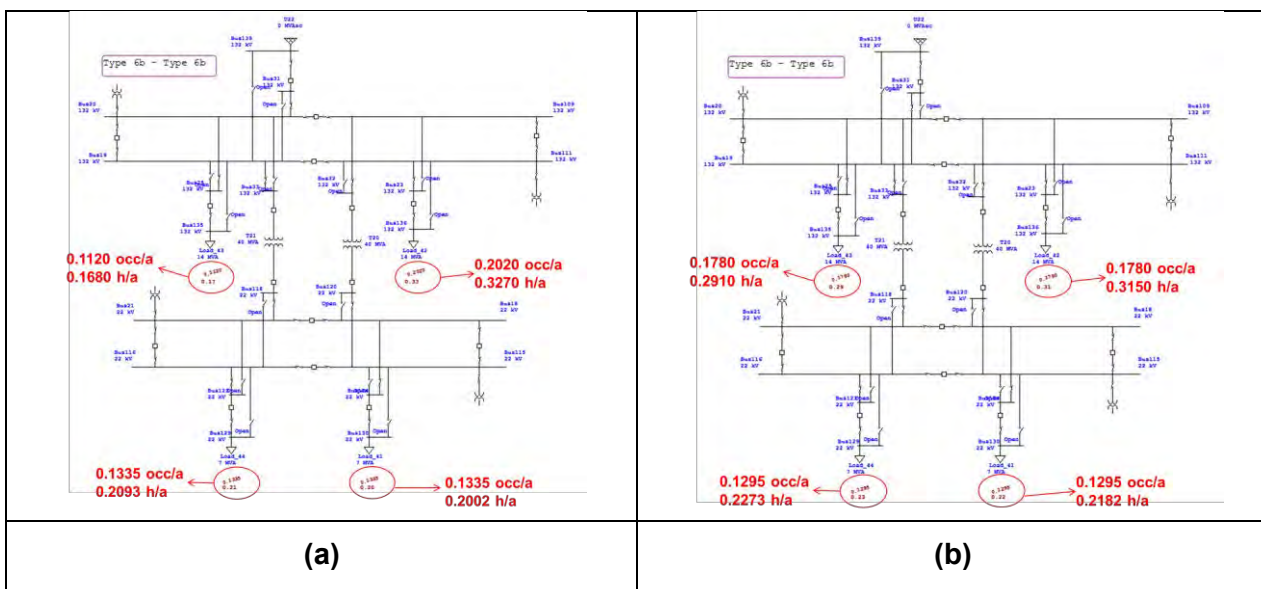
The results for a firm Type 5b – Type 5b substation with 2 x source feeders, 3 x upstream load feeders and 2 x downstream load feeders are shown in Figure C-3. Figure C-3 (a) shows the results with the majority of upstream feeders connected to the **same** busbar as the by-pass isolators, while Figure C-3 (b) shows the results with the majority of upstream feeders connected to the **opposite** busbar as the by-pass isolators.



**Figure C-3: ETAP unavailability results for a Type 5b – Type 5b substation with two source feeders and an uneven number of load feeders**

The results for a firm Type 6b – Type 6b substation with 1 x source feeder, 2 x upstream load feeders and 2 x downstream load feeders are shown in Figure C-4:

- (a) Figure C-4 (a) shows the results with the source feeder connected to the **same** busbar as the load feeders (connected to the **opposite** busbar as the by-pass isolators).
- (b) Figure C-4 (b) shows the results with the source feeder connected to the **opposite** busbar as the load feeders (connected to the **same** busbar as the by-pass isolators)
- (c) Figure C-4 (c) shows the results with the source feeder connected to the **same** busbar as the load feeders (connected to the **same** busbar as the by-pass isolators).
- (d) Figure C-4 (d) shows the results with the source feeder connected to the **opposite** busbar as the load feeders (connected to the **opposite** busbar as the by-pass isolators).



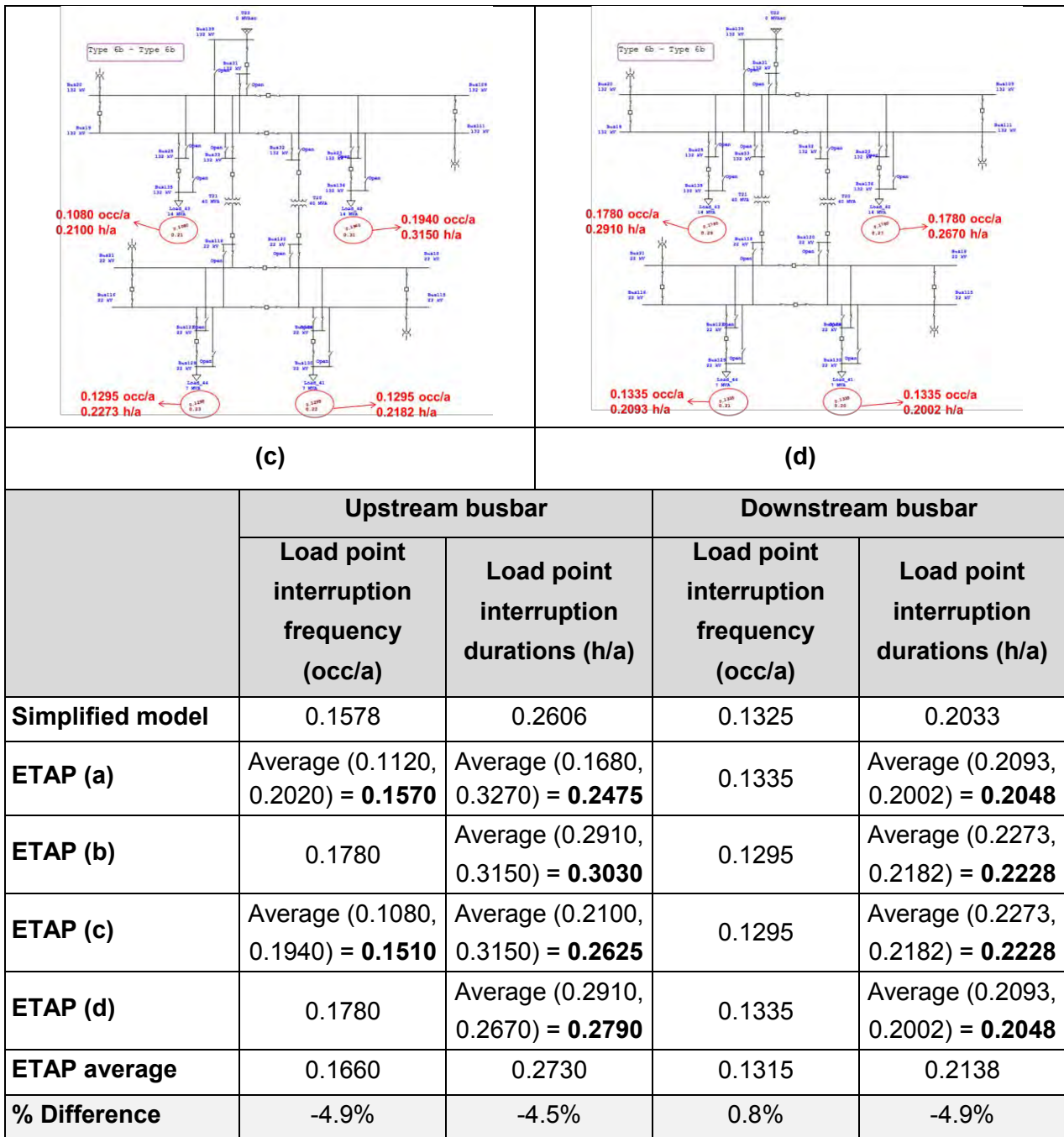
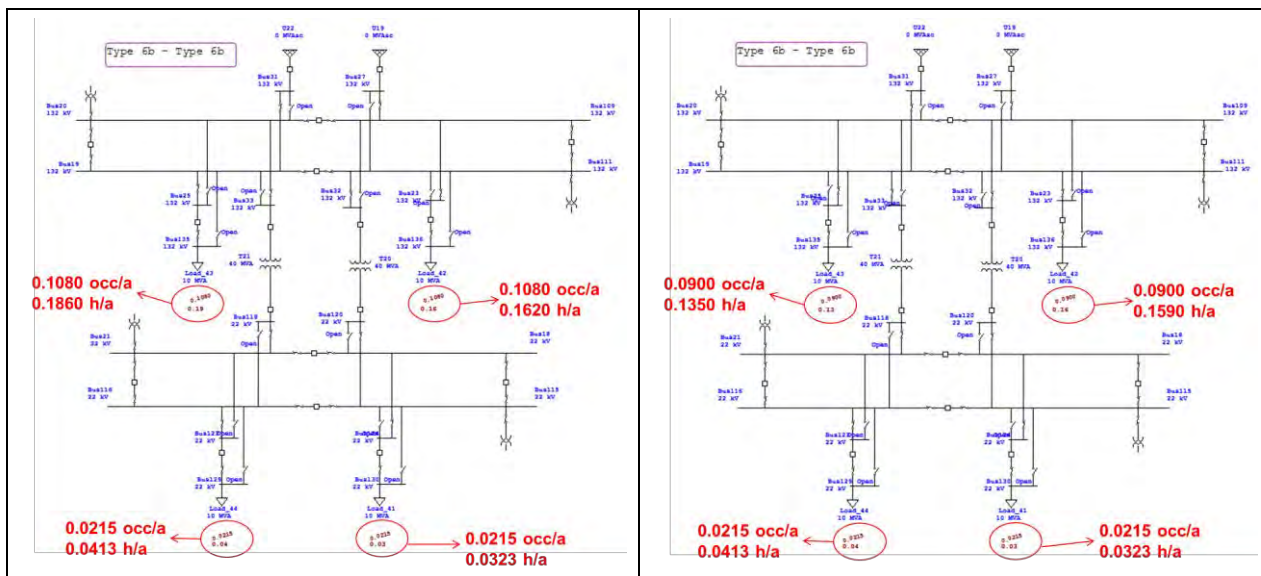


Figure C-4: ETAP unavailability results for a Type 6b – Type 6b substation with one source feeder

The results for a firm Type 6b – Type 6b substation with 2 x source feeders, 2 x upstream load feeders and 2 x downstream load feeders are shown in Figure C-5. Figure C-5 (a) shows the results with the upstream load feeders connected to the **same** busbar as the source feeders, while Figure C-5 (b) shows the results with the upstream load feeders connected to the **opposite** busbar as the source feeders.



	Upstream busbar		Downstream busbar	
	Load point interruption frequency (occ/a)	Load point interruption durations (h/a)	Load point interruption frequency (occ/a)	Load point interruption durations (h/a)
<b>Simplified model</b>	0.0990	0.1605	0.0225	0.0383
<b>ETAP (a)</b>	0.1080	Average (0.1860, 0.1620) = <b>0.1740</b>	0.0215	Average (0.0413, 0.0323) = <b>0.0368</b>
<b>ETAP (b)</b>	0.0900	Average (0.1350, 0.1590) = <b>0.1470</b>	0.0215	Average (0.0413, 0.0323) = <b>0.0368</b>
<b>ETAP average</b>	0.0990	0.1605	0.0215	0.0368
<b>% Difference</b>	0%	0%	4.7%	4.1%

**Figure C-5: ETAP unavailability results for a Type 6b – Type 6b substation with two source feeders and an even number of load feeders**

The results for a firm Type 6b – Type 6b substation with 2 x source feeders, 3 x upstream load feeders and 2 x downstream load feeders are shown in Figure C-6. Figure C-6 (a) shows the results with the upstream load feeders connected to the **same** busbar as the by-pass isolators, while Figure C-6 (b) shows the results with the upstream load feeders connected to the **opposite** busbar as the by-pass isolators.

