University of Southern Queensland
Faculty of Engineering and Surveying

Modern Distribution Network Planning and Application to Development of Electricity Infrastructure

A Dissertation Submitted by
Grujica S. Ivanovich
Principal Engineer Distribution Planning and Capacity
Ergon Energy
2010

In fulfilment of the requirements of
Master of Engineering Research

Abstract

The Network Planners face significant challenges in planning and development of electricity networks. These challenges are driven by different factors. The most influential factors are change of economic environment and regulation models, climate and weather patterns, implementation of new technologies, multiple customer choice and transition of distribution networks from passive to active and more sustainable models.

In the last few years we have seen dramatic changes in the network nature, its topology and load management options. Parallel with intensive load growth, different energy supply models are evolving forcing distribution planners to accommodate new techniques and planning methodologies to simulate and efficiently plan future networks.

The modern Distribution Network Planning implements combination of traditional network planning options and so called non-network solutions. Advance load forecasting techniques and simulation of network dynamics based on different topologies, variable system regimes and load categories with detail network and project risk assessments are its core components. It also includes study of network demand management, smart grids, distributed energy resources (DER), embedded generation, energy storage equipment and grid support systems. Modelling of impact on distribution High (HV) and Low (LV) networks of photovoltaic (PV) units and other renewable, alternative and new technologies is now an organic part of distribution planning processes, as well as understanding of all aspects of massive penetration of plug-in electric vehicles (PEV) in electricity network which is expected in near future.

This Master Dissertation firstly formulates position of the Distribution Network Planning in the business model of the majority of electricity utilities and interfaces with numerous stakeholders and describes fundamental components of distribution planning principles.

In the next step, it describes limitations of existing distribution planning principles and after the revision of available literature provides concept of new distribution planning principles to meet future technical, economical, technological, environmental and loading challenges.

The critical network planning components are also studied. Principles of load forecasting, plant rating, voltage regulation management, system reliability, power quality, network power losses, renewable and smart grid scenarios followed by project and network risk assessment and project economic evaluation are demonstrated.

Finally modern distribution planning principles are applied in a real distribution network augmentation project related to long term planning of the airport electricity infrastructure. This Master Dissertation uses the airport only as an example application and addresses the examiner's comments.

Certification of Dissertation

I certify that the ideas, studies, analysis, results and conclusions set out in this dissertation are entirely my own effort except where otherwise indicted and acknowledged.

I further certify that the work is original and has not been previously submitted for assessment in any other course or institution.

Grujica S. Ivanovich (Candidate) Date

Professor David Thorpe (Supervisor) Date

Acknowledgements

There are numerous people who have contributed either directly or indirectly to this work. I would like to thank firstly my family, my wife Natasha and our little stars, daughter Tijana and son Dushan who graciously accepted my spiritual absence from home during the writing this thesis.

I would like to thank my late parents Stale and Mila for their support from the heavens and provided opportunity to exist on this planet and create things which will last for decades and serve for good of the future generations.

I would also like to acknowledge my supervisor Prof Dr David Thorpe. This study would not have been possible without his continued guidance, support and advice. Throughout the duration of this project he has been extremely patient, inspiring and has been a pleasure to work with.

I am also very grateful to Prof Dr Ron Sharma and Dr Fouad Kamel for their comments, technical advices, continued support, interest in and assistance with the project.

There were also numerous colleagues in Ergon Energy, supervisors of Graduate Electrical Engineers and Co-op Engineering Students, who gave encouragement to complete the project. In particular, I would like to mention Distribution Planning Engineers Peter Bacic, Blake Harvey and Russell Christ and Network Capability and Utilisation Engineers Lee Hermann and Jian Bin Zhou.

Finally, but by no means last, I wish to thank the Faculty of Engineering and Surveying and the Office of Research and Higher Degrees for their support and assistance. My thanks also extends to all those at the University who made this such a pleasant experience.

Table of Contents

List of Tables

List of Figures

Glossary

AAWI	Average Annualised Wage Increase
ABS	Australian Bureau of Statistics
ADMD	After Diversity Maximum Demand
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AEP	Asset Equipment Plan
AER	Australian Energy Regulator
AMI	Advanced Metering Infrastructure
CAC	Connection Asset Customer
CAPEX	Capital Expenditure
CICW	Customer Initiated Capital Works
Code	Queensland Electricity Industry Code
CPI	Consumer Price Index
CPRS	Carbon Pollution Reduction Scheme
DC	Direct Current
DEE	Dangerous Electrical Events
DM	Demand Management
DMIA	Demand Management Innovation Allowance
DMIS	Demand Management Incentive Scheme
DMS	Demand Management System
DNAP	Distribution Network Augmentation Plan
DNSP	Distribution Network Service Provider
DUOS	Distribution Use of System
EDSD Review	Electricity Distribution and Service Delivery Review
EE	Ergon Energy
EG	Embedded Generator
EGW	Electricity Gas Water
EK	Elektrokosmet
ENA	Energy Networks Association
ESOO	Electricity Statement of Opportunities
EX	Energex
FIT	Feed-in-tariff
GDP	Gross Domestic Product
GRP	Gross Regional Product
GSL	Guaranteed Service Level
GSP	Gross State Product

GST	Goods and Services Tax
GW	Gigawatt
GWh	Gigawatt hour
HDBC	Hard Drawn Bare Copper
HVDC	High Voltage Direct Current
ICC	Individually Calculated Customer
ICT	Information Communication and Telecommunications
IT	Information Technology
kV	Kilovolt
kVA	Kilovolt-ampere
kW	Kilowatt
kWh	Kilowatt Hour
LV	Low Voltage
MAIFI	Momentary Average Interruption Frequency Index
MAR	Maximum Allowable Revenue
MED	Major Event Day
MSS	Minimum Service Standard
MVA	Megavolts-ampere
MVAR	Megavar reactive component of power
MW	Megawatt
MWh	Megawatt hour
NDM	Network Demand Management
NEEI	National Energy Efficiency Initiative
NER	National Electricity Rules
NIEIR	National Institute of Economic and Industrial Research
NMI	National Metering Identifier
NPV	Net Present Value
OPEX	Operating Expenditure
PoE	Probability of Exceedance
QCA	Queensland Competition Authority
RE	Renewable Energy
Rules	National Electricity Rules
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control and Data Acquisition
SCAMS	Substation Contingency and Management System

SGSC	Smart Grid, Smart City
SNAP	Sub-transmission Network Augmentation Plan
SWER	Single Wire Earth Return
TaDS	Transmission and Distribution Services
TCP	Transmission Connection Point
TMED	Major Event Day Threshold
TWI	Trade Weighted Index
UbiNet	Ubiquitous Network
URD	Urban Residential Development
VAr	Volt Ampere Reactive
VCR	Value of Customer Reliability
VR	Voltage Regulator
VT	Voltage Transformer
W	Watt
WACC	Weighted Average Cost of Capital

Definitions

This chapter is combination of Literature Review and the Author independent works. The author extended the list of definitions (including some of the new definitions) to cover most of the areas of power engineering discussed in this study.

ABS: Air Break Switch - A switch in which the interruption of the circuit occurs in air. Air is used as the insulation medium between the open contacts

AAAC: All Aluminium Alloy 6201 Conductor

AAC: All Aluminium Conductor

ACAR: All Aluminium Alloy Reinforced

ACSR: Aluminium Conductor Steel Reinforced

ACSS/TW: High Temperature EC Aluminium Conductor Steel Supported

ADMD: After Diversity Maximum Demand. For most residential and rural customers ADMD is in the order of 3 - 6kVA, equating to 12 - 24A

Bandwidth Setting: A deliberate band of inaction within the VRR to ensure the voltage regulating scheme is stable and does not action merely because of previous action

BSS (BSP): Bulk Supply Substations or Bulk Supply Point (110/33kV, 132/66kV, 220/110kV) – a transmission substation that supplies electricity to transmission and sub-transmission networks of electricity distributors

CAIDI: Customer Average Interruption Duration Index (minutes). Average duration of each permanent interruption (= SAIDI/SAIFI).

CB: Circuit Breaker – an automatically-operated electric switch designed to protect an electric circuit from damage caused by overload or short circuit. Its basic function is to detect a fault condition and, by interrupting continuity, to immediately discontinue electrical flow

CD (Customer/km^2): Customer Density

Contingency Event: As defined by the National Electricity Rules: "an event affecting the power system which NEMMCO experts would be likely to involve the failure or removal from operating service of a generating unit or transmission element."

Customer: An entity or individual who is an end-user of electricity

Distribution (High or Medium) Voltage: A voltage nominally greater than 1000V but less than or equal to 35kV. For the purpose of this document nominally voltages of 3.3kV, 6.6kV, 11kV, 12.7kV, 19.1kV, 22kV and 33kV where there is a direct conversion to low voltage

Discount Rate: The rate used to discount future cash flows to their present values

DLR: Dynamic Line Rating – ratings for equipment which a based on real time or near real-time measurement of loading, ambient conditions and equipment temperature data

DME: Department of Minerals and Energy (Queensland Government) – the technical regulator

DNSP: Distribution Network Service Provider

DSA: Distribution System Automation

DSS: Distribution Substation – a substation with a primary voltage of 11kV, 12.7kV, 19.1kV, 22kV or 33kV and low voltage as a secondary

DTS: Distributed Temperature Sensing - a tool that allows the accurate rating of UG cables in real time

ECR: Emergency Cyclic Rating - maximum permissible peak daily emergency loading for the given load cycle that a transformer can supply without exceeding the maximum allowable hotspot temperature of 140^{o}C

Fault Rating: The capability of the equipment to carry or interrupt fault currents, which are specified as rated short-time current or short circuit breaking capacity

Feeder Type: An isolated, long rural, short rural or urban feeder as the case may be

Float Voltage: The voltage level set to the VR relay

GHGE (t, CO_2/p.a.): Annual Greenhouse Gas Emission

HVDC: High-Voltage Direct Current System, use predominantly in power systems with long undersea cable links (> 50 km) and long overhead lines (> 600 km), for interconnection of different grids or networks, where control of transmitted power is of importance or combinations of the above

Internal Rate of Return (**IRR**): Is a rate of return used in capital budgeting to measure and compare the profitability of investments. It is also called the rate of return (ROR). In more familiar terms, the IRR of an investment is the interest rate at which the costs of the investment lead to the benefits of the investment.

Interruption: Any loss of electricity supply to a customer which is associated with an outage on any part of the electricity supply system up to, but not including, the service fuse. An interruption is reported as starting when remote monitoring equipment signals the loss of supply or where monitoring equipment is not installed: when the customer first reports the loss of supply.

I^2R (kW): Conductor Losses

Isolated Feeder: A feeder that is not connected to the national grid, as that network is defined in the Electricity Act.

LD (kVA/km^2): Load Density

LDC: Load Drop Compensation, an auxiliary control equipment which makes a voltage regulator hold a fixed voltage at a point remote from the voltage regulator by making the regulator output voltage components for voltage drop in part of the feeder

LCM: Lost Customer Minutes

LF: Load Factor - the average power divided by the peak power, over a period of time (0<LF=1)

Long Rural Feeder (LR): A feeder which is not a CBD, urban or isolated feeder with a total route length greater than 200 km.

Loss Factor: It is an expression of the average power factor over a given period of time, and is used in the energy industry to express the losses in transmission and distribution from heat, incomplete combustion of fuels and other inefficiencies.

Low Voltage (LV): Nominally 230/400 volts, but includes 240/480 volt systems (voltage up to and equal to 1000 volts)

MAIFI: Momentary Average Interruption Frequency Index is the average number of momentary interruptions per customer

MD: Maximum Demand is the largest current normally carried by circuits, switches and protective devices; it does not include the levels of current flowing under overload or short circuit conditions

Minimum Service Standard (MSS): The minimum standard for SAIDI and SAIFI network reliability that customers can expect on average

Momentary Interruptions: Interruptions in the supply voltage for longer than 0.5 second up to 1 minute in duration. Momentary interruptions are typically between 1 to 10 seconds in duration and relate to the dead-time of reclosers and auto reclosing circuit breakers

Nameplate Rating: The continuous rating of the equipment

NCR: Normal Cyclic Rating – maximum permissible peak daily loading for the given load cycle that a transformer can supply each day of its life, through summer and winter ambient temperatures, without reducing the designed life of the transformer

NDM: Network Demand Management – peak load management process which includes load reduction at the customer levels (e.g. changing tariff structure and improving insulation of houses)

NEMMCO: The National Electricity Market Management Company. NEMMCO is responsible for the operation and administration of the National Electricity Market in Australia

NER: National Electricity Rules

NPV: Net Present Value is defined as the total present value (PV) of a time series of cash flows. It is a standard method for using the time value of money to appraise long-term projects.

Outage: A planned or unplanned loss of supply which may affect customers.

P: Real (Active) Power - the capacity of the circuit for performing work in a particular time (Watts)

PF: Power Factor - the ratio of the real power flowing to the load to the apparent power and is a number between 0 and 1 (frequently expressed as a percentage, e.g. 0.5 pf = 50% pf). Power factor only applies to alternating current (AC). Direct current always has a power factor of 100%.

PMR: Pole Mounted Recloser

Payback Period: In business and economics refers to the period of time required for the return on an investment to "repay" the sum of the original investment

PoE (10% and 50%): 10% and 50% Probability of Exceedance – the forecasted load which has a 10% (50%) probability of being met or exceeded for a given year (e.g. the load that will occur as a result of a 1 in 10 year (10%PoE), or of a 1 in 2 year (50%PoE) summer in terms of maximum demand

POPS: Plant Overload Protection Scheme is a protection scheme using logic and load measurement to protect plant against overload where deliberate acceptance of risk of inability to supply is policy. It may be associated with underfrequency load shedding circuitry

Power Quality (PQ) or Quality of Supply (QoS): the quality of the electricity supply in regards to such things as waveform quality, frequency, voltage levels and rate of change of voltage

PV: Photovoltaic Systems which convert solar into electric energy and interfaced to the grids through power electronic converters

Q: Reactive Power is a concept used to describe the loss of power in a system arising from the production of electric and magnetic fields. Although reactive loads such as inductors and capacitors dissipate no power, they drop voltage and draw current, which creates the impression that they actually do. This “imaginary power” or “phantom power” is called reactive power. It is measured in a unit called Volt-Amps-Reactive (VAR)

QCA: Queensland Competition Authority, the electricity distribution regulatory authority in Queensland

Reliability: The continuity of the electricity supply

RMU: Ring Main Unit - normally consists of switches on both sides of the T-off, one to open the ring and another at the connection to the distribution transformer using switch and a fuse separately, or switch-fuse combination

S: Apparent Power – it is the product of the current and voltage of the circuit. Due to energy stored in the load and returned to the source, or due to a non-linear load that distorts the wave shape of the current drawn from the source, the apparent power can be greater than the real power (kVA)

SAIDI: System Average Interruption Duration Index (min)

SAIFI: System Average Interruption Frequency Index (permanent interruptions)

SCADA: Supervisory Control and Data Acquisition, a computer system for gathering and analysing real-time data

Set Point: The voltage level set to achieve the regulating scheme as sensed by the VR Relay (after any LDC correction is applied)

Smart Grid: The application of information and communication technology to improve the efficiency and effectiveness of the generation, transmission and distribution, and usage of electric power

Short Rural Feeder (SR): A feeder with a total route length less than 200 km, and which is not a CBD, urban or an isolated feeder

STR: Soil Thermal Resistivity, it affects the basic UG cable rating values, cyclic rating factors and heating due to neighbouring cables (m.K/W)

Sustained Interruption: Loss of electricity supply to a customer which is associated with an outage on any part of the electricity supply system and which exceeds one minute in duration

STER: Short-time Emergency Rating - maximum permissible loading for the given load cycle that a transformer can supply for up to two hours, immediately following the loss of one of the transformers in a multiple transformer zone substation, where each of the transformers had been previously supplying its share of the substation's short-time emergency capacity. By the end of two hours, the load has to be reduced to at least the emergency cyclic rating

Sub-transmission Voltage: For the purpose of this document nominally 33kV and 66kV

System Loss: The total of all energy lost or wasted on a system due to line loss and other forms of energy loss, unaccounted energy use and theft among other factors is referred to as system loss

Swell: A temporary increase of the rms voltage at a point in the electrical system above a threshold for less than 1 minute. Swells are described by duration and maximum voltage

SWER: Single Wire Earth Return supply system used to supply remote rural areas

Switchgear: The combination of electrical disconnects, fuses and/or circuit breakers used to isolate electrical equipment. Switchgear is used both to de-energize equipment to allow work to be done and to clear faults downstream

THD: Total Harmonic Distortion, a measure of the effective value of harmonic distortion

Time Delay: A deliberate period of inaction within the VR Relay to ensure the voltage regulating scheme is stable and does not action merely because of previous action and the result of this change on the power system and other voltage regulators. It may be dependent on the magnitude of any variation from the set point seen by the VR Relay. A suitable setting also helps to guard against excessive system voltages following transient or short term line outages

TNSP: Transmission Network Service Provider

Transmission Voltage: For the purpose of this document nominally 110kV, 132kV and 220kV

Transients: Very short event variations caused by load switching or lightning. Transient types include oscillatory and impulsive

Urban Feeder (UR): A feeder with an annual actual maximum demand per total feeder route length greater than 0.3 MVA/km and which is not a CBD, short rural, long rural or an isolated feeder

Voltage Fluctuations: Random or continuous variations of the voltage. They are generally caused by customer load switching and may be caused by network switching.

Voltage Regulation: The level of variation in the voltage that occurs at a site

Voltage Sag (dip): A temporary reduction of the voltage at a point in the electrical system below 90% of the nominal. Sags are described not only by retained voltage but also duration. They may last from half a cycle to one minute

Voltage Unbalance: A condition in poly-phase systems in which the rms values of line to line voltages (fundamental component) or the phase angles between them are not all equal

XLPE: Cross Linked Polyethylene Underground Cable

ZSS: Zone Substations (66/11kV, 66/22kV, 33/11kV, 33/22kV, 110/11kV, 132/22kV) are supplied from BSS via transmission (132kV or 110kV) or sub-transmission feeders (66kV or 33kV) and provide supply for distribution feeders (11, 22 or 33kV).

CHAPTER 1

INTRODUCTION

Electricity systems are complex, with literally hundreds of thousands of individual components, each with differing characteristics, ages and interdependencies. This network continuously balances supply and demand, subject to the variances of weather, temperature, customer behaviours and random events elaborated upon later (Chapter 4).

Planning and development of distribution networks pursues a number of often conflicting objectives such as:

- Distribution network load forecasting
- Constraint identification
- Provision of capable and safe distribution network that will supply existing and future customers loads
- Elimination of existing and future system constraints
- Minimization of power losses
- Improvement of network reliabilities with minimization of not supplied load and energy and reduced customer loss minutes
- Maintain appropriate quality of supply and levels of reliability on the existing distribution network
- Minimization of investment and operation and maintenance costs
- Development of an effective capital investment programme based on project priorities and risk assessments
- Integration of distribution augmentation plans with other capital works, etc.

Some of the above objectives are in conflict because by their nature distribution network assets are ‘long lived’. Any deferral of capital expenditure or stage development may appear attractive economically, but not necessarily technically attractive, where ‘early intervention’ may appear logical.

It is why in the context of the Electricity Supply Industry, planning is generally considered as:

I. Part engineering science
II. Part experience
III. Part intuition
IV. Part inspirational visionary and
V. Part art.

A variety of different static and dynamic objectives, as well as combination of engineering approaches in solving planning problems, make the concept of distribution network planning so attractive, interesting and important subject which shape future of the humankind.

1.1 Position of Distribution Network Planning in Electricity Utility

Commonly used single and three-phase distribution voltages are 11kV and 22kV. There are also other voltages (33kV, 5kV, 6.6 kV, 3.3 kV) to be found, but in minority. The rural regions are also serviced by single wire earth return (SWER) systems (11, 12.7 and 19.1kV). Planning and development of these systems is primary task of distribution network planning.

The position of distribution network planning in modern electricity utilities is very specific. It is dictated by its accountabilities, business models and internal organisational structure. However, the major roles of Distribution Planning are universal and based on the author's experience address the following five planning levels of distribution network:

- Contingency planning
- Operational planning
- Project planning
- Short term planning
- Long-term (Strategic) planning.

Distribution High Voltage (HV) network is the major subject of Distribution Planning. With Low Voltage (LV) networks, distribution feeders are the most dynamic parts of electricity systems, with extensive 'planned' and 'un-planned' reconfigurations. Some of distribution networks are subjects of thousands modifications and reconfigurations on the daily basis (as parts of standard contingency, operational and project planning processes).

The focus of this research project is a study of existing distribution network planning model and development of proposed modern distribution planning processes related to short- and long-term planning of distribution network developments to meet the future load growth, planning and security criteria and environmental/climate change requirements.

Distribution Planning is one of the central groups in Network Management structure, with very complex and intensive interfaces with other groups and processes. Figure 1.1 shows position of Distribution Planning in Ergon Energy. In its sphere of influence are 'planning related' groups, like sub-transmission and substation planning, network development, strategic planning, customer connections, plant rating, network operations and reliability planning, as well as groups with organic connections with planning like protection, system maintenance, communication, SCADA (Supervisory Control and Data Acquisition), project management, asset planning, power quality, network design, network demand management, renewable and alternative energy solutions and system investigations. A very important component of modern distribution planning is also related to co-operation and joint workings with other distribution planning groups, research centres, universities and local town planning groups.

The Distribution Planner is generally the first point of contact for major developments and projects within the regions. Examples might be a new shopping centre, a new mining venture or some other significant business enterprise. They are therefore the 'eyes and ears' of the organisation in preparing for new electrical loads and load growth generally. Also, from time-to-time, the various groups will contact the Distribution Planner seeking general information on feeder loading, load growth rates, major new customers, etc. This information is aggregated across electricity utility, to in turn to provide data to allow them to plan the required transmission infrastructure.

Figure 1.1 – Position of Distribution Network Planning

Parallel with improvement of system capabilities, voltage regulation and system fault levels, Distribution Planning improves network reliability and quality of supply. Typical example of reliability improvement is planning of establishment of new distribution feeder or system reconfiguration which provide improved reliability indices.

Improved voltage regulation and system re-arrangement recommended by Distribution Planning Engineer improves voltage profile of distribution feeder, including voltage variations, harmonics, unbalances and other quality of supply factors.

In addition to planning, development and technical importance, Distribution Planning has a huge impact on financial component of capital planning management and general project life cycle. It is at the beginning of project management, at the very first stage in the project life cycle and any potential problems in its organisation and process structure could have serious impact on the next stages of a particular project and entire Capital Expenditure Programme (CAPEX).

1.2 Existing Model of Distribution Network Planning

The ‘traditional’ concept of general distribution planning process developed by this author in Ergon Energy in 2001 introduced has four major components – study of existing networks to address existing limitations, investigated network augmentation related options (‘network solutions’), comparisons of different network options (traditionally, one preferred and two or three alternative options) and recommended works with technical, financial and risk assessment components included (Figure 1.2). It is so called ‘development’ or ‘planning report’ stage in project life cycle, at the beginning of project management process. The next stage is design based on planning report recommendations.

A big disadvantage of the old planning scheme is the presence of only ‘traditional’ network solutions and lack of renewable and alternative energy solutions. Also, another big limitation is that technical, financial and risk assessments are placed in the last stage of distribution planning process (‘Recommendation’), just before transition of project from planning into design stage. Any additional corrections (e.g. preliminary project quote estimate) could cause delay in finalisation of distribution planning stage and consequently re-scheduling of all next project stages.

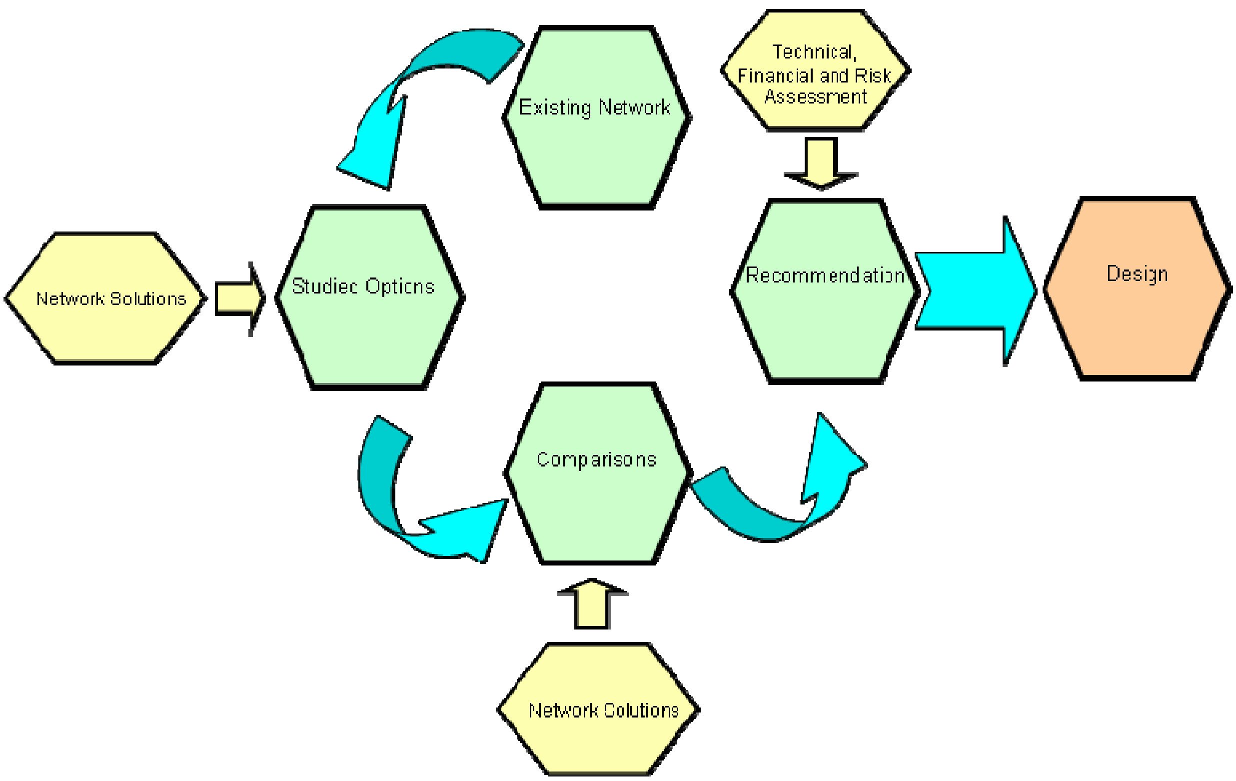


Figure 1.2 – ‘Traditional’ Distribution Planning Process

There is another important limitation of ‘traditional’ distribution planning. It is also known as ‘static’ planning because its treats the distribution network as a static subject with load flow models and analysis based on three ‘static’ values based on low (30%), medium (50%) and peak (100%) load conditions. Consequently, such network models have ‘static’ presentation of load and voltage profiles, without active or dynamic components which are actually among the major characteristics of distribution network.

Further analysis of the four major components shows that the ‘traditional’ concept of existing network study has two major limitations. Firstly, it is related ‘only’ to distribution network from the feeder circuit breakers (CB) to distribution substations, which means that distribution planning process ignored upstream assets – substations (zone and bulk) and transmission networks (sub-transmission and transmission). Secondly, components of existing network study, as shown on Figure 1.3, although covering important parts of the distribution feeder do not provide full picture about the ‘health’ of distribution systems. When the network planner opens the model of a particular distribution feeder the very first impression is its similarity with the human body. The zone substation represents the head and heart, feeder backbone logically human’s backbone and spurs hands and legs. Even, there are ‘old’ and ‘young’ feeders, there are reinforced systems with different amputations added to extend their operational and economical lives, new feeders supplied from very old substations, or old feeders with new components. Every feeder has specific characteristics and one of the major ones is its natural status, its ‘health’ conditions. On the feeder ‘body’ there are hundreds of poles, switching, protection and metering devices, voltage regulators, reactors and capacitors, kilometres of overhead conductors and (sometimes) underground cables. These feeder components serve to supply loads based on planning and security criteria, with adequate reliability and power quality, to protect the feeder (or its sections) and to extend feeder’s functionality. They also serve as some kind of sensors distributed across the entire body of the feeder, providing network planning engineers with critical data about the status of the feeder, actually about the health of the feeder.

The ‘traditional’ concept of existing distribution network study has vertical structure distribution planning that includes only partially overview of feeder status (Figure 1.3). Technical characteristics have very basic components, like area of supply, feeder total length and backbone conductor. Feeder capacity and capability are based on its technical characteristics, maximum load and very general weather conditions (summer and winter, day and night) for the entire region.

The component of customers represents a simple collection of customer numbers and their major load type characteristics (domestic, industrial, commercial and mixed). In conjunction with feeder technical characteristics and operational performances, this chapter includes very basic ‘customer related’ reliability indices of a particular feeder providing only part of the real reliability picture. As noted, modelling and load and voltage profile components provide only level of constraints based on ‘static’ simulations, as understanding of fault levels was composed together with protection specifics. Finally, feeder load forecast includes future major customers (‘block loads’) and natural load growth without detail understanding of energy forecast and weather corrections.

Such vertical profile of existing network study is simple statistical analysis of several, but not all feeder/load components. The rapid change of environment (network topologies, area of supply, load profiles and climate) requires different model of distribution planning. ‘Traditional’ concept is simple not enough to address all critical issues and develop the best configurations capable to meet future requirements.

Based on the author’s expertise, the major limitations of the ‘traditional’ concept are:

I. Covers only parts of distribution network
II. Lack of interfaces with sub-transmission components of the network
III. Full understanding of voltage regulation specifics
IV. Use of static ratings
V. Exclusion of dynamic plant ratings and scientific validation of weather parameters for different climate zones
VI. Lack of energy and load driven reliability indices
VII. Ignorance of importance of energy forecasts and weather correction parameters
VIII. Impact of network topologies and load profiles on climate change is not addressed
IX. Renewable and alternative energy solutions are excluded.

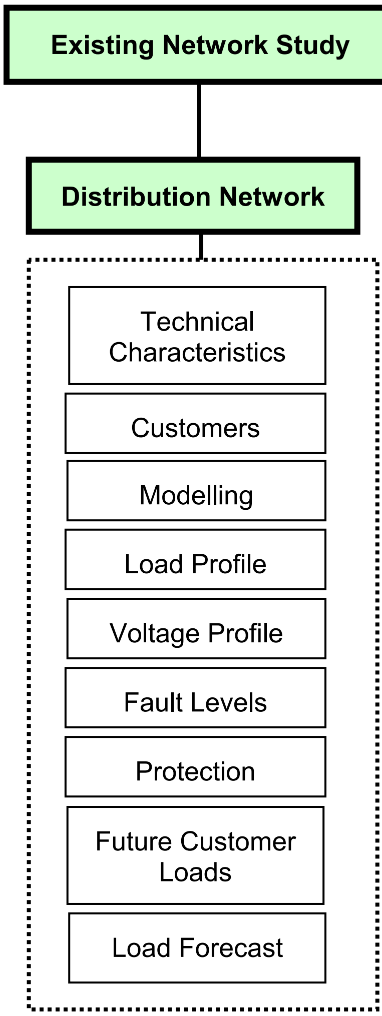


Figure 1.3 – Components of Existing Network Study

Exclusion of energy and load related reliability indices from existing distribution network study have negative consequence on project economics addressed in the last component of 'traditional' concept of distribution planning ('Recommendations'). Economic model includes comparison of finance elements related to capital and operational/maintenance cost and expected project benefits usually based only on reduced power losses (converted to dollars). In distinction to customer reliability indices, driven by government regulatory requirements, energy and load related reliability indices have also dollar components which can be utilised in Net Present Value (NPV) analysis to improve benefits of recommendations and provide additional justification for its implementation.

1.3 Project Objectives

The aim of this project is to analyse the following major components of the 'traditional' distribution planning process:

- Initiation of distribution planning study
- Determination of project objectives
- Data management
- Planning and security criteria
- Study of existing network
- Characteristics of supplied area
- Existing limitations
- Customer connections and specifics
- Load forecasting
- Future system constraints to meet load growth
- Network modelling
- Study of different network options
- Proposed option
- Technical recommendations
- Characteristics of proposed network
- Preliminary project quote estimate
- Comparisons of different options – advantages and disadvantages.

After addressing limitations of 'traditional' distribution planning model, this research project develops modern distribution planning processes and demonstrate practical applications of modern planning methodologies into the real distribution network augmentation project associated with the long term development of the airport distribution network (Figure 1.4).

Development of modern distribution planning principles is the product of long time experience in planning and development departments of distribution companies of 'Elektrokosmet' (EK, Serbia) and Energex (EX, Australia) and Ergon Energy (EE, Australia). In addition, a lot of research works have been carried out, including studies of planning processes in national and international electricity utilities. An important part of this Dissertation is also revision of available literature. This will be discussed in Chapter 2.