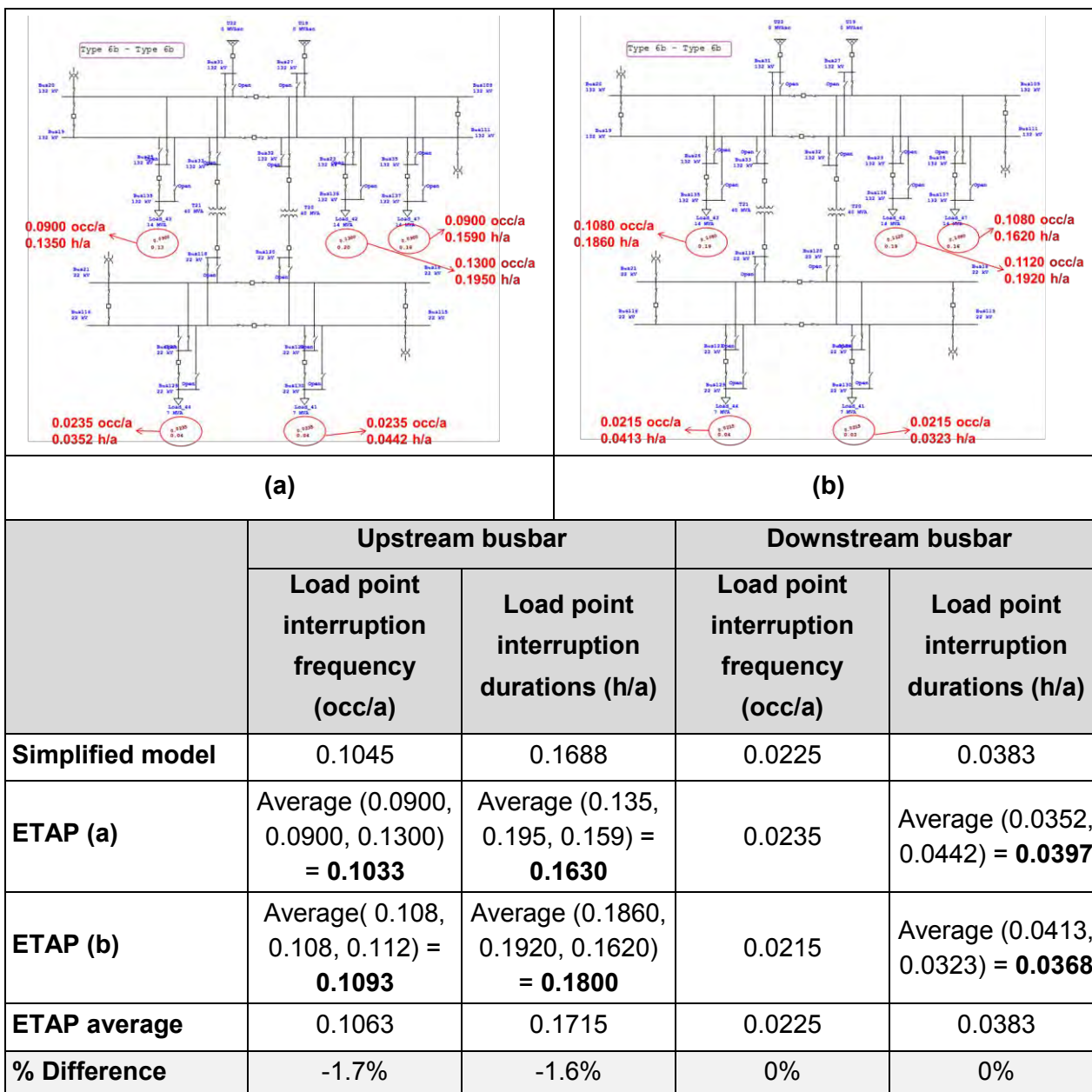


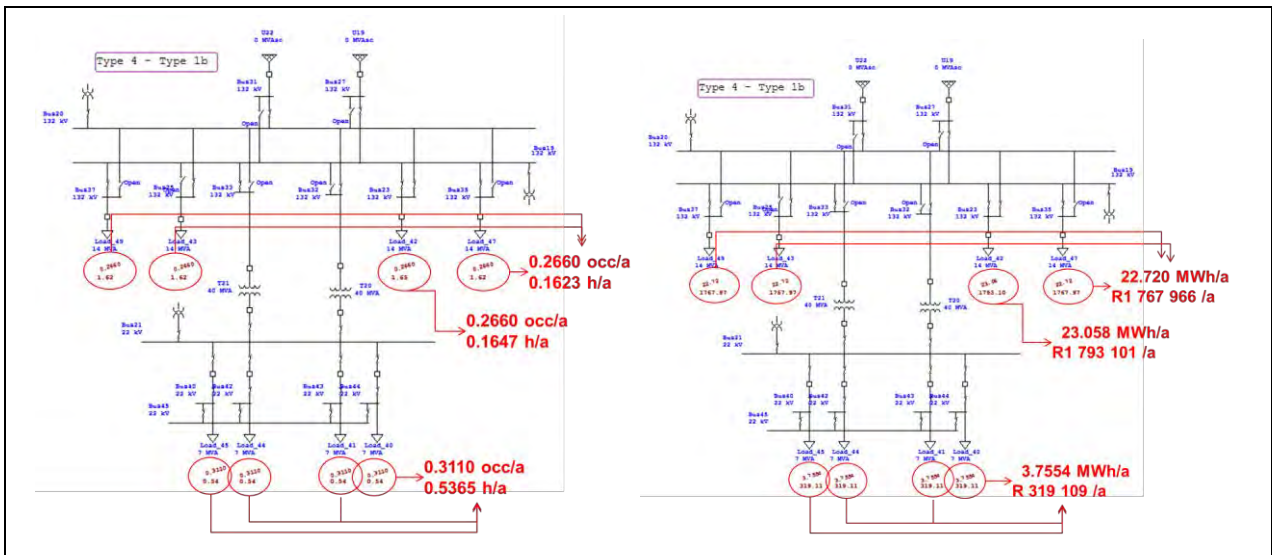
Figure C-6: ETAP unavailability results for a Type 6b – Type 6b substation with two source feeders and an uneven number of load feeders

## **Annex D      Verification of simplified cost of interruption results**

This section shows the ETAP results for verification of the simplified cost of interruption results, as summarised in section 10.2. A summary of the substation configuration with a cross-reference to the relevant figure is given in Table D-1. This is followed by ETAP snapshots of the results, with a table comparing the simplified results with the ETAP result and the percentage difference between the two.

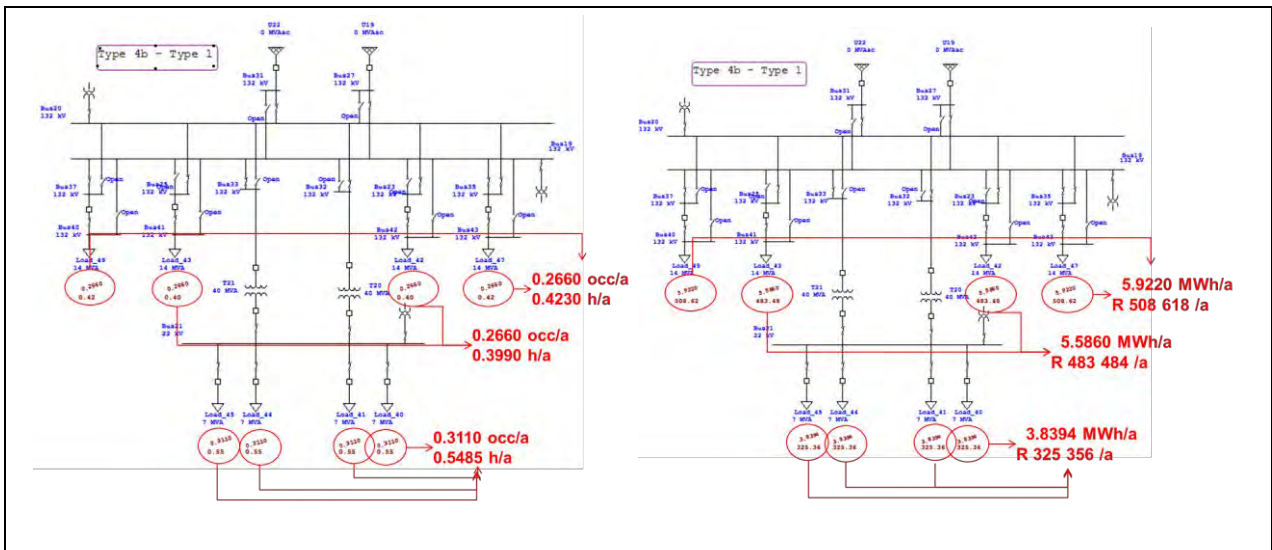
**Table D-1: Summary of ETAP results shown for the verification of the simplified reliability calculation**

<b>No</b>	<b>Substation configuration</b>	<b>ETAP snapshot</b>
1	Firm Type 4 – Type 1b	Figure D-1
2	Firm Type 4b – Type 1	Figure D-2
3	Firm Type 5 – Type 2	Figure D-3
4	Firm Type 5b – Type 2	Figure D-4
5	Firm Type 6 – Type 3b	Figure D-5
6	Firm Type 6b – Type 3	Figure D-6
7	Firm Type 7 – Type 1	Figure D-7



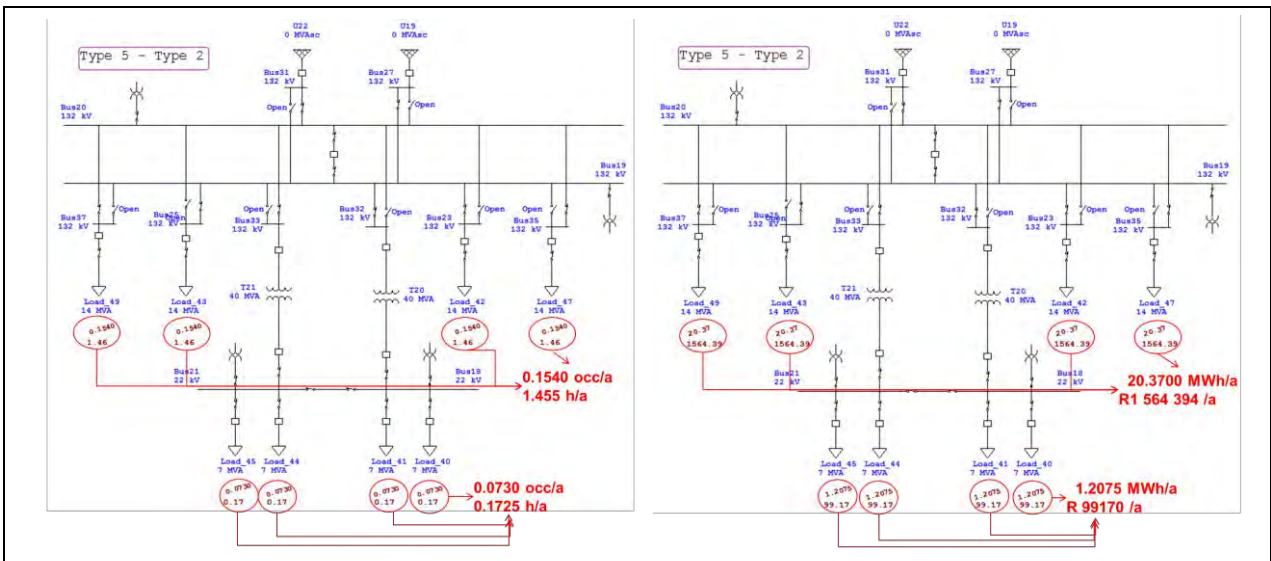
	Upstream busbar				Downstream busbar			
	Interruption frequency (occ/a)	Interruption duration (h/a)	ENS (MWh/a)	Interruption Cost (R/a)	Interruption frequency (occ/a)	Interruption duration (h/a)	ENS (MWh/a)	Interruption Cost (R/a)
Simplified	0.2660	0.16290	91.224	7 065 240	0.3110	0.5365	15.0220	1 257 270
ETAP	0.2660	Average (0.1623 x 3, 0.1647) = 0.1629	22.72 x 3 + 23.058 = 91.218	1 767 966 x 3 + 1 793 101 = 7 096 999	0.3110	0.5365	3.7554 x 4 = 15.0216	319 109 x 4 = 1 276 436
% Difference	0%	0%	0%	-0.4%	0%	0%	0%	-1.5%