1.4 Application

The application part of this dissertation has two major parts – research and study and technical implementation of recommended solutions.

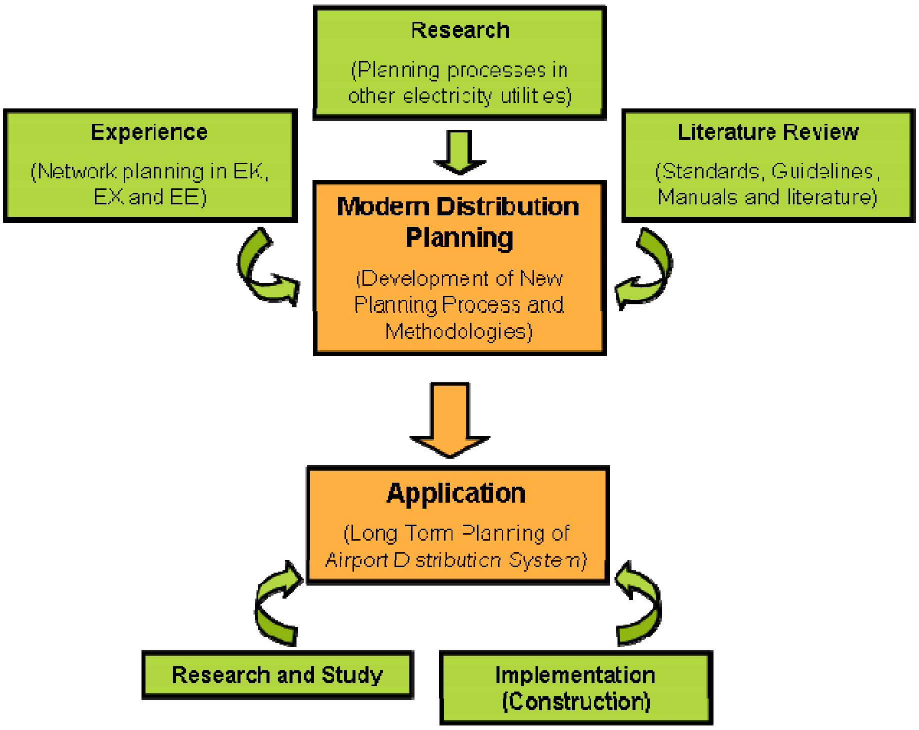


Figure 1.4 – Components of research project

The author is demonstrating planning applications on a very specific project – long term development of distribution network on one of the major airports. The idea to consider analysis of electricity network supplying the largest airports as a subject for this thesis is based on strategic distribution planning study completed for one of the corporations managing infrastructure of one of the largest airports in Australia. This study is a worldwide pioneering study in the field of the long term planning of electricity systems of the modern airports. Recommendations from the report have been included in the next two Capital Expenditure periods (until 2015) and most of them have already been implemented or are currently in different construction stages.

The study was primarily driven by existing constraints of the airport electricity network (distribution and sub-transmission) and the extensive expected level of developments at the airport in the next decades. In addition, for the first time modern planning criteria from electricity industry have been implemented in long term development of one of the airports. This study included research and investigation of the airport electricity infrastructure which may be implemented in future developments of any modern airport in the world.

Compare with studies of areas supplied by standard distribution network, the profile of electricity supply of large airports has lot of specifics and challenges. They are related above all to a high concentration of continues and sensitive loads, predominantly supplied via an extensive UG system. Management of such a network, its control, operation, planning and development requires implementation of the new principles and non-standard methods implemented in this study.

This research project could also be utilised in more effective transition of the future generations of Graduate Electrical Engineers from the university to the electricity industry.

1.5 Project Considerations

The major considerations of this research project are:

- Project outcomes must be applicable to the current environment and operating standards of modern electricity utilities and
- Confidentiality issues related to the strategic study of the airport distribution network in regards to the release of specific data and goals from the project

1.6 Outline of Dissertation

This Master Dissertation is structured based on the following major parts:

- Chapter 2 is a review of publications and corporation materials that are relevant to this work
- Chapter 3 is devoted to explanation of proposed modern distribution planning principles. Understanding of the concept of electricity network planning, its specifics and interactions and platform for transition from 'traditional' to 'modern' planning are among the main challenges in the changing environment of the 21st century. In the frame of this thesis, specific modern distribution principles developed during the studies of electricity networks have been included.
- Chapters 4-12 consider all major components in distribution planning. It includes load forecasting, plant rating, system reliability, voltage regulation, power quality, SWER networks, renewable energy solutions, smart grids, network risk management and economics of distribution planning principles
- Chapter 13 provides application of modern distribution planning principles into the real augmentation project. Results from a detailed strategic distribution planning study of one of the modern airports are presented in this chapter. The airport distribution network system planning incorporates the following components:
    - Different elements of the airport master plan
    - Load forecasting methods
    - Factors that are considered in airport strategic distribution system planning
    - Risk assessment and risk analyses of the airport distribution network
    - Climate change effects of the existing and future airport distribution network
    - Project management of the airport distribution network augmentation
    - Assessment of estimated costs of the airport distribution network augmentation
- Chapter 14 concludes the dissertation. It includes a summary of project achievements, discussion, suggestions for further work and educational part which may be evaluated as a separate thesis.

CHAPTER 2

LITERATURE REVIEW

2.1 Introduction

Components of distribution planning processes have been more or less research topics for decades and this has resulted in a relatively large number of publications. Hundreds of papers have been published dealing with topics such as statistical analysis of network data, assessment of power system components, reliability theory, probabilistic load flow, transient analysis, voltage regulation, power quality, project risk assessment and economic evaluations. Yet, in spite of a tremendous growth in the number of papers and their applications in various areas of distribution planning, there is no single book which could serve as a reference source for a network planning engineer or a student interested in the topic of principles of distribution planning processes.

After an exhaustive review of current international literature the author has identified several mostly international papers and documents which describe some of the aspects of general distribution network planning business models. In Australia, a very brief description of major components of distribution planning processes can be found in the Sinclair Knight Merz's (SKM) report for the Australian Energy Market Commission (AEMC) and presentations in the Network Planning Session on the 3rd Ergon Energy's Network Conference (2008).

In addition to review of relevant available technical literature on distributed network planning, this project includes revisions of the Distribution Network Service Provider's (DNSP's) Technical Standards, Australian Standards and technical literature about modern airport infrastructure planning.

Papers were selected for this review based on their relevance to the specific power engineering fields and generally to the aim of developing modern distribution planning methodologies. The main objective of the review was to ascertain, through the published and non-published works of previous researchers and network planning engineers, the range of feasible existing and future specific engineering areas for their implementation in developed model of modern distribution planning process.

These sources do not address distribution network planning process in general, but only separated components. The major reasons why there is no published literature which covers in details the structure of distribution planning, its processes, interfaces and characteristics are:

- Specifics of distribution planning processes
- Complex interactions with other power engineering areas and
- Differences between business models of electricity utilities.

Logically, the structure of distribution planning models has been driven by internal business plans of electricity utilities. They usually have different planning criteria, different boundaries, different system voltages and different planning responsibilities. It is the main reason why experience collected during the years of work in planning and development departments in different utilities is the basic of this thesis.

Study and analysis of existing distribution networks include the following major areas:

I. Area of supply – size, configuration, environmental, potentials for the future development
II. Topology of existing sub-transmission and distribution networks
III. Load profile including maximum demand based on seasons and period of the day, voltage regulation details, power losses and fault levels

IV. Level of constraints for existing zone sub-stations and distribution feeders and risk assessment
V. Customer connections, tariff structure, type of supplied load, customer and load densities
VI. Protection issues
VII. Network performance including reliability data
VIII. Power quality issues.

Each of these areas has been analysed in different papers with a brief review some of them provided below. Some of them will be elaborated in the chapters that follow.

2.2 Distribution Network Planning Process

CEA (1982) identifies three levels of performance analysis in the distribution planning process. The first level includes analysing the four basic factors:

- Voltage drop
- Thermal capacities
- Short circuit capacities and
- Service reliability.

One or more preliminary technical models of system development result from the first level performance analysis with long-term (master plan) and short-term (equipment scheduling and capital budgets) developed. Financial model may be applied at this level. Second level supplements co-ordinated protection, voltage fluctuation and harmonics as components of the second level analysis. Finally, third level covers insulation co-ordination and physical limitations.

Neimane and Andersson (1999, p. 260) suggest a multi-criteria dynamic approach to distribution network reinforcement planning. The aim of the dynamic optimisation is to find the best strategy of the network development among the set of possible development plans during the estimation period, minimising simultaneously several objectives. Four criteria have been identified in the model – cost, reliability, annual losses and security constraints on voltage drops and line currents.

According to Neimane (2001, p. 344) the complexity of distribution planning processes is mainly caused by presence of multiple objectives, large number of variables and especially uncertain information.

Based on SKM's report (2005, pp 25-40), conceptual distribution planning process has four major steps – load forecast, constraints identification, options analysis and capital approval, programming and governance. It also identifies demand management and embedded generation as an important consideration in the system planning process and recognises climate change and its impact on the future load growth.

The hierarchy of objectives for Distribution Network Planning described by Abdallah (2005, pp 644-647) identifies satisfaction of growing and changing load demand economically, reliably and based on safety standards as general objectives. Planning and development of distribution networks pursues a number of conflicting objectives: minimization of power losses, capital investments, operation and maintenance cost and energy not supplied due to interruption in the network.

Further on, this author illustrates the mathematical and the algorithm of the branch and bound method to find the optimal design configuration for the distribution networks, and improve efficiency of planning process.

This method however, does not address all major components of distribution network planning process and excludes analysis of some of its critical drivers like improvement of voltage regulation, power quality, fault levels, plant rating and impact of renewable energy sources.

Jain at al. (2008) notes that at the beginning of the planning process the future requirements as well as decisive parameters, like load growth, equipment standards have to be specified by the utility and the consultant. All collected points will be taken into consideration to develop suitable variants for the future network. The key point is that suitable measures for short- and medium-term development are influenced by the long-term planning concept. Therefore, the general long-term concept is setting the course and gives the basis for detailed next year decisions.

According ADEA (2008), effective distribution network planning process begins from distribution system and identification of requirement for reinforcements and future expansions, which is known as the ‘bottom-up’ approach.

2.3 Load Forecasting

According to a report by Acil Tasman (2010, p.2), principles of best practice spatial demand forecasting requires that both top-down and bottom-up spatial forecasts are produced independently of one another, and including proper weather correction and normalisation, temporary load transfers and discrete block loads. On the system based level, another report by Acil Tasman (2010, p.5) presents a method which uses energy and maximum load peak load forecast in combination with weather correction, economic and demographic data. Although highly sophisticated and comprehensive, this approach has a big disadvantage as it recommends use of temperature variation as the main component of weather correction and Probability of Exceedence (PoE) methodology. Demands driven by non-temperature sensitive loads (like mines and irrigation systems, for example) are excluded from this model consequently leading to conclusion that it is appropriate only for small and composed electricity systems. Another negative observation is that the determination of long term losses is not addressed as an important part of load forecasting.

On the opposite side, Ivosevic (1970, p. 446) puts in the focus of load and energy forecasting economic growth as the main driver. He describes three major components dictating increase of maximum demand and energy consumption over the time. One component has a monotonous character during the long period of time. Some economic activities have increasing trends, and at the same time others shows signs of regression. They both combine form the most influential factor in economic growth development. The second component is periodical, repeating in certain intervals of time, as the third one so called ‘sudden’ component has characteristics of temporary, short-time events happening with no strict economic rules.

2.4 Network Reliability

In the field of network reliability, Anders (1990. p.318) describes probability concepts in electric power systems, highlighting the problem of treating the frequency and duration indices as random variables.

ESSA Guidelines for Reliability Assessment Planning (1995, p.24) explains slow introduction of probabilistic reliability analysis based on Markov modelling due to lack of motivation in low inflation high growth environments and difficulties with data management. However, this source clearly presents importance of energy and load related reliability indices and notes that probabilistic reliability techniques has contributed to the development of new project ranking.

2.5 Power Quality

In his book, Mielczarski (1997, pp 143-189) describes impact of different power quality related factors on distribution networks. In addition to standard power quality factors like harmonics, transients, asymmetry and voltage variations and fluctuations, Mielczarski discuss about problems with management of power disturbances.

For example, Australian Standard AS2279, like most other standards, defines maximum harmonic distortion in the supply voltage at the common coupling point. It does not provide information on reasons for the distortion, assuming that non-linear loads generate harmonic currents. However, voltage distortion depends on the reaction of the network to the injection of harmonic currents, which puts electricity utilities to manage harmonic distortion based using adequate customer connection agreements.

2.6 Network Losses

The calculation of network losses has always been important to system planners and designers, but until the recent introduction of carbon trade scheme their management and reduction have never been accepted in any electricity utility as one of the priorities.

Ivosevic (1970, p. 178) highlights importance to consider continuously power losses in all major network planning studies based on peak load conditions, which is accepted as the basic model in calculation of power losses.

Anders and Mielczarski (1997, pp 281-317) note that efficiency of electricity systems in conjunction with cost of power losses is another important driver in reduction of network losses should be given serious consideration. Among opportunities for loss reduction, authors describe higher distribution voltages and load shifting (or system reconfiguration) as the best methods.

Interestingly, there are no so many published studies about impact of renewable and alternative energy solutions on network losses. Freris and Infield (2009) very briefly talk about this subject and think that it is not always true that renewable energy or distributed generation because are nearer to the loads reduce network losses. Its availability profile in time, according to these authors, should reasonable match that of the local demand which is not always the case.

2.7 Planning of SWER Schemes

Imagined and developed as simple networks supplying very basic loads of no more than 30-50 customers, single wire earth return (SWER) schemes have been evaluated to extremely complex networks with extensive network planning challenges.

Modern SWER networks have typical size of SWER isolating transformer of 100kVA (or more), standard distribution transformers larger than 10kVA, 60-100 (or more) customers and extensive lengths (even >1000km) with very sensitive power quality issues. Unfortunately, although SWER schemes are parts of electricity networks for decades, there are not so many published papers describing their specifics and above all addressing complexity of their future developments.

For decades generations of network planners have been using two iconic SWER sources. 'The father' of SWER schemes, Mandeno (1947, pp 234-270) described the basis of SWER networks, and with The Electricity Authority of New South Wales' book (1968) his material still serves as the main source for SWER planning.

However, these sources provide only basic explanations how SWER operates, about different SWER structures, like single, duplex and triplex-SWER schemes, earthing requirements, protection and design specifics and SWER economics.

Now many SWER networks are reaching capacity. In addition, customer reliability and power quality expectations have increased considerably with the advance of the digital age. Consequently much of the SWER network will require some form of upgrade in the coming years, which is challenge knowing that conventional network augmentations of SWER schemes are costly and difficult to justify. In addition, network planners require better understanding of power quality issues on SWER schemes, especially impact of harmonics on SWER isolating transformer performance and voltage regulation sensitivity in the environment where After Diversity Maximum Demand (ADMD) of single SWER customer exceeds 3kVA and peak load on isolating transformers is over 70-80kVA.

Also, there are very few papers about potential future development options of SWER schemes. In one of them, Wishart (2010) introduces non-embedded distributed generation as one of solutions and notes that the key quantity in this field is to investigate voltage sensitivity with respect to changes in power.

2.8 Plant Rating

The field of plant rating includes five major parts – understanding of ambient conditions, components of substations, overhead lines, underground cables and distribution plants with the current-carrying capabilities. Each of these parts could be divided in separate independent components with specific rating characteristics. Rating of most of them is covered in the manufacturer's manuals and guidelines, which is however statistical capacity which may defer from the real ratings and provide usually too optimistic figures.

In the area of system capacity one of the most influential factors is design and construction / installation, which converts plant rating into one of the most complex engineering areas with huge impact on future planning of electricity networks. It is one of the main reasons why there are no published sources covering rating performances of all network plants. However, some of the distribution utilities internally or with the assistance of external consultants work hardly to produce generic plant rating manuals and address critical issues related to every plant included in the system capacity loop. Old plant rating manual of the Sydney City Council (S.C.C., 1970) is one of the most important sources for network capability and planning engineers.

Also, there has been little attention devoted in the past to the requirement of de-rating factors and deep understanding of their characteristics. With the economic pressure, the distribution systems are becoming more heavily loaded and hence more prone to thermal overloading, so it is an imperative to understand all plant rating issues and design and loading characteristics of individual plants.

Of special interest is understanding of heat model of underground (UG) cable as the current rating of UG cables is dependent on the way heat is transmitted to the cable surface and then dissipated to the surroundings. The classic paper by Neher and McGrath (1957) is still widely used, together with the IEC Standard 287. McAllister (1982) and Anders (1997, pp 23-33) describe heat model of UG cable addressing that conductor and metal sheath are exposed to the maximum temperatures. In another important source, Anders (2005, pp 77-211) describes capability performances of underground cables crossing unfavourable thermal environments. Cable rating standards deal with uniform laying conditions only; in reality, such conditions are very seldom as cables often cross heat sources (other cables), or pass through areas of high soil thermal resistivity reducing their capabilities.

Rating of UG cables is a complex issue with many topics not fully addressed, like forced cooling of the UG cables, rating of cryogenic cables, thermal properties of different soil compositions, dynamic rating of cables and thermal analysis of cable joints. Some of these subjects are too specialized to be included in a general reference and require comprehensive and multidisciplinary plant rating approach highlighted as potential future work in Chapter 14.3 of this Dissertation.

Rating of power transformers is relatively well documented and understood, but traditionally it is analysed independently. In the substation rating loop components like bus-bars, bushings, current transformers and transformer cables have critical importance for capacity of power transformers. This author is managing two groups in Ergon Energy. One of them is Network Capability and Utilisation Group. One of its major accountabilities is submission of detail substation plant rating reports. Based on author's experience, there are lot of examples where even normal capacity of power transformers is limited by the rating and conditions of some of current carrying equipment installed prior to transformer.

Another area which is not well documented is dynamic rating based on real-time ambient conditions and conductor temperature and loads recorded on different sections of the feeder. Dynamic plant rating philosophy introduces a new approach in the field of network capabilities and utilisation and general network management and capital expenditure programmes.

In conjunction with dynamic rating, impact of plant conditions and operational characteristics requires lot of studies in the future to address all relevant factors in the area of system capacity and utilisation.

2.9 Renewable Energy in Power Systems

Renewable energy sources differ from conventional sources in that, generally they cannot be scheduled, they are much smaller than conventional power stations and are often connected to the electricity distribution system rather than the transmission system. The integration of such time variable distributed or embedded sources into electricity network requires special consideration from both - technical and distribution planning process perspective in general.

In the last few years, numerous papers and books have been published focusing on impact of renewable energy sources on distribution networks. However, in Australia the effects of increased photovoltaic (PV) system utilization on the utility grid have not been investigated or analysed in detail, and require further investigation, particularly pertaining to the different network topologies. AS4777 Grid connection of energy systems via, developed from the International IEEE standard 595, has unknown issues at increasing levels of penetration. The application of the AS4777 standard in the Ergon Energy network environment is questioned by the unknown implications of:

- Dynamic power flows and After Diversity Maximum Demand (ADMD) assessment
- Voltage Management
- Summative power quality and harmonic distortion as PV cell systems increase in popularity
- Implications with regard to protection, and islanding in low-fault level locations
- Management processes with regard to device control, data management and connection processes.

Freris and Infield (2009, pp 177-187) note that the connection of a distributed generator usually has the effect of raising the voltage which in addition is a complicated issue by the presence of automatic voltage control mechanisms (like on-load-tap changers or line-drop compensation) in distribution network.

Chant (2009) highlights network control management as one of the critical components in penetration of PV systems in distribution networks. Electricity utilities in Australia leave control of PV systems to the individual owner and as long as PV systems meet requirements from AS4777, they can be connected to the distribution network.

PV systems generally have been considered as individual systems and their respective components. It is important to broaden this view and also regard the total capacity of distributed generation (DG) on the distribution network.

Another serious issue is the lack of set penetration levels. Many countries in the world, including Australia still do not have set penetration limits for PV systems. Laukamp et al. (2007) found that the maximum tolerable capacity of PV to a single feeder was found to be an average of 7 kW per apartment and that the increase of voltage level and increased voltage unbalance deserve special attention.

Caamaño et al. (2007, pp 25-29) present further data about voltage raise, stating that in Germany 6kW per household is the preferred level of penetration. Also, voltage fluctuations from passing clouds have essentially no impact on voltage dips and swells, because of slow ramps and an averaging effect over large areas. The possible occurrence of unintentional islanding in distribution networks with distributed generation has been one of the major issues in connection with DG. However, investigations have shown that likelihood and risk of personal injury or death from such an event are below other risks accepted by society.

Watt (2004) identifies that at an individual feeder level, PV output correlates well with commercial loads, indicating a strong case for PV use in commercial buildings in Australia. PV systems on schools also correlate well with their daytime load profiles. For residential loads, the peak is typically in midday to late afternoon. In areas with high air conditioner penetration the peak load is significantly higher on hot days and can remain high up to 6 or 7pm. For PV to contribute usefully to the peak the PV output curve must be displaced or storage added. This may be in the form of electrical or thermal storage.

Overall, it can be concluded that the European experiences experience and perception of PV-DG is positive. Grid connected PV plants have demonstrated compatibility with LV distribution networks even at high densities. On another hand, some of the potential concerns are not PV-specific, but common to most Distributed Generation technologies. Consequently, technology advances and harmonisation of technical requirements achieved in the DG field will also facilitate the integration of PV-DG in future electricity networks. Main concern in nearly all countries is voltage rise from end-of-feeder generation. This effect is noticed, however in strong grids it is not critical. It may become critical in terms of violation of power quality standards, or loss of power due to voltage limitation, or costs for grid strengthening mainly in rural areas with higher impedance networks.

2.10 Project Management and Risk Assessment

Traditional concept of distribution planning generally ignore processes following planning study, or minimise input of distribution planning in the next stages in project management like design, construction and project completion. There was no clear picture abut the post-planning study processes and what is the role of distribution planning once when planning study is completed and processed to design.

More complex issue is risk assessment, as distribution planning process includes at least three different types of risks. Firstly, there is risk assessment based on planning and security criteria which addresses limitations and constraints affecting distribution feeder. Poor reliability performance recorded on a particular feeder may or may not mean that lost energy or lost customer minutes on this feeder are higher than on another feeder with better reliability indices. Also, from planning criteria perspective, peak loads approaching normal capacity of a particular feeder's UG cable exit compare with another feeder with lower level of utilisation but higher maximum demand, higher load growth and specific type of customers. These components in general dictate feeder's criticality and its priority in risk assessment process.

Interestingly, there are no many published sources related to project management and risk assessment in the power industry, which may be logical knowing specifics of electricity market. Turner (1999, pp 93-257) describes the project management functions via managing scope, project organisation, quality, cost, time and risk. These components could be applied in project management of power industries, as well.

For decades risk management was one of the most poorly researched and documented areas of project management. However, in the last years that has been changed and now this area is subject of numerous documents. Turner (1999, pp 229-257) describes risk management as a four-step process, starting with identification of project risks and assessment of their impact. Next stage is development of strategies to reduce the risk, and finally control and monitoring of the risks as they occur and the effectiveness of applied strategies.

According Thorpe (2007, p.5.6), a project has three major deliverables – time, cost and quality and these are supported by, among others, risk management. Effective and efficient risk management has a significant communication component, depends on good human resources and utilises good procurement practice as one means of risk treatment.

CHAPTER 3

PROPOSED MODEL OF MODERN DISTRIBUTION NETWORK PLANNING PROCESS

Modern distribution network planning principles should consider electricity network as a dynamic system consisting besides conventional generation and transmission components numerous distributed energy resources, renewable, alternative and smart grid technologies. In such dynamic systems, the nature of customers is changing from consumers of electricity to the combination of consumers and small scale generators. Accordingly, traditional distribution planning requires a detail revision and transition to the real-time planning with implementation of modern planning principles, dynamic modelling techniques and superior load forecasting methods.

3.1 General Concept of Modern Distribution Network Planning Process

In general, the concept of modern distribution network planning, as shown on Figure 3.1, has four major phases.

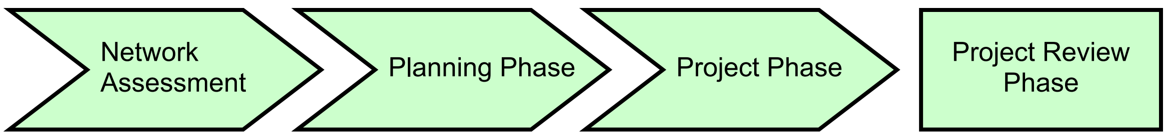


Figure 3.1 – The Major Phases of Modern Distribution Network Planning Process

Network assessment includes three major steps:

I. Current State Assessment (CSA) of Distribution Network
II. Distribution Network Capability Report (DNCR) and
III. Distribution Network Augmentation Plan (DNAP).

Current State Assessment of Distribution Network is a detail revision of distribution feeders' status, their technical, loading, voltage, protection and reliability performances, 5 and 10-year load forecasting and precise determination of existing and future constraints based on distribution network planning criteria (Appendix A).

Present distribution network planning criteria for system capacity is ‘3 into 2’, which means that two feeders have to have enough capacity to take load from the third feeder which is out of supply (Figure 3.2). To supply load at risk under ‘3 into 2’ scenario, distribution feeders must not be loaded above 66% of their normal capacity. Hypothetically, if three feeders are loaded during peak load conditions to 66% of their normal capacity, and if the failure of feeder occurred when all three feeders had maximum loads, 70% of F2’s maximum load could be transferred to two adjacent feeders F1 and F3, leaving 30% at risk. However, to eliminate any load at risk, in addition to peak load under normal conditions, planning security criteria includes maximum carrying contingency load. For 11kV feeders maximum supplying load is 4MVA under normal conditions, and 6MVA under contingency conditions. So, if all three feeders are loaded to maximum demand (MD) of 4MVA, with contingency carrying peak of 6MVA, 100% of load from F2 could be transferred to F1 (2MVA) and F3 (2MVA).

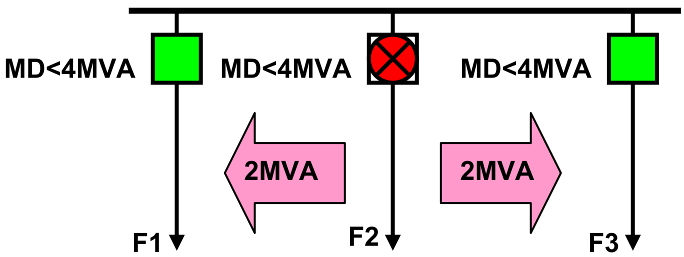


Figure 3.2 – Distribution Network Planning Security Criteria

In the next stage, analysed data about levels of system limitations are reported in the format of Distribution Network Capability Report. Network planner determines exposure of existing and future constraints and prioritises augmentation works in the 5- and 10-year Distribution Network Augmentation Plan (DNAP). It is very complex pyramidal process with huge consequences for the future capital programme and performances of electricity utilities (Figure 3.3).

According the planning model developed by this author, the planning phase starts at end of Network Assessment phase and includes all planning related activities from the beginning to the end of distribution network planning study. In addition to process dynamics which will be elaborated in Chapter 3.2, planning stage requires at the beginning clear determination of project needs, objectives and consequently adequate planning levels. As noted in Chapter 1, there are five basic planning levels:

- Contingency planning (CP)
- Operational planning (OP)
- Project planning (PP)
- Short term or tactical planning (STP) and
- Long-term (Strategic) planning (LTP).

Methodologies, techniques and reporting for these planning levels are different. For example, contingency planning has two major levels – multiple load transfers between two or more zone substations and relatively simple reconfiguration affecting one or two distribution feeders. The network planner involved in contingency planning prepares diagram of load transfers (elaborated in Appendix D) based on system performances, configurations, tie capacities, location of switching devices, loading and voltage profiles, customer types and load transfer modelling.

Operational planning covers in general less complex planning studies. Some of them are connection of small scale customers (generally <1MVA), voltage regulation analysis (zone substation or distribution voltage regulator settings and Line Drop Compensation-LDC), fault levels, motor start, load balancing and temporary minor reconfiguration to meet immediate needs.

This author analysis show that Project Planning (PP) as the first planning level which is, on one side related to capital expenditure programme, and on the opposite side has short-, or long-term impacts. It seats at the top of distribution network and project augmentation pyramid (Figure 3.3).

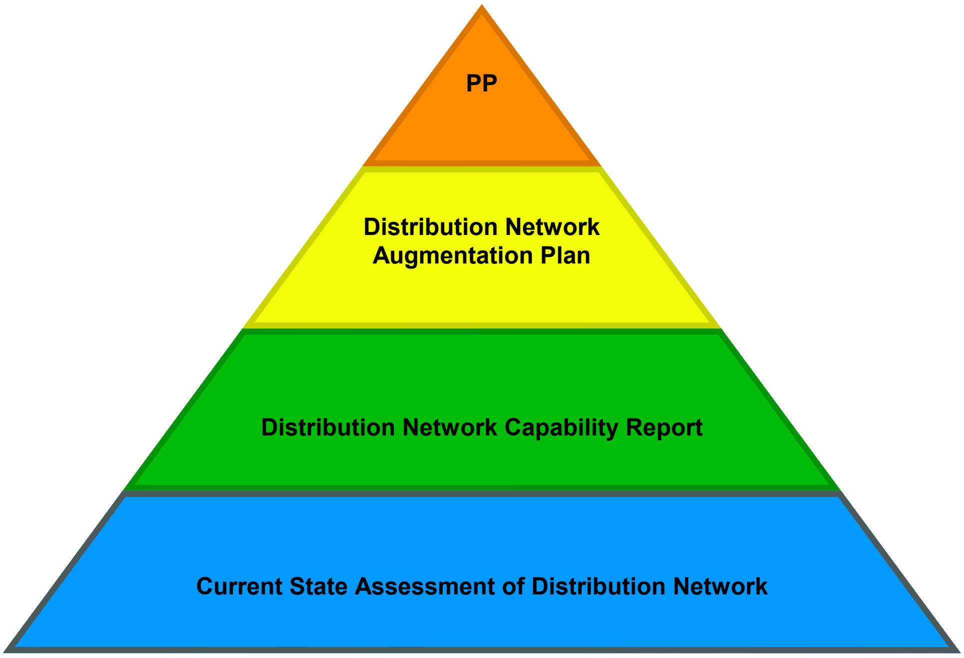


Figure 3.3 – Distribution Network Assessment and Project Augmentation Pyramid

An important part of Project Planning is determination of project category. Distribution network augmentation projects could be classified based on their main focus and their complexity. Another general characteristic of Project Planning level is priority of projects. Distribution augmentation projects included in Project Planning stage are the most critical projects, with the highest immediate capacity or voltage constraints which require urgent attention. Their completion dates are usually spread between the first two years in the current Capital Expenditure Programme.

In regard to the main project focus, in general, there are two categories – ‘A’ and ‘B’. Category ‘A’ includes all projects developed to manage immediate existing system limitations based on constraint levels identified during the stage of Current State Assessment of distribution feeders and priorities set in Distribution Network Augmentation Plans. These projects also include management of major load growths and proactive control of distribution network planning criteria. Category ‘B’ projects are driven by ‘other’ drivers like sub-transmission feeder constraints, capacity limitations problems at zone substation, replacement and refurbishment plans and reliability improvements.

Further analysis shows that in terms of project complexity, Project Planning also recognises two major categories – major and minor augmentation projects. Major projects have critical importance for studies area of supply, with positive impact on distribution and sub-transmission networks capacities and future capital expenditure plans. They could fit both categories, ‘A’ or ‘B’, and their scope includes intensive (and expensive) recommendations. Typical major projects are replacement of UG cable exits, establishment of new distribution feeder, major network reconfiguration or connection of block loads (>1MVA). Major project requires detailed and comprehensive planning study, economic analysis, risk assessment and adequate project submission and endorsement process.

On the opposite side, minor projects are related to less complex augmentation plans and do not require detailed planning studies. In general, they consist of network modelling and brief technical and financial recommendations, without detail risk assessment. These projects could be managed by Distribution or Area Asset Planning Officers, in co-ordination with Distribution Planning Engineer who must check and approve recommendations. Typical minor projects are reconductoring, installation of voltage regulators and simple system reconfigurations to overcome capacity, voltage or reliability related constraints.

According this author’s research, an important consideration in the Project Planning stage is the extent to which Network Demand Management (NDM) and Distributed Generation (DG) options may assist in meeting future demand requirements on the distribution systems, and the extent to which such opportunities may defer or possible eliminate the need for certain distribution network augmentation. Modern concept of distribution network planning considers the transparency and opportunity for NDM and DG and treats these solutions as standard development options comparable with ‘traditional’ network augmentation options. Actually, it recommends study of NDM option at the very beginning of Planning Phase.

Short-term or Tactical Planning (STP) is similar to Project Planning. The main distinction is longer planning horizon with planned completion dates between 3 and 5 years, so at end of 5-year regulatory period of Capital Expenditure Programme. Also, the STP projects are more proactive and include studies of development of multiple distribution feeders from existing zone substations, replacement of multiple UG cables and complex reconfigurations.

In the focus of Long-term (Strategic) Planning (LTP) level is development of certain areas of the major load centres like Central Business Districts (CBD) and commercial and industrial zones, with comprehensive demographic and load forecasting studies. A typical LTP project includes development of new distribution network from new zone substations and global development schemes. Their impact does not stop on the local zone and distribution voltage levels. On the geographical level, new zone substations with new distribution networks dramatically change development, demographic and economic performances of the certain areas. From system perspective new distribution feeders change network topologies and their performances and provide long-term capacities affecting distribution and sub-transmission networks. The period of study could be similar to the planning horizons of PP and STP levels (0-5 years). It may be extended beyond 5 years in conjunction with strategic system planning and transmission and sub-transmission planning.

3.2 Dynamic Components of Distribution Network Planning Process

Author of this thesis spent lot of time investigating dynamic components of network planning. Based on these studies, it is concluded that modern distribution network planning concept accepts dynamic nature of the planning problems, and includes the following four major dynamic components presented in Figure 3.4.

The major variables dictating dynamics of distribution networks are system load, plant rating and asset conditions and remaining operational life. Load related parameters like current, voltage, power factor, energy consumption, real and reactive power are extensive variables in time and areas of supply.

Rating of overhead (OH) conductors, UG cables, distribution and power transformers and other network assets, as well as their remaining capabilities and life economics are also very dynamic and variable in time and climate zone including the area of supply.

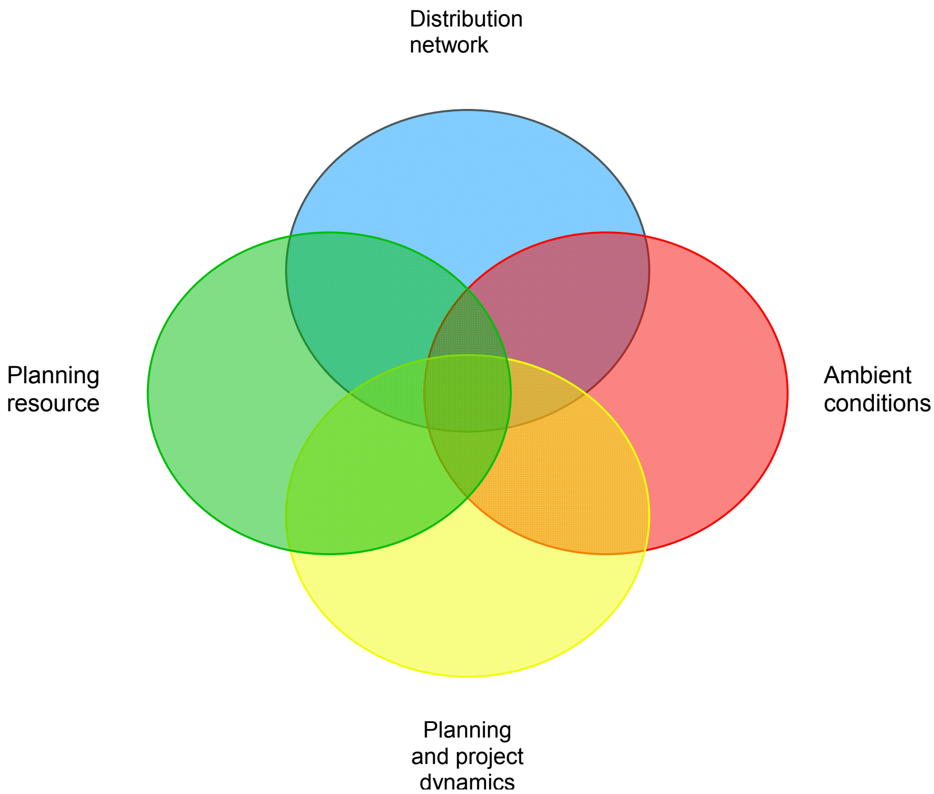


Figure 3.4 – Dynamic Components of Distribution Network Planning Process

The second major dynamic component incorporates ambient conditions and climate specifics with critical impact on temperature related loads and plant rating profiles. As temperature plays a significant role in driving system maximum loads, wind predominantly dictates rating specifics of OH conductors. Also, weather factors are critical in energy and load forecast on system levels and spatial load forecast on substation levels.

Planning and project environments dynamics relate to variables during all major stages in project management. The planning stage is a dynamic process which includes collection of data, continuous analysis, intensive communication with different internal and external stakeholders, simulation and modelling and all activities related to progress of planning study and project deliverables. An additional important variable of this stage is data management, above all data availability and quality. The project itself is a dynamic system with continuous technical, resources and economic variables.

Understanding of planning resources dynamics is very complex subject which require detailed and comprehensive analysis. Network planning process requires top level subject matter expertise, high analytical skills, patience, persistence, multidisciplinary approach, outstanding communication and team work, universal knowledge of modelling tools, planning and security criteria, and other engineering areas affected with planning of distribution networks. Additional complexity is work with uncertain and unreliable data forcing network planner to analyse system using assumptions and comparisons with similar networks with available data.

The network planner is an universal 'institution' combining parallel with planning skills numerous engineering areas like strategic visionary, forecasting, reliability, protection, power quality, knowledge of renewable, alternative and new technology solutions, economics, demographics and even some kind of engineering arts and fillings for the most efficient network topologies.

3.3 Planning Phase of Modern Distribution Network Planning Process

Similar to the 'traditional' concept, the author has proposed that the Planning Phase of modern distribution network planning process has four major steps (Figure 3.5):

I. Study of existing networks
II. Studied options
III. Comparisons and
IV. Recommendations.

However, each of these steps has been changed and transformed based using a multilayer approach. The major characteristics of Planning Phase of modern distribution network planning process are implementation of the following major steps:

- Study of 'non-network' solutions (like renewable, alternative and new technology solutions) is included in the second stage of distribution planning process, together with investigation of 'network' solutions
- In the same stage ('Studied Options') are included two very important studies - risk assessment and preliminary quote estimate. In the early stage, network planners are now capable to address risk profile of studied distribution feeder and project risk assessment specifics, as well as to do preliminary financial analysis using modern tools developed specifically to address rescannable accurate project quotes
- Stage of Comparisons is consequently changed to adopt 'non-network' solutions. In addition to technical and economical comparisons of different network options, network planners now compare different 'non-network' solutions (e.g. network demand management option versus some of the renewable solutions) and 'network' and 'non-network' solutions. It is a very specific challenge, predominantly due to different nature of economics in the structure of material, operational and overhead costs on one side and potential benefits on the opposite side of standard network augmentation and 'non-network' options
- After transition of risk assessment and preliminary quote estimate into the second planning stage, 'Recommendation' includes 'only' provision of technical and financial specifics for design stage.

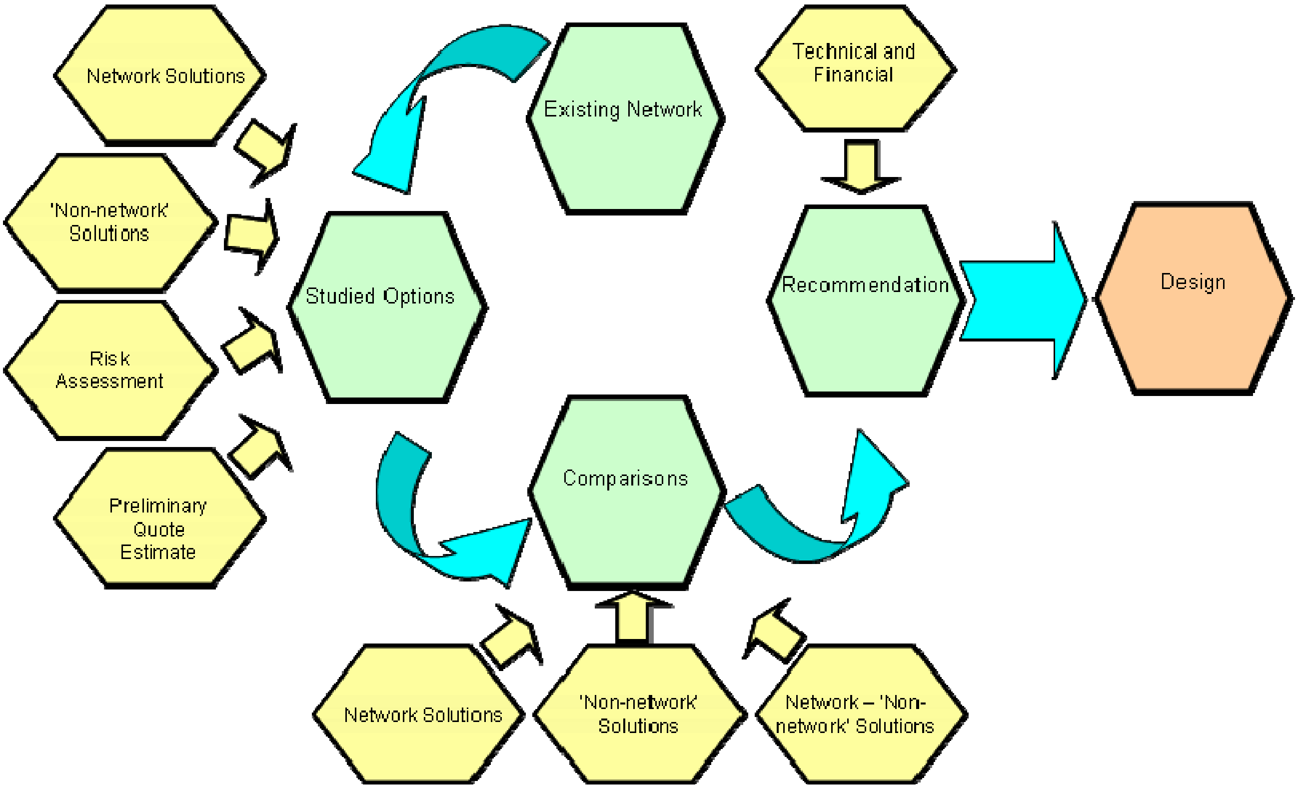


Figure 3.5 – Planning Phase of Modern Distribution Network Planning Process

The modern distribution planning process includes also fundamental change in management of some of the major components of Planning Phase. As noted in Chapter 1, the 'traditional' planning concept considers 'only' distribution feeder. Modern distribution planning however treats network as combination of different voltage levels with 'bottom-up' approach addressing major impact of recommended distribution developments (and major customer connections) on zone substations and sub-transmission levels. Of course, detail sub-transmission planning will follow as part of sub-transmission planning processes, however now network planners (distribution, sub-transmission and strategic) have organic integrity between their planning processes.

The modern concept proposed by the author includes variety of different additional studies as presented in blue colour in Figure 3.6, like planning of network reliability, power quality, weather correction in load forecasting etc.

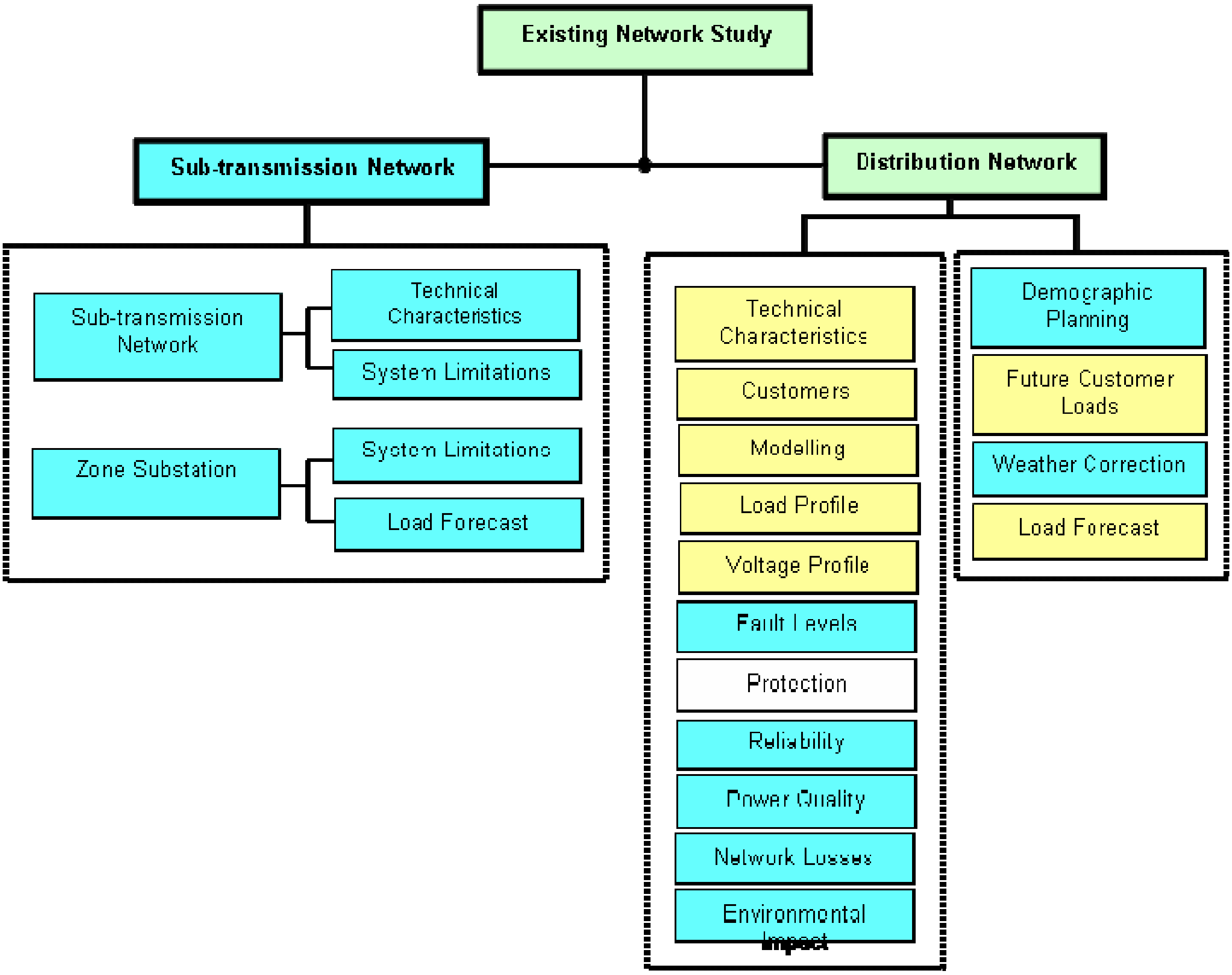


Figure 3.6 – Proposed 'Modern' Existing Distribution Network Study Process

In Figure 3.6 in yellow are shown planning areas (technical characteristics, customer connections, network modelling and load and voltage profile) with recommended significant improvements. As an example, on Figure 3.7 is presented 'modern' aspect of voltage regulation with its four main components. Development of proper voltage profile of distribution feeder includes understanding of voltage planning criteria, revision of voltage regulation (AVR) settings at power transformers (and voltage regulators) at zone substation, settings of existing distribution voltage regulators (including Line Drop Compensation LDC) and tap zone plans.

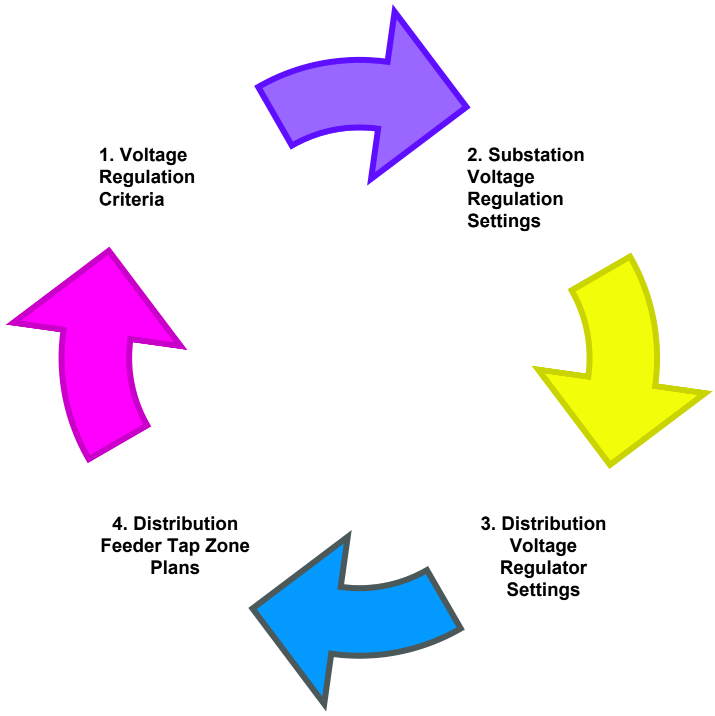


Figure 3.7 – 'Modern' Voltage Regulation Planning

Load forecasting is another very important planning area which has faced intensive modifications. The 'traditional' planning approach was based on three fundamental load forecasting components – organic ('natural') load growth, block loads and load transfers. However, modern load forecasting is more complex and requires more specific attention. On the system level (load growth of entire electricity utility) there are load and energy growths with different patterns and logics. In this area weather/temperature correction based on 50PoE and 10PoE probabilities is critical for understanding of future trends in conjunction with natural (historic) growth, economic drivers and global demographics. The concept of 50PoE and 10PoE methodologies is elaborated in Chapter 4. However, on substation and distribution feeder (spatial) levels equally are dominant natural load growth, block loads, planned load transfers (e.g. due to development of new distribution networks), weather correction and demographic planning (Fig. 3.8).

Demographic planning is relatively new area in the world of modern load forecasting evaluated from traditional town planning. It requires understanding of local town development zones, type, time and level of developments, economic drivers, water supply specifics, as well as After Diversity Maximum Demand (ADMD) parameters for all planning zones.

In the next step, based on these data and network topologies it is relatively easy to develop low, medium and high spatial forecasting scenario and allocate loads not only based on the area of supply or zone substation, but on distribution feeder level too.

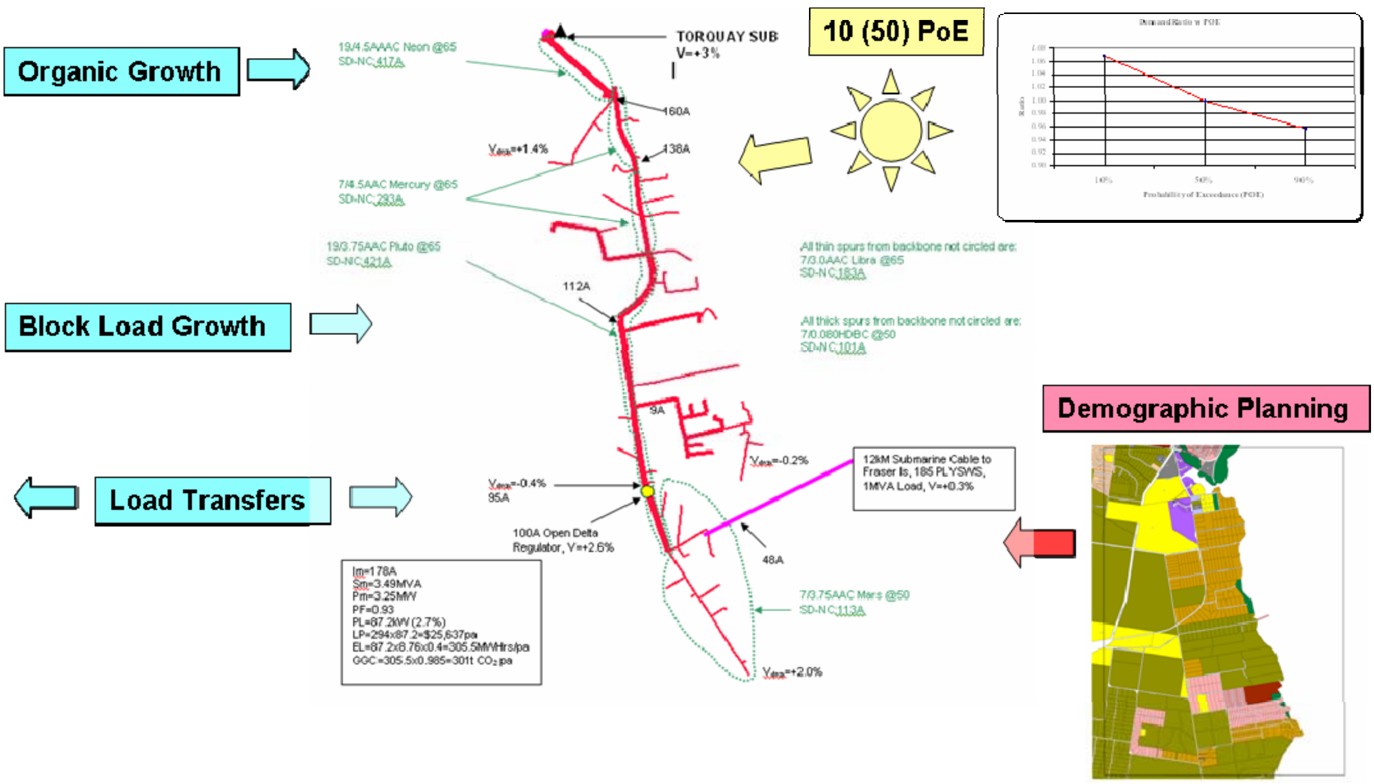


Figure 3.8 – 'Modern' Load Forecasting Process

The network planner analysis numerous different network augmentation options summarised in Figure 3.9 and elaborated in the following chapters. Their prime objectives are to improve system capacities, voltage regulation and fault levels.

In addition to network augmentation options, in the Studied Options stage modern concept of distribution network planning includes variety of 'non-standard' network options presented in Figure 3.10. Study of alternative energy solutions and new technology options includes three basic categories:

I. Renewable energy solutions

II. Distributed energy resources (DER) and

III. Customer solutions.

Analysis of Network Demand Management (NDM), energy storage, photo-voltaic (PV) systems, small-scale distributed embedded and non-embedded generators or combination of these technologies and techniques is a paradigm of modern distribution network planning. This new approach is now an organic component of planning processes, especially in the field of rural distribution and SWER system planning where it is hard to justify project economics.

The first pilot NDM SWER project to reduce peak load on one of the SWER isolating transformers in Ergon Energy network resulted to benefits of 20% maximum demand reduction during summer day conditions, with expenditure of approx 50% of planned network augmentation project. In total there were only four customer affected. Five more Ergon Energy's SWER NDM projects are now progressing to test further different NDM scenarios.

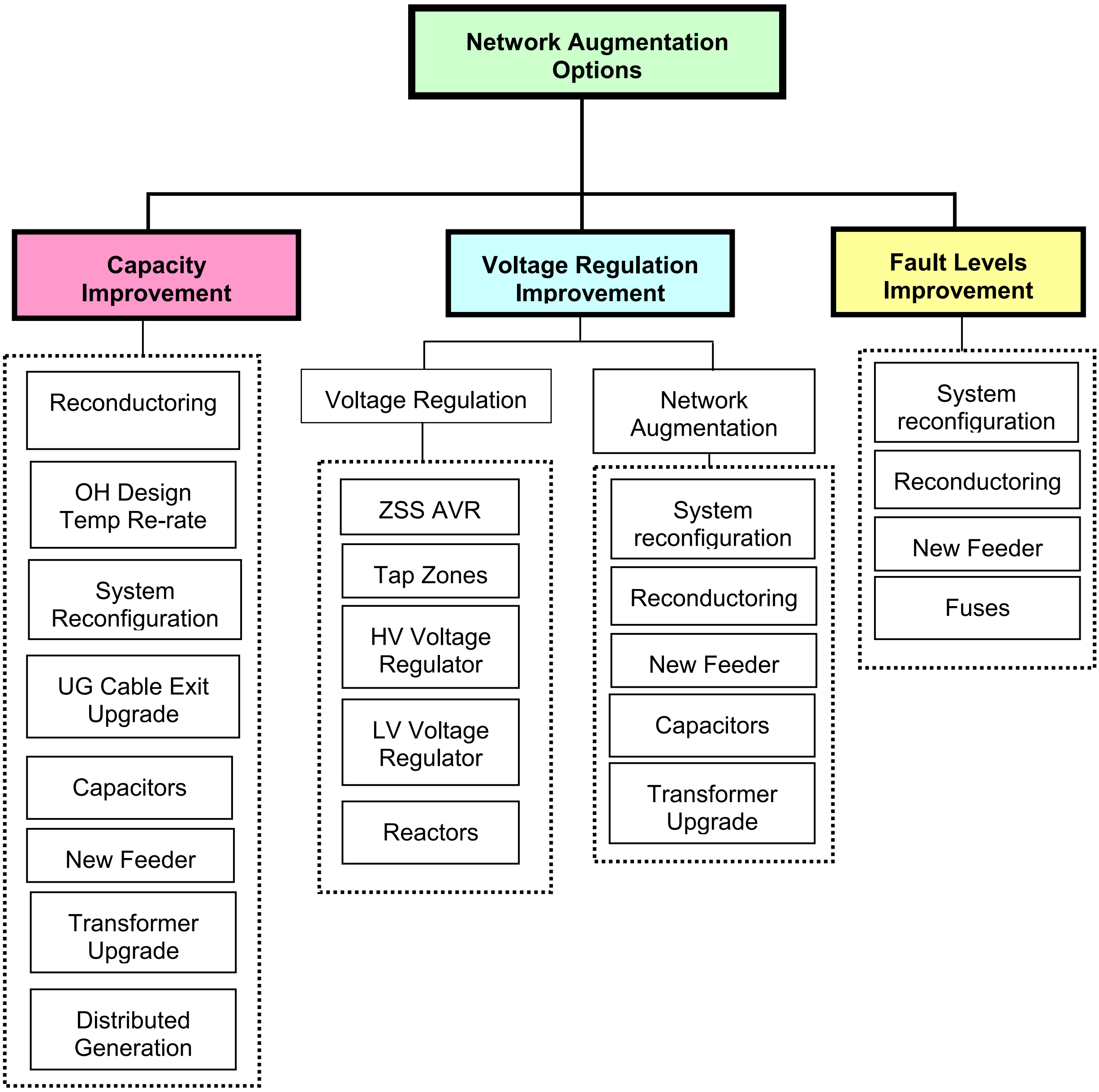


Figure 3.9 – Studied Network Augmentation Options

Energy Storage (ES) is another interesting project with substantial positive impact on distribution networks, especially on weak, long and old rural systems and SWER schemes. Traditional scheme of ES operates only in conjunction with the grid. During light load conditions a 10kVA ES unit charging its batteries from the grid. Then, during peak load conditions and extensive network loads, ES provides supply to the connected load reducing total system peak demand. Also, during power interruptions ES supplies customer load improving system reliability. Modern concept of ES however includes combination of ES, renewable energy solution (PV systems) and standard grid connection, with most of supply provided through ES charged by PV systems. This combination is one of the most prominent and effective future power supply arrangements in the rural and isolated areas.

In distinction to ES which is designed as a single customer supply solution, Grid Utility Support System (GUSS) provides higher capacity (up to 200kVA). GUSS is capable to supply a cluster of customers combining an embedded generator, energy storage facility and PV units. This system is consequently more expensive and requires intensive maintenance programmes. However, located on strategic points of the long rural and SWER network, GUSS can provide reliable power supply and reduce or even eliminate needs for expensive network augmentation options.

Low Voltage Regulator (LVR) is another new technology device which is already in use in few electricity utilities (Ergon Energy, Energex and Country Energy). It is a simple and very effective unit with wide spectrum of voltage regulation which improve customer voltages during peak load conditions and increased voltage drops. It is a reliable low maintenance device, which can also serves as an energy conservation unit. In so called cluster arrangement on SWER schemes, LVRs are in some cases economically more preferable voltage improvement solution than standard distribution Voltage Regulators.

Implementation of different NDM solutions and ES, GUSS and LVR devices, in conjunction with solar farms, solar thermal storage, wind and geothermal energy sources, non-embedded generators, smart homes and Power Factor (PF) correction projects are fundamental alternative energy initiatives. In Ergon Energy they are in different stages of development and integration and this author participates in the majority of these projects.

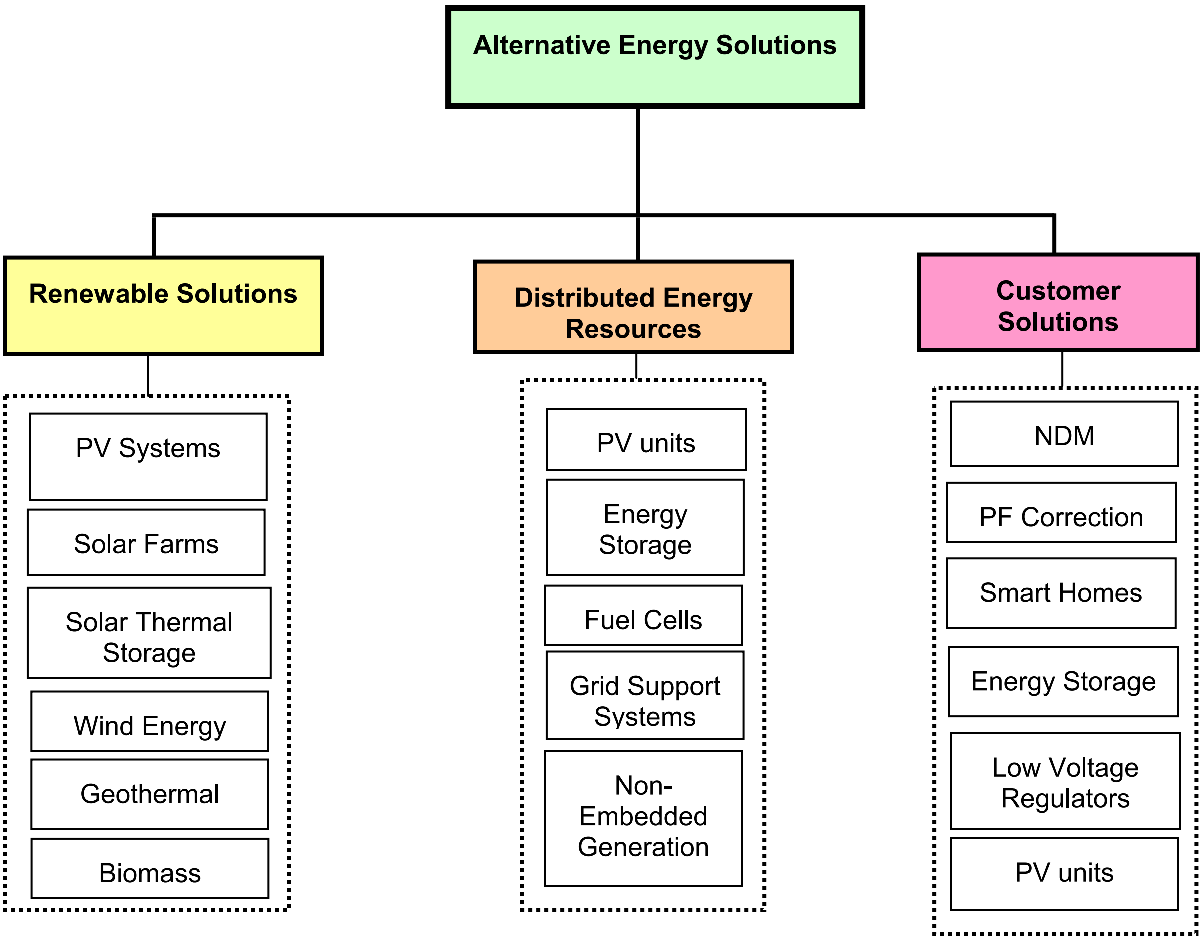


Figure 3.10 – Studied Alternative Energy Solutions

3.4 Project Phase of Modern Distribution Network Planning Process

The end of Planning Phase is marked with submission of recommended works and project endorsement. Recommendations in the format of project scope move to the next stage of distribution network planning process called Project Phase. At the beginning of Project Phase is Design Stage, followed with Construction and finished with Project Commissioning (Figure 3.11). After the project completion, revision of the project outcomes will follow in the Project Review Phase.

What is the role of the network planner in the Project Phase of project management? The proposed modern distribution network planning process does not stop with the submission of recommendations and transition of project from planning to the design stage. In distinction to traditional concept described in Chapter 2.10, the modern distribution network planning includes an active participation of distribution planner in all three stages of the Project Phase, especially during the Design stage.