Figure D-1: Verification of HV/MV firm Type 4 – Type 1b substation



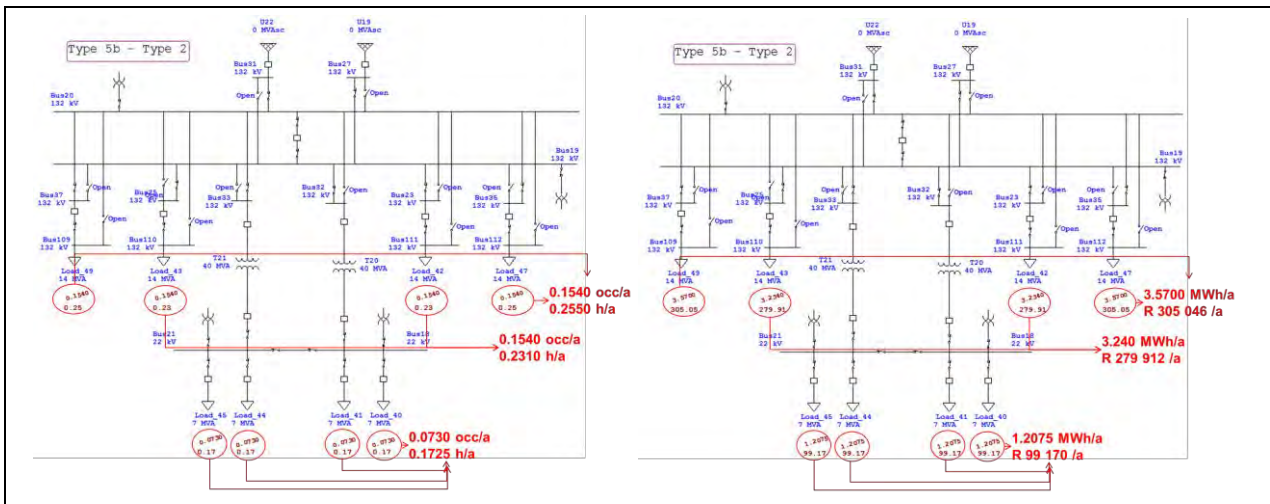
	Upstream busbar				Downstream busbar			
	Interruption frequency (occ/a)	Interruption duration (h/a)	ENS (MWh/a)	Interruption Cost (R/a)	Interruption frequency (occ/a)	Interruption duration (h/a)	ENS (MWh/a)	Interruption Cost (R/a)
Simplified	0.2660	0.4140	23.1840	1 962 240	0.3110	0.5485	15.3580	1 282 470
ETAP	0.2660	Average (0.423 x 2, 0.399 x 2) = 0.4110	5.922 x 2 + 5.586 x 2 = 23.0160	508 618 x 2 + 483 484 x 2 = 1 984 204	0.3110	0.5485	3.8394 x 4 = 15.3576	325 356 x 4 = 1 301 424
% Difference	0%	0.7%	0.7%	-1.1%	0%	0%	0%	-1.5%

Figure D-2: Verification of HV/MV firm Type 4b – Type 1 substation



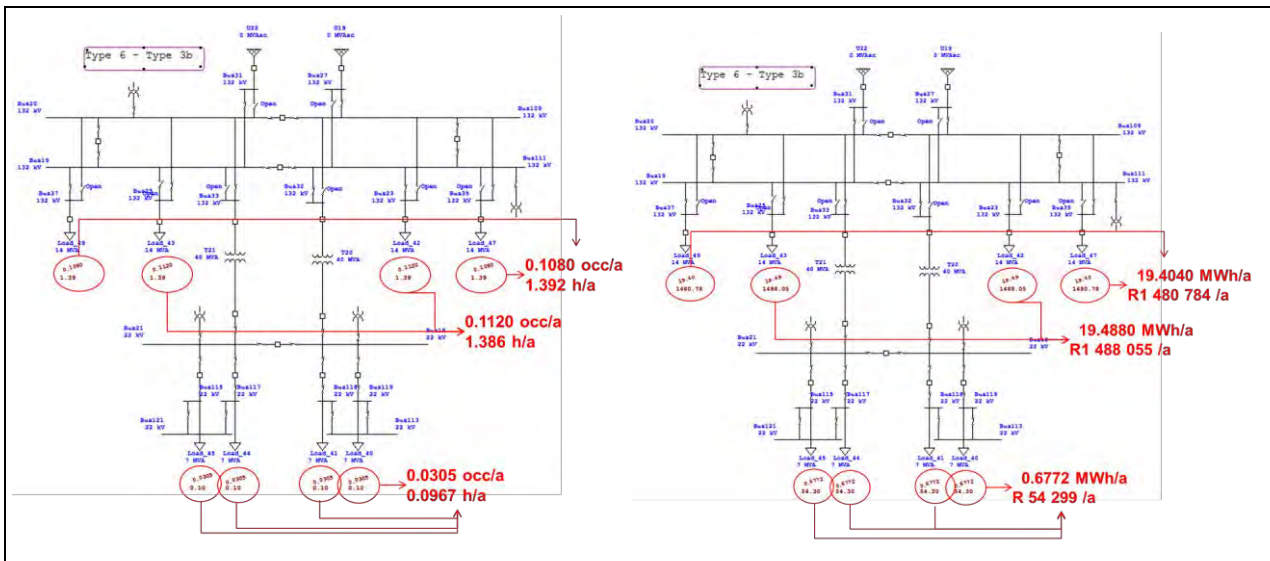
	Upstream busbar				Downstream busbar			
	Interruption frequency (occ/a)	Interruption duration (h/a)	ENS (MWh/a)	Interruption Cost (R/a)	Interruption frequency (occ/a)	Interruption duration (h/a)	ENS (MWh/a)	Interruption Cost (R/a)
Simplified	0.1540	1.4550	81.4800	6 240 360	0.0730	0.1725	4.8300	392 910
ETAP	0.1540	1.4550	20.37 x 4 = 81.4800	1 564 394 x 4 = 6 257 576	0.0730	0.1725	1.2075 x 4 = 4.8300	99 170 x 4 = 396 680
% Difference	0.0%	0.0%	0.0%	-0.3%	0.0%	0.0%	0.0%	-1.0%

**Figure D-3: Verification of HV/MV firm Type 5 – Type 2 substation**



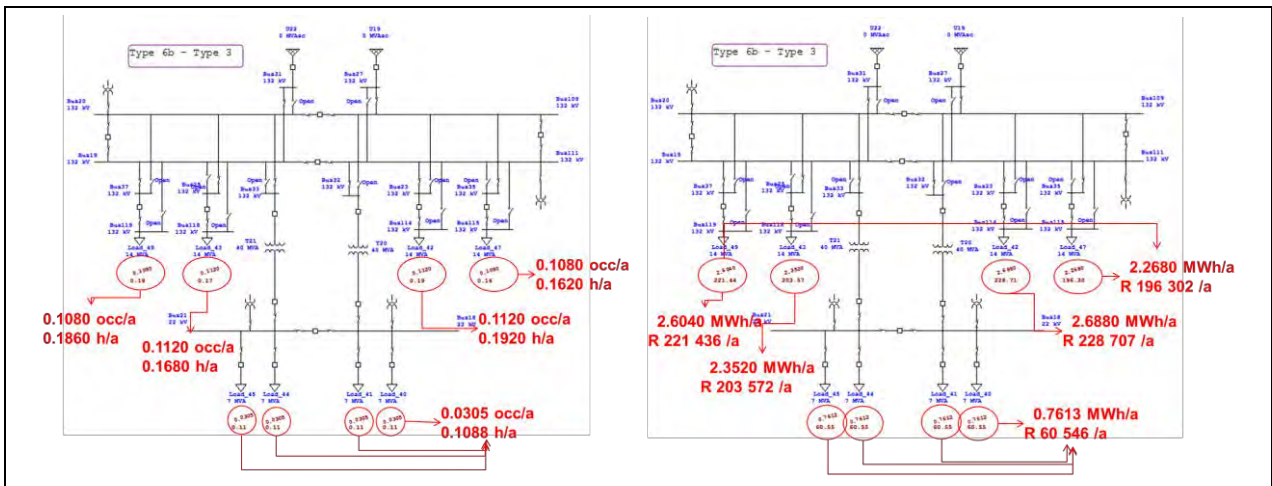
	Upstream busbar				Downstream busbar			
	Interruption frequency (occ/a)	Interruption duration (h/a)	ENS (MWh/a)	Interruption Cost (R/a)	Interruption frequency (occ/a)	Interruption duration (h/a)	ENS (MWh/a)	Interruption Cost (R/a)
Simplified	0.1540	0.2430	13.6080	1 149 960	0.0730	0.1725	4.8300	392 910
ETAP	0.1540	Average (0.255 x 2, 0.231 x 2) = 0.2430	3.57 x 2 + 3.24 x 2 = 13.62	305 046 x 2 + 279 912 x 2 = 1 169 916	0.0730	0.1725	1.2075 x 4 = 4.8300	99 170 x 4 = 396 680
% Difference	0.0%	0.0%	0.0%	-1.7%	0.0%	0.0%	0.0%	-1.0%

**Figure D-4: Verification of HV/MV firm Type 5b – Type 2 substation**



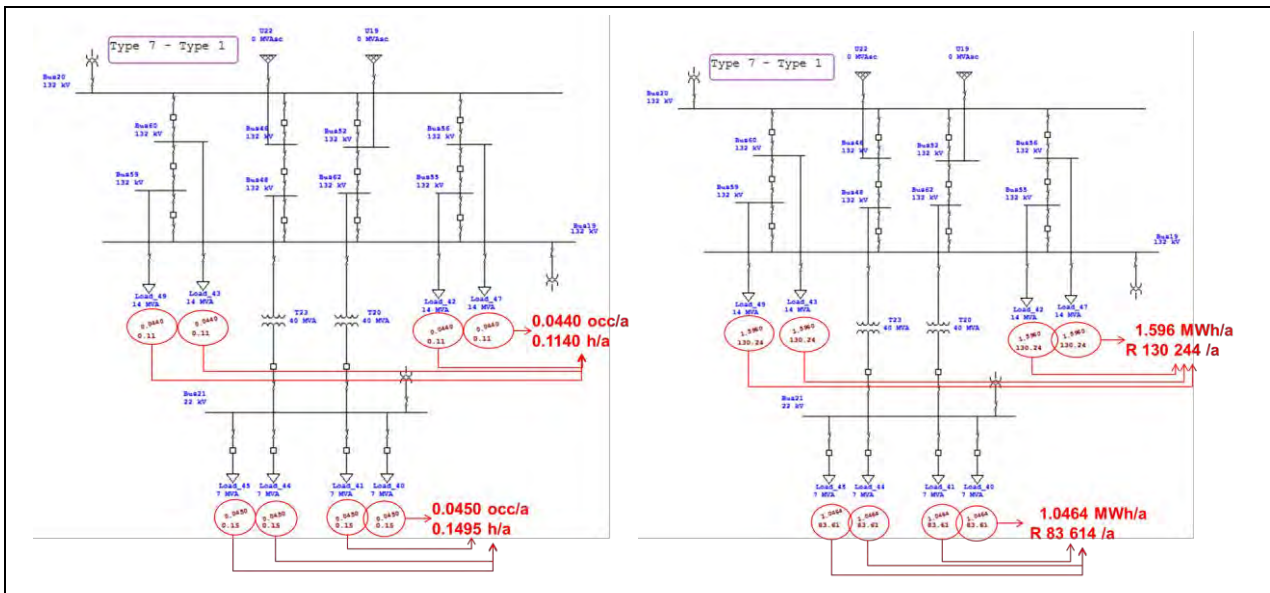
	Upstream busbar				Downstream busbar			
	Interruption frequency (occ/a)	Interruption duration (h/a)	ENS (MWh/a)	Interruption Cost (R/a)	Interruption frequency (occ/a)	Interruption duration (h/a)	ENS (MWh/a)	Interruption Cost (R/a)
Simplified	0.1100	1.3890	77.7840	5 926 200	0.0305	0.0968	2.7090	215 985
ETAP	Average (0.108 x 2, 0.112 x 2) = 0.1100	Average (1.392 x 2, 1.386 x 2) = 1.3890	19.404 x 2 + 19.488 x 2 = 77.7840	1 480 784 x 2 + 1 488 055 x 2 = 5 937 678	0.0305	0.0967	0.6772 x 4 = 2.7088	54 299 x 4 = 217 196
% Difference	0.0%	0.0%	0.0%	-0.2%	0.0%	0.1%	0.0%	-0.6%

Figure D-5: Verification of HV/MV firm Type 6 – Type 3b substation



	Upstream busbar				Downstream busbar			
	Interruption frequency (occ/a)	Interruption duration (h/a)	ENS (MWh/a)	Interruption Cost (R/a)	Interruption frequency (occ/a)	Interruption duration (h/a)	ENS (MWh/a)	Interruption Cost (R/a)
Simplified	0.1100	0.1770	9.9120	835 800	0.0305	0.1088	3.0450	241 185
ETAP	Average (0.108 x 2, 0.112 x 2) = 0.1100	Average (0.186, 0.168, 0.162, 0.192) = 0.1770	2.604 + 2.352 + 2.688 + 2.268 = 9.9120	221 436 + 203 572 + 228 707 + 196 302 = 850 017	0.0305	0.1088	0.7613 x 4 = 3.0452	60 546 x 4 = 242 184
% Difference	0.0%	0.0%	0.0%	-1.7%	0.0%	0.0%	0.0%	-0.4%

Figure D-6: Verification of HV/MV firm Type 6b – Type 3 substation



	Upstream busbar				Downstream busbar			
	Interruption frequency (occ/a)	Interruption duration (h/a)	ENS (MWh/a)	Interruption Cost (R/a)	Interruption frequency (occ/a)	Interruption duration (h/a)	ENS (MWh/a)	Interruption Cost (R/a)
Simplified	0.0440	0.1140	6.3840	515 760	0.0450	0.1495	4.1860	332 850
ETAP	0.0440	0.1140	1.596 x 4 = 6.3840	130 244 x 4 = 520 976	0.0450	0.1495	1.0464 x 4 = 4.1856	83 614 x 4 = 334 456
% Difference	0.0%	0.0%	0.0%	-1.0%	0.0%	0.0%	0.0%	-0.5%

Figure D-7: Verification of HV/MV firm Type 7 – Type 1 substation

## Annex E Preferred substations configurations for different design criteria

The tables with the optimal substation configurations for the three voltage levels (HV-HV, HV-MV and MV-MV) and three of the customer damage functions (Function 1, 7 and 13) are shown below.

No. of source feeders	No. of upstream load feeders	No. of down-stream load feeders	Busbar peak load (MVA)								
			6.25	7.5	8.75	12.5	15	17.5	25	30	35
Transformer size:			5 – 10 MVA			10 – 20 MVA			20 – 40 MVA		
1	0	2	F_1-1	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b
1	0	4	U_1-1	F_1-1	F_1-1	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b
1	0	6	U_1-1	F_1-1	F_1-1	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b
1	0	8	U_1-1	F_1-1	F_1-1	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b
1	2	2	U_1-1	F_4b-4b	F_4b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b
1	2	4	U_1-1	F_1-1	F_4b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b
1	2	6	U_1-1	F_1-1	F_1-1	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b
1	2	8	U_1-1	F_1-1	F_1-1	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b
1	4	2	U_1-1	F_1-1	F_4b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b
1	4	4	U_1-1	F_1-1	F_1-1	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b
1	4	6	U_1-1	F_1-1	F_1-1	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b
1	4	8	U_1-1	F_1-1	F_1-1	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b
2	0	2	U_1-1	F_4-4b	F_4-4b	F_4-4b	F_4-4b	F_4-4b	F_3-4b	F_3-4b	F_3-4b
2	0	4	U_1-1	F_1-1	F_1-1	F_4-4b	F_4-4b	F_4-4b	F_3-4b	F_3-4b	F_3-4b
2	0	6	U_1-1	F_1-1	F_1-1	F_4-4b	F_4-4b	F_4-4b	F_3-4b	F_3-4b	F_3-4b
2	0	8	U_1-1	F_1-1	F_1-1	F_4-4b	F_4-4b	F_4-4b	F_3-4b	F_3-4b	F_3-4b
2	2	2	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_5b-4b
2	2	4	U_1-1	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_5b-4b
2	2	6	U_1-1	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_5b-4b
2	2	8	U_1-1	F_4b-1	F_4b-1	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_5b-4b
2	4	2	U_1-1	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_5b-4b	F_5b-4b
2	4	4	U_1-1	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_5b-4b	F_5b-4b
2	4	6	U_1-1	F_1-1	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_5b-4b	F_5b-4b
2	4	8	U_1-1	F_1-1	F_4b-1	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_5b-4b	F_5b-4b

**Figure E-1: Results for an MV/MV substation (CDF 1)**

No. of source feeders	No. of upstream load feeders	No. of downstream load feeders	Busbar peak load (MVA)											
			6.25	7.5	8.75	12.5	15	17.5	25	30	35	50	60	70
Transformer size:			5 – 10 MVA			10 – 20 MVA			20 – 40 MVA			40-80 MVA		
1	0	2	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b
1	0	4	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b
1	0	6	F_4b-1	F_4b-1	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b
1	0	8	F_4b-1	F_4b-1	F_4b-1	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-5b
1	2	2	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b
1	2	4	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b
1	2	6	F_4b-1	F_4b-1	F_4b-4b	F_4b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b
1	2	8	F_4b-1	F_4b-1	F_4b-1	F_4b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-5b
1	4	2	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b
1	4	4	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b
1	4	6	F_4b-1	F_4b-1	F_4b-4b	F_4b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b
1	4	8	F_4b-1	F_4b-1	F_4b-1	F_4b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-5b
2	0	2	F_1-1	F_1-1	F_4-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b
2	0	4	F_1-1	F_1-1	F_1-1	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b
2	0	6	F_1-1	F_1-1	F_1-1	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b
2	0	8	F_1-1	F_1-1	F_1-1	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-5b
2	2	2	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b
2	2	4	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b
2	2	6	F_4b-1	F_4b-1	F_4b-4b	F_4b-4b	F_4b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b
2	2	8	F_4b-1	F_4b-1	F_4b-1	F_4b-4b	F_4b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-5b
2	4	2	F_3-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b
2	4	4	F_1-1	F_4b-4b	F_4b-4b	F_4b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b
2	4	6	F_1-1	F_4b-1	F_4b-4b	F_4b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b
2	4	8	F_1-1	F_4b-1	F_4b-1	F_4b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-5b

Figure E-2: Results for an HV/MV substation (CDF 1)

No. of source feeders	No. of upstream load feeders	No. of downstream load feeders	Busbar peak load (MVA)									
			25	30	35	50	60	70	100	120	140	
Transformer size:			20 – 40 MVA			40-80 MVA			80-160 MVA			
1	0	2	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-5b	F_4b-5b	F_4b-5b	F_4b-5b	F_5b-5b	F_5b-5b
1	0	4	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-5b	F_4b-5b	F_4b-5b	F_4b-5b	F_5b-5b	F_5b-5b	F_5b-5b
1	0	6	F_4b-4b	F_4b-4b	F_4b-5b	F_4b-5b	F_4b-5b	F_4b-5b	F_4b-5b	F_4b-5b	F_5b-5b	F_5b-5b
1	0	8	F_4b-4b	F_4b-5b	F_4b-5b	F_4b-5b	F_4b-5b	F_4b-5b	F_4b-5b	F_4b-5b	F_5b-5b	F_5b-5b
1	2	2	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b
1	2	4	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b
1	2	6	F_5b-4b	F_5b-4b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b
1	2	8	F_5b-4b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b
1	4	2	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b
1	4	4	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b
1	4	6	F_5b-4b	F_5b-4b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b
1	4	8	F_5b-4b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b
2	0	2	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-5b	F_3-5b	F_3-5b	F_3-5b	F_3-5b	F_3-5b
2	0	4	F_3-4b	F_3-4b	F_3-4b	F_3-5b	F_3-5b	F_3-5b	F_3-5b	F_3-5b	F_3-5b	F_3-5b
2	0	6	F_3-4b	F_3-4b	F_3-5b	F_3-5b	F_3-5b	F_3-5b	F_3-5b	F_3-5b	F_3-5b	F_3-5b
2	0	8	F_3-4b	F_3-5b	F_3-5b	F_3-5b	F_3-5b	F_3-5b	F_3-5b	F_3-5b	F_3-5b	F_3-5b
2	2	2	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b
2	2	4	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b
2	2	6	F_5b-4b	F_5b-4b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b
2	2	8	F_5b-4b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b
2	4	2	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b
2	4	4	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b
2	4	6	F_5b-4b	F_5b-4b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b
2	4	8	F_5b-4b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b

Figure E-3: Results for an HV/HV substation (CDF 1)

No. of source feeders	No. of upstream load feeders	No. of downstream load feeders	Busbar peak load (MVA)									
			6.25	7.5	8.75	12.5	15	17.5	25	30	35	
Transformer size:			5 – 10 MVA			10 – 20 MVA			20 – 40 MVA			
1	0	2	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1
1	0	4	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1
1	0	6	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1
1	0	8	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1
1	2	2	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1
1	2	4	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1
1	2	6	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1
1	2	8	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1
1	4	2	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1
1	4	4	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1
1	4	6	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1
1	4	8	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1
2	0	2	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1
2	0	4	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1
2	0	6	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1
2	0	8	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1
2	2	2	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1
2	2	4	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1
2	2	6	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1
2	2	8	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1
2	4	2	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1
2	4	4	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1
2	4	6	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1
2	4	8	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1

Figure E-4: Results for an MV/MV substation (CDF 7)

No. of source feeders	No. of upstream load feeders	No. of downstream load feeders	Busbar peak load (MVA)											
			6.25	7.5	8.75	12.5	15	17.5	25	30	35	50	60	70
Transformer size:			5 – 10 MVA			10 – 20 MVA			20 – 40 MVA			40-80 MVA		
1	0	2	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1
1	0	4	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1
1	0	6	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1
1	0	8	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1
1	2	2	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_4b-1
1	2	4	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_4b-1
1	2	6	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_4b-1
1	2	8	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_4b-1
1	4	2	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1
1	4	4	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1
1	4	6	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1
1	4	8	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1
2	0	2	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1
2	0	4	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1
2	0	6	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1
2	0	8	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1
2	2	2	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1
2	2	4	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1
2	2	6	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1
2	2	8	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1
2	4	2	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1
2	4	4	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1
2	4	6	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1
2	4	8	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1

Figure E-5: Results for an HV/MV substation (CDF 7)

No. of source feeders	No. of upstream load feeders	No. of down-stream load feeders	Busbar peak load (MVA)									
			25	30	35	50	60	70	100	120	140	
Transformer size:			20 – 40 MVA			40-80 MVA			80-160 MVA			
1	0	2	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1b	S_1-1b
1	0	4	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1
1	0	6	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1
1	0	8	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1
1	2	2	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_4b-1	S_4b-1	S_4b-1	S_4b-1b	S_4b-1b
1	2	4	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_4b-1	S_4b-1	S_4b-1	S_4b-1	S_4b-1
1	2	6	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_4b-1	S_4b-1	S_4b-1	S_4b-1	S_4b-1
1	2	8	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_4b-1	S_4b-1	S_4b-1	S_4b-1	S_4b-1
1	4	2	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_4b-1	S_4b-1b	S_4b-1b	S_4b-1b
1	4	4	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_4b-1	S_4b-1	S_4b-1	S_4b-1
1	4	6	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_4b-1	S_4b-1	S_4b-1	S_4b-1
1	4	8	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_4b-1	S_4b-1	S_4b-1	S_4b-1
2	0	2	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1b	S_1-1b
2	0	4	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1
2	0	6	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1
2	0	8	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1
2	2	2	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_4b-1b	S_4b-1b
2	2	4	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_4b-1	S_4b-1
2	2	6	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_4b-1	S_4b-1
2	2	8	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_4b-1	S_4b-1
2	4	2	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1b	S_1-1b
2	4	4	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1
2	4	6	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1
2	4	8	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1	S_1-1