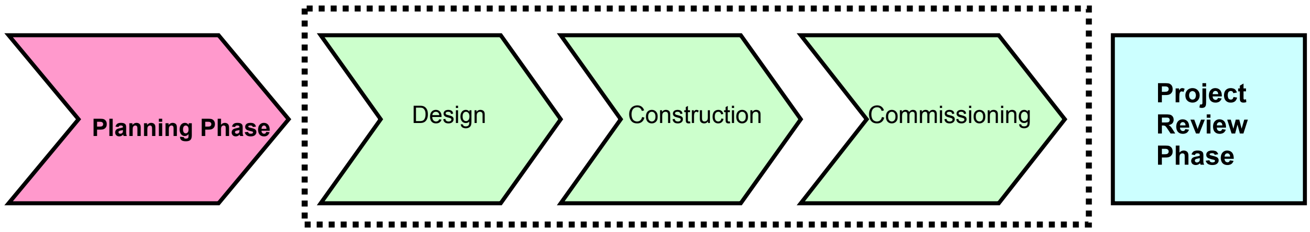


Figure 3.11 – Project Phase of Modern Distribution Network Planning

The distribution planner will produce planning documentation that will form the basis of a ‘design brief’ that is issued to a designer. The designer may be internal or external. In Ergon Energy, as well as in other electricity utilities, standard design requirements are set out in the following two manuals:

- Overhead Design Manual
- Underground Design Manual

Some specific examples are:

- Standard Conductors (overhead and underground)
- Guidance on Route Selection, easements, substation site selection etc
- Guidance on Load Types and their ADMD.

However, detailed design remains the responsibility of the designer (internal or external). Planners seeking information on such matters as minimum ground clearances, clearances between circuits, clearances between underground services etc should refer to the respective design manuals.

Communication between planners and designers is bi-directional and continuous. After completion of design drawing the network planner must review the design schemes before their endorsement and transition to the construction stage.

During the construction and commissioning staged, the role of distribution planners is monitoring and, if necessary consultative. The distribution planner observes the progress of a particular project and co-ordinate any current and future related planning study.

3.5 Project Review Phase of Modern Distribution Network Planning Process

Project Review Phase is the last stage in modern distribution network planning model. After the commissioning, the distribution planner checks the final construction drawings, assess project outcomes and compares developed network configurations with recommendations from the distribution planning study. Also, the network planner compares estimated figures from the planning study with recorded data from the new distribution network. It is important to verify level of accuracy of planning study and based on corrections improve planning methodologies for future investigations. Differences between simulated and real loads in the range between 10% and 20% are expected for planning studies completed 3-4 years before project completion.

Just before end of Project Review Phase, the network planner finalised project in data base and integrates with other reviewed projects.

3.6 Modern Distribution Network Planning Process and Program Management

In addition to Project Management, the proposed modern distribution planning process includes participation and involvement of the network planners in Program Management. A Program consists of a group of related projects or endeavours managed and co-ordinated to give benefits and controls not available when individually managed (Figure 3.12).

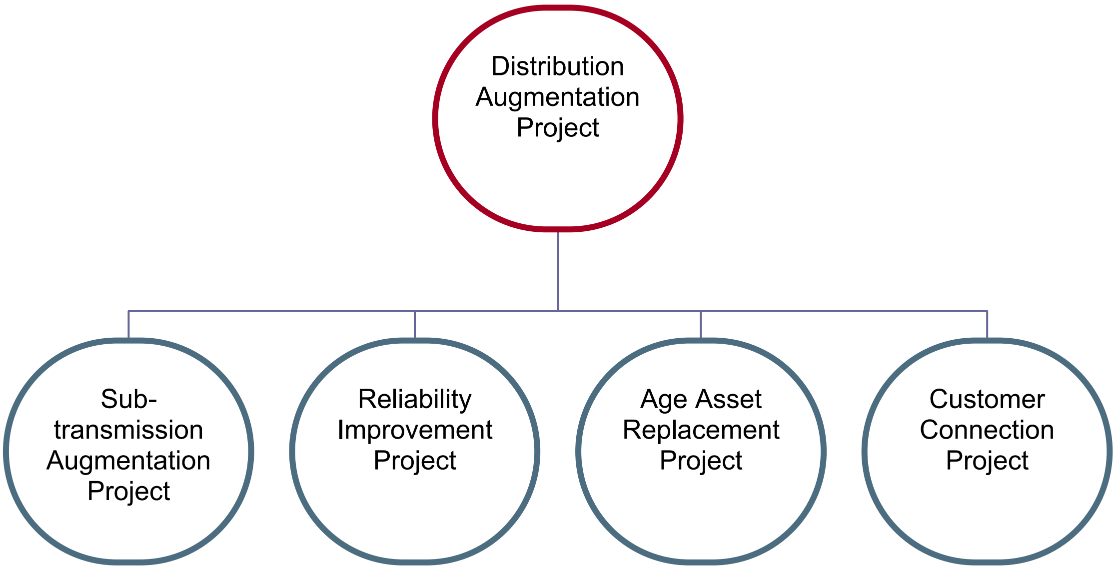


Figure 3.12 – Program of Related Projects

Distribution augmentation projects have big impact on the dynamics of related augmentation and non-augmentation projects. In Figure 3.12 we can see Program consisting of four projects related to a particular distribution augmentation project. For example, establishment of a new distribution feeder improves transfer capacities between zone substations and in the area in general. It may defer some of associated sub-transmission projects. Every new feeder improves network performances and reliability of affected distribution systems and can affect plans for reliability improvements in the area. Also, between some of distribution augmentation and age asset replacement projects exists strong bi-directional connections. Projects related to reinforcement of distribution feeders via replacement of old steel and copper conductors with new large aluminium conductors also improve age profile and life cycle of all affected assets on distribution feeders (conductors, poles, cross-arms, insulators …). Large customer connection projects are traditionally linked with distribution augmentation projects as both have huge impact on general network performances.

Therefore, it is an imperative that the network planner considers related projects driven by different objectives and analyse their interconnection with distribution augmentation projects. It is critical to keep Program Management as a standard component of distribution planning process

3.7 Summary of Modern Distribution Network Planning Processes

Working in different distribution utilities and studying their distribution network planning processes developed many years ago, the author concluded that soon or later electricity utilities will be forced to modify their major business functions. As distribution network planning is one of the core functions of any electricity utility, the author of this Master Dissertation spent years developing stage by stage the new concept of the distribution network planning processes.

In the first step, the planning process was structured to satisfy modern principles of the standard network planning. It required development a comprehensive format of distribution planning report to cover all critical aspects of the network planning. The distribution feeder load forecasting with demographic and town planning, appropriate risk assessment, quote estimate techniques, technical characteristics and network power losses were the first components of the distribution network planning processes which have been modified.

In the next stage, this author included categorisation of customer connections, greenhouse gas emissions due to power losses and fault level analysis.

In the third stage, the distribution network planning processes have been extended with advanced voltage regulation models (including tap zone plans), network reliability, quality of supply and modified load forecasting with implementation of weather corrections.

Finally, non-network solutions (renewable and alternative energy options) have been included in the distribution network planning processes, with preliminary risk assessment and comparison methodologies extended with non-network solutions as well.

Most of these components are now organic parts of the distribution network planning processes in Ergon Energy and through the Joint Working projects with Energex they have been implemented as a common network planning in Queensland. Under control of single Australian Electricity Regulator (AER) it is expected that some of components or entire modern distribution network planning processes developed by this author will be implemented on the national level, as well.

However, despite very positive feedback and outstanding results of the new network planning concept, this author thinks that in the coming years the distribution network planning processes will be subject to more changes and modification. Some of the major future works in these areas are described in the last chapter (14.3) of this Dissertation.

CHAPTER 4

ENERGY AND LOAD FORECASTING

Load forecasting is a critical element in the network planning process. Forecasting sets the benchmark for the expectations of how different network elements will perform now and into the future. Based on these performance expectations decisions can be made to augment or rearrange the network to ensure that the network performance and reliability criteria set by the business can be met.

4.1 Forecasting Period

The forecasting period refers to the time looking forward for which estimates of loading (demand and energy) are calculated, estimated or provided by other means. The period of forecasting has a relationship to the accuracy of the estimated load or energy.

Generally, the period of demand forecasting must at least match the shortest possible asset augmentation lead time. In order to provide the opportunity to have sufficient network capability available to meet the customer (or Network operator's) expectations the period of forecast must at least match the start up and commissioning time of the projects used to ensure capacity.

For bulk substations most businesses consider 10 year forecasts as a minimum with some forecasting up to 25 years (Ergon Energy 2003).

In the case of zone substations a period of 10 years may be appropriate. However, in the case of HV feeders a shorter time in the order of a few years may be more appropriate. This is due to the relatively short planning, design and construction time for feeder augmentation projects.

Most businesses consider 5-10 year forecasts as a guide for the augmentation of zone substations. In cases where new zone substations must be built, longer lead times and hence longer forecasting periods must be used especially where land acquisition and planning (land use and community) issues are involved.

In planning for HV feeder augmentation, forecast periods are generally 2-5 years. This period matches the planning, scoping and implementation times for augmentations at feeder level.

4.2 Forecasting Procedure

The general procedure for choosing appropriate forecast periods is generally in consideration of the planning time and future capital expenditure.

From the planning time perspective, absolute maximum time to plan, design and construct a solution to the probable amount of load at risk is required. For example, for zone substation a long lead time is needed for augmentation and solution of issues further upstream indicating a longer planning period. Whereas HV feeder augmentations and LV augmentations can be completed relatively quickly therefore short forecasting periods of say up to 5 years will meet that need.

Another consideration is the business planning aspect. The business may require forecasts and hence estimates of future cash flows for business planning purposes. These requirements may impose a different set of criteria upon the choice of optimum forecasting periods compared to Network criteria alone.

The advantage of a long forecasting period at this level of voltage or connection is that it will provide a significant level of support to the justification of the large investments necessary for terminal station augmentation. As discussed above, lead time to achieve terminal station augmentation is considerable and forecasting must at least match that lead time to be effective.

Many businesses will require some form of long term load and demand forecasting as an indicator of long term capital investment.

Longer forecasting periods may also be used to identify other, perhaps more efficient alternatives to terminal station augmentation. Examples here are non network solutions such as demand management, embedded generation (both solutions requiring substantial lead times to commence).

The main limitation to long term forecasting is the accuracy and availability of relevant data.

A further limitation is effect of external influences such as macro economic activity, business development environment, etc. on the accuracy of the demand forecasts.

4.3 Forecasting Accuracy

Any credible forecasting methodology must include the ability to measure the forecasts accuracy, and the level of accuracy must fit within acceptable limits. Where the accuracy is measurable and is acceptable for the purpose at hand, the network planner's confidence should be enhanced in planning the augmentation of their network. A forecasting process that delivers inaccurate or less accurate forecasts will make the task of the network planner more difficult. Greater uncertainty arising from an inaccurate forecasting methodology will also increase the cost of the network by requiring a larger buffer to reduce the risk of insufficient capacity from any unforeseen event.

Hence a key aspect of any forecasting methodology is that it should meet minimum accuracy requirements. All models will include errors by nature of the fact that they are an approximation of the real world and these errors will limit the model's accuracy. In order to assess the model accuracy, its forecasting performance should be assessed using both in-sample and out of sample tests.

Developing processes in order to accurately capture the relationship between demand and its long run economic, demographic and weather related drivers is expected to deliver substantial benefits both in terms of improving the networks performance as well as achieving this level of performance at the minimum cost.

There is an additional issue which complicates the assessment of a forecasting method's accuracy in predicting future loads. This arises from the fact that the best performing model in predicting load in the future may not be the best from the network planner's point of view.

This is because the network planner is mostly concerned with the impact of extreme weather events on the network. It is possible that a model which minimises the error between the forecast and the actual loads that are observed is not the best at representing future load under specific weather conditions (i.e. extreme weather). A model which poorly represents the extreme peaks, but which does well in terms of overall accuracy may not be suitable for network planning purposes (ACIL Tasman 2010, p. 23).

4.4 Forecasting Drivers

Any forecasting methodology should incorporate the key drivers either directly or indirectly. This includes the demographic, economic, weather and appliance drivers.

This could potentially include:

I. Economic growth

II. Population growth

III. Growth in the number of households

IV. Temperature, humidity and rainfall/wind data

V. Growth in the number of air conditioning systems

VI. Growth in the number of heating systems

VII. Growth and change in usage of key appliances

VIII. Growth in renewable and alternative energy resources (like PV systems, energy storage devices and distributed generation).

By explicitly incorporating the key drivers, rather than using linear trends, the methodology will have the flexibility to adjust to forecast changes in the drivers that are not necessarily reflective of the past.

4.5 Forecasting Methods

Most businesses use a combination of trending of normalised historic load data and inputs including known future loads, economic growth, weather, municipal development plans, etc. to arrive at their load forecasts.

Normalising is used to smooth out the effect of short term effects or abnormal situations. An example could be that the station may have been operated abnormal for some time in order to supply other load whist maintenance was carried out or another augmentation was commissioned. The additional load and demand would then have to be normalised out of the forecast in order to arrive at a baseline forecast.

Forecasts of a long term nature generally have both historic and forward components. The historic data and associated trends are commonly used to validate the forward looking analysis of current data. High level connections (terminal stations and bulk supply point demand and load) contain a significant amount of diversity; therefore historic trends in growth are generally smooth by nature and a good basis for comparison.

The selection of data inputs depends on the relevance to the particular business and the environment in which the network is operated.

The general procedure for forecasting follows the generic aspects as follows:

- Collection of historic data and trend analysis – This ensures that the starting point for the forecast is relevant and credible.
- Collection of data indicating the trends to future load growth (or decline). This usually takes the form of known project values and/or analysis of network load constraints
- Interpretation of non network data as a modifier to the trend analysis of the above. For examples, indicators of economic growth, housing approval rates, population forecasts, appliance development information, geography, weather patterns, emerging quality issues, etc.

Addition or subtraction of non-network generation input either as full time or part time support.

Choice of a consistent methodology and set of data inputs should provide stability to long term forecasting. The exact set of data inputs will depend on the relevance to the particular distribution business and the characteristics and area of the network under consideration.

4.6 Data Types

The well known main criteria used to determine data series suitability for use in the modelling methodology are:

I. Reputability of the data source

II. Reliability of the data source

III. Completeness (No or few missing values)

IV. Suitably long time series

V. Accuracy of the data.

There are many types of data that can be used in conjunction with the commonly used selection of measured network loadings.

In most cases SCADA is the major source of load data, followed by wholesale meters at terminal stations and billing meters for energy consumption by customers.

SCADA and wholesale meters will provide an accurate data stream for current demands and loads. When trended over time and corrected for known events, this is a valuable forecasting input.

In the case of bulk supply substation forecasting and large zone substations (long range forecasting) many of the usual non network data sources may not be relevant. For example, localised Council development permits may be useful in short term forecasting, however, overall Council and Government municipal development plans will be more relevant.

Some businesses collect customer requested loads (especially in the case of major developments) and factor those into forecasts as well as various indicators of economic activity both at the macro level and at the customer (retail) level. Macro level economic indicators are generally more suited to the longer forecasting periods such as for bulk supply substations.

LV loadings can also be useful for short term planning if collected in a widespread and systematic nature, however, assumptions due to time of recording and temperature correction need to be considered. LV loadings collected as spot readings can be corrected for temperature, i.e. manipulated to become virtual summer day maximum demands by the use of the following and applied to short term planning of LV circuits by using the simple tool below.

SCADA and wholesale meter information is valuable data for the forecasting process especially at feeder, zone substation and terminal station level. Historic data (10 to 15 years) is also valuable especially as a validation of forward looking trends.

All data inputs must be considered as having some form of limitation or inherent inaccuracy.

The skill of the network planner must be used to ascertain the relevance of these data limitations and their overall effect on the accuracy (confidence level) of the forecasts produced.

Lower voltage level data generally needs greater manipulation, verification and normalisation in order to support longer term planning.

The majority of data used in the weather modelling process are sourced from the Australian Bureau of Statistics (ABS) and the Bureau of Meteorology (ACIL Tasman 2010, p.12).

Data sourced from the ABS can be regarded as accurate and the probability of subsequent revisions to data is generally low. ABS data can also be considered to be reliable in the sense that the economic and demographic data used in this forecasting methodology are unlikely to be discontinued.

Similarly, the Bureau of Meteorology, while having a large number of poor quality weather sites, has established a number of high quality temperature sites which have few missing values, are homogeneous over time and have a very long record of unbroken daily recordings.

4.7 Growth Scenarios

A common approach by the majority of Businesses is to forecast load and demand using a range of growth scenarios (high, medium and low growth).

This range of scenarios is useful in setting the scope of potential capital requirements for a business rather than detailed planning for augmentation of network assets. Consideration of a range of scenarios is particularly applicable to large scale investment options or as a modifier to a rolled up total of network investments. Commitment to large augmentations (especially terminal station assets) would normally have to be justified with a detailed business case outlining the possible spread or range of potential growth scenarios.

In terms of applying low, medium and high growth scenarios to the standard 10 or 25 year demand forecast at bulk supply and the major zone substation levels it seems prudent to use growth indicators that also have a significant forecast horizon. Such factors may include any of the macro economic indicators.

High, medium and low growth scenarios are generally applied to 50% Probability of Exceedance (POE, average conditions) forecasts.

An example of growth scenarios that may be considered includes (Dalitz 2008):

- Extreme High Growth – 10%POE forecast scaled (factored up) by high economic growth
- High Growth – 50%POE scaled by high economic growth
- Average Growth – 50%POE – assuming existing macro economic growth forecast rates
- Low Growth – 50%POE scaled by lowest macro economic growth rate forecasts.

A range of demand growth scenarios can be used to develop business models for the forecasting of possible range of capital investment funds. The spread of forecasts can be used to determine the extent of risk associated with network development and the coverage of contingency plans.

4.8 Temperature Correction

Any type of forecasting that exclusively relies on historic data is exposed to variations the operating environment and the nature of the (customer) load itself. Additional data used to address the limitations of historic data projections needs to be robust and relevant to the application.

A key aspect to any electricity demand forecasting methodology will be weather normalisation or weather correction. It is a well established fact that electricity demand is highly sensitive to weather as a consequence of heating and cooling loads (ACIL Tasman 2010, p. 13). Hot conditions in summer result in high peak demands. Cold days in winter also result in higher peak demand for electricity.

For this reason, any comparison of historical electricity loads over time requires these loads to be adjusted to standardised weather conditions. Without weather normalisation, any linear trend relationships of maximum demand will be susceptible to bias. Conclusions reached on the basis of forecasting with non-weather normalised data are likely to be erroneous and the accuracy of such models is likely to be compromised.

It is imperative that any demand forecasting methodology incorporate an appropriate form of weather normalisation or correction. Any method that relies on non-weather adjusted demand data is likely to be seriously flawed.

Peak summer electricity demand is sensitive to ambient temperature and dominated by increased use of air conditioning & refrigeration.

Demand forecasts are developed which have a 50% and 10% probability of being exceeded due to extreme ambient temperature. The peak load forecast would be expected to be exceeded in extreme summer or winter ambient temperatures occurring on a long run average every second year (50% probability) or every tenth year (10% probability).

It is useful to apply temperature correction in order to be able to make informed comparisons between various load forecasts and growth scenarios.

The aim of temperature correction is to present actual load data and forecasts in a form that assumes constant or baseline temperature. Seasonal variations can then be built into the forecasts as a temperature modifier (50%POE, 10%POE, etc). In this manner the effect of seasonal variation can be seen as a direct result on the forecast.

Load forecasts can be "corrected" for the effects of seasonal temperature variations in a number of ways. At the zone substation or bulk supply network level, most businesses forecast demand and load on the basis of 50%POE and 10%POE.

At 50%POE, the forecast value for any particular year has a 50% chance of being exceeded by the actual value. By inference 50%POE represents the average expectation for forecast load and demand whereas 10%POE is a "high" forecast likely on average one in ten years.

The methods by which forecasts are corrected to particular temperature criteria vary.

All methods rely on accurate data for previous load and demand as well as temperature information at and in the vicinity of the previous system peak loads.

The brief methodology adopted by on distribution business in carrying out the annual 11-year load forecasting exercise is outlined as follows (VenCorp 2003, p.28):

- Actual demand that occurred at the various connection points including terminal stations & zone substations in the preceding summer is obtained.
- The average temperature of the day the peak demand occurred is obtained.
- The Probability of Exceedance of the forecast (POE) corresponding to the average temperature is derived by using VenCorp's information. A non linear relationship exists here.
- The actual demand is then adjusted to the corresponding 10th or 50th percentile POE so that comparison could be made on a common basis. This is a linear relationship.
- The adjusted demand is then scaled up using a historical growth factor for the local zone substation. This local historical growth rate ranges from 0.3% - 1.0% depending on the area and season.

Tables 4.1 shows summer 10th, 50th & 90th percentile average daily temperatures as determined from studies carried out by VenCorp.

Table 4.1- Average Temperature and Maximum Demand Vs POE [VenCorp, 2003, p.43]

Probability Of Exceedance (POE)	**10%**	**50%**	**90%**
Average Daily Temperature	32.9 ^{o}C	29.6 ^{o}C	27.1 ^{o}C
Maximum Demand (MW)	1069.1	1000	958

Figure 4.1 shows the non linear relationship between Average Temperature & POE as determined from studies carried out by VenCorp.

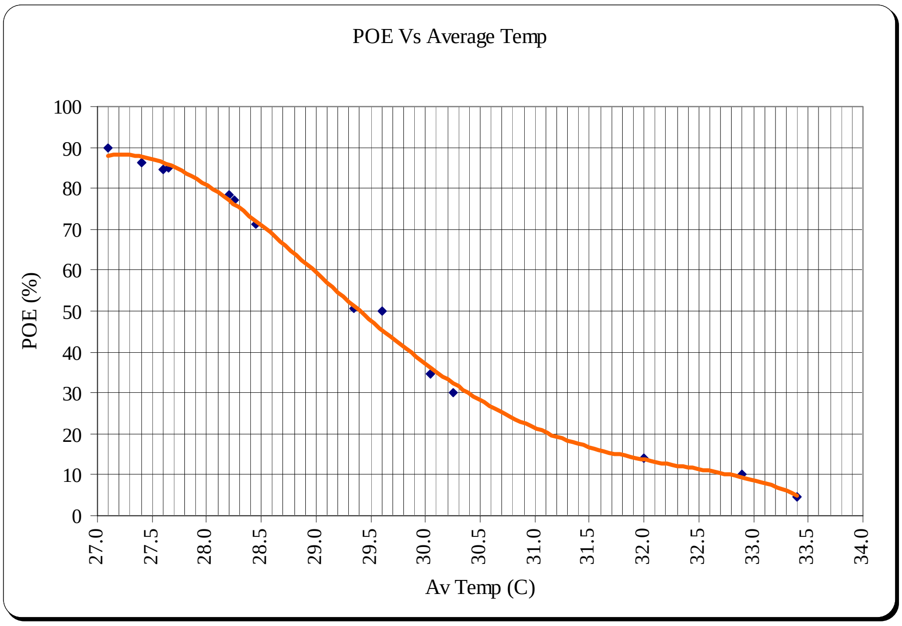


Figure 4.1 - Average Temperature Vs POE [VenCorp, 2003, p.45]

The relationship between peak demand and POE as determined from historical records is presented on Figure 4.2. The average difference between 10th percentile and 50th percentile is 6.91% and that between 50th percentile and 90th percentile is 4.11%. These figures vary slightly between connection points.

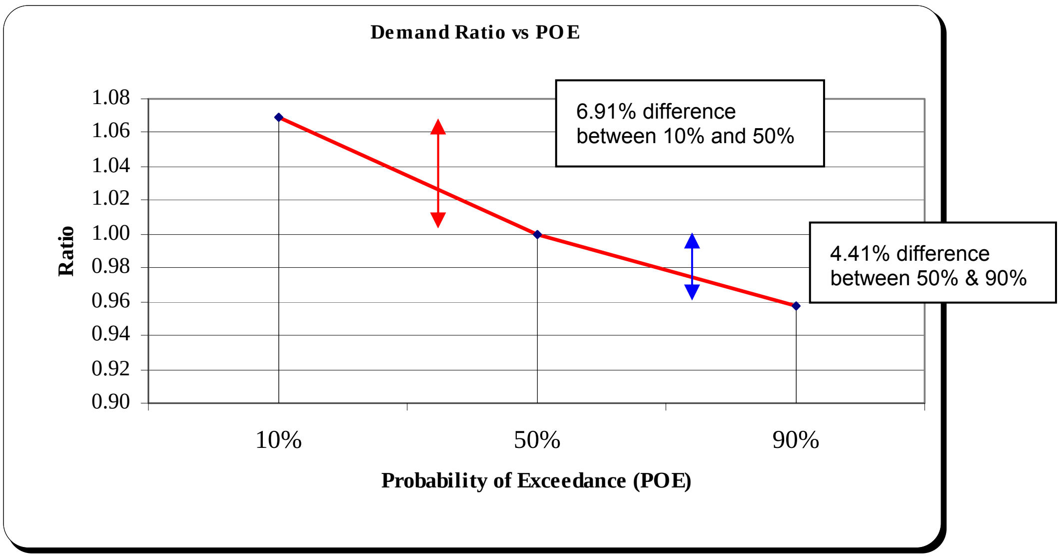


Figure 4.2 - POE Vs Demand [VenCorp, 2003, p.46]

4.9 Spatial Forecast

Zone substations generally exhibit several phases of growth. Typically, zone substations start off growing very slowly as they occupy what is basically farmland or land that was otherwise vacant. Next they then enter a ramp up phase when new developments start to come online. During this phase they exhibit quite high rates of growth. This high growth rate is driven predominantly by increasing customer numbers and can persist for an extended period (up to 10 years depending on the pace of development). As the area serviced by the zone substation reaches saturation, growth in demand begins to slow. Increasing demand at the zone substation during this phase of growth generally comes from increases in demand per household rather than increasing customer connections.

The pattern of load growth for a zone substation over time from its establishment to the point where it reaches maturity point is characterised by the diagram shown in Figure 4.3.

In assessing the individual zone sub-stations it is important to recognise which phase of growth the particular zone substation is in. This recognition is informed by recent historical growth, local development and economic activity and an assessment of the longer term growth potential of the local area.

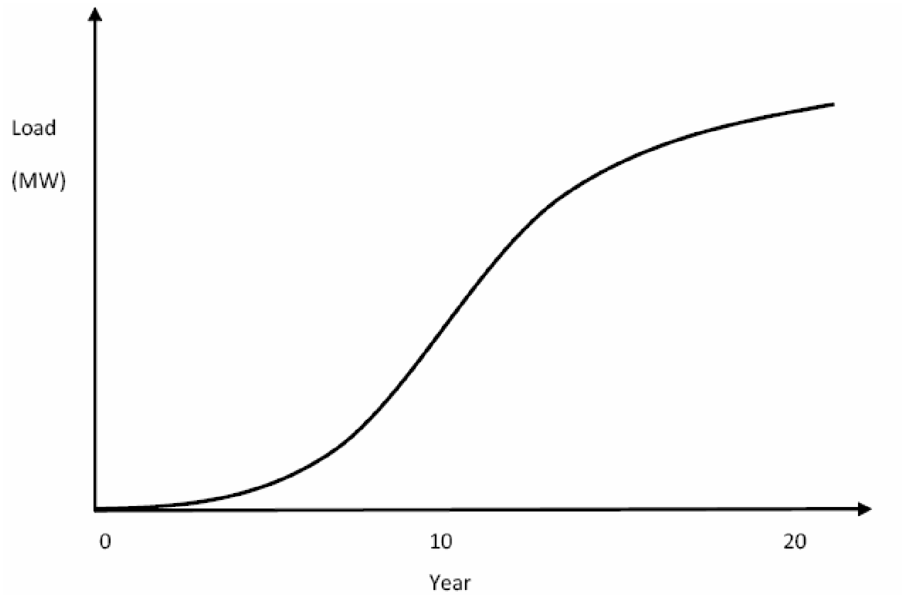


Figure 4.3 – Typical Life Cycle and Load Profile of a Zone Substation [ACIL Tasman 2010, P.8]

Knowledge of where an individual zone substation fits in its life cycle can help inform the network planner as to what kind of growth rate can be expected from that zone substation in the future. The diagram also highlights the importance of being able to determine the inflection points in the curve which may signal the transition from a low growth zone substation to a high growth zone substation and vice versa.

In the case of urban substations, where the initial loading on a substation can be the result of shifting some load from an adjacent substation, the starting point of the curve would be greater than zero, with the one or more adjacent substations from which load was transferred being reduced accordingly.

Forecasts are not cast in stone and need to be updated at regular intervals as new and improved information becomes available. Hence the shape and maturity point of the curve would expect to be updated each year or two as new information became available, including the inclusion of any block loads and permanent transfers.

Compare with system maximum demand forecast, temperature correction of individual zone substations is very difficult for a number of reasons:

I. Load transfers across time (temporary and permanent)

II. There is a higher degree of non weather related randomness driving demand at the zone substation level

III. Block loads coming online may add a discrete jump into a zone substation time series which may resemble a temporary transfer.

In order to apply a temperature correction methodology similar to the one applied at the system level, care needs to be taken to ensure that the time series that is being analysed is consistent both across individual seasons and within the seasons. In order to do this, considerable resources need to be deployed. This difficulty can be partly overcome by applying temperature correction proportionally depending on zone substation type.

In other words the forecasters would undertake a complete temperature correction procedure for a representative subset of the total number of zone substations depending on the extent to which each is residential, commercial or industrial. The percentage shifts between the actual peak and the temperature corrected 50% POE and 10% POE values would then be applied to the other zone substations within the same classification on a proportional basis.

An alternative approach involves applying a simulation based temperature correction method to individual bulk supply points and then making a proportional adjustment to the individual zone substations in the specific bulk supply point. This approach has the appeal that temperature correction is applied at a higher level, however, neglects the fact that individual zone substations under the same bulk supply point can have very different characteristics and thus very different temperature sensitivity. For example it is possible for two adjacent zone substations to have different customer mixes, with one being predominantly residential and the other comprising mostly commercial or industrial customers.

Because these two zone substations will exhibit quite different temperature sensitivity characteristics, it makes more sense to temperature correct them using a zone substation or perhaps bulk supply point that has a similar customer mix compared to the bulk supply point in the zone it is actually in.

It should be noted that weather correction at the zone substation is a fundamental element of developing an accurate spatial forecast. Implementing weather correction techniques at the zone substation level requires considerable resources compared with the existing effort, even where it is undertaken for a representative subset and applied proportionally to like substations.

As an example, specific data about maximum demand average temperature and the corresponding POE are presented in Table 4.2.

Table 4.2 - Record of Peak Demand [VenCorp, 2003, 51]

Year	Date	Min Temp	Max Temp	Ave Temp	POE
1999/00	3/02/2000	26.6	40.2	33.4	5.2%
2000/01	8/02/2001	23.6	36.9	30.3	32.0%
2001/02	15/02/2002			27.7	85.0%
2002/03	24/02/2003	24.5	35.6	30.1	35.0%
2003/04	17/12/2003	21.0	38.3	29.7	44.0%

Table 4.3 presents the comparison of peak demands forecast as reported in this example, actual demand and temperature corrected demand. These are total demand figures aggregated at the connection points.

Table 4.3 - Comparison of Actual Vs Forecast Demand [VenCorp, 2003, p. 53]

Year	Report Submission		Actual Demand		POE per VenCorp	Temp Corrected	
	MW	MVA	MW	MVA		10% POE-(MW)	Growth
1999/00			1177		5.0%	1168	
2000/01	1238	1412	1233	1406	30.0%	1274	9.09%
2001/02	1265	1448	1147	1313	85.0%	1272	-0.18%
2002/03	1296	1490	1177	1354	34.6%	1226	-3.60%
2003/04	1326	1530	1240	1430	44.0%	1312	6.97%
2004/05	1357	1569					
	Average compound growth (2001-2004) – Temp Corrected						2.94%

To be consistent all corrections are done to the base of 50th percentile POE and then subsequently converted to 10th percentile. This is to account for the difference in gradient between the two sectors. The 10th percentile is 6.91% higher than the 50th percentile, which in turn is 4.11% higher than the 90th percentile.

This means that a peak demand of 1000 MW on a 50th percentile day (Ave temp=29.6 ^{0}C) is equivalent to 1069 MW on a 10th percentile day (Ave temp=32.9 ^{0}C) and 958 MW on a 90th percentile day (Ave temp=27.1 ^{0}C).

The main advantage of the 50%POE forecast is that statistically it represents the average expectation going forward. The average load and therefore the average augmentation program and derived capital spend requirement is valuable for business planning for the very the long term and for assets that have a generally long lead time to be established or augmented. In this respect, 50%POE is suited to the forecasting of loads for terminal stations and bulk supply connection points.