Figure E-6: Results for an HV/HV substation (CDF 7)

No. of source feeders	No. of upstream load feeders	No. of down-stream load feeders	Busbar peak load (MVA)									
			6.25	7.5	8.75	12.5	15	17.5	25	30	35	
Transformer size:			5 – 10 MVA			10 – 20 MVA			20 – 40 MVA			
1	0	2	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b
1	0	4	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b
1	0	6	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-5b	F_4b-5b
1	0	8	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-5b	F_4b-5b	F_4b-5b
1	2	2	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b
1	2	4	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b
1	2	6	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-5b	F_5b-5b
1	2	8	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-5b	F_5b-5b	F_5b-5b
1	4	2	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b
1	4	4	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b
1	4	6	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-5b	F_5b-5b
1	4	8	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-5b	F_5b-5b	F_5b-5b
2	0	2	F_4-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b
2	0	4	F_4-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b
2	0	6	F_4-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-5b	F_3-5b
2	0	8	F_4-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-5b	F_3-5b
2	2	2	F_4b-4b	F_4b-4b	F_4b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b
2	2	4	F_4b-4b	F_4b-4b	F_4b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b
2	2	6	F_4b-4b	F_4b-4b	F_4b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-5b	F_5b-5b
2	2	8	F_4b-4b	F_4b-4b	F_4b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-5b	F_5b-5b	F_5b-5b
2	4	2	F_4b-4b	F_4b-4b	F_4b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b
2	4	4	F_4b-4b	F_4b-4b	F_4b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b
2	4	6	F_4b-4b	F_4b-4b	F_4b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-5b	F_5b-5b
2	4	8	F_4b-4b	F_4b-4b	F_4b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-5b	F_5b-5b	F_5b-5b

Figure E-7: Results for an MV/MV substation (CDF 13)

No. of source feeders	No. of upstream load feeders	No. of downstream load feeders	Busbar peak load (MVA)													
			6.25	7.5	8.75	12.5	15	17.5	25	30	35	50	60	70		
Transformer size:			5 – 10 MVA				10 – 20 MVA				20 – 40 MVA			40-80 MVA		
1	0	2	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_5b-5b	F_5b-5b	F_5b-5b	
1	0	4	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_5b-5b	F_5b-5b	F_5b-5b	
1	0	6	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-5b	F_4b-5b	F_5b-5b	F_5b-5b	F_5b-5b	
1	0	8	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-4b	F_4b-5b	F_4b-5b	F_4b-5b	F_5b-5b	F_5b-5b	F_5b-5b	
1	2	2	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-5b	F_5b-5b	
1	2	4	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-5b	F_5b-5b	
1	2	6	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	
1	2	8	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	
1	4	2	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-5b	F_5b-5b	
1	4	4	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-5b	F_5b-5b	F_5b-5b	
1	4	6	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	
1	4	8	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	
2	0	2	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-5b	F_3-5b	
2	0	4	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-5b	F_3-5b	F_3-5b	
2	0	6	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-5b	F_3-5b	F_3-5b	F_3-5b	F_3-5b	
2	0	8	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-4b	F_3-5b	F_3-5b	F_3-5b	F_3-5b	F_3-5b	F_3-5b	
2	2	2	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-5b	F_5b-5b	
2	2	4	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-5b	F_5b-5b	
2	2	6	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	
2	2	8	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	
2	4	2	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-5b	F_5b-5b	
2	4	4	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-5b	F_5b-5b	F_5b-5b	
2	4	6	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	
2	4	8	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-4b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	

Figure E-8: Results for an HV/MV substation (CDF 13)

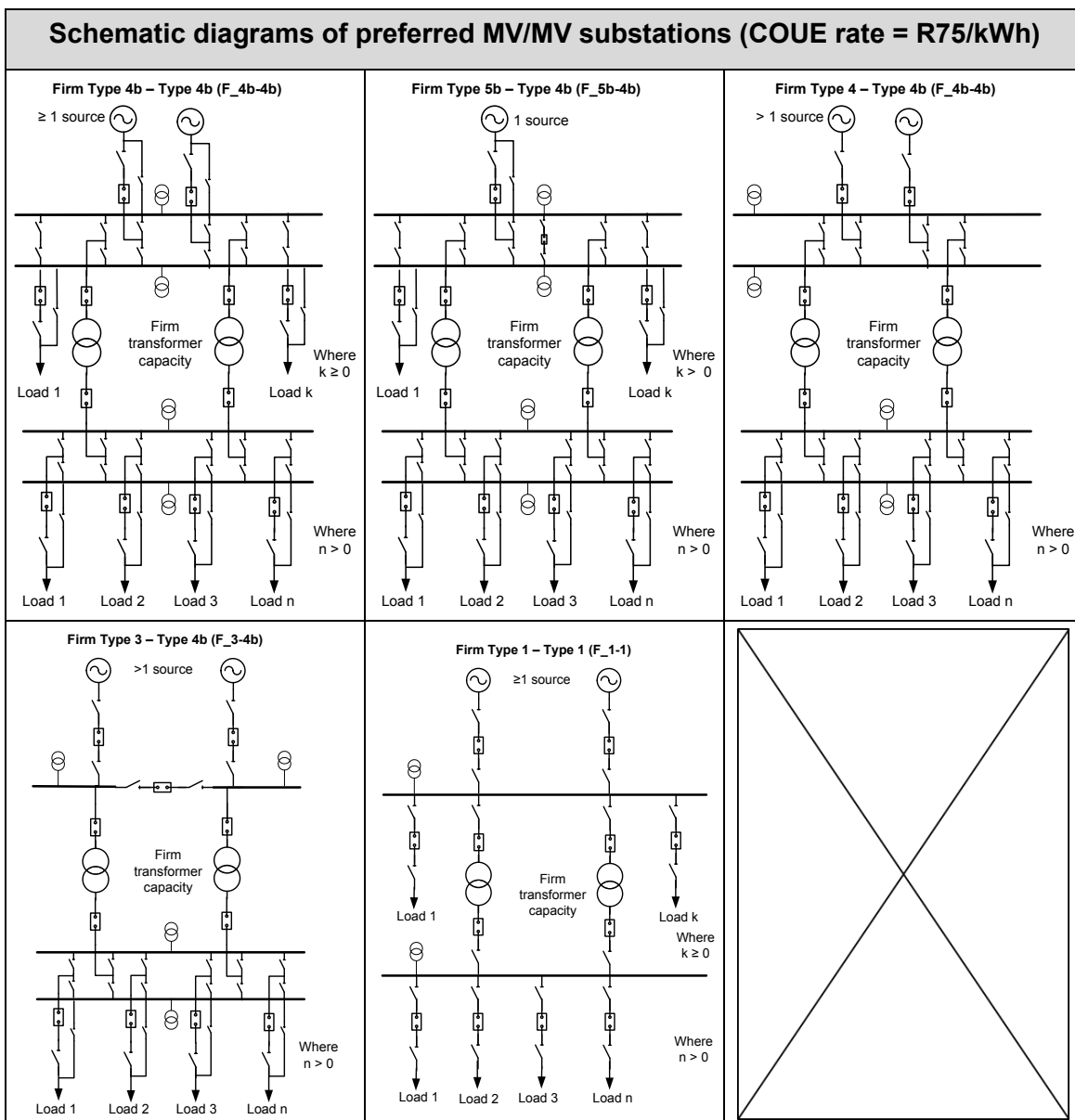
No. of source feeders	No. of upstream load feeders	No. of downstream load feeders	Busbar peak load (MVA)								
			25	30	35	50	60	70	100	120	140
Transformer size:			20 – 40 MVA			40-80 MVA			80-160 MVA		
1	0	2	F_4b-5b	F_4b-5b	F_4b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b
1	0	4	F_4b-5b	F_4b-5b	F_4b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-6b	F_5b-6b
1	0	6	F_4b-5b	F_4b-5b	F_4b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-6b	F_5b-6b	F_5b-6b
1	0	8	F_4b-5b	F_4b-5b	F_4b-5b	F_5b-5b	F_5b-5b	F_5b-6b	F_5b-6b	F_5b-6b	F_5b-6b
1	2	2	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b
1	2	4	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-6b	F_5b-6b
1	2	6	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-6b	F_5b-6b	F_5b-6b
1	2	8	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-6b	F_5b-6b	F_5b-6b	F_5b-6b
1	4	2	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_6b-5b	F_6b-5b	F_6b-5b
1	4	4	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_6b-5b	F_6b-6b	F_6b-6b
1	4	6	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_6b-6b	F_6b-6b	F_6b-6b
1	4	8	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-6b	F_6b-6b	F_6b-6b	F_6b-6b
2	0	2	F_3-5b	F_3-5b	F_3-5b	F_3-5b	F_3-5b	F_3-5b	F_3-5b	F_3-5b	F_3-5b
2	0	4	F_3-5b	F_3-5b	F_3-5b	F_3-5b	F_3-5b	F_3-5b	F_3-5b	F_3-6b	F_3-6b
2	0	6	F_3-5b	F_3-5b	F_3-5b	F_3-5b	F_3-5b	F_3-5b	F_3-6b	F_3-6b	F_3-6b
2	0	8	F_3-5b	F_3-5b	F_3-5b	F_3-5b	F_3-5b	F_3-6b	F_3-6b	F_3-6b	F_3-6b
2	2	2	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b
2	2	4	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_6b-5b	F_6b-6b	F_6b-6b
2	2	6	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_6b-6b	F_6b-6b	F_6b-6b
2	2	8	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-6b	F_6b-6b	F_6b-6b	F_6b-6b
2	4	2	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_6b-5b	F_6b-5b	F_6b-5b
2	4	4	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_6b-5b	F_6b-6b	F_6b-6b
2	4	6	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_6b-6b	F_6b-6b	F_6b-6b
2	4	8	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-5b	F_5b-6b	F_6b-6b	F_6b-6b	F_6b-6b

Figure E-9: Results for an HV/HV substation (CDF 13)

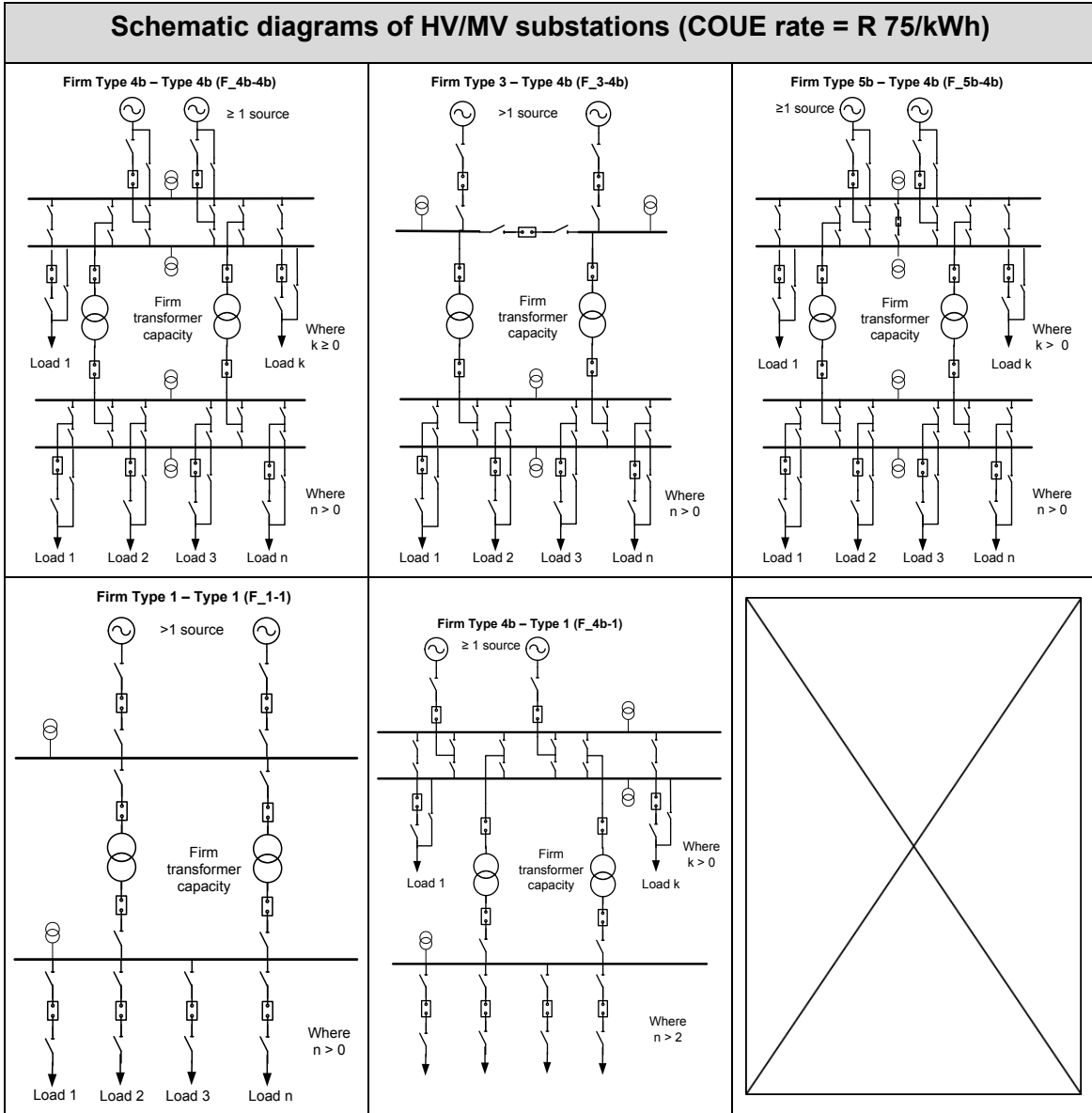
## Annex F      Schematic diagrams of the preferred substation configurations

Schematic diagrams of the preferred substation configurations are shown below, grouped per

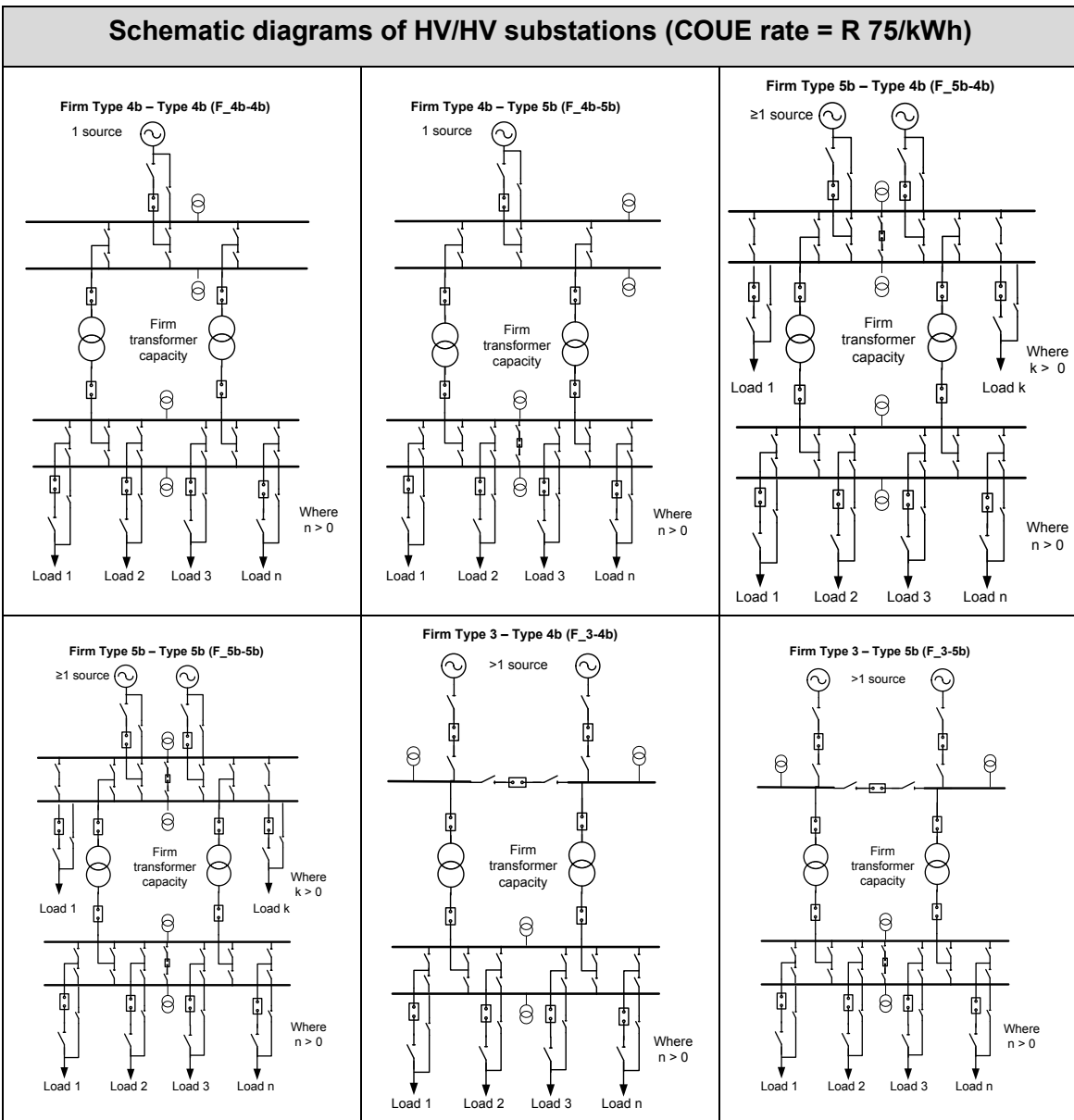
- (a) Customer outage duration cost; and
- (b) Substation voltage level.



**Figure F-1: Preferred substation configurations for MV/MV substations (COUE rate = R 75/kWh)**

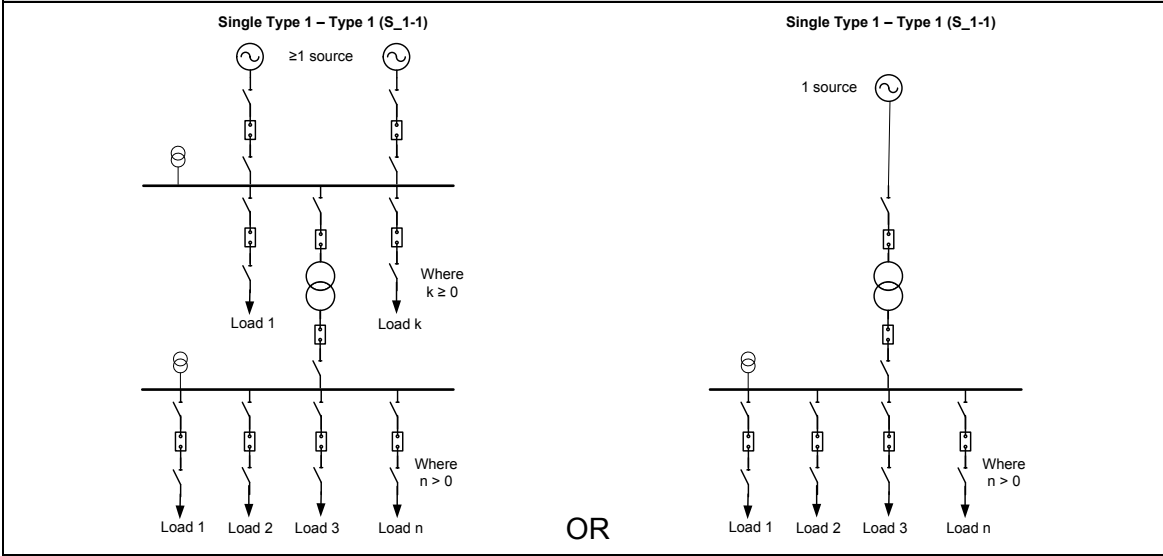


**Figure F-2: Preferred substation configurations for HV/MV substations (COUE rate = R 75/kWh)**



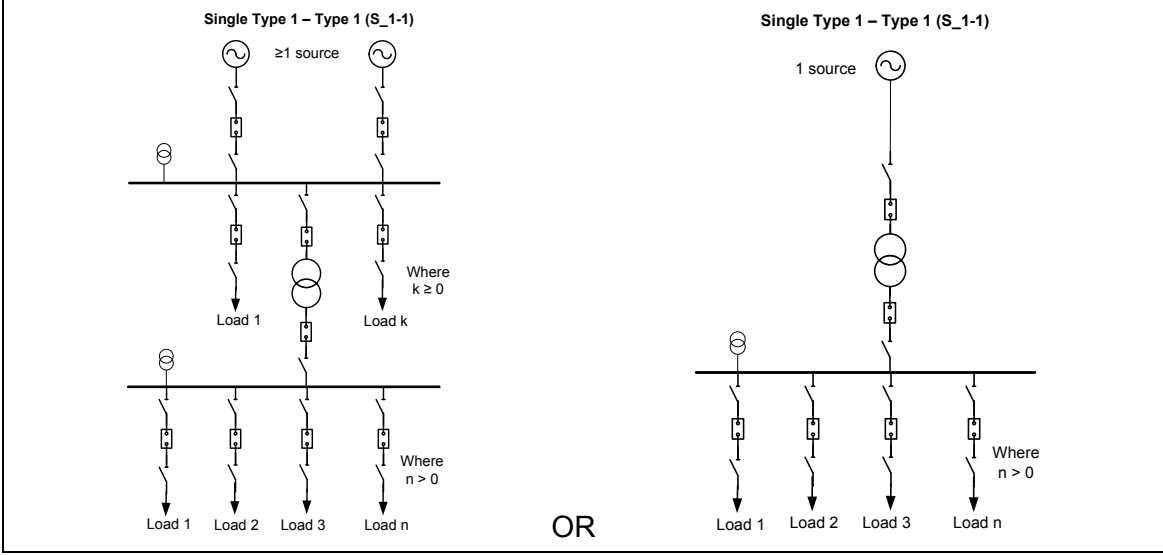
**Figure F-3: Preferred substation configurations for HV/HV substations (COUE rate = R 75/kWh)**