10%POE forecasts can therefore be seen as less likely to be achieved but at the same time lower risk, if the predominate risk is of course not having sufficient capacity available to meet demand. 10%POE forecasts may be used to set the upper edge of the investment forecast envelope.

The main and obvious limitation of a 50%POE forecast is that it is only the average in any year. Similarly it also represents the average or the mid point of the envelope of load forecasts into the future. As the 50%POE forecast is generally useful for planning and business modelling for the extended long term (say 10-25years), variations in actual load and demand from this forecast year upon year must be expected. By its very nature 50%POE will represent the average load growth over the long term with the actual loads scattered both sides of the average in any and all years.

The inference here is that if the nature of the asset and the sensitivity of loading on that asset to the performance of the business are high and the time to plan and implement augmentation is long, then other forms of forecast corrections must be used.

For shorter term assets it would be prudent to examine both 50%POE and 10%POE forecasts. The 50%POE forecast would establish the benchmark augmentation scope and the 10%POE may be used to quantify the level of risk associated with augmentation planning based on the average forecast.

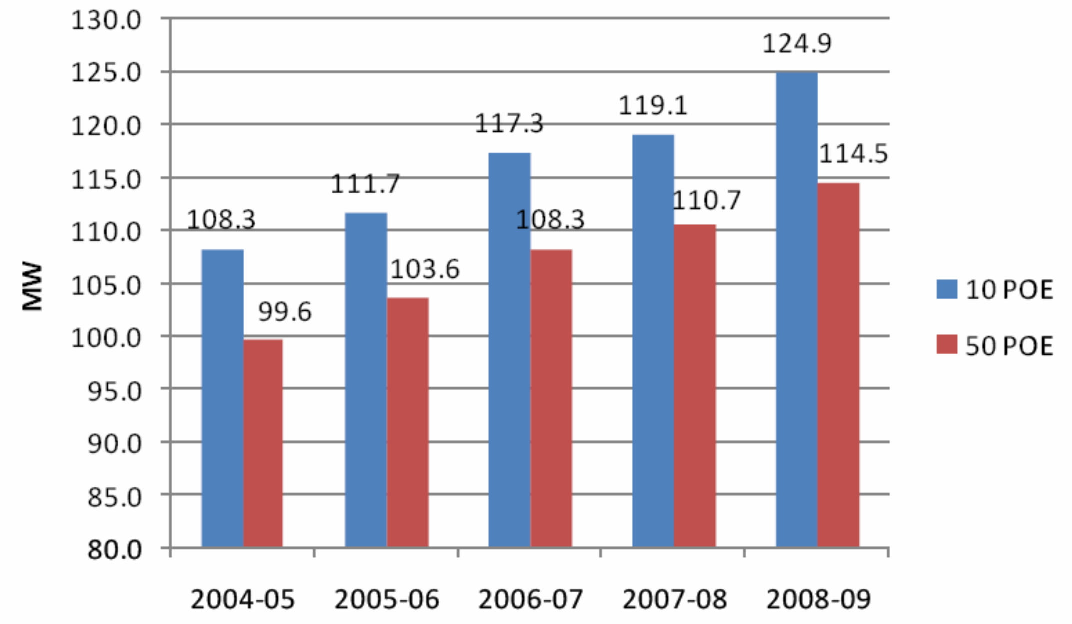


Figure 4.4 – A Bulk Supply Point Temperature Corrected 10 and 50% POE MD [ACIL Tasman 2010, p.55]

4.10 Short Term Forecasting Tools

Having established various tools for 'modelling' the loads (demand) on the electricity network, one of the primary responsibilities of the Distribution Planner is to forecast what might happen to those loads into the future.

In this section we will examine 'short term' forecasting (typically 3-5 years) which is predicated upon the general assumption that tomorrow will be similar to yesterday. In the next section we will examine 'longer term' forecasting, where that assumption is not necessarily so (but may be one of the 'scenarios' considered).

For short term forecasting we would typically use, in increasing order of complexity:

- Simple estimate (e.g. year on year percentage or average percentage increase)
- First order regression (e.g. ordinary least squares method)
- Multi-variable regression (e.g. correlating with mean temperatures, rainfall etc).

For the last of these, we would need some appropriate software tool (such as 'Forecast Pro' - see www.forecastpro.com) as otherwise the manual calculations become tiresome. We can illustrate the other two methods with an empirical example for our fictitious 'Any-Town Zone Substation' (Table 4.4).

Examining the above table we can note the following:

I. The maximum demand does not occur in the same month each year
II. The increase from 2005-2006 (4.17%) is significantly less than the average increase of the six year period (5.31%), if we were to only look back one year.
III. For the years immediately prior to 2006, there was an increasing percentage trend, implying 2006 may have been a 'mild' year and hence an aberration.

Using the "average annual increase" we would predict a July 2007 forecast maximum demand of 31.33 MW.

Using the "average annual percentage increase" we would predict a July 2007 forecast maximum demand of 30MW x 1.0531 = 31.59 MW.

Table 4.4 - Historical Maximum Demand Data for the Any-Town Zone Substation [Dalitz 2008, p.38]

Year	Y (MW) Max. Demand	X (month)	Annual Increase (MW)	Annual Increase (%)
2000	22	60	-	-
2001	23.1	73	1.1	5.0
2002	24.4	85	1.3	5.63
2003	25.5	96	1.1	4.51
2004	27	107	1.5	5.88
2005	28.8	121	1.8	6.67
2006	30	132	1.2	4.17
Average			1.33	5.31

4.11 Long Term Forecasting

There are two well known broad frameworks that can be used for longer term electricity demand forecasting (Dalitz 2008, p.41). They are:

- Quantitative only
- Scenario based (which have a qualitative and a quantitative component)

Examples of Quantitative methods are:

- Trend extrapolation (graphical techniques)
- Top Down Modelling (elasticity's, income growth, population growth etc)
    - General Equilibrium econometric modelling
    - Partial Equilibrium econometric modelling
- Bottom up modelling (Appliance stock, penetration rates, appliance efficiencies, saturation rates etc)
    - At the final consumer level
    - At the producer (intermediate consumer) level

In a Scenario based approach, a "possible future" is expressed in qualitative terms, and on developing some assumptions based on that future, any of the above quantitative methods may be used to predict future demands.

Only scenario based forecasting has any possible chance of predicting potential long term outcomes (i.e. 10 to 50 years out) because it includes both forecasting frameworks (quantitative and qualitative).

For Planners and Policy makers, scenario based analysis can be useful in a number of ways:

I. Some strategies or policies may be applicable / successful under various scenarios, effectively becoming "no regrets" options. An example (in generation) may be policies that encourage renewable energy sources.
II. Some strategies or policies may succeed only under a very specific future scenario, and in any other future could be retrograde or harmful. Such strategies should therefore be avoided. An example may by the use of tariffs to protect indigenous fossil fuel production.
III. Some strategies or policies may have uncertain, or even negative, long term environmental effects. Examples may be storing spent nuclear fuel or geo-sequestration of CO_2.

Technological change can only be captured by a 'scenario' based forecasts. Even developments in areas unrelated to energy consumption, may impact on lifestyle and demographics, which in turn affects energy consumption, such as extending life times. Other developments, such as fuel cells, the hydrogen economy, and photovoltaic technologies, can radically change energy futures.

Below are some typical 'growth indicators' that might be altered in the 'data spreadsheets' for the different scenarios developed (Dalitz 2008, p.41):

- Gross Development (GDP) Growth (electricity component, typically 50% of GDP)
- Personal Income Growth (PIG)
- Population Growth (POP)
- Efficiency co-efficient (grid and appliances)-EFF
- Oil price inflator (to the extent it affect electricity demand or price)-OPI
- Gas price inflator (used for electricity generation or as a substitute)-GPI
- Price inflator (used to give real electricity price in 2007 dollars).

With some of these growth indicators, a 'saturation' point may be reached at some intermediate point in the model. Examples could be population growth (due to physical constraints) of Efficiency Factors (simply due to the laws of thermodynamics).

4.12 Embedded Generation

Embedded generation is a critical factor for consideration when formulating a forecasting strategy and procedure. The contribution of embedded generations can be significant especially when available at normal system peak times. It is generally accepted that the contribution of embedded generation should not be netted off existing load forecasts unless there are specific and exploitable network support contracts in place. If Network Support Contracts (NSCs) are in place then the business needs to examine the risk associated with the delivery of the NSC contributions at period of call before automatically considering them as negative loads.

In the case of a forecast of HV feeder loading for a feeder that connects to a co-generator, the forecast can be calculated as:

I. Existing forecast = 6.25MVA based on established load forecasting methods and considering all loads from network customers.

II. Co-generator net export to network = 3MVA

III. Therefore the demand forecast attributed to this feeder can be 6.25-3.0 = 3.25MVA assuming the co-generator is available and operating and exporting at the maximum during the expected time of feeder peak demand.

IV. Alternatively, a more conservative approach considers the risk of unavailability of the co-generator during feeder peak loading times. The feeder load forecast in this case would be 6.25-0 = 6.25MVA.

The advantage of being able to consider an embedded generator as a negative load can be significant in terms of peak demand reduction and possibly deferral of augmentation investment.

Similarly the energy contribution of embedded generation can be netted off against forecasts where the capacity of the generators can be used to the advantage of the network.

In a highly probabilistic planning sense, embedded generation network support may be considered (as a negative load) if the level of risk associated with the generator providing network support matches the characteristic reliability of the network.

CHAPTER 5

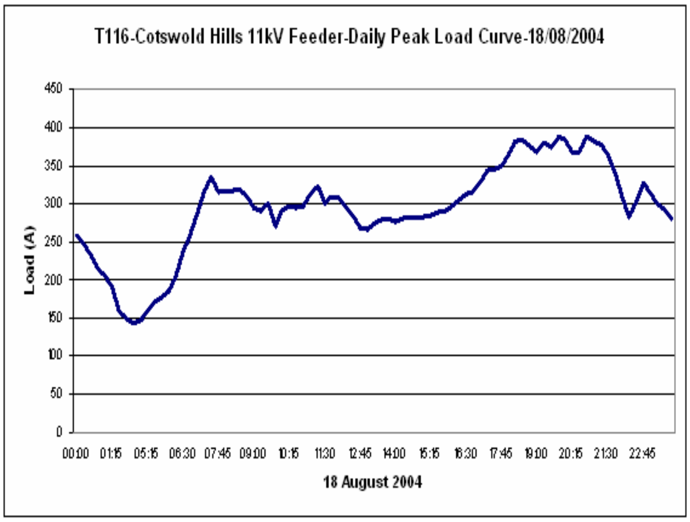
DISTRIBUTION FEEDER PLANT RATING

Distributors typically have hundreds or thousands of HV distribution feeders (HV DF) in their networks. The standard HV distribution voltages used in HV distribution networks are 11kV, 22kV, 33kV, 12.7kV SWER, 19.1kV SWER. Determination of proposed HV DF ratings are typically driven by their daily load cycles, peak loads, feeder type, transfer capabilities, future load growth, fault levels, voltage profile and distribution planning criteria. In addition, O/C protection settings determine rating of existing HV DF.

5.1 Distribution Feeder Loading

HV distribution feeders have different load profiles and daily load cycles. In general, there are six standard daily load cycles used in derivation of the permissible loadings. The following are standard categories of loads on HV DFs:

1. Domestic (summer and winter)
2. Mixed – Predominantly Domestic (summer and winter)
3. Mixed – Predominantly Industrial (summer and winter)
4. Industrial (summer and winter)
5. Continuous (summer and winter).



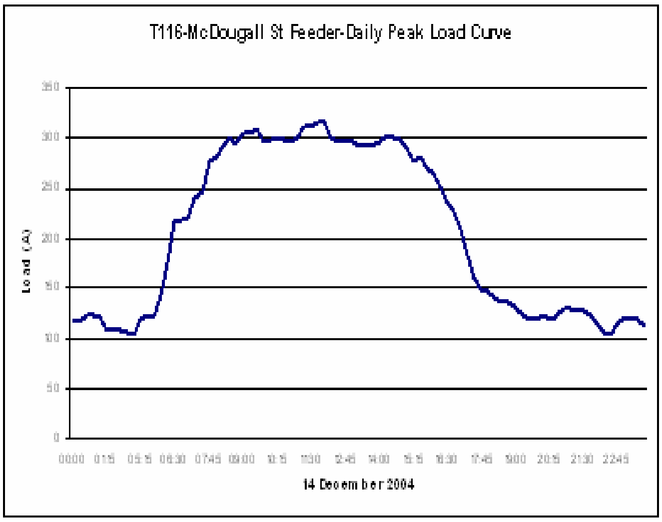


Figure 5.1 - Typical Daily Load Cycles for Domestic (above) and Industrial Feeder

Typically, residential loads have a morning and evening peak. Industrial loads tend to be steady throughout the day, or during the factory hours. Commercial loads are high during trading hours and low the rest of the time. Some areas experience a summer peak, while others have their highest loads in winter.

In addition, based on system configuration and load/voltage profile there are following categories of HV DF:

I. Urban HV DF (MD>0.3MVA/km, or MD>200A)
II. Semi-rural HV DF (MD<150A)
III. Rural HV DF (MD<100A)
IV. SWER schemes (<400kVA).

5.2 Ratings of Overhead Conductors

Urban feeders have typically summer day normal ratings between 200A and 400A, with high capable UG cable exit and OH conductor on its backbone. They supply more than 1000 domestic and commercial customers, via 3 phase distribution transformers with typical range between 100kVA and 1500kVA. Some of them (e.g. industrial feeder) provide supply for single or few very large industrial or special customers.

Short and long rural feeders' ratings vary between 100A and 200A, usually without UG cable exits, until rating of SWER schemes is dictated by the capacity of its isolating transformer.

Traditionally, HV DF have been rated on the basis that all types of circuits are limited by the same operational limitations. This gives the worst case scenario and results in all types of circuits having a variable capacity ranging from a maximum under winter night conditions to a minimum under summer day conditions.

Overhead conductors are rated in accordance with the Standard Ambient Conditions and Standard Design Temperatures.

Standard Ambient Conditions are (Hermann 2010):

- Standard ambient temperatures for
  - Summer Day
  - Summer Evening
  - Summer Night
  - Winter Day
  - Winter Evening
  - Winter Night
- Wind velocity for
  - Normal conditions (traditionally less or equal to 1 m/s) and
  - Contingency (Emergency) conditions (traditionally 2 m/s)
- Wind angle
- Wind turbulence
- Conductor emissivity
- Conductor absorptivity
- Albedo (reflectance from ground)
- Direct solar radiation intensity
- Solar altitude
- Diffuse solar radiation intensity
- Atmospheric clearness number.

Standard Design Temperature for the new OH circuits is 75^{o}C (sub-circuit at 15^{o}C). Old circuits are constructed using traditionally 50^{o}, 55^{o} and 60^{o}C operating temperature and the sub-circuit at 15^{o}C (Energex 1999).

For 75°C designed lines the actual conductor temperature could reach 110°C [35(ambient) + 60(load current) + 15(solar radiation)] without breaching statutory clearances.

The following factors affect conductor temperature which limits conductor capacity (Sinclair Night Merz 2001):

1.	Ambient temperature [Ta]	
2.	Conductor current [I2R]	Source Heat
3.	Solar intensity [Ps]	Heat Gain
4.	Magnetic core [Pm]	Heat Gain
5.	Forced-convection (wind) [Pf]	Cooling
6.	Natural convection [Pn]	Cooling
7.	Radiative cooling [Pr]	Cooling

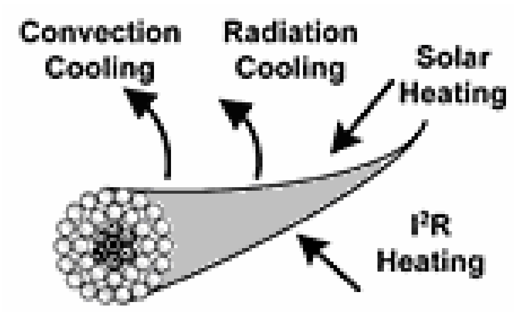


Figure 5.2 – Conductor thermal balance [Hermann, 2010]

Heat Thermal Balance equation includes these factors (Hermann 2010):

- In a nutshell: heat inputs = heat outputs (temperature is stable)
    - I2R + Ps + Pm – Pn – Pf – Pr = 0
- Heat inputs
    - I2R due to conductor resistance
    - Ps due to solar heating
    - Pm due to magnetic core heating in ACSR
- Heat outputs
    - Pn due to natural convection
    - Pf due to forced convection (i.e. wind)
    - Pr due to radiation
- Terms are temperature dependent.

The maximum line loading is subject to its “rating.” While any one of several variables can govern the rating of a circuit, perhaps the most common limiting factor is minimum ground clearance.

As utilities load their transmission lines to higher levels, the conductors heat up, elongate and sag. The real limiting factor, and hence the basis for a line's rating, is often the ability of the utility to maintain a safe clearance between energized conductors and the ground, trees, vehicles and other objects directly below the line, as set forth in regulations.

Most electricity utilities use so called Static (Deterministic) Line Ratings methodology based on conductor current which produces the maximum allowable conductor temperature for a given set of fixed weather conditions.

Such approach requires minimal implementation or ongoing maintenance costs, but has the following disadvantages:

I. Requires accurate climatic models to fix base weather conditions
II. Conservative ratings based on “worst case” conditions give rise to more expensive designs.
III. Lost of capability during favourable weather conditions
IV. No visibility of line operating conditions.

When utilities calculate static ratings they make conservative assumptions about ambient conditions (low wind and high summertime temperatures) coinciding with transmission lines heating up due to high electrical loads.

Collectively, these factors manifest themselves in ratings that are much lower than the true power capacity of the line. As a result, lines often have significant “hidden” capacity available for use if unknowns associated with how the conductors are responding in real-world conditions could be lessened or eliminated. Some studies show most transmission lines can carry 5% to 20% more power than they do under present limitations (Fig. 5.3).

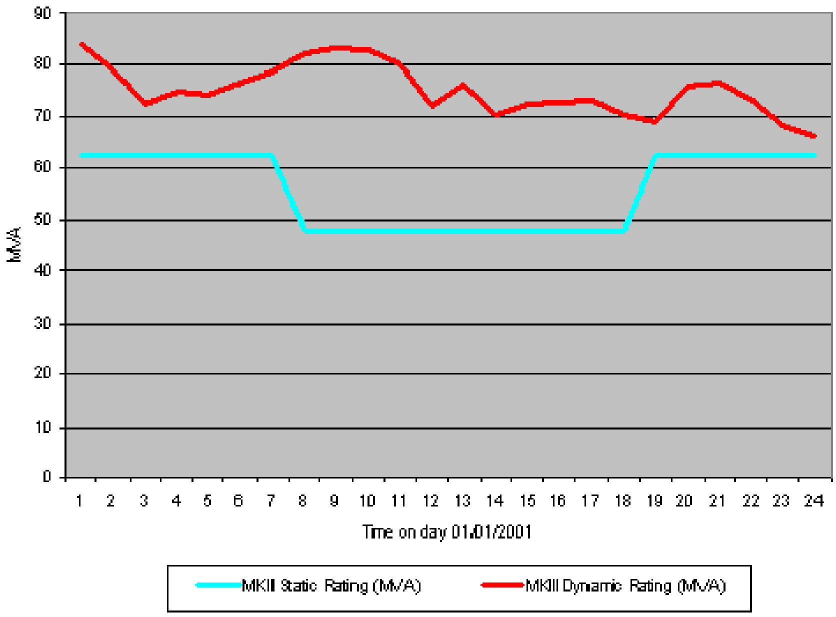


Figure 5.3 – Comparison of Static and Dynamic Line Rating

Thermal rating of overhead lines is affected by ambient conditions (wind speed and direction, ambient temperature, precipitation and humidity and solar radiation) and line construction (materials).

In order to accurately rate a line, constant monitoring of ambient conditions and conductor temperature is required. In this instance real-time data is delivered by Dynamic Line Rating Program (DLRP - Fig. 5.4) managed in Ergon Energy by the author and consisting of:

- Weather Station capable to measure meteorological parameters
- Line Conductor Temperature Logger or Line Tracker LT50 which measure conductor surface temperature and real-time load, and
- Sagometer to measure real-time ground clearances and use the hidden capacity.

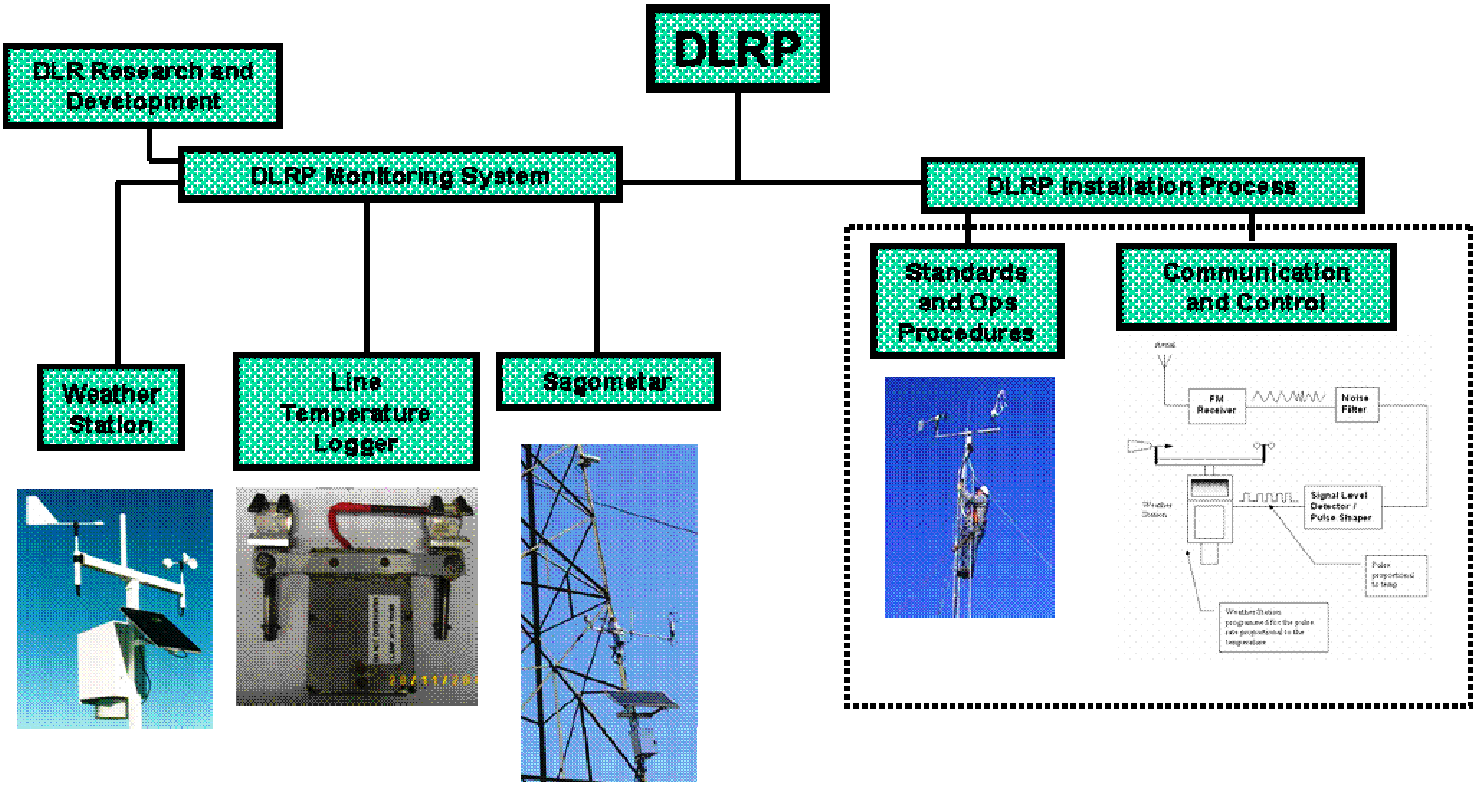


Figure 5.4 – Dynamic Line Rating Program Structure

Concept of Dynamic Line Ratings is similar to Static Method except Real Time data is used in the calculation (Hermann 2010).

- Heat Inputs – Heat Outputs ≠ 0 and equation becomes:
    - o I2R + Ps + Pm – Pn – Pf – Pr = m.C.dT/dt
    - o m= mass of conductor
    - o C= specific heat
    - o dT/dt = rate of conductor temperature change
- Temperature change is not instantaneous due to thermal inertia of conductor.
- A few minutes of “overload” can elapse before design temperature is reached.
    - o Provision for a pre contingency temperature which is less than design temperature.

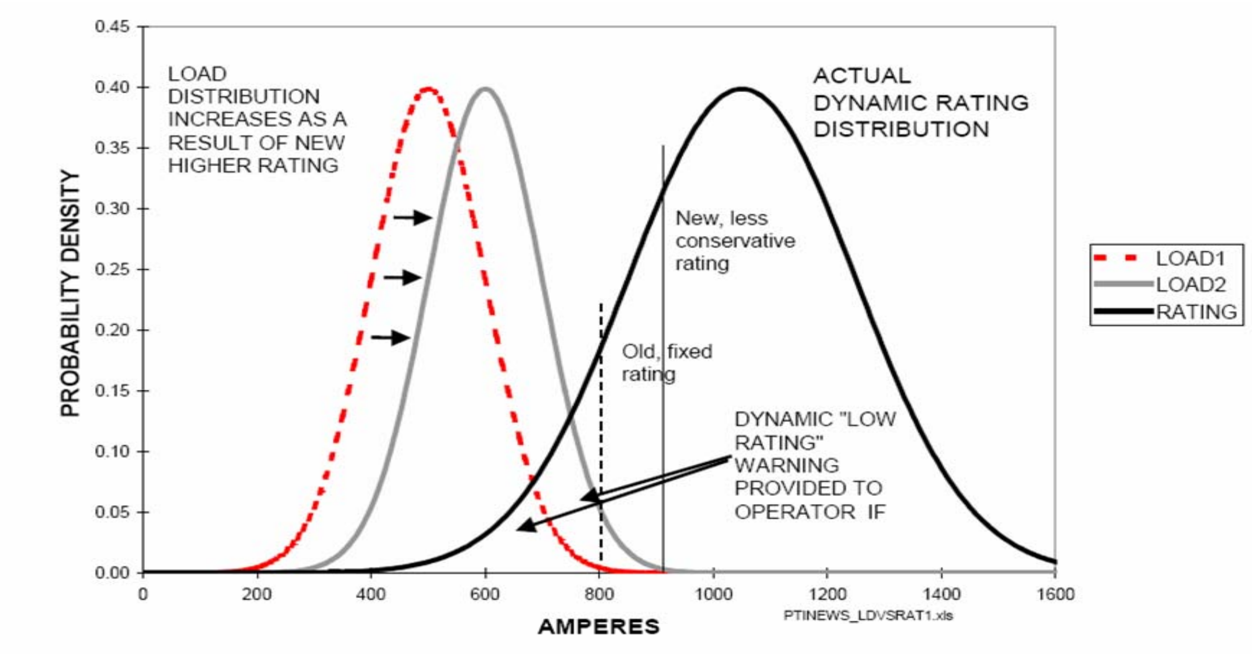


Figure 5.5 – Increasing line utilization while reducing risk by dynamic rating [Hermann, 2010]

- Advantages
    - o Typical increases claimed are 5 – 30%
        - ▪ NOTE: Operating above 20% increases risk to network!
    - o Flexible approach to uncertain load growth.
    - o Ratings are displayed in the format to which the system operator is accustomed. These include:

- Real time capability of the line
- Present line current
- How much additional capability remains
- Present Static State vs. Real Time Capability
- How close the line is compared to the allowable sag limit
- Time until the present sag increase might cause a clearance violation.

Comparison of dynamic rating based on real-time data recorded between 10 and 20 April 2010 on one of the 11kV feeders out of West Toowoomba Zone Substation and static Summer Day ratings under normal (SDN) and emergency (SDE) conditions is presented in Figure 5.6.

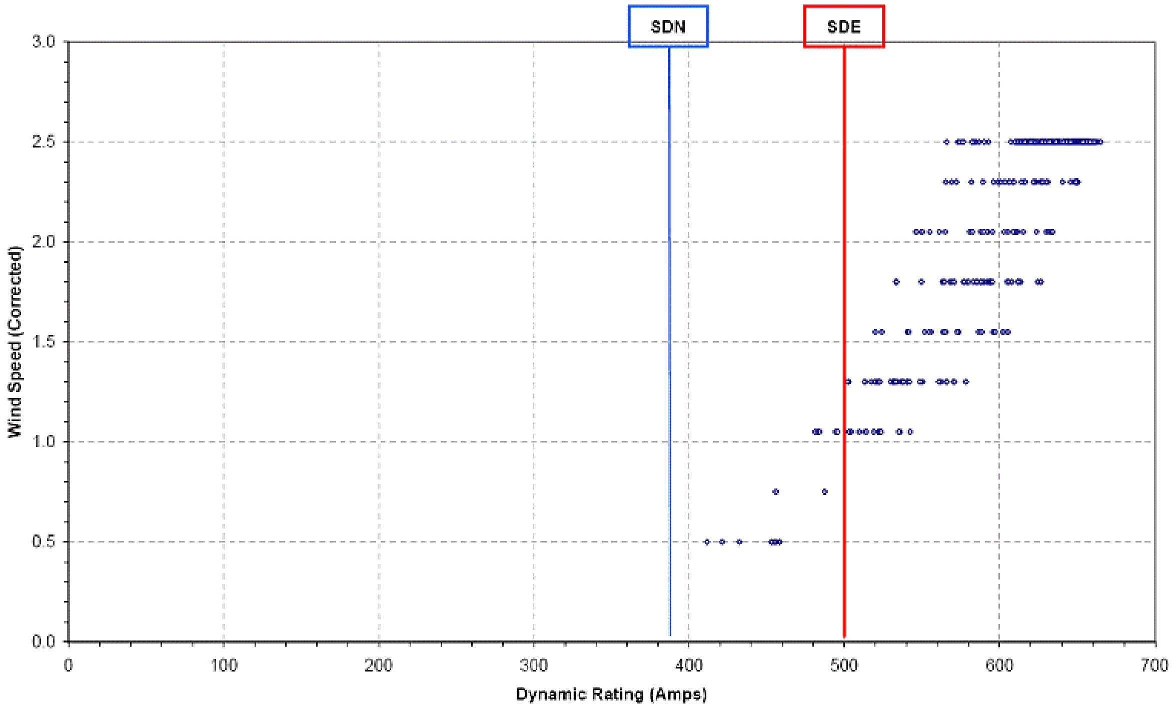


Figure 5.6 – Dynamic Rating versus Static Rating [Hermann, 2010]

Installed on an overhead conductor, temperature logger device LT50 recorded current load and ambient and conductor temperatures providing for the first time simultaneous data about three critical parameters. As shown on Figure 5.6, dynamic line rating (500A-680A) is much higher than normal rating (SDN=390A). Also, during DLR was 95% of time higher than emergency rating SDE (500A). Average dynamic rating was approximately 65% higher than standard rating under normal conditions applied by the Planning and Network Operation Engineers in the past.

- Disadvantages
    - Need for Real Time Communication to SCADA
    - Installation and Material Cost
    - Operator Training and Acceptance
    - Need for additional weather stations.

Determination of dynamic rating of OH lines is of critical importance in the areas of network planning and operation, capital budget, system reliability and one of integral components in development of ‘smart’ networks.

5.3 Ratings of Underground Cables

The rating of an underground cable (UG) depends upon many environmental factors, including the proximity, number, and loading of adjacent circuits. Load cycle shape affects the maximum allowable peak load cycle load, and the preload affects the cables capability to carry short time emergency loading. Cyclic rating factors are applied for UG cables supplying domestic (winter), mixed (winter) and industrial (summer).

Fundamental factors determine Continuous and Cyclic rating of UG cables are the following:

I. Conductor
II. Insulation
III. Cable Structure
IV. Soil & Air Temperature
V. Soil / Backfill Thermal Resistivity
VI. Bonding
VII. Buried Depth
VIII. Load Factor
IX. Soil Moisture
X. Mutual Heating & Spacing
XI. Solar Radiation.

A 630mm^2 Cu XLPE UG cable ratings (bury depth=0.8m, trefoil, single-point bonding, soil temp=25ºC) as a function of Soil Thermal Resistivity (STR) and buried depth are presented on Fig. 5.7, and Fig. 5.8.

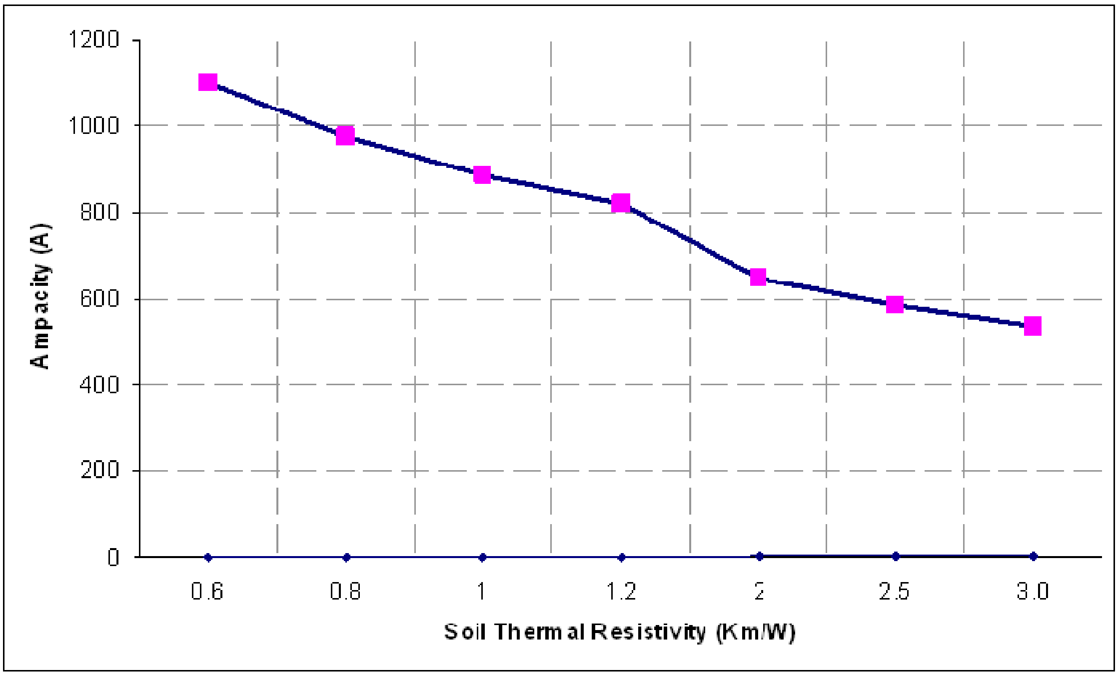


Figure 5.7 - UG Cable Rating and STR [Zhou, 2010]

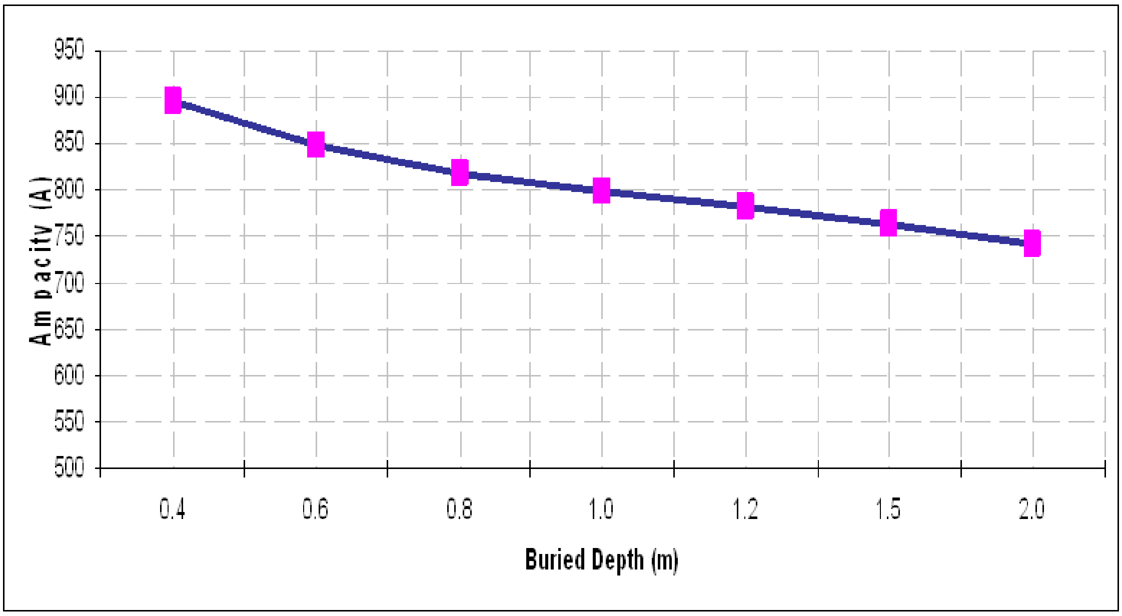


Figure 5.8 - UG Cable Rating and Buried Depth [Zhou, 2010]

5.4 Determination of Conductor/Cable Rating

The general procedure for determination of OH conductor ratings is the following:

1. Determine technical data of OH conductors (size, conductor type, design temperature)
2. Analyse standard ambient conditions (including season and day/night conditions)
3. Select voltage
4. Select load conditions (normal or contingency).

OH Conductors Rating Calculators MKIII, MK3 and MK4 use in Ergon Energy for example provide:

- Feeder ratings for different ambient and design conditions under normal and contingency conditions
- Fault rating.

Cable ratings require whole of circuit calculations. It is also important to base the ratings on "As Built" records.
In the past we have found large differences between ratings produced from models performed at the beginning of a project due to any of the following:

I. Original models only looked at the design outside the sub.
II. Original models only looked at the design inside the sub.
III. Models did not consider variations that occurred during construction (should be present in the "As Built").

Of specific importance is understanding of thermal resistivity (TR), what it takes to achieve either the TR values or the circuit clearances shown on the construction drawings, the ratings impact of a poor native soil when the cable route passes through soils that were not considered likely at the time of design and many other factors.
Typical problems are also related to installation completed partially inside and outside the substation fence using different standards and management of the circuit clearances or the thermal properties of the materials in the construction.
The general procedure for determination of UG cable ratings is the following (SECV-DISTNET 1993):

- Voltage level
- Cable size and type
- Cable description/insulation
- Determine laying conditions
- Select standard ambient conditions
- Select load conditions (continuous or cyclic).

Two standard UG cable software packages provide the following:

- Underground Cable Design Software SYROLEX 2 (Fig. 5.9)
    - Underground Cable Design Software
    - Analyse of steady stated cyclic problems
    - Ratings of UG single, double and triple circuits
    - Soil Thermal Resistivity, depth and specific back fill material
    - Trench arrangement
    - Thermal models
    - Moisture migration in the soil
    - Radiation flux at the soil

- Underground Cable Design Software CYMCAP
    - Underground Cable Ampacity Calculation
    - Temperature rise calculations
    - Modelling of upgrading existing and designing new UG cables
    - Graphical presentation
    - Different cable installation conditions
    - Cables in pipes
    - Simulation of cables in air
    - Different cable types within one installation
    - Non-isothermal earth surface modelling
    - Cyclic loading patterns
    - Modelling of multiple cables
    - Bonding arrangements
    - Transient analyses
    - Magnetic field module.

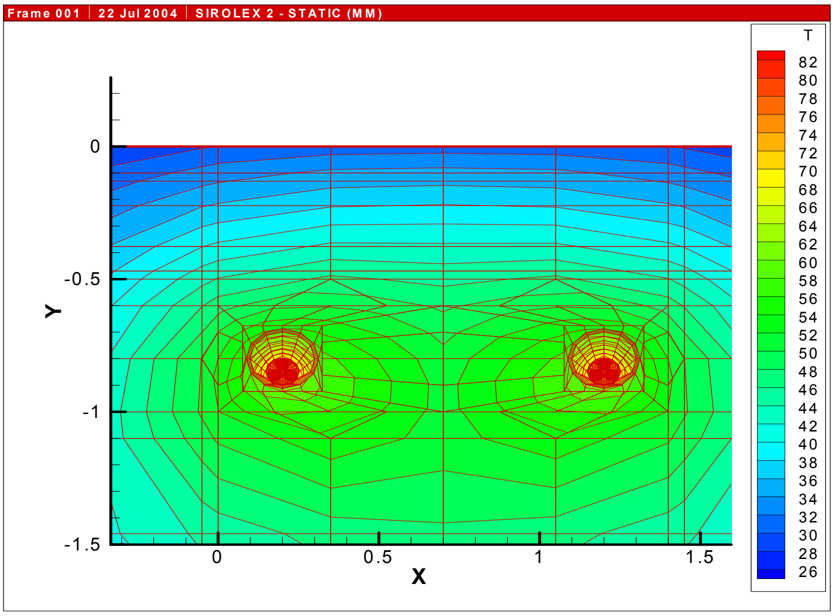


Figure 5.9 – SYROLEX Thermal Model of UG Cables [Stephens, 2003]

Appropriate determination of OH and UG ratings improves models of distribution network and provide accurate capacity, transfer capabilities and conductor fault rating in analyse of existing and future constraints. Methods are relatively simple, flexible, and with good database do not take long time to be applied.

Limitations in determination of OH conductor ratings are the absence of economic rating, the damage limit curves do not take into account loss of heat to the surrounding and necessity to determine planning criteria rating separately.

Limitations in determination of UG cable ratings are number of cables that can be modelled in a trench, number of layers of back fill that can be used in modelling and installation.

5.5 Distribution Feeder Conductor Selection

General practises are to use:

I. Aluminium (AAC and AAAC) conductors of a size appropriate to the loading in an urban environment
II. Small reinforced Aluminium (ACSR) conductors have a place in rural constructions where the maximum demands are expected low. Where corrosion is a problem small AAAC/1120 conductor provide an alternative conductor
III. Reinforced and galvanized Aluminium (ACSR/GZ) and steel (SC/AC) conductors in SWER constructions.

In regard 11kV UG cable selection, general practises are based on planning criteria and recommend the following major cables:

- 240mm^{2}Cu - standard UG cable exit
- 240mm^{2}Al – backbone routes outside ZSS
- 400mm^{2}Cu – specific high loads or where is rating limited by cable installation conditions
- 95mm^{2}Al – laterals only.

Overhead Conductors and Underground Cable Selection methodology is based on the four major criteria:

1. Distribution Feeder Load Profile
2. Technical Considerations
3. Economic Analysis and Cost Implications
4. Greenhouse Gas Emission Savings.

The general procedure for selection of OH conductor and UG cable ratings is based on standard determination of the following factors:

- Planning criteria
- Load cycle
- Voltage profile
- Transfer capacity
- Load growth (10 year)
- Power losses savings
- Load density
- Fault levels
- Design specifics
- Construction and installation arrangement
- NPV sensitivity
- Climate change effects.

On the following Table 5.1 is presented an example of load forecast for 11kV distribution network based on summer and winter maximum loads, expected 5- and 10-year growth rates, feeder rating for OH conductors and UG cables and planning criteria. The author has developed 11kV system consisting of five 11kV feeders with only one feeder with expected maximum demand above 50% of normal summer day capacity in 2016/17 marked in yellow in Table 5.1.

Standardisation of OH conductor and UG cable selection provides significant improvement of system capacities for specific feeder types, augmentation conditions, and future load growth.

Detail planning study is necessary under control of the experience distribution planner.

Table 5.1 - Distribution Feeder Rating, Load Forecast and O/L Risk Assessment

Feeder (Category)	Growth Rate (1-5 yr)	Growth Rate (6-10 yr)	Season	Cable Section	Cable Rating	N-1 (N)	07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17
View St (U)	4.44	2.68	Summer	OH	417	275	130	136	142	148	155	159	163	167	172	177
				UG	410	271										
	3.25	2.15	Winter	OH	530	350	117	121	125	129	133	136	139	142	145	148
				UG	459	303										
Shiel St (U)	4.44	2.68	Summer	OH	417	275	135	141	147	154	161	165	169	174	179	183
				UG	410	271										
	3.25	2.15	Winter	OH	530	350	122	125	130	134	138	141	144	147	150	154
				UG	459	303										
Perth St (U)	4.44	2.68	Summer	OH	574	379	152	159	166	173	181	186	191	196	201	206
				UG	410	271										
	3.25	2.15	Winter	OH	748	494	137	141	146	151	155	159	162	166	169	173
				UG	459	303										
Macarthur St (U)	4.44	2.68	Summer	OH	417	275	130	136	142	148	155	159	163	167	172	177
				UG	356	235										
	3.25	2.15	Winter	OH	530	350	117	121	125	129	133	136	139	142	145	148
				UG	381	251										
High St Feeder (U)	4.44	2.68	Summer	OH	574	379	156	163	167	172	176	181	186	191	196	201
				UG	510	337										
	3.25	2.15	Winter	OH	748	494	140	145	148	151	155	158	161	165	168	172
				UG	571	377										

Note 1: Colour code for rural feeders: RED – Peak load > N (100% of Cable Rating); YELLOW – Peak load > 80% of Cable Rating; GREEN – Peak load < 80% of Cable Rating; Colour code for urban feeders: RED – Peak load > N-1 (66% of Cable Rating); YELLOW – Peak load > 50% of Cable Rating; GREEN – Peak load < 50% of Cable Rating; BLACK – Peak load > Normal Capacity

Note 2: All feeder growth rates are based on 10 year forecasts from CSA 2006 SW.xls

Note 3: Summer peak assumed for worst case scenario. Due to diversity substation load has winter peak.

Note 4: Feeder classification for planning purposes is: R = Mostly Rural, U/R = Urban and some Rural component, U = Urban feeder

5.6 Practical Limits for Overhead Conductors

The ‘skin effect’ is the concentration of current flow at the conductor surface (or skin).This physical phenomena can be explained by considering that a conductor is made up of a multitude of thin and concentric conductors all carrying load currents. The current in each of these is generating a corresponding and proportional magnetic flux which encircles all other concentric conductors of smaller diameter. The inner concentric conductors are therefore subjected to higher self-induced back electromotive forces (higher inductive reactance of the inner layers compared to the outer layers) which force the load current to flow through the outer layers of the conductor.

The skin effect is one cause of Alternate Current (AC) resistance being greater than the Direct Current (DC) resistance of a conductor. The skin effect can be used to our advantage, for example, the use of tubular busbar in high current installations such as switchyards.

With Overhead Transmission lines where high currents may need to be catered for, we can alleviate the skin effect by using ‘bundled’ conductors; that is multiple conductors per phase held a small distance apart by spacers. Typically two conductors per phase are used at 66kV or 132kV and four conductors in a bundle at higher voltages (e.g. 330kV). Bundling is not generally required at distribution voltages, but has been used in 33kV urban networks.

5.7 HV UG Cable Selection Guide

Underground cables can be rated using the same principles as those used for rating overhead conductors, but become considerably more complex, due to (Zhou 2010):

- The insulating material used and its thermal limitations
- Dielectric losses, again related to the insulation material
- Charging current losses that arise from the 'capacitance' of cables
- Sheath losses (that arise through the transformer effect and eddy currents)
- The significant variation in soil resistivity that occurs, affecting both direct buried cables and those laid in ducts
- Mutual heating effects from adjacent cables.

Distribution Planners and Designers should familiarise themselves with some of the other 'de-rating' factors contained in AS 3008.1, which include:

I. Installation in ducts (buried)
II. Installation in ducts (in air of varying temperature)
III. Installations on cable trays (horizontal, vertical, perforated etc.)
IV. Cables exposed to sunlight (direct and shaded)
V. Effect of varying soil temperatures (for buried systems) (AS 3008.1 1989).

The thermal resistivity of soils can vary over the route of (particularly long) cables. For transmission voltages (132kV and above) and where a high reliability is required, strict control of bedding and backfill material is prudent.

CHAPTER 6

NETWORK RELIABILITY

Reliability of distribution network has always been an important priority in electric delivery planning and operations. "Reliability" as normally applied to power distribution is the ability of the power delivery system to make continuously available sufficient voltage, of satisfactory quality, to meet the consumers' needs.

6.1 Customer Related Reliability Indices (SAIDI, SAIFI, CAIDI & MAIFI)

The electricity network, despite its complexity and hundreds of thousand of individual components, is extremely reliable. There are many reasons for this, including:

- In-built levels of Redundancy (e.g. N-1, N-2)
- In-built safety factors (particularly for structural elements)
- Established Standards for equipment (both Australian & International)
- Established Suppliers with many years experience in design & manufacture
- Highly skilled personnel to design, install, operate and maintain the network.

A typical customer might, on average, experience 300minutes without supply in any given year. Expressed as a percentage, we can calculate:

$$\text{Reliability} = \frac{(\text{Total minutes in year} - \text{Total minutes without supply}) \times 100}{\text{Total minutes in year}}$$

$$= \frac{(365 \text{ days} \times 24 \text{ hours/day} \times 60 \text{ minutes/hour} - 300) \times 100}{(365 \text{ days} \times 24 \text{ hours/day} \times 60 \text{ minutes / hour})}$$

$$= 99.943\ \%$$

For a typical electricity utility urban customer, or the Metropolitan customers of the various Australian electricity utilities who typically experience on average only 100 minutes without supply annually, this equates to 99.98% reliability.

The above approach to expressing reliability is particularly useful when dealing with the public, media or politicians because of its simplicity. The more 'complex' industry standard measures for reliability are outlined in the next section.

The following indicators are commonly used throughout Australia and overseas for measuring reliability of electricity networks.

Table 6.1 – Customer Related Reliability Indices (Ergon Energy 2010)

Measure/description	Index	Definition
Total number of minutes a distribution network customer on average is without electricity / year	**SAIDI** System Average Interruption Duration Index	The sum of the duration of each sustained customer interruption (in minutes), divided by the total number of customers (averaged over the financial year). SAIDI excludes momentary interruptions.
Number of interruptions on average, a distribution network customer's supply is interrupted per year	**SAIFI** System Average Interruption Frequency Index	The total number of sustained customer interruptions, divided by the total number of customers (averaged over the financial year). SAIFI excludes momentary interruptions.
Average duration of each interruption	**CAIDI** Customer Average Interruption Duration Index	The sum of the duration of each sustained customer interruption (in minutes), divided by the total number of sustained customer interruptions (SAIDI divided by SAIFI). CAIDI excludes momentary interruptions.
Number of momentary interruptions, on average per customer per year	**MAIFI** Momentary Average Interruption Frequency Index	The total number of customer interruptions of one minute or less duration, divided by the total number of customers (averaged over the financial year).

Central to the calculation of the above indicators is the calculation of "Lost Customer Minutes" or LCM's. This concept is best explained by a few examples:

6.1.1 Example 1

Lightning strikes the overhead mains on fictitious 11kV feeder, locking out the 11kV circuit breaker. Customers report a flash and loud bang in supplied area. A quick patrol confirms no major damage to the insulators on pole, where there is evidence of a flashover. The Control room successfully closes CB. Two thousand customers have been without supply for 30minutes. Lost Customer Minutes will be 2000x30 = 60,000 LCM's.

If this is the only outage on this feeder for the year, then for this feeder we can calculate the following:

SAIDI = 60,000 LCM's/2000 Customers = 30 minutes

SAIFI = 2000 Customer Interruptions/2000 Customers = 1.0

CAIDI = SAIDI/SAIFI = 30 minutes

6.1.2 Example 2

Two weeks after the above event (in the same reporting period), a high load snags an overhead service, flicking it up into the high voltage mains, again in the same supply area on the same 11kV feeder. Customers again report a flash and loud bang. The patrol finds the service up in the 11kV (although the high load is gone). In consultation with the Control Room, an air break switch (ABS) on the source side is opened and a 'partial restoration' on feeder effected by closing CB, restoring supply to 1000 customers (before the ABS). This 'partial restoration' occurs after 30 minutes. The worksite is then isolated, an access permit issued, and the service quickly removed from the HV.

Supply to the remaining 1000 customers on feeder occurs after another 30 minutes or 60 minutes after the initial interruption. If the outages of Example 1 and Example 2 are the only outages on feeder 22 for the year, then we calculate the following (for this feeder):

SAIDI = [Ex 1 LCM's +Ex 2 (partial) LCM's +Ex 2 (final) LCM's]/ 2000Cust

= [60,000 LCM's + 30,000 LCM's + 60,000 LCM's]/2000 Cust

= 75 minutes

SAIFI = (2000 Customer Interruptions + 2000 Customer Interruptions)/2000 Customers

= 2.0

CAIDI = SAIDI/SAIFI = 37.5 minutes

What the above example demonstrates is some of the complexities and anomalies of reliability reporting:

1. The 'average' customer supposedly saw 75 minutes without supply, but no customer is in fact in this category. Half had 60 minutes without supply and half 90 minutes.
2. Partial restorations complicate recording of the processes with three blocks of LCM's to be registered, but only two outages experienced.

Another feature of reliability indices is they cannot be averaged (e.g. for different feeders or regions). The network planner must always go back to the LCM's and the combined customer numbers, and re-calculate.

6.2 Energy Related Reliability Indices

Currently most of the network planners only use dollar per customer minute and dollar per customer interruption as the measurements of reliability benefit. However those figures are not comprehensive enough to represent dollars lost due to energy lost for a specified interruption time. For example, energy lost on a heavy loaded industrial urban feeder is significantly larger than on a short rural residential feeder given by the same interruption time. Therefore energy related reliability analysis was introduced.

The cost of unsupplied load must be considered from both a customer and supplier viewpoint. From a customer point viewpoint the cost of the unsupplied load is difficult to determine accurately as it is dependent on a range of factors including:

- Type of customer and time of outage
- Outage frequency and duration
- Magnitude of load interrupted.

The impact of an outage on a customer ranges from minor inconvenience for domestic customers to major problems for commercial and industrial, or priority customers. From a supplier viewpoint unsupplied load results in loss of revenue (sales). Other costs associated with an outage include handling customer enquiries, negative impact on corporate image and potential loss of market share. The latter items are somewhat intangible and their true value is unknown.

The indexes used in previous chapters like SAIFI and SAIDI are classified as customer orientated indices. In this section load and energy orientated indices are introduced. One of the important parameters required in the evaluation of load and energy-orientated indices is the average load at each load-point busbar.

The average load L_a is given by $L_a = L_p f$ (where L_p = peak load demand for period, f = load factor for the period). The total energy demanded is the average energy times the time period in hours. Based on L_a the following major energy related reliability indices are calculated as:

- Energy not Supplied Index, ENS= $\Sigma L_{ai} U_i$ - total energy not supplied by the system where L_{ai} is the average load connected to load point 'i'
- Average Energy not Supplied, AENS = $\Sigma L_{ai} U_i / \Sigma N_i$ - total energy not supplied / total number of customers served (in energy load per customer)
- Average Customer Curtailment Index, ACCI = $\Sigma L_{ai} U_i / \Sigma N_a$ - total energy not supplied / total number of customers affected (energy lost per affected customer). This index is useful for monitoring the changes of average not supplied energy

6.3 Value of Customer Reliability (VCR)

Several studies have been conducted to ascertain the economic impact of unserved energy, the most recent being conducted by Charles Rivers Associates (CRA) for VenCorp in 2008. The report derived the value of unserved energy for four customer classes for Victoria. Table 6.2 shows the value of unserved energy for the four customer classes surveyed by CRA.

Table 6.2 – VenCorp VCR (VenCorp 2008, p.34)

Customer Sector	Value of Customer Reliability (VCR) (2007) $/kWh
Residential	$4.46
Commercial	$30.82
Industrial	$11.26
Agriculture	$1.31
Total	$47,85

The CRA study was conducted in Victoria only. To validate the results for South East Queensland two alternative studies were conducted both confirming that the figures are reasonable.

The AER, in its Service Target Performance Incentive Scheme (STPIS), has decided to base its incentive rates on the average VCR figures from the CRA (2008, p.34) study. A figure of $47,850 per MWh for rural and urban customers and double this amount ($95,700 per MWh) for CBD customers.

6.3.1 Example 3

A 15km 11kV radial overhead feeder has an outage rate of 0.10 faults / km/year, with a restoration time of 2 hours on average. The feeder has a maximum demand of 4MVA, 0.9 p.f. and load factor of 0.5. Is the installation of a $30 000 recloser justified if the cost of lost energy is accepted by $2/kWh and a five year economic life is considered?

The initial system annual lost energy can be calculated as follows:

Lost energy = number of faults/year x energy lost per fault

Number of faults /year = 15km x 0.1 faults/km/year = 1.5

Lost energy per fault (average) = average demand (kW) x average fault duration
= 4000 x 0.9 x 0.5 x 2 = 3600kWh

Average annual lost energy = 1.5 x 3600 =54900kWh

If the load is evenly distributed over the feeder length then the optimum placement of the recloser would be 7.5km from the substation.

For the system with a recloser the lost energy is as follows:

Final system lost energy = energy lost for faults past recloser + energy lost for faults before recloser.

Energy lost for faults past recloser = 7.5 x 0.1 x 4000 x 0.9 x 0.5 x 2 = 2700kWh

Total energy lost = 2700 + 1350 = 4050kWh

Energy saving by installing recloser = 1350kWh/year x $2/kWh = $2,700

NPV (over 5 year life) = $10,235 (saving) - $30,000 (cost) = -$19,765

The project has a negative NPV and is therefore not worthwhile.

6.4 Regulatory Obligations

Electricity utilities in Queensland operate in a regulated environment with the Queensland Competition Authority (QCA), Queensland Department of Employment, Economic Development and Innovation (DEEDI) and recently the Australian Energy Regulator (AER) being the regulatory bodies (Ergon Energy 2010).

Three standard existing service obligations under the Queensland Electricity Industry Code (EIC) and a fourth regulatory obligation about to commence under the AER's service obligation are:

I. Minimum Service Standards (MSS) covering average reliability performance levels delivered to customers
II. Guaranteed Service Levels (GSL) covering the performance standards applicable to individual customers
III. Worst performing feeder performance monitoring and reporting as part of the Network Management Plan
IV. Service Target Performance Incentive Scheme (STPIS).

6.4.1 Minimum Service Standards (MSS)

The MSS are part of utility's licence conditions. While there are no financial penalties for not meeting the MSS, the organisations are required to employ best endeavours to ensure they are not exceeded. The limits specified in the Code are inclusive of both planned and unplanned events. Ergon Energy uses the current MSS target minus 10% as its internal target. Planner should design the network to meet the internal MSS target. The MSS targets are set out in EIC.

The MSS apply to SAIDI and SAIFI components of the total planned and unplanned outages for the feeder categories CBD, urban, short rural and long rural, but after exclusion events are removed.

6.4.2 Guaranteed Service Levels (GSL)

Guaranteed Service Levels (GSL) for sustained interruptions of small customers are also provided by the Department of Employment, Economic Development and Innovation's Electricity Industry Code. Thus it is important for a planner to understand the implications of poor network reliability performance and attempt to design networks with minimized GSL payments.

6.4.3 Worst Performing Feeders (VPF)

As part of EIC compliance, electricity utility is required to define their worst performing feeders and report on them in their respective Network Management Plans (NMP). This requires the feeders to be analysed annually for performance improvement opportunities and inclusion in operating and capital works programmes if appropriate.

Electricity utility identifies its Worst Performing Feeders (WPF) and prioritises them based on internal guidelines. A Feeder Improvement Plan (FIP) is developed to improve the reliability and performance of the identified WPF in its network and other feeders within their network. The distribution planner should make regular reference to this list and consider improvements which can logically be made when planning networks.

6.4.4 Service Target Performance Incentive Scheme (STPIS)

Australian Energy Regulator (AER) has become responsible for the economic regulation of distribution network service providers (DNSPs) in the National Electricity Market. From 1 July 2010, the AER will introduce a Service Target Performance Incentive Scheme (STIPS), applicable to DNSPs in Queensland.

STPIS is intended to encourage DNSPs to maintain and improve service performance for customers due to unplanned interruptions. This scheme will operate independently of the Electricity Industry Code's MSS.

6.5 Reliability Planning Principles

The reliability planning principles to adhere to are:

- Plan the network to meet a set of performance standards/targets. For reliability these targets are SAIDI, SAIFI, CAIDI and MAIFI.
- Plan the network for both short term and long term performance targets.
- Investment in the network should be based on minimum capitalised cost (NPV) of capital and operating expenses to meet required performance.
- The design life should match the economic and operational life of the equipment.
- Reliability performance is variable and generally follows a log normal distribution. Allowance for this variability should be considered in all reliability planning studies to meet performance targets.
- A reliability solution should be consistent with other network requirements of capacity /security and power quality.
- A reliability plan may consider a sequence of multiple projects to achieve short and long term performance targets.
- Where possible two reliability planning options should be considered to improve reliability to required performance target.
- Credible options shall only be included in any planning analysis.
- All reliability planning studies should consider solutions in accordance with the Order of Merit to elicit the best value NPV solution.
- The aim of reliability planning studies is to improve reliability to an acceptable level according to the various customer segments.
- Utilise standard building blocks.

A reliability planning report should outline the preferred solution to meet a reliability performance target in the most economical way. The Reliability Investment Guide prescribes the procedure for selecting the best value option in detail (Ergon Energy 2010). Projects have to consider two criteria:

- The value of the investment has to be less than or equal to the Value for Customer Reliability (VCR) and operational costs; and
- The solution proposed has to be the lowest capitalised cost of each SAIDI minute saved of at least two alternative solutions.

The reliability planning report should be a succinct but comprehensive report describing the reliability limitation and the options to improve reliability. Reliability planning report should address:

1. the study area and scope
2. the reliability performance required for the area of study
3. the current reliability performance
4. any dependant or associated projects underway or planned for the future
5. types, quantities and geographic locations of faults over last 3 years
6. previous reliability works in study area
7. reliability improvement delivered (difference between points b and c)
8. alternative options (such as refurbishment etc)
9. financial component.

6.6 Feeder Reliability Categories

Seven reliability categories (R1-R7) have been established based on the standard CBD, Urban and Rural categories to allow more differentiation between customer segments. The criteria recognises the increasing expectations of customers and the community for a reliable supply of electricity, the diverse values, functions and needs of the customer classes and the infrastructure and services that can be economically delivered. The table below shows the feeder categories and their determination criteria which is based on feeder load density. The sub-categories are classified by using a combination of parameters namely: Load per km, Energy per km and Customers per km (Ergon Energy 2010).

This combination provides an accurate representation of the feeder sub category. On some feeders, the peak load and number of customers may not be very high, yet because of a flat load profile, the energy delivered on that feeder may be substantial. Alternatively, there are feeders with relatively low peak load and energy usage, yet have significant customer numbers. Similarly, other feeders have very high peak loads, yet supply only one or a small number of customers and also have low annual energy consumption. Given this, the network planner considers that peak load, customer numbers and also energy consumption per km are all key measures in assessing the importance of a feeder and its allocation into a category.

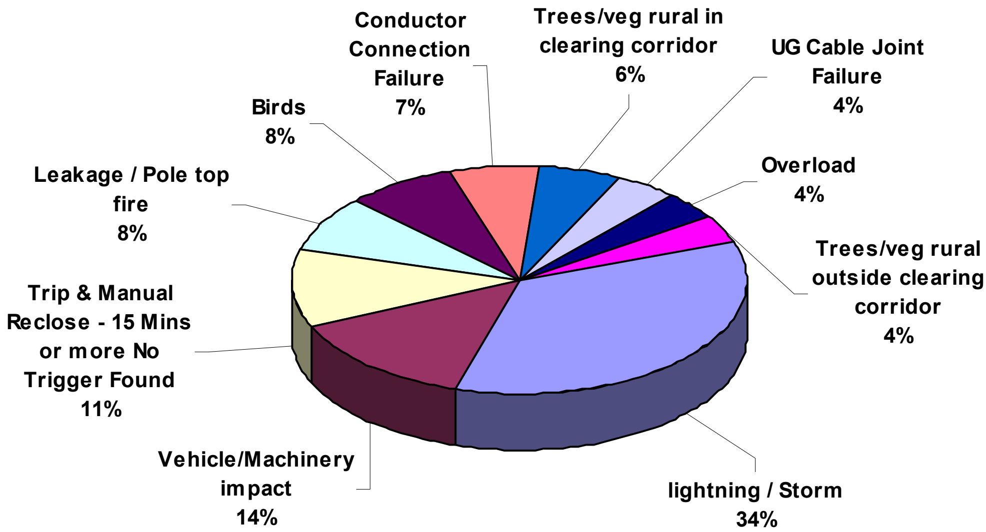


Figure 6.1 – Top Ten Contributors to the Distribution Feeder Performance (Ergon Energy 2010)

Although many of the customer classes associated with the reliability categories have the same loading criteria, it is expected that networks supplying essential community, commercial and industrial load, would generally be planned, designed, operated and maintained to a higher level of reliability than networks supplying other load. In addition, high-density loads of a common class would, by their nature, be easier to service at a consistent level of reliability according to need than low density and mixed loads.

6.7 Reliability Zones

In general there are two reliability zones referred as primary and secondary reliability zones of a feeder. A Primary Reliability Zone is that part of a feeder where any fault will result in an outage of all customers on the feeders. The outage rate in this zone needs to be minimised and the topology needs to facilitate easy restoration of supply to non faulted segments. A secondary Reliability Zone is that part of a feeder where a fault only results in some customer losing supply.