**Schematic diagrams of preferred MV/MV substations (COUE rate = R 5/kWh)**



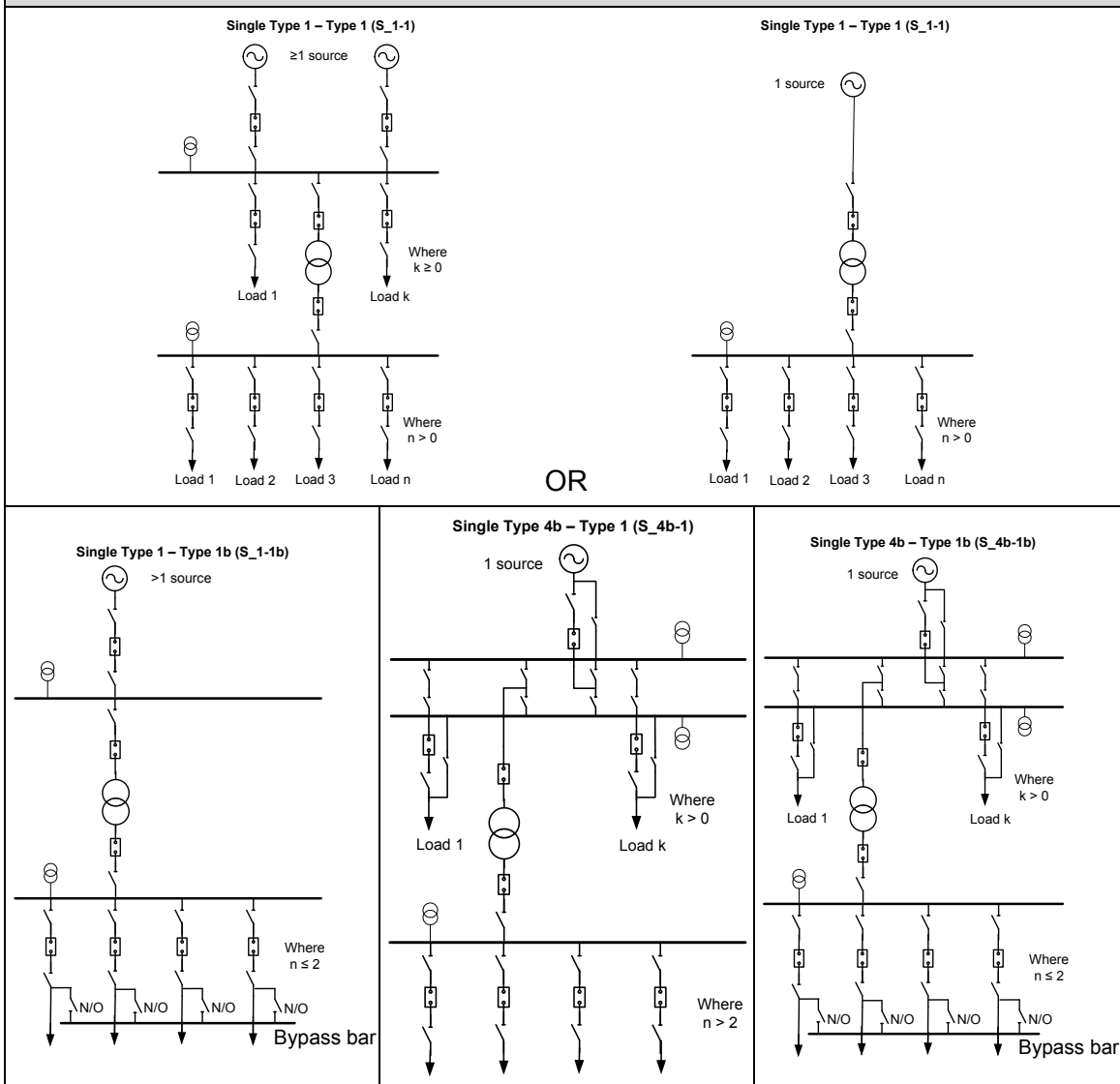
**Figure F-4: Preferred substation configurations for MV/MV substations (COUE rate = R 5/kWh)**