6.8 Planning Network Reliability

Standard reliability improvement options are (Ergon Energy 2010):

I. Application of open wire constructions
II. Application of overhead line fuses
III. Application of reclosers and sectionalisers
IV. Application of isolator switches
V. Application of new feeders
VI. Application of new substations
VII. System reconfiguration
VIII. Application of Undergrounding
IX. Application of Covered Conductor Thick (CCT) and ABC
X. Vegetation Management
XI. Application of phase spacers.

Use of pole mounted reclosers (PMR) is one of the standard reliability improvement options, especially on long rural distribution feeders (Figure 6.2). Location of PMR is selected based on configuration of feeder and reliability indices for every section. Applying one PMR on example shown in Figure 6.2 reliability improvement of 25% is achieved.

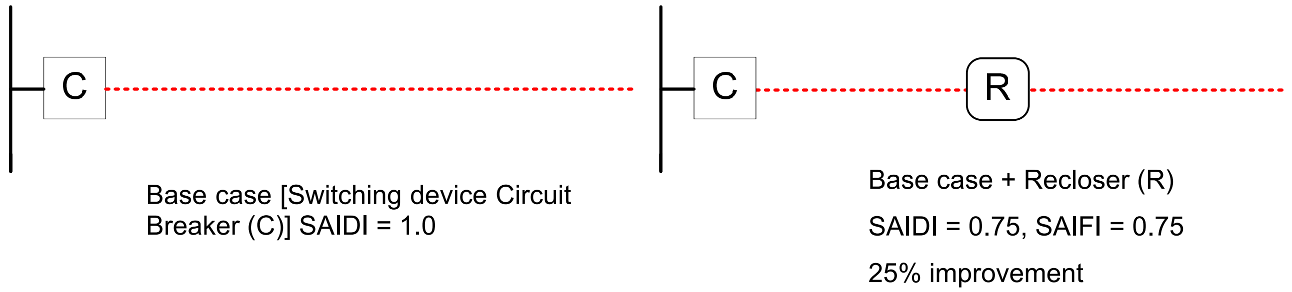


Figure 6.2 – Reliability Improvement Scenarios (Ergon Energy 2010)

Another popular reliability improvement option especially on urban networks is system reconfiguration. The author of this dissertation has achieved significant reliability improvements in high density 11kV networks of Hervey Bay and Toowoomba applying relatively simple, efficient and not expensive reconfiguration option. Vegetation management (in urban and semi-rural areas) and phase spacers (in rural areas) are also standard and not expensive reliability improvement options, especially in Ergon Energy, as Energex extensively uses covered conductor thick (CCT) in the areas with high vegetation.

Before applying any of above options, it is required to identify studied network topologies and based on them develop the best reliability planning approach.

There are two major categories of reliability analysis:

- Reliability analysis of radial network and
- Reliability analysis of complex meshed networks.

Reliability of radial networks is relatively simple especially when used with a network-modelling tool that allows reliability analysis (DINIS). Applications include reliability analysis for:

- Placement of Pole Mounted Reclosers (PMR)
- Construction of feeder ties
- Network Automation Schemes
- New distribution feeders
- Optimum network configuration.

Reliability analysis of complex meshed networks is more complex and involves techniques such as MARKOV modelling to assess reliability performances.

The general procedure for reliability analyses is based on the following elements:

1. Determination of Reliability Parameters
2. Distribution Reliability Modelling
3. Reliability Evaluation and Performance Measures
4. Determination of Load Point Indices
    a. Load Point Failure Rate [λ]
    b. Load Point Interruption Time [U]
    c. Load Point Interruption Duration [r]
5. Customer Oriented Indices
    a. SAIFI
    b. SAIDI
    c. CAIDI
    d. MAIFI
6. Load and Energy Oriented Indices
    a. Average Load at Each Load Point
    b. Energy Not Supplied Index [ENS]
    c. Average Energy Not Supplied Index [AENS]
7. Distribution System Reliability Improvement Strategies
8. Reliability Evaluation for Project Justification.

As an example, major components of two Distribution Feeder Reliability Assessment tools are presented:

- Reliability Indices Calculator
    - Input
        - Feeder Section, Length, Customers on Section
        - Affected Customers, Average Fault Duration
    - Output
        - Existing Reliability Indices (SAIDI, SAIFI, CAIDI, MAIFI) and Targets
        - Proposed Reliability Indices (SAIDI, SAIFI, CAIDI, MAIFI)
- Distribution Feeder Reliability Assessment Tool
    - Input
        - Feeder Length, Customers and Customer Density
        - Faults/Yr, Customer Interruptions/Year
        - Average Lost Customer Minutes/Year
    - Output
        - Saved Customer Interruptions/Year
        - Saved Average Lost Customer Minutes/Year.

CHAPTER 7

VOLTAGE REGULATION MANAGEMENT

Distributors typically have long electricity network (with total length even exceeding 100,000 km) supplying hundreds of thousands of customers within statutory voltage limits and standard voltage fluctuation limits. These limits are determined by some statute or government regulation.

Traditionally, steady state voltage limits are:

- LV Supply – 240V +/-6% (226-254V)
- HV Supply - +/- 5% of nominal.

It is standard practice to have On Load Tap Changing (OLTC) and Line Drop Compensation (LDC) on 33/11kV transformers. LDC adjusts the transformer taps so that the 11kV substation bus voltage is regulated at a higher voltage during high load periods to compensate for large voltage drops down to 11kV feeder. Similarly, during light load conditions, the bus voltage is regulated lower due to feeder lower voltage drop.

The ability to boost substation voltage during high load periods depends on the type of load and lengths and loading of 11kV feeders. If zone substation has several long domestic feeders and a single short industrial feeder (non-homogeneous loads), then this restricts the amount of boost that can been applied during peak load periods.

Typical substation bus 11kV voltage levels are:

- High Load (20MVA) – High volts (11.3kV)
- Low Load (7 MVA) – Low Volts (11.0kV).

Downstream on distribution feeder, a step voltage regulator (SVR) controls line voltage levels to ensure that the voltage received at the customers' premises remains within statutory limits. SVRs are usually designed to regulate voltage in the range +/-10%, in 32 steps, with 5/8 percent voltage change per step.

Overall voltage control is achieved by carefully determining the load-induced voltage drops in the HV and LV lines and strategically placing voltage regulators along the system to compensate for these calculated network voltage drops. This process effectively results in each device operating to maintain the voltage at acceptable levels within its zone of operation. Regulating transformers have on-load tap changing facilities and a voltage control system that enables each device to change voltage ratios as needed to maintain customer voltage levels within acceptable limits. To successfully perform this function, voltage regulators must have both an adequate tapping range to compensate for system voltage changes on the input side as well as appropriate control voltage settings to maintain acceptable voltage levels on the output side.

Single-phase SVRs may be applied to a distribution system in a variety of configurations as listed below:

I. A single-phase circuit
II. On phase of a three-phase star or delta circuit with two regulators (open delta)
III. A three-phase, four-wire, multi-grounded star circuit with three regulators
IV. A three-phase, three-wire star or delta circuit with three regulators (closed delta).

Open (presented on Fig 7.1) and closed delta-connected units are very common and interrelated, which means that regulating one phase there is also a voltage change on the other phases.

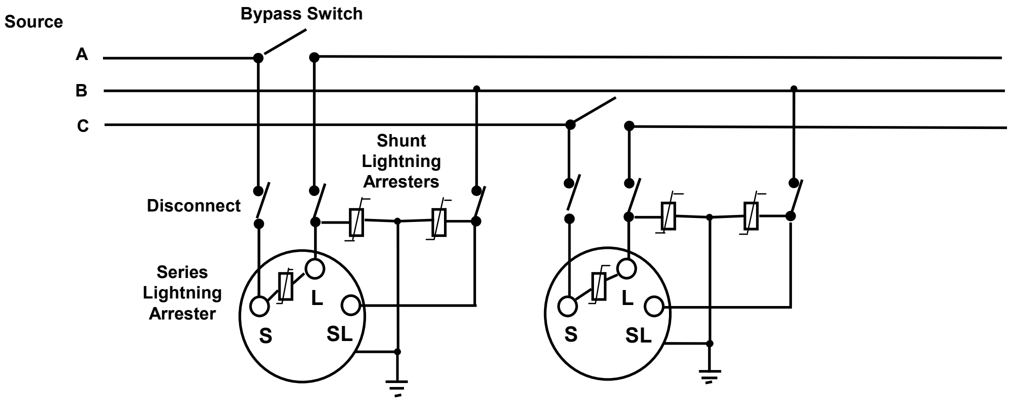


Figure 7.1 – Three-Wire Open Delta VR Arrangement (Ergon Energy 2003)

Typically, distribution transformers (11kV/433V) do not have on load changing, but have the following two off load taps either side of nominal (5 positions in all):

- Taps: -5% -2.5% 0% +2.5% +5%
- Position: 1 2 3 4 5

The new distribution transformers have seven tap positions with more flexibility added only on voltage decrease (buck) side and Tap 5 as nominal.

Maximum LV distribution voltage drop (from distribution transformer LV terminals to service connection to customer at end of LV system) of 10V is typically used as parameter for HV and LV system design.

LV service voltage drop (from the LV mains to the customer point of supply) is maximum 2.5V.

Typical system problems related to voltage stability are:

- Voltage regulation at zone substation
  - o The LDC at the zone substation cannot precisely control the 11kV bus voltage to what we need. This is a function of the size of the transformer taps and is typically at least +/-1/2 tap bandwidth which can give a fair range of fluctuation at times
  - o During high or low load periods maximum or minimum tap on the substation 3/11kV transformers may be reached resulting desired bus voltage could not being achieved.
- Distribution network topology
- Size of OH conductors
- Feeder load profile
- 11kV system unbalance can cause substantial difference between individual phase voltages
- Poor power factor loads
- Non-adequate tap zones
- Non-adequate position of open points between feeders
- Limitations of distribution VR LDC settings
- Distribution transformers load profile
- Motor starts and other switching operations.

The author of this dissertation applied the following options for voltage improvement:

1. Installation of new line voltage regulator
2. Change of voltage regulation settings and LDC on existing VR
3. Change off-load taps at zone substation transformers
4. Change taps on distribution transformers (development of new tap zone plans)
5. System reconfiguration and load shifts (on short rural and semi-rural networks)
6. Installation of line capacitors for power correction
7. On LV networks connected on SWER schemes – installation of Low Voltage Regulators (LVR)
8. Network Demand Management (NDM)
9. Establishment of new feeder (voltage improvement is secondary objective)
10. Increase conductor size (this option must be applied based on detail technical and economical analysis)
11. Change standard voltage from 11kV to 22kV (this option is not standard and must be applied based on detail technical and economical analysis)
12. Conversion of 12.7kV SWER network to 22kV 3-phase systems (this option also is not standard and must be applied based on detail technical and economical analysis).

7.1 Voltage Variations at Customers Premises

As noted, under the Electricity Act electricity utility must maintain under normal operating conditions an average or steady state RMS value of voltage at the customer's point of supply within a tolerance of +/- 6% of nominal 240/415 low voltage supply. This equates to a voltage range of 226 – 254 Volts. For high voltage supply +/-5% of nominal is acceptable unless otherwise agreed with the customer. These tolerances are not guaranteed under all conditions as brief excursions outside this range may still occur due to factors outside the control of electricity utility. Typical excursions may occur when a sub-transmission line is isolated from the network due to a fault & the tap-changers on the affected zone transformers have to increase taps as programmed by the Voltage Regulating Relay (VRR) due to the increased voltage drop in the sub-transmission network.

It is also noted that a standard distribution voltage of 230/398 V is proposed with +10% and –6% variation. This equates to a voltage range of 216 – 253 Volts. Although the upper voltage limit of the new standard is similar to the existing standard (253 V & 254 V respectively), the lower limit of the new standard is some 10 V lower than the existing standard (216 V & 226 V respectively). The introduction of the new standard may have to be delayed due to many customer appliances still in service designed to the existing standard & not capable of withstanding the lower voltage tolerance of 216 V of the new standard. To satisfy the requirements of both the existing voltage standard & the possible introduction of a new voltage standard this policy has adopted the tolerances of the existing voltage standard (ie 240 V +/- 6%) to comply with.

7.2 Purpose of Voltage Regulation

Power transformers at bulk supply & zone substations have on load tap-changers and either a VRR or control system which monitors the nominated (sub-transmission or HV Distribution) bus voltage and controls the transformer tap-changer by a raise/ lower operation to maintain the bus voltage within the set limits. Power transformer taps typically have 17 taps (16 steps of 1¼% nominal voltage) with 5% buck & 15% boost. Transformers with extended tapping ranges of 17½% or 20% boost are sometimes required for high impedance transformers or when the network requires additional voltage support under contingency conditions.

Line regulators are strategically located along the feeders to compensate for network voltage drops. These latter regulators are generally single phase units which can be connected in either open delta or closed delta configuration to form a 3 phase regulator station. In the open delta configuration 2 regulators are connected between 2 phases on the feeder. In the closed delta configuration 3 regulators are connected between all 3 phases. The advantage of a closed delta configuration is that an additional 15% regulation may be obtained over an open delta configuration and specific balance of 3 phase voltage may be achieved. With either configuration load bonus (increased rating of regulator above nameplate) may be achieved by restricting the range of operation of the regulator tap-changer. Generally line regulators have more taps of smaller steps typically 32 taps of ⅝% of nominal voltage. The regulators have a microprocessor control unit as an integral part of the regulator which has several modes of voltage regulation operation from which to select.

The essential controls of any regulating relay include the set point voltage, a bandwidth setting, a time delay control and a Line Drop Compensator (LDC) setting.

7.3 Sub-transmission Voltage Regulation

In general the LV busbars at Transmission Bulk Supply Substations are operated with only a fixed reference or float voltage and without Line Drop Compensation. It is the responsibility of electricity utility to define the sub-transmission voltage set points at its Bulk Supply Substations. The following limits are generally applied for design/ planning purposes. Other site specific limits may be accepted following detailed planning and consultation with all the relevant parties.

Table 7.1 – Voltage Limits at Transmission BSS (Ergon Energy 2003)

System Voltage (kV)	Max Voltage (kV)	Set Point Voltage (kV)
132	145	143 (108.3%)
110	121	119 (108.2%)
66	72.5	71 (107.6%)
33	36.3	35.5 (107.6%)

Under system contingency situations, the voltage will not be permitted to rise beyond the system highest voltage (e.g. 110% of nominal). The settings here determine the voltages on the sub-transmission network. In the case of parallel transmission and sub-transmission networks, the transformer regulator settings determine the reactive (VAr) flows on the network. Real power (W) flow is determined by the phase angle between the voltages of the interconnected substations.

7.4 Distribution Voltage Regulation

To date most 11 kV & 22 kV feeders are regulated by means of a Line Drop Compensation scheme either by means of a VRR or SCADA system. The extent to which LDC increases the voltage profile of distribution feeders is somewhat compromised by the tendency of different feeder loads to narrow the attainable voltage limits. For example urban & rural loads supplied from the same substation tend to limit the allowable LDC range in that the peak rural load typically occurs at night when the substation bus voltage is not at maximum volts. Generally the substation bus voltage is set to maximum during the day when the urban load is highest from larger industrial & commercial customers. Due to these limitations it is recommended that voltage regulation schemes utilising LDC now only be designed for smaller zone substations (< 10 MVA) with a predominantly rural load.

For larger zone substations (> 10 MVA) in an urban environment it is recommended that the substation bus voltage be set only to a float voltage of 1.03 pu without any LDC (ie independent of load). Distribution transformers would need to have their taps set according to voltage profiles compiled from feeder studies (ie DINIS) to meet statutory regulations. The taps set on the distribution transformers would also have to take into consideration the various voltages ratios for distribution transformers from past standards (Refer Table 7.2 - Tap Setting Schedule).

Table 7.2 - Tap Setting Schedule (Ergon Energy 2003)

Tap Setting	433/250 V Transformer	415/240 V Transformer
-10.0% Buck		
-7.5% Buck		
-5.0% Buck	11550	11088
-2.5% Buck	11275	10824
Nominal	11000	10560
+2.5% Boost	10725	10296
+5.0% Boost	10450	10032

Where feeders continue from an urban environment into a rural area it is recommended that voltage regulators be installed to boost the feeder voltage. These regulators should utilise LDC control to boost the voltage according to the feeder load. The settings for the line regulators should be determined from feeder voltage profiles performed from DINIS studies. The regulators should be assessed for either open or closed delta configuration with the load bonus option installed if nameplate rating is to be exceeded.
The recommended distribution transformer tap setting (buck/ boost) for a 1.03 pu float bus voltage is shown in Table 3 for the calculated voltage drop along the feeder for various conditions (ie 100% or 75% loading, 433/250 V or 415/ 240 V distribution transformers, or urban/ rural feeder).

Feeder Voltage constraints were calculated generally based on maximum voltage drop experienced at peak load. Line Drop Compensation was not considered in this review and could be utilised on a specific case-by-case basis.

7.5 Line Drop Compensation

Regulating transformers have on-load tap changing facilities and a voltage control system that enables each device to change voltage ratios as needed to maintain customer voltage levels within acceptable limits. To successfully perform this function, voltage regulators must have both an adequate tapping range to compensate for system voltage changes on the input side, as well as appropriate control voltage settings to maintain acceptable voltage levels on the output side.

Although there are many important factors contributing to successful voltage regulation it is the setting of the regulator controls that we will focus on in this paper. The essential control settings for a regulator consist of a Set Point Voltage, a Time Delay control (including Operating Modes), a Bandwidth setting and a Line Drop Compensator (LDC) setting.

Metering inaccuracies, un-identified changes to phase connections or to current transformer (CT) and voltage transformers (VT) nameplate values require special consideration as they may impact significantly on the regulator response. The application of calculated LDC values alone can easily be flawed because of sensitivity to many different variables. Hence a more secure method of setting determination other than by calculation alone is essential to guarantee the effective operation of LDC.

With the Vx setting on zero the + Vr setting is progressively increased in steps and the resulting regulator output voltages recorded. The regulator may boost or buck depending on the phase connection of the current reference applied to the LDC. To achieve a result with a high level of accuracy the Vr value should be adjusted to change the regulator output voltage by at least 5% overall. This minimizes the effect of the bandwidth setting in the results. Negative Vr values are now applied and the results again recorded. The Vr setting is then returned to zero and a similar procedure followed for the + Vx and – Vx settings. The Set Point Voltage may need to be adjusted during the test to avoid creating system voltage problems. Results from each step should be recorded in tabular form for comparison purposes.

The function of the LDC is to compensate for load induced voltage drop in the HV power system by increasing the output voltage of the regulator in response to load increases in the system. However there are different methodologies in use for applying LDC control to voltage regulators. Two of the most common will now be considered.

7.5.1 Load Centre

Some setting practitioners will identify a centre of load somewhere along the HV system and try to maintain a constant voltage at this point. Having determined where this point is located they would then set the LDC control to represent the resistance (R) and inductive reactance (X) of the line to this point. The application of this method was possibly the first and easiest method of understanding LDC operation and obtaining functional LDC settings. This popular approach works towards establishing some LDC control and is used primarily to minimize the amount of voltage change seen by individual customers in the regulator's zone of operation. To understand what this means consider the normal operation of a voltage regulator without LDC set.

The output voltage at the regulator is held relatively constant varying as allowed within the bandwidth setting. As a result the customer at the remote end of the HV network will see the full effect of the load-induced voltage drops in the HV system. When the LDC is set using the centre of load method then the voltage at the regulator is boosted as the system load is increased. This lessens the voltage change seen by the remote customer while the customer nearest the regulator will now see some voltage change. The voltage levels will effectively swing about the chosen constant voltage fulcrum. The ideal amount of LDC used would have the voltage rise seen by the first customer located immediately after the regulator and the voltage drop seen by the most remote customer as being equal. Thus we see that the accurate determination of this centre of load is significant if we are to achieve this approach for all customers within the voltage regulators zone of operation. Clearly it is necessary to identify at an early stage the degree of regulator control required as application of this method might not guarantee the desired regulation.

7.5.2 LDC Control

A different and more rigorous control methodology adopted by Network owners is to use the LDC control to effectively extend the allowable HV voltage drop in their system. This is achieved not only by the careful co-ordination of the LDC response but also by the use of “off nominal” tap settings on distribution transformers. This technique also uses the fulcrum method but it is extended to embrace a vital relationship between distribution transformer tap settings and specific regulator output voltages. In the system being regulated, distribution transformers nearest the regulator and those furthest away from the regulator could make use of “off nominal” tap settings to help extend HV voltage drop limits. In theory the acceptable HV voltage drop in the ideal radial system used in Australia could almost be doubled by use of this method as opposed to not using LDC at all. Obviously this desired objective is sought by Network owners and is the fundamental reason or having “off nominal” tap settings available on distribution transformers. Of course in practice there are many obstacles preventing Network owners from achieving full LDC control. These obstacles vary from differences in area load profiles to difficulties in setting regulator control voltage targets.

With the need to drive the system harder comes the need to drive the system smarter by implementing more effective voltage control systems. Improvements in regulator control technology and the widespread adoption of sophisticated system modelling software have helped create this opportunity. Although the methodologies discussed here are not necessarily the only ones they are certainly amongst the more popular in use today.

7.5.3 LDC Procedure

To decide on appropriate target voltages the Planning Engineer must first determine the HV voltage drop and the associated transformer tap settings that will be employed along the feeder. From these settings the light load and peak load voltage targets are established. So it is necessary to consider the voltage levels being produced by the regulator during various system loading periods. For example where +5% boost taps are employed on some distribution transformers the regulator voltage level will need to be lowered during the light load period to avoid creating high voltages for customers at these locations.

Particular attention also needs to be paid to the regulator loading properties where load current and power factor variations play an important role in determining appropriate LDC settings. Power factor variations are generally related to the inclusion of shunt capacitors or line-charging effects as well as seasonal load variations along the feeder.

Components of the LDC control will provide a response directly related to these power factor changes. Hence two important variables in the calculation of LDC response, the current magnitude and the power factor need to be clearly identified.

Having decided on appropriate target voltages for the regulator output the correct Resistance Volts (Vr) the Reactance Volts (Vx) and the Set Point Voltage (Vset) now need to be established for the LDC control. It is necessary that the nature of the 3 phase reference vectors for voltage and current used to drive the LDC be known before starting. For example, one of the line to line voltages may be used as the voltage reference while any of the line currents or various combinations thereof may be used to derive the LDC compensator voltage. Identifying the overall VT and CT values used in the control metering is also essential. With this information, system engineers can ultimately perform calculations to determine the right mixture of the Resistance Volts, Reactance Volts and Set Point Voltage to install on the LDC control. The angles of the current and voltage references used by the regulator control will determine if we will need to apply + or – values to the Resistance and Reactance Volts settings to obtain the appropriate control response.

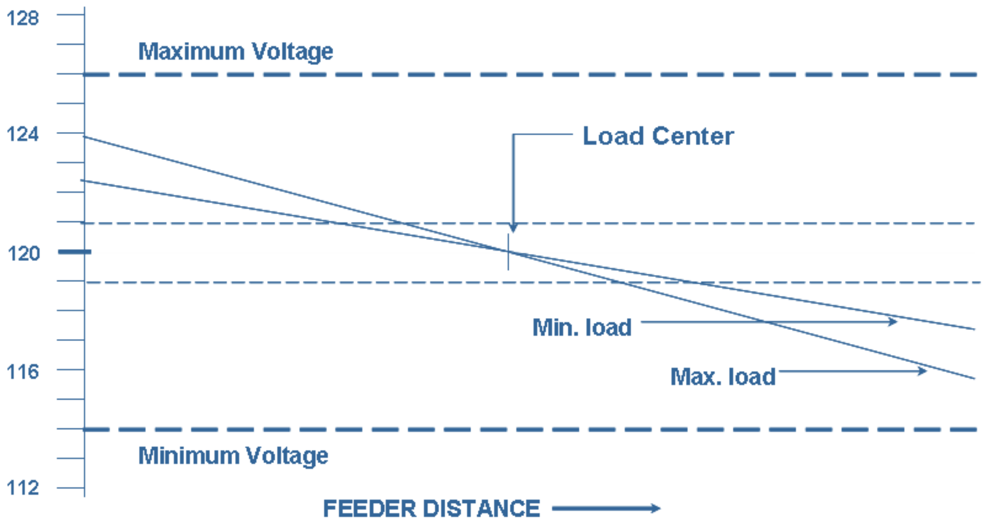


Figure 7.2 – LDC Operation (Ergon Energy 2003)

After the decision is made to set the LDC it is important to document the proposed LDC operating range for use by key operation and repair staff and to compile and publish the strategic zonal tap setting plans. It is likely the LDC operation is designed to permit the use of “off nominal” tap settings in specified areas within the regulator's zone of operation so voltage settings chosen for the regulator LDC will directly relate to these tap ratios. It is after all not just the LDC setting values that need to be scribed onto the door of the control box but also the desired target voltage range produced by these settings. This information is best documented as part of the overall tap setting plan. To install LDC effects without a comprehensive tap setting plan may leave operating staff floundering when it comes to setting appropriate tap ratios or confirming correct LDC response.

Before changing the LDC settings it is important to establish the present tap setting ratios on the distribution transformers. The new LDC settings might need to have minimal impact on the majority of present tap settings while establishing an opportunity to use boost taps on the remote ends of the feeder to rectify existing voltage problems. Sometimes the progressive implementation of LDC effects is less traumatic on the system and the individuals involved hence is an effective and prudent work practice for the regulator specialist to consider.

Finally it is important that equivalent compensator settings be represented in any system load flow model so future load growth studies can automatically flag the need to modify existing settings or change the tap setting plan when required. Successful operation of LDC principles often demands this type of modelling support as part of a secure monitoring system.

7.5.4 LDC Limitations

It is very important to address limitations of LDC. There are situations where actually exclusion of LDC settings may be necessary to fix additional system's voltage problems. For example a regulator may control two spurs with different configuration, load and voltage drop profiles. The combined load current driving the compensator may not serve either effectively and may prove to be detrimental to the required voltage regulation for the individual feeders. Removal of the LDC setting may be necessary leaving the Set Point Voltage as the main method of regulator voltage control. This decision generally requires a detailed knowledge of system load profiles for loads along all feeders and may best be found from a reliable recording process during the investigative stage. The required data would include load current profiles, power factors and voltages at the voltage regulator and simultaneous voltage recordings from sensitive points along the feeders. A detailed model of the system may then be needed for the operator to explore the options to optimize voltage regulation.

7.6 Distribution Feeders with insignificant LV Reticulation

The following voltage ranges were considered for simulation purposes (based upon valid criteria) (Ergon Energy 2003):

- Bandwidth Voltage Regulation at Regulator / Tap-changer = 0.5 to 1%
- Distribution Transformer Voltage Drop = 2.8 % (high utilisation / low diversity)
- LV Reticulation Voltage Drop = 1%
- Co-incident factor of Voltage Drop From beyond the Distribution Transformer = 0.8
- Statutory Voltage Regulation = +- 6% (i.e. 12%)
- Unbalance = 1%
- Design Distribution HV Voltage Drop = 7% (Ergon Energy 2003).

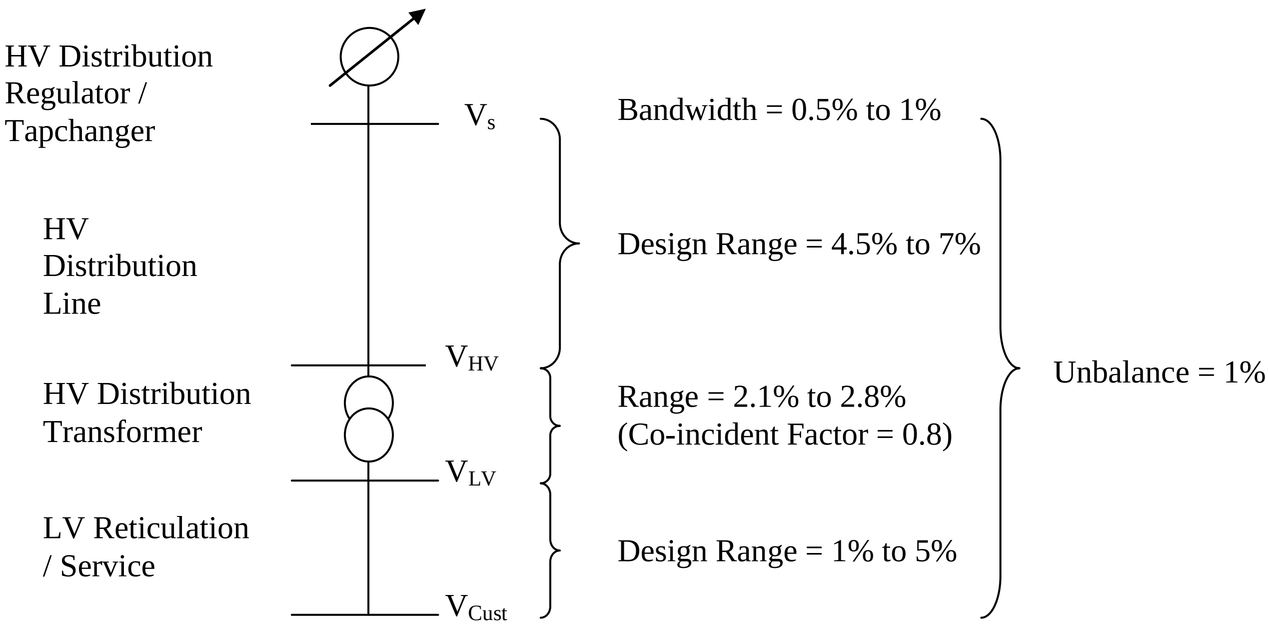
7.7 Distribution Feeders with insignificant LV Reticulation

The following voltage ranges were considered for simulation purposes (based upon valid criteria):

I. Bandwidth Voltage Regulation at Regulator / Tapchanger = 0.5 to 1%
II. Distribution Transformer Voltage Drop = 2.1 % (low utilisation / high diversity)
III. LV Reticulation Voltage Drop = 5%
IV. Co-incident factor of Voltage Drop From beyond the Distribution Transformer = 0.8
V. Statutory Voltage Regulation = +/- 6% (ie. 12%)
VI. Unbalance = 1%
VII. Design Distribution HV Voltage Drop = 4.5% (Ergon Energy 2003).

The Distribution Feeders were assimilated based upon schematic presented in Figure 7.3.

Figure 7.3 – Voltage Regulation Management of Typical Distribution Feeder (Ergon Energy 2003)



CHAPTER 8

POWER QUALITY AND NETWORK LOSSES

Quality of electricity supply has a wide range of meanings such as harmonic distortion, voltage deviations, asymmetry and reliability. From the technical point of view, quality of electricity supply can be seen as the interaction of three major problems (Mielszarski 1997, page 3-5):

1. Voltage disturbances
2. Harmonic distortion and
3. Asymmetry.

Reliability of supply is a measure of supply quality based on reliability indices. However, not all disturbances influencing supply quality have a direct impact on the reliability of power quality. Reliability indices cannot express all characteristics of supply quality.

Voltage disturbances have an immediate and visible effect on the quality of supply, interrupting the supply of electricity energy or resulting in annoying voltage flicker. Electricity users and supply authorities are aware of these problems, and a number of measures have been undertaken to reduce the impact of voltage disturbances on the quality of supply.

Harmonic current distortion was considered the major quality indicator for many years, but it was mostly a problem of large industrial users with equipment such as AC/DC rectifiers, arc furnaces or welding equipment. Nowadays, the increasing penetration of electronic equipment supplied by direct current and the need for alternating current rectification, results in significant harmonic distortion of supply voltages and currents. On the other hand, the use of modern information technologies, communication systems and computer networks requires a high quality of supply.

Asymmetry of supply or unbalance of supply voltages and currents in three-phase systems can also have negative effects on supply quality. It leads to excessive losses and subjecting electrical equipment insulation to excessive voltages. Adequate compensation of reactive power under asymmetrical supply conditions can significantly reduce network unbalance, hence improving the supply quality.

Quality of supply should be considered together with network loss management, in particular reactive power compensation. The insulation of reactive power compensating equipment can improve the quality of supply by the reduction of voltage drops, reducing flickering, and improved voltage profiles along distribution feeders. However, the same q\equipment, when not properly designed and installed, may lead to quality degradation by boosting harmonic levels, causing network resonance or voltage surge during capacitor energization.

8.1 Voltage Deviations

A perfect supply voltage is represented by a sine-wave with the constant magnitude and frequency. In practice, the supply voltage fluctuates as a response of the power system to load variations, switching processes, faults and lightning.

There are several possible classifications of voltage disturbances. Basic types of voltage disturbances are shown in Table 8.1.