**Schematic diagrams of preferred HV/MV substations (COUE rate = R 5/kWh)**

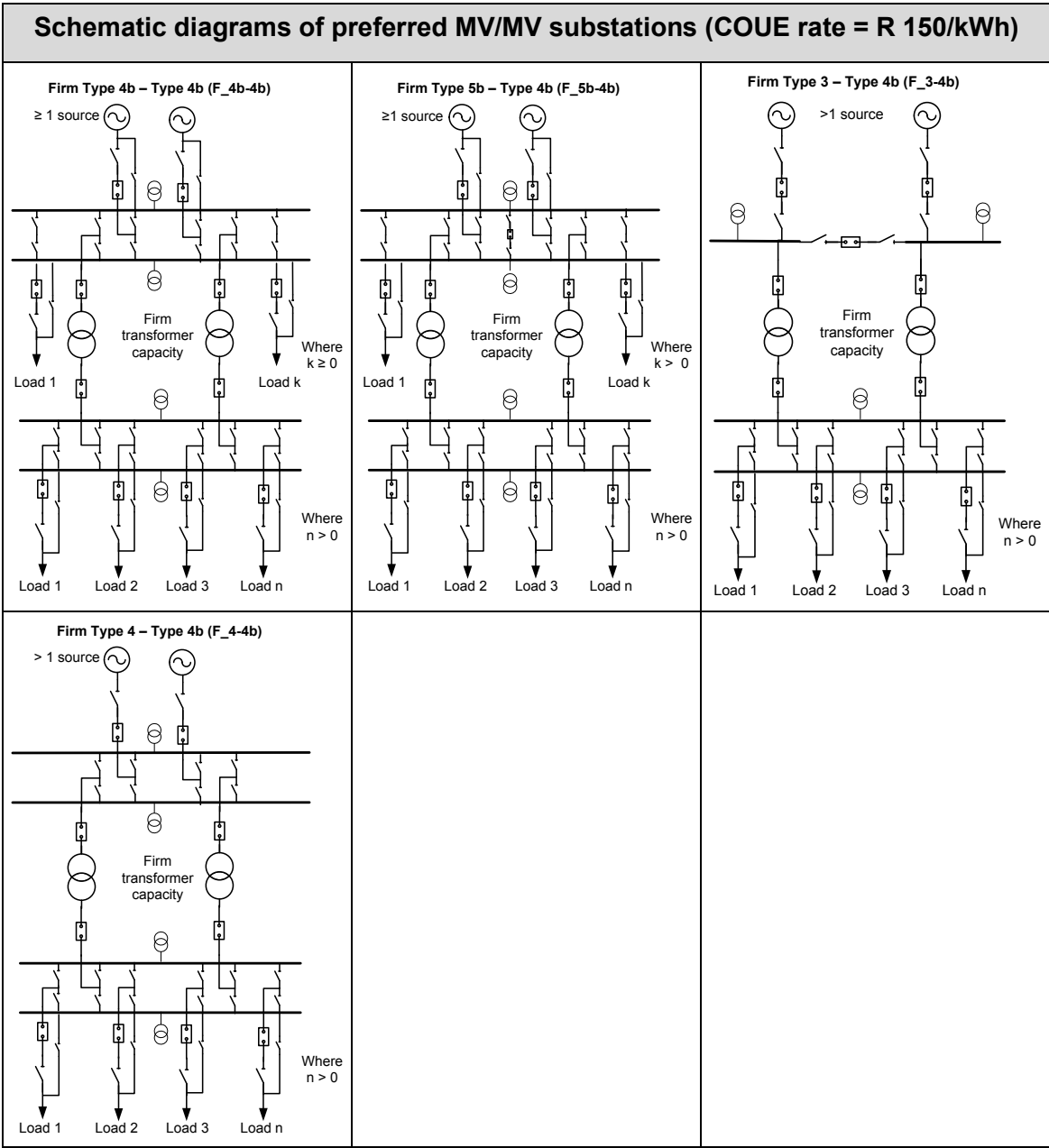


**Figure F-5: Preferred substation configurations for HV/MV substations (COUE rate = R 5/kWh)**

**Schematic diagrams of preferred HV/HV substations (COUE rate = R 5/kWh)**

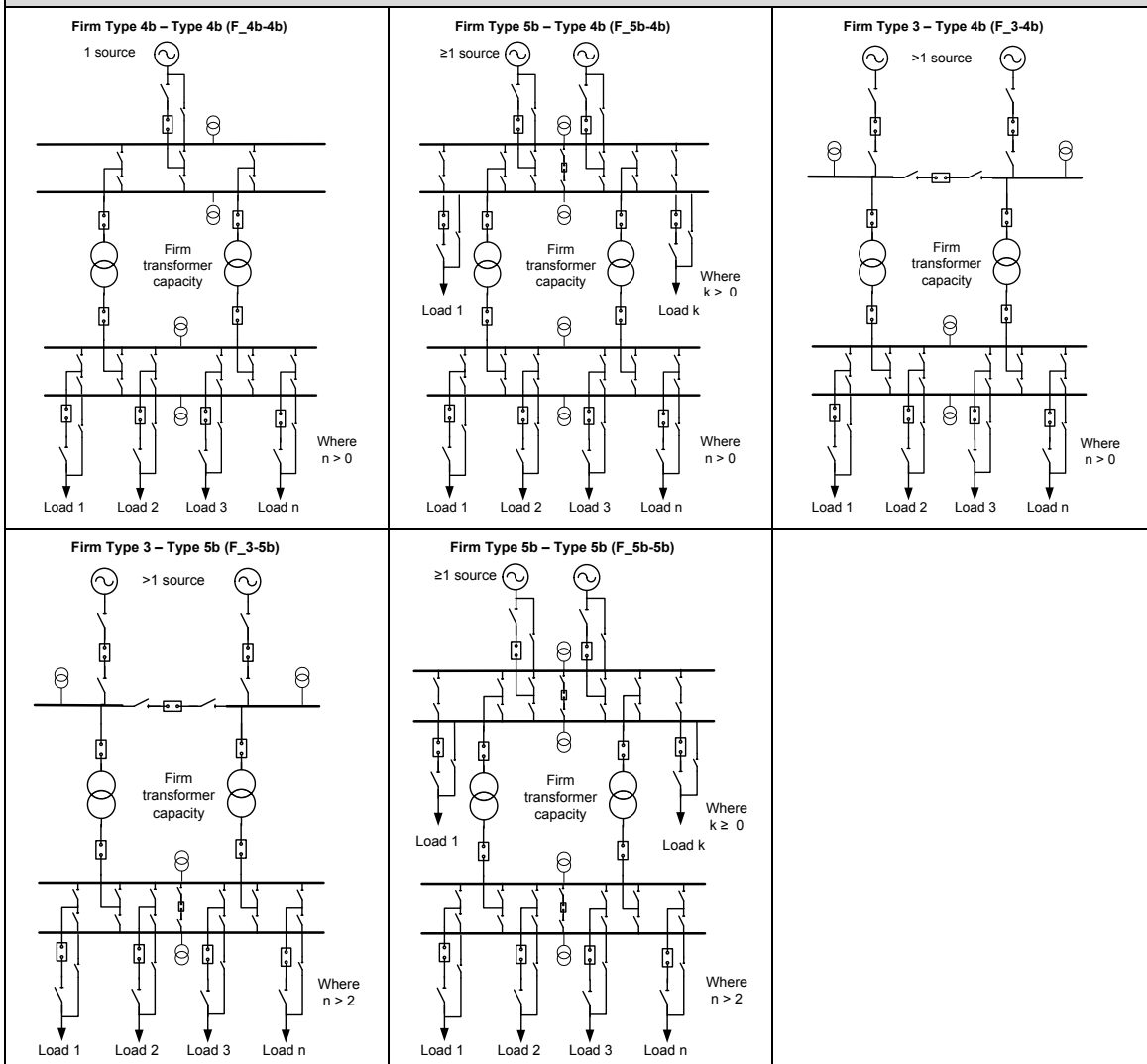


**Figure F-6: Preferred substation configurations for HV/HV substations (COUE rate = R 5/kWh)**



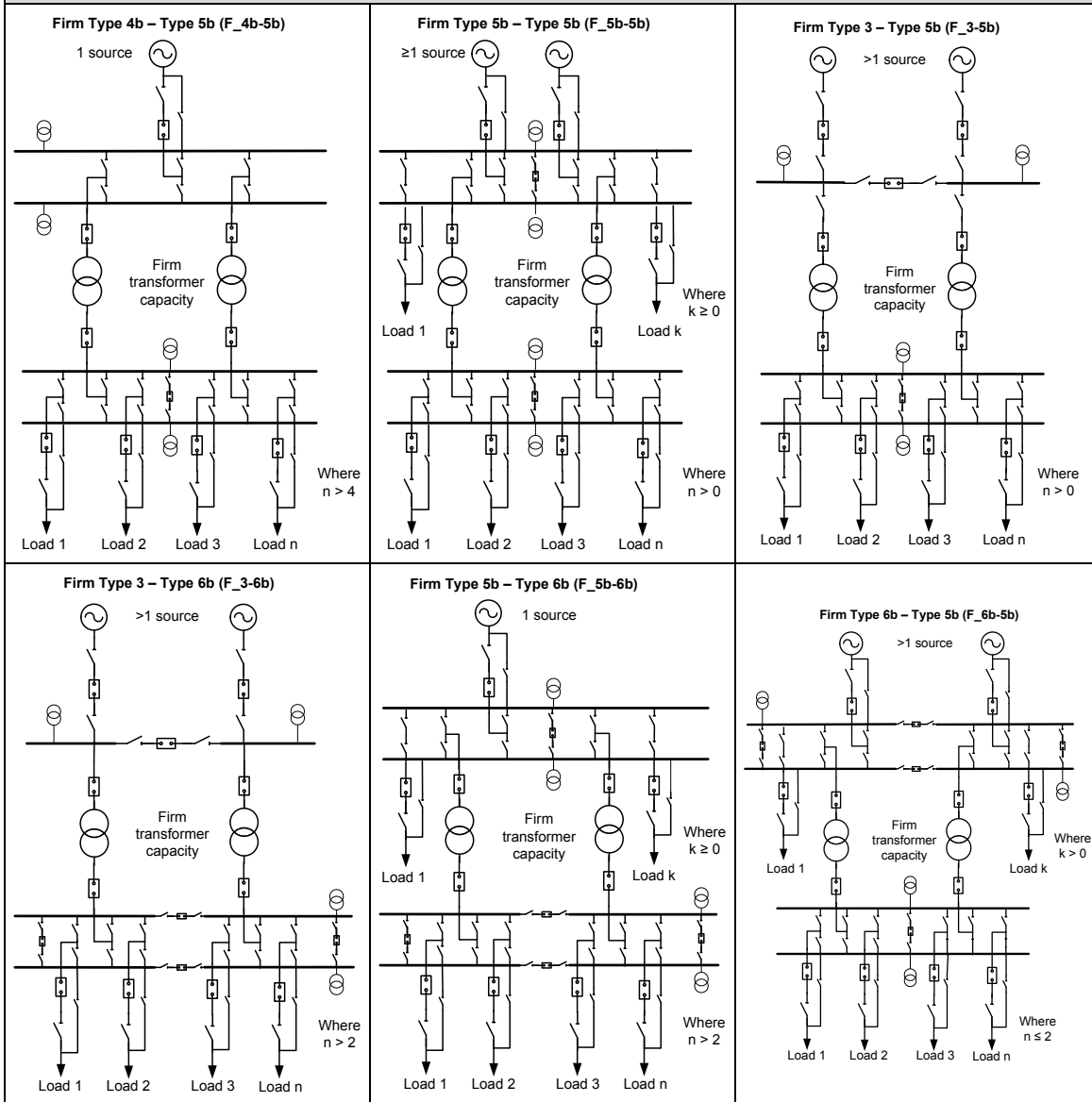
**Figure F-7: Preferred substation configurations for MV/MV substations (COUE rate = R 150/kWh)**

**Schematic diagrams of preferred HV/MV substations (COUE rate = R 150/kWh)**

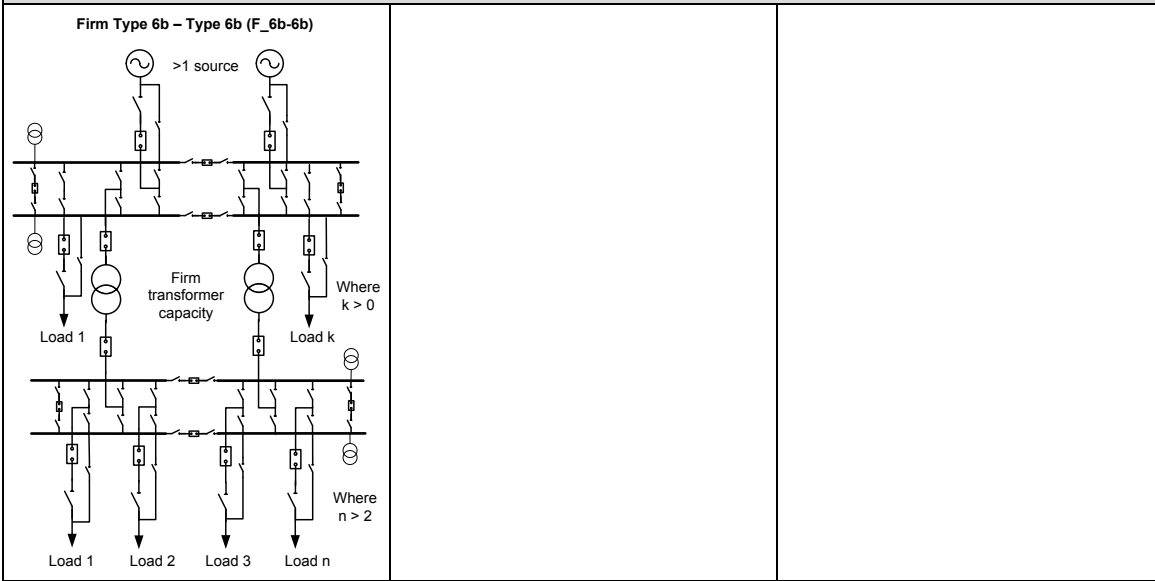


**Figure F-8: Preferred substation configurations for HV/MV substations (COUE rate = R 150/kWh)**

**Schematic diagrams of preferred HV/HV substations (COUE rate = R 150/kWh)**



**Schematic diagrams of preferred HV/HV substations (COUE rate = R 150/kWh)**



**Figure F-9: Preferred substation configurations for HV/HV substations (COUE rate = R 150/kWh)**

## Annex G Description of the Excel model

This section gives a high level overview of the Excel model that was developed to calculate and compare the life cycle cost of the 432 different substations for each of the 720 different design criteria.

The excel model consists of:

(a) **Input data:**

- (i) **“Substations”**: This sheet contains the list of substations that are compared, with the design information of each. The design information is entered per busbar and includes the voltage, the number of transformers supplied by the busbar, the total installed capacity of these transformers, the peak load supplied from the busbar, the number of source and load feeders connected to the busbar, the busbar type classification and the name of the upstream busbar (only relevant to the downstream busbars). A unique name and ID is assigned to each busbar on these input sheets. If 20 substation configurations are compared, the input sheet will have 40 lines of data, i.e. one line for each busbar.
- (ii) **“Scenarios”**: This sheet contains all the input values that should be considered for the different parameters which describe a specific scenario. A snapshot of this sheet, showing data for only two scenarios, are shown in Figure G-1. This sheet is used during the clustering process (see “clustering” below under “calculation” sheets.)

Description	Busbar	Unit	Scenario 1	Scenario 2
Voltage	Upstream	kV	132	132
	Downstream	kV	22	22
Number of source fdrs			1	1
Number of load feeders	Upstream		0	0
	Downstream		2	4
Peak Load	Upstream	MVA	0	0
	Downstream	MVA	6.25	6.25
COUE Unplanned Frequency	Upstream	R/kW.occ	R 1.00	R 1.00
	Downstream		R 1.00	R 1.00
COUE Unplanned Duration	Upstream	R/kWh	R 5.00	R 5.00
	Downstream		R 5.00	R 5.00
COUE Planned Frequency	Upstream	R/kW.occ	R 0.30	R 0.30
	Downstream		R 0.30	R 0.30
COUE Planned Duration	Upstream	R/kWh	R 1.50	R 1.50
	Downstream		R 1.50	R 1.50

**Figure G-1: Snapshot of the “Scenario” input sheet in the Excel Model**

(b) **Libraries:** The libraries contain assumptions that are used in the calculations. The following libraries are included:

- (i) **“Failure\_rates”**, includes the planned and unplanned failure rates and outage durations for each component;
- (ii) **“Substation\_costs”**, includes the capital cost of all equipment in the substation and the assumptions for operational costs;
- (iii) **“Equipment\_count”**, specifies the number of components for each of the busbar type classifications. These component counts are used to determine the total substation cost as well as the number of failures. For example, the busbar breaker count for a Type 1 busbar is 0, and for a Type 6 busbar is 4. The number of busbar VTs for a Type 1 busbar is 1, and for a Type 3 busbar is 2.
- (iv) **“Impact\_failures”**, defines the impact of a failure of a specific component, for each busbar configuration. Abbreviations are used to describe the impact, and these abbreviations are then interpreted on the calculation sheet. There are four sheets which describe the impact of failures, i.e.
  - impact of unplanned failures on the busbar before switching
  - impact of unplanned failures on the downstream busbar before switching
  - impact of unplanned failures on the busbar after switching
  - impact of unplanned failures on the downstream busbar after switching

The impact of planned failures is similar to the impact of unplanned failures after switching, therefore no separate library sheets are created for this.

(c) **“Calculations”**: These are the sheets that contain all the calculations. Each of these sheets reads the input data from the input sheet and use this data in the calculations. Each calculation sheet therefore has the same number of data rows as the input sheet (i.e. if 20 substation configurations are compared, the calculation sheets will have 40 lines of data). The calculation sheets reference the library sheets for the assumptions required in the calculation. A snapshot of one such calculation sheet is shown in Figure G-2. The model has the following calculation sheets:

- (i) **“Utility\_cost”**, calculates the initial capital cost as wells as operations and maintenance cost during the lifetime of the substation. This sheet uses the values from the “substation costs” and “equipment count” library.
- (ii) **“Unavailability\_planned”**, calculates the interruption frequency and interruption duration due to planned outages.
- (iii) **“Unavailability\_unplanned”**, calculates the interruption frequency and interruption duration due to unplanned outages.
- (iv) **“Unavailability\_total”**, calculates the total interruption frequency and interruption duration due to planned and unplanned outages.
- (v) **“Life\_cycle\_cost”**, converts the unavailability of each busbar to a customer cost, using the customer damage function provided on the scenario input sheet (see below). The sheet also performs the ranking to determine which is the optimal substation for a specific scenario,

BB_ID	SSName	MRL_lsc	MRL_BE	MRL_BH	MRL_Trf	Dur_AS_lsol	Dur_AS_BB	Dur_AS_Bktr	Dur_AS_Trf	Freq_BB_A	Freq_B_B	Freq_B_R	Freq_B_S
1001_22	Single Type1- Type1	0.25	0	0.25	0.25	2	0	4	8	0.25	0	0	0
1002_22	Single Type1- Type1b	0.25	0	0.25	0.25	2	0	4	8	0.25	0	0	0
1003_22	Single Type1- Type2	0.25	0	0.25	0.25	2	0	4	8	0.25	0	0	0.375
1004_22	Single Type1- Type3	0.25	0	0.25	0.25	2	0	4	8	0.25	0	0	0.375
1005_22	Single Type1- Type3b	0.25	0	0.25	0.25	2	0	4	8	0.25	0	0	0.25
1005A_22	Single Type1- Type4	0.25	0	0.25	0.25	2	0	4	8	0.25	0	0	0
1005S_22	Single Type1- Type4b	0.25	0	0.25	0.25	2	0	4	8	0.25	0	0	0
1006_22	Single Type1- Type5	0.25	0	0.25	0.25	2	0	4	8	0.25	0	0	0
1007_22	Single Type1- Type5b	0.25	0	0.25	0.25	2	0	4	8	0.25	0	0	0
1008_22	Single Type1- Type6b	0.25	0	0.25	0.25	2	0	4	8	0.25	0	0	0
1009_22	Single Type1- Type6	0.25	0	0.25	0.25	2	0	4	8	0.25	0	0	0
1010_22	Single Type1- Type7	0.25	0	0.25	0.25	2	0	4	8	0.75	0	0	0

**Figure G-2: Snapshot of one of the calculation sheets in the Excel Model**

- (d) **“Scenario\_input”** sheet: This sheet contains the information for a specific scenario, i.e.:
  - (i) Customer interruption cost
  - (ii) Load factor
  - (iii) Power factor
  - (iv) Project life

This sheet is also linked to the input sheet such that the input data can be changed to perform different scenarios. The input data that can be changed from this sheet is:

- (v) Voltage (upstream and downstream busbar)
  - (vi) Number of source and load feeders (upstream and downstream busbar)
  - (vii) Peak load (upstream and downstream busbar)
- (e) **“Clustering”** sheet: This sheet calculates the total score of each substation for all scenarios within a cluster and then rank the options to determine the preferred substation configuration. It is important to note that a macro is used for this step. This macro requires an input sheet which specifies all the inputs that should be considered for each of the different scenarios within the cluster. The macro runs through the following steps for each scenario:
- (i) Paste the data from the scenario input sheet to the scenarion sheet
  - (ii) Perform the life cycle cost calculation
  - (iii) Paste the “score” of each substation to the clustering sheet, in the column identified for the specific scenario.

These three steps are repeated for each scenario. Once the results for all scenarios are pasted, the total substation “score” for the cluster is calculated, and the substations are ranked to determine the preferred configuration.

ooooo End of document ooooo