Table 8.1 – Basic Types of Voltage Disturbances (Mielszarski 1997, page 144)

Disturbance	Type 1: Transient or Oscillatory Over-voltage	Tape 2: Momentary Under- or Over-voltage	Type 3: Sustained Under-Voltage or Outage
Typical cause of disturbance	• Lightning • Network switching	• System faults • Large load changes • Equipment malfunctions	• Excessive load • System faults • Extreme load changes • Equipment malfunctions
Typical threshold of disturbance	130% of rated RMS voltage or higher	0-87%; 106-130% of rated RMS voltage	<87% of rated RMS voltage
Typical duration of disturbance	Spikes of 0.5-200 microsecond duration	0.5-120 cycles, depending upon distribution equipment	Restoration in a matter of seconds if correction is automatic and 30 min or longer if manual
Effect	• Equipment damage • Errors	• Shutdown • Equipment damage • Errors	• Shutdown • Equipment damage

One of the main reasons for the use of different categories of voltage disturbances is that these are different approached to solving power quality problems, depending on the particular type of the problem. There are also different requirement for measurement and phenomena analysis. The commonly accepted classification for voltage disturbances is the classification presented by IEEE Recommended Practices Std 1159-1995, defining the following categories of disturbances (Mielszarski 1997, page 145):

- Transients
- Short-duration variations
- Long-duration variations
- Voltage fluctuations (flicker)
- Voltage deviations
- Voltage unbalance (asymmetry)

Voltage disturbances are the most obvious effect of degradation of supply quality, resulting in customers' complains. There are many measures which can be undertaken to eliminate voltage disturbances or reduce their negative effects.

8.2 Transients

Transients describe short rapid changes of supply voltage magnitude. They can be classified into two categories:

- Impulsive
- Oscillatory.

Transients with a primary frequency between 5-500 kHz are termed as medium frequency transients. They may result from energization of capacitors connected back-to-back. They may also be a response to an impulsive transient. A transient with a primary frequency less than 5kHz and duration from 0.3-0.5 ms is defined as a low frequency transient which may results from capacitor bank energization and from resonance between the capacitor and system impedance.

Oscillatory transients with principal frequencies less than 300Hz are frequently associated with ferro-resonance and transformer energization. Transients are characterized by high frequencies and are relatively quickly damped by the resistance of circuits. Damping properties of an electrical circuit do not allow transients to propagate through the network. However, an electrical transient can excite a power system and result in oscillatory transients representing voltages and currents that charge polarity rapidly.

Oscillatory transients with frequency between 0.5-5MHz are caused by various types of switching processes, and they are often the response of a network to an impulsive transient. Some power electronic equipment can also produce oscillatory transients as a result of communication.

8.3 Short-duration Variations

8.3.1 Interruptions

An interruption occurs when the supply voltage or load current decreases to less than 0.1pu (10%) for a period not exceeding one minute. Interruptions result from faults, switching of large loads, or loss of line connections. Because the voltage magnitude is smaller than 10%, the interruptions are measured by their duration, which depends on the reclosing capability of the protection system. When large induction motors are connected to the faulted line, the voltage does not drop to zero. The residual voltage appears as a result of the back-emf effect of motors. This effect may increase the levels of fault currents.

8.3.2 Sags (Dips)

Voltage sags (dips) are usually associated with system faults, but they can also be caused by the switching of large loads or starting large motors. The preferred practice, consistent with the IEC terminology, recommends the usage ‘a sag to 20%’ which means that he line voltage is reduced down to 20% of the rated value. The term sag is used mostly in the US, while the IEC definition for this phenomenon is a dip.

During the starting process, induction motors draw large currents that values 5-10 times larger than the rated values. These currents are predominantly inductive, since they are associated with the development of a magnetic field during the starting process. There are several methods to reduce induction motor starting currents including:

I. Double-cage or deep-bar rotor
II. Starting transformer
III. Star/delta switch
IV. Power electronic inverters.

The duration of sags can be divided into three categories, which coincide with categories of interruptions and swells:

- Instantaneous
- Momentary
- Temporary.

8.3.3 Swells (Surges)

A swell is defined as an increase in an rms voltage or current for duration from 0.5 cycles to one minute with typical magnitude between 1.1 and 1.8pu. Swells are not as common as sags. In most cases, they are caused by line-to-ground faults in underground systems. These faults result in voltage rise in un-faulted phases. Large capacitors can also cause voltage swells. In a grounded system, a phase-to-phase fault does not cause a voltage swell.
Voltage sags and swells (surges) are shown in Figure 8.1.

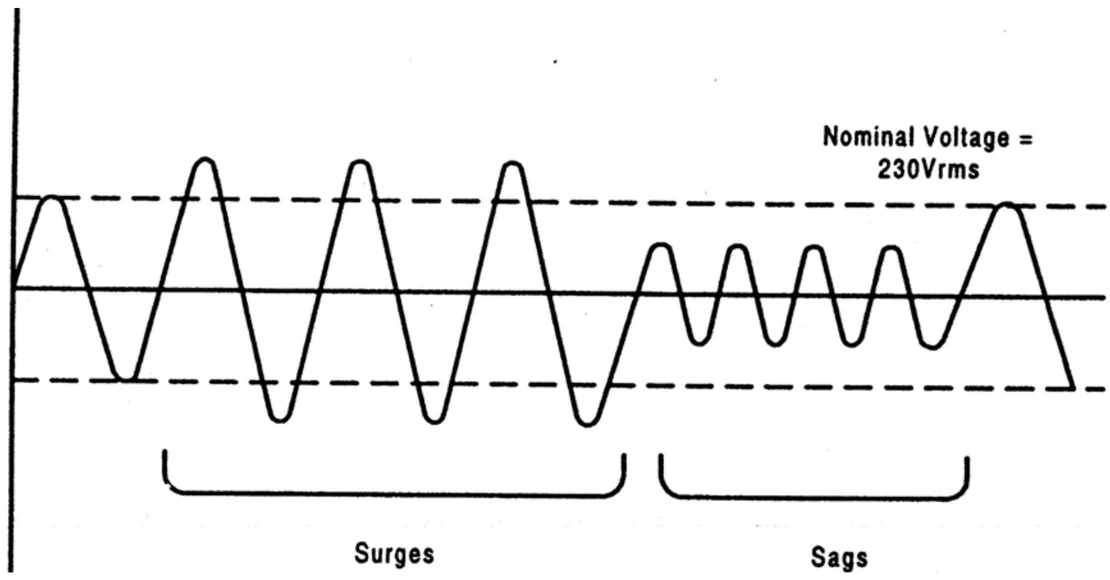


Figure 8.1 – Voltage Surges and Sags (Mielszarski 1997, page 154)

8.4 Long-duration Variations

Long-duration variations are defined as voltage deviations that last longer than one minute. They may be either over-voltages or under-voltages and predominantly result from load variations and switching operations. Categories of long-duration voltage variations are shown in Table 8.2.

Table 8.2 – Categories of Long-duration Voltage Variations (Mielszarski 1997, page 155)

Category	Duration	Voltage Magnitude
Over-voltages	> 1 min	1.1-1.2 pu
Under-voltages	> 1 min	0.8-0.9 pu
Sustained Interruption	> 1 min	0.0 pu

8.4.1 Over-voltages

Over-voltages may result from reactive power over-compensation, an improper voltage regulation system or, most frequently from the incorrect tap zone plans. They are characteristic for periods of low loads like weekends, when distribution transformer tap changers are set for high loads.

8.4.2 Under-voltages

Contrary to over-voltages, under-voltages appear during high load periods, especially in the network with capacity limitations during peak load conditions.

8.5 Voltage Fluctuations (Flicker)

The European Standard IEC – 1000-2-1 defines voltage fluctuations as a cyclical variation of the voltage or series of random voltage changes the magnitude of which does not exceed the range of +/-10%. In general, there are four major types of voltage fluctuations (Mielszarski 1997, page 158):

- Type a: Periodic rectangular step voltage changes of equal magnitude
- Type b: Series of step changes of voltage which are irregular in time
- Type c: Clearly separated voltage changes which are not all step changes
- Type d: Series of random or continuous voltage fluctuations.

The main sources of voltage fluctuations are industrial loads like:

1. Welding machines
2. Arc furnaces
3. Rolling mills
4. Mine winders.

Rapid variation in the voltage magnitude is known as flicker as voltage fluctuation has impact on light intensity. Flickers are limited by standards and recommended practices. The European approach sets a limit for the short-term flicker severity in the range from 0.6 to 0.8.

8.6 Harmonics

Harmonics are defined as sinusoids at integer multiples of the supply frequency which combine with the fundamental frequency to give distorted waveform. The origin of harmonic waveforms in power systems can be traced to the prevalence of non-linear loads. These are associated with both traditional magnetic devices such as transformers and modern power electronic devices such as rectifiers and inverters.

Power electronic systems are based on semi-conductor devices which switch the circuit current according to some predetermined control algorithm. The switching rarely coincides with zero crossing of the mains; hence current pulses are produced. The non-linear nature of these circuits means that even when a sinusoidal voltage is applied, the resulting current will be non-sinusoidal and will contain harmonics. Effectively, the load becomes a source of harmonic currents, which are fed back into the system where they interact with the system impedance to produce harmonic voltage distortion.

It is estimated that about 40% of all electricity generated is conditioned by power electronics before consumption. A major reason behind this trend to power electronic conditioning is the increased system efficiencies that can be obtained using power electronics. A second d factor contributing to increased power system harmonics is the change in design philosophy by electr8ical equipment designers. In the past, equipment designs tended to be under rated or over designed. Now, in order to be competitive, power devices and equipment are more critically designed.

Harmonic analysis of distorted waveforms is a transformation that decomposes the waveform into its harmonic components. Summation of harmonic components results in the original distorted waveform as shown in Figures 8.2.

8.6.1 Total Harmonic Distortion Factor

Distortion Factor is defined as the ratio of the rms value of the harmonic content to the rms value of the fundamental quantity expressed as a percentage of the fundamental.

$$\text{DF} = \sqrt{\frac{\text{sum of squares of amplitude of all harmonics}}{\text{square of amplitude of fundamental}}} \quad 100\%$$

Voltage distortion factor is referred as Total Harmonic Distortion Factor (THD). The compatibility levels for harmonics on the electricity supply system are provided in AS/NZS610000.3.6.

Measurements for harmonics are to be taken at the point of common coupling in minimum intervals of one week. 10 minute averages and daily assessment of 3s, 150 cycle values for at least one week are to be evaluated (Mielszarski 1997).

The utility has to achieve a distribution of disturbances lying below the compatibility level. It does so by choosing a value less than the compatibility level, called the planning level, limiting all disturbances to this value. Planning levels may differ in different parts of the power system – for example they may be allowed to be larger in rural areas where there is less equipment that may be affected. The Standard suggests typical values of planning levels as summarised in Table 8.2.

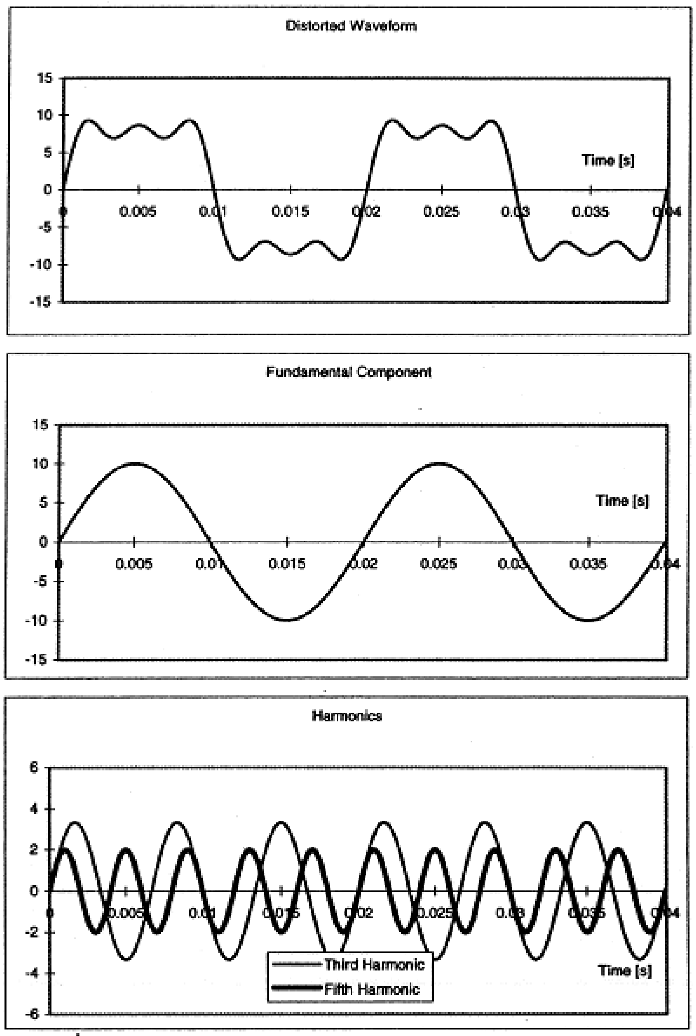


Figure 8.2 – Components of a Distorted Waveform (Mielszarski 1997, page 64)

Compared with AS 2279.2, a key feature of the new limits is that they are larger for low order harmonics and fall off with increasing frequency to smaller values. The even harmonics are limited to less than half the nearby odd harmonics. A new class of triplen harmonics has been introduced with limits between the nearby odd and even harmonics. The high voltage limits are still about half the medium voltage values.

The main steps in assessing the acceptability of a utility's harmonic voltage levels are as follows:

- Measure the harmonic voltage continuously over a period of at least a week.
- Determine the 95% cumulative probability value that is the value which is not exceeded for 95% of the time, and confirm that it is not grater than the planning level.

Table 8.3 – Odd, Triplen and Even Harmonics (Mielszarski 1997, page 102)

Odd harmonics non-triplen			Triplen harmonics			Even harmonics		
Order h	Harmonic voltage %		Order h	Harmonic voltage %		Order h	Harmonic voltage %	
	LV/MV	HV		LV/MV	HV		LV/MV	HV
5	5	2	3	4	2	2	1.6	1.5
7	4	2				4	1	1
11	3	1.5	9	1.2	1	6	0.5	0.5
13	2.5	1.5				8	0.4	0.4
17	1.6	1	15	0.3	0.3	10	0.4	0.4
19	1.2	1				12	0.2	0.2
37	0.5	0.5	39	0.2	0.2	40	0.2	0.2
THD MV: 6.5%, HV: 3%								

Since consumers may have several converters, the standard limits the total harmonic of the consumer installation rather than the current drawn by a particular converter. The acceptability of a consumer's installation is assessed by comparing current harmonics against an emission standard calculated as will be described later. Time variation is accounted for by a similar approach to that used in assessing a utility's disturbance levels.

8.6.2 Notching

There is no explicit limit on notching. It is possible to show that the fall of voltage limit with increasing harmonic order provides an indirect limit on nothing. Notches more than 5° wide are limited to a depth of about 20% as in AS 2279.2. For narrow notches, the standard limits the notch area. This is a sensible approach as the difficulty in filtering a narrow notch is proportional to the notch area.

8.6.3 Summation Laws for Combining Harmonics

The combined effect of harmonic voltages from several different sources is not simply the arithmetical sum of the individual voltages. The voltages are 95% probability levels of distributions which are unlikely to be identical and there will be phase differences between the voltages which can become significant at higher frequencies. Two summation laws are proposed in the standard:

- First summation law: makes use of diversity factors, similar to AS 2279.2, but taking more factors into account.
- Second summation law: this is a power law recommended as being more general and will be described here in more detail.

Table 8.4 – Harmonic Planning Levels (Mielszarski 1997, page 103)

	Voltage Level					
h	132kV	66kV	33kV	22kV	11kV	0.415kV
2	1.1	1.3	1.3	1.7	1.7	1.8
3	2	2.6	2.8	4.3	4.3	4.5
4	0.6	0.7	0.73	0.96	0.96	1
5	2	2.8	3.1	5.1	5.1	5.5
6	0.3	0.35	0.36	0.48	0.48	0.5
7	2	2.6	2.7	4.2	4.2	4.5
8	0.27	0.31	0.32	0.43	0.43	0.45
9	0.81	0.92	0.95	1.27	1.27	1.35
10	0.27	0.31	0.32	0.42	0.42	0.45
11	1.5	1.8	1.9	3	3	3.3
12	0.12	0.13	0.14	0.19	0.19	0.2
13	1.5	1.7	1.8	2.5	2.5	2.8
14	0.12	0.13	0.14	0.19	0.19	0.2
15	0.18	0.2	0.2	0.28	0.28	0.3
16	0.12	0.13	0.14	0.18	0.18	0.2
17	1	1.1	1.2	1.6	1.6	1.8
18	0.12	0.13	0.13	0.18	0.18	0.2
19	0.81	0.88	0.9	1.23	1.23	1.35
20	0.12	0.13	0.13	0.18	0.18	0.2
21	0.12	0.13	0.13	0.18	0.18	0.2
22	0.12	0.13	0.13	0.18	0.18	0.2
23	0.7	0.77	0.79	1.18	1.18	1.35
24	0.12	0.13	0.13	0.18	0.18	0.2
25	0.51	0.54	0.55	0.76	0.76	0.85
26	0.12	0.13	0.13	0.18	0.18	0.2
27	0.12	0.13	0.13	0.18	0.18	0.2
28	0.12	0.13	0.13	0.18	0.18	0.2
29	0.46	0.47	0.48	0.67	0.67	0.76
30	0.12	0.12	0.13	0.17	0.17	0.2
31	0.44	0.45	0.45	0.63	0.63	0.73
32	0.12	0.12	0.13	0.17	0.17	0.2
33	0.12	0.12	0.13	0.17	0.17	0.2
34	0.12	0.12	0.13	0.17	0.17	0.2
35	0.4	0.4	0.4	0.57	0.57	0.67
36	0.12	0.12	0.13	0.17	0.17	0.2
37	0.38	0.38	0.38	0.54	0.54	0.64
38	0.12	0.12	0.13	0.17	0.17	0.2
39	0.12	0.12	0.13	0.17	0.17	0.2
40	0.12	0.12	0.13	0.17	0.17	0.2
THD	3	4.1	4.4	6.6	6.6	7.3

8.6.4 Sources of Harmonic Currents

The main sources of wave distortions are (QUT EEP208 2003):

- Six-pulse Bridge Rectifiers - Harmonic order is function of the number of output pulses in one main cycle. Typical harmonics generated by six-pulse bridge rectifiers are the 5^{th}, 7^{th}, 11^{th} and 13^{th}
- Arc furnaces - Harmonic content is continually varying, being a function of furnace conditions, position of electrodes, steel scrap and random arc between electrodes, and electrodes and grounding. A feature of these systems is the presence of sub-harmonics, e.g. harmonics at frequencies below the fundamental frequency
- Static VAr Compensator – The thyristor-controlled reactor (TCR) is used as a static compensator for distribution systems to reduce voltage flicker, improve power factor, correct imbalance and improve power system stability. The 3^{rd}, 5^{th} and 7^{th} harmonics generated by the Static VAr Compensator have the largest values
- Discharge Lamps – Various categories of discharge lamps generate harmonic current of odd order with the 3^{rd}, 9^{th} and 15^{th} harmonics as dominant. New energy efficient component fluorescent lamps with and electronic starter and ballast generate a full spectrum of odd harmonics with the THD Index in many cases larger than 100%

- Commercial Buildings – The main individual sources in high-rise commercial buildings equipped with relatively new wiring system (<10 years) are:
  - Information technologies (computers as non-linear loads) – current THD=196-420
  - Mixed- and non-linear fluorescent lighting - THD=64-110
  - Power distribution boards - THD~30%
  - Variable speed drivers (equipped with AC/DC rectifier, DC link and an inverter) used in lift control. Current THD is in order between 50-100, and voltage THD is usually <5.
- Domestic Electronic Equipment – TVs, VCRs, radios, computers, electronically controlled washing machines, compact fluorescent lamps. Single-phase rectifiers are commonly used as power suppliers for such electronic equipment. Although the rated power of a single device is small, the large number of electronic devices causes serious problems in domestic areas, in particular in densely populated cities. Between 30-50% of domestic loads has nonlinear current and voltage characteristics resulting in harmonic current generation.

8.6.5 Harmonic Flow

Harmonic current generated by nonlinear loads flow into the supply system penetrating supply lines and other loads. Investigation of harmonic flow requires the consideration of equivalent circuits for all frequencies, analyzing the development of equivalent circuits with impedances calculated due to the harmonic frequencies. The flow of harmonic currents causes voltage drops along supply line impedances, affecting other loads.

8.6.6 Effects of Harmonics

The effects of harmonics depend on the type of equipment; the most susceptible equipment is that designed to be supplied by a pure sine-wave, while the least susceptible type has heating functions (QUT EEP208 2003).

- **Motors and Generators -** Harmonic currents in an electrical machine create mechanical oscillations (caused by 5^{th} and 7^{th} harmonics), additionally increasing iron and heat losses. The harmonics can also cause a pulsating torque output, affecting product quality where the machinery driven is sensitive to speed variations. Harmonic currents have both a thermal effect, increasing machine temperature, and a mechanical effect manifested by vibration at the rotor and increased motor noise. Applying a voltage waveform, which contains harmonics to the stator, will lead to corresponding harmonics in the windings inducing their extra heating and the flow of harmonic currents in the rotor. For example, the 5^{th} and 7^{th} harmonics in the stator combine produce a 6^{th} harmonic current in the rotor manifesting in additional heating and torque pulsation

- **Transformers -** The presence of harmonics in transformers results in an increase in copper losses and stray flux losses as well as iron losses, and consequently reduced efficiency of transformer and their rated capacity

- **Power Cables** - Cable capacitance may lead to the resonance, resulting in voltage stress and corona with the potential to dielectric failure. When cables are subjected to harmonic currents, they are prone to heating. This is caused by losses resulting from the flow of particular harmonics, as well as the skin effect for higher frequencies

- **Capacitors -** Capacitor impedance depends strongly on the frequency of the supply. For higher harmonics, capacitors represent low impedance, resulting in a large current flow even for small voltage distortion. Harmonics increase both heating and dielectric stresses. And can even cause capacitor failure

- **Computers -** Computers and associated equipment require an ac source that has no more than 5% harmonic voltage distortion, with the largest single harmonic being no more than 3% of the fundamental

- **Metering -** Induction disk meters may be affected by harmonic flow resulting in both positive and negative errors, depending on the type of meter and harmonic involved. The presence of harmonic causes errors in metering (usually to read high) and instrumentation circuits depending on the meter construction. A Canadian study reports that a 20% fifth harmonic content produce 10-15% error in three-phase wattmeter

- **Switchgear and Relaying -** Harmonics can increase heating and losses in switchgear, reducing steady-state current, carrying capacity, and shortening the life of insulating components. Relay operation in the presence pf mixed frequency distortion is close to normal, bur errors occur for single frequency harmonic inputs. It is difficult to define relaying response to harmonics, since there are many types of relays and many variations in the nature of distorted waveforms

- **Telephone Interference -** Although it is difficult to place special limits on the harmonic influence on a telephone line, harmonics can affect telephone circuits producing magnetic and electric fields that impair the satisfactory performance of communication systems (described by Telephone Influence Factor TIF).

8.6.7 Reduction of Harmonics

When harmonic distortion appears in distribution systems, the problem of reactive power compensation is changed into the complex problem of reactive power compensation and harmonic distortion reduction. There are at least two possible approaches:

I. Install shunt tuned filters to compensate reactive power and reduce harmonics
II. Reduce harmonics by other methods such as internal active and passive filter, phase shifting, injection, etc. and install capacitor banks to reduce reactive power.

Installation of tuned filters is a well known technique, but it has a number of limitations (expensive devices, with high losses and inefficiency for varying loads, as arc furnaces). Tuned filters can be used for compensation of reactive power and harmonic reduction. Mostly, they are used for large loads.

The second approach uses different methods to reduce harmonic distortion and then consider compensation of reactive power. This approach is more difficult from the design point of view, but in many cases, it is the only solution for medium sized and small customers.
Two techniques have been proposed for injecting current into the transformer windings in order to restore a sinusoidal waveform in the supply current (third harmonic current injection and dc ripple injection).

8.7 Asymmetry

Voltage asymmetry (in-balance or unbalance) is the ratio of the negative (2) or zero-sequence component (0) to the positive-sequence component (1) – Fig. 8.3.
In four-wire grounded star connection LV distribution systems the phase currents are different, leading to differences in the supply voltages. Normally, the maximum phase-voltage unbalance occurs at the end of distribution feeders (Mielszarski 1997, page 189).

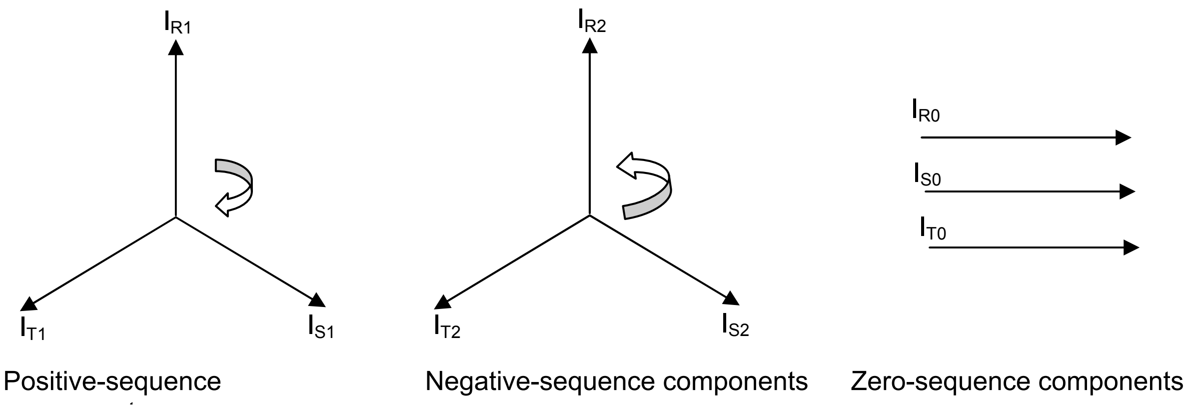


Figure 8.3 – Asymmetrical Components (Mielszarski 1997, page 192)

Unbalanced voltages on three-phase motors cause additional losses in the rotor. Also, some electronic equipment, including computers, may be affected by unbalances when asymmetry is larger than 2.5%.

Asymmetry is caused by the following factors:

1. Single-phase industrial loads
2. Single-phase residential loads
3. Difference in the phase resistance and reactance of some loads
4. Difference in self and mutual impedances of supply lines
5. Arc furnaces and other unsymmetrical loads.

Arc furnaces are the largest sources or asymmetrical currents which vary significantly during the production process (between 25% and 100%).
Caused by asymmetrical loads, asymmetrical voltages at the Points of Common Coupling (PCC) supply asymmetrical currents to other loads, including symmetrical which leads to further asymmetry in the supply system. Asymmetry is characteristic for distribution networks, especially residential and rural networks, but can also be observed in sub-transmission networks.

Asymmetrical voltages have negative effects on electrical equipment connected to the same network, in particular on induction motors and the power electronic equipment.
Typical effects of asymmetry include:

- Additional losses in distribution feeders, synchronous machines and electrical equipment
- Reduction of maximum output power of induction machines
- Motor vibration
- Reduction of insulation life time as an effect of additional losses and increase in temperature
- Increase in demand for reactive power

- Reduction of capacitive reactive power
- Reduction of power factor
- Reduction in distribution system efficiency.

Asymmetry affects both electrical equipment and distribution lines. The mostly affected components of distribution network are:

- Synchronous machines
    - o Additional losses in rotors and stators
    - o Mechanical forces in rotor shaft
    - o Additional mechanical torque
    - o Reduction of generated power
- Induction machines
    - o Reduction of maximum output power
    - o Reduction of mechanical torque
    - o Increased demand for power
    - o Reduction of lifetime due to increased winding temperature
    - o Motor vibration
- Capacitors
    - o Reduction of reactive power compensation
    - o Increased losses
    - o Reduction of capacitor lifetime (asymmetry of 2% may result in the capacitor lifetime reduction of 20-25%)
- Transformers
    - o Increase of secondary voltages
    - o Increase of no-load losses
    - o Reduction of lifetime due to increased winding temperature
- Distribution Lines
    - o Change in reactive power demand
    - o Additional voltage drops along the lines
    - o Increase of neutral currents
    - o Malfunction of protection equipment.

Most countries have developed standards to limit the value of asymmetrical voltages and currents. International Electrotechnic Commission (IEC) Standard No 34-1, 1969, updated in 1980 for example recommends that the coefficient of the negative-sequence voltage should be 1% (long-term asymmetry) and 1.5% (for short-term asymmetry). Other standards give similar values of limits, but for practical purposes, it can be assumed that the voltage asymmetry should not exceed:

$$1.5\% \text{ for } \alpha_{V2} \text{ and } 1\% \text{ for } \alpha_{V0}$$

The best and most simple way of improving symmetry is to design the load based on symmetrical load currents. This solution is however not applicable in many cases when the structure of the load or the distribution network causes asymmetry (for example, long single-phase lines in rural areas). Other techniques in reduction of asymmetry are to generate symmetrizing currents in Three-phase Three-wire Systems and use of single-element, two- and three-component compensators.

8.8 Network Power Losses

Efficiency in transmission and distribution networks is becoming more and more important, so that magnitude of power losses should be given serious consideration. In many developing countries network losses are composed of technical and non-technical (or commercial) losses. The technical losses are caused by the dissipation of heat in electrical equipment, as generally the issue of non-technical losses is in principle social problem.

Modern load flow packages like DINIS have modules to present network power losses based on provided network topologies, technical characteristics of distribution feeders and load profiles. These modules also give information on possible loss strategies listed below.

The process for evaluating network losses in overhead lines and underground cables are somewhat different. For example, OH conductors have magnetization losses, whereas insulated UG cables have additional dielectric losses. An additional source of losses in UG cables are Joule losses caused by circulating and eddy currents flowing in metallic parts of the cable.

Determination of current-dependent losses is very complex predominantly due to dependence of electrical resistances of metallic parts on the temperature. For OH conductors, evaluation of the average conductor temperature requires computation of heat gains due to Joule, ferromagnetic, solar and ionization (corona) heating and calculation of heat losses caused by convection, radiation and evaporation.

For UG cables, the heat gains caused by Joule losses in the conductor, shields, sheath, armour and pipe, as well as dielectric losses in the insulation, are balanced by heat losses in the materials forming the thermal circuit of the cable.

There are different options which network planners and designers can use to reduce the power losses. In general, these options could be separated into the following five major groups shown on Figure 8.4.

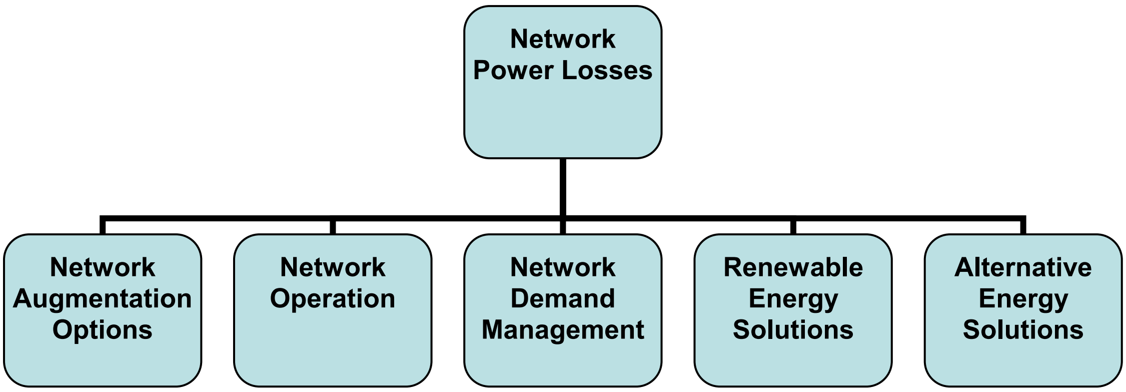


Figure 8.4 – Options to Reduce Network Power Losses

Standard network augmentation options for reduction of power losses are (Ivanovich 2008):

1. Selection of optimal OH conductors and UG cables (Figure 8.5)
2. Network reconfiguration (the author of this dissertation achieved 11kV feeder loss reductions of up to 30% or approx 1MW using this method)
3. Establishment of new distribution feeders
4. Plan future distribution networks considering maximum reduction of power losses based on technical and economical models
5. Replacement of old and small conductors (HDBC and AC/ZG)
6. Under-grounding the overhead network
7. Adequate zone substation sites
8. Compensation of reactive power and PF improvement (Figure 8.6)
9. Increase of nominal operative voltages (Figure 8.7) (in conjunction with long term strategies)
10. Uniform feeder loads
11. Selection of adequate motors and distribution transformers
12. Distributed generation
13. Implementation of Smart Grid technologies.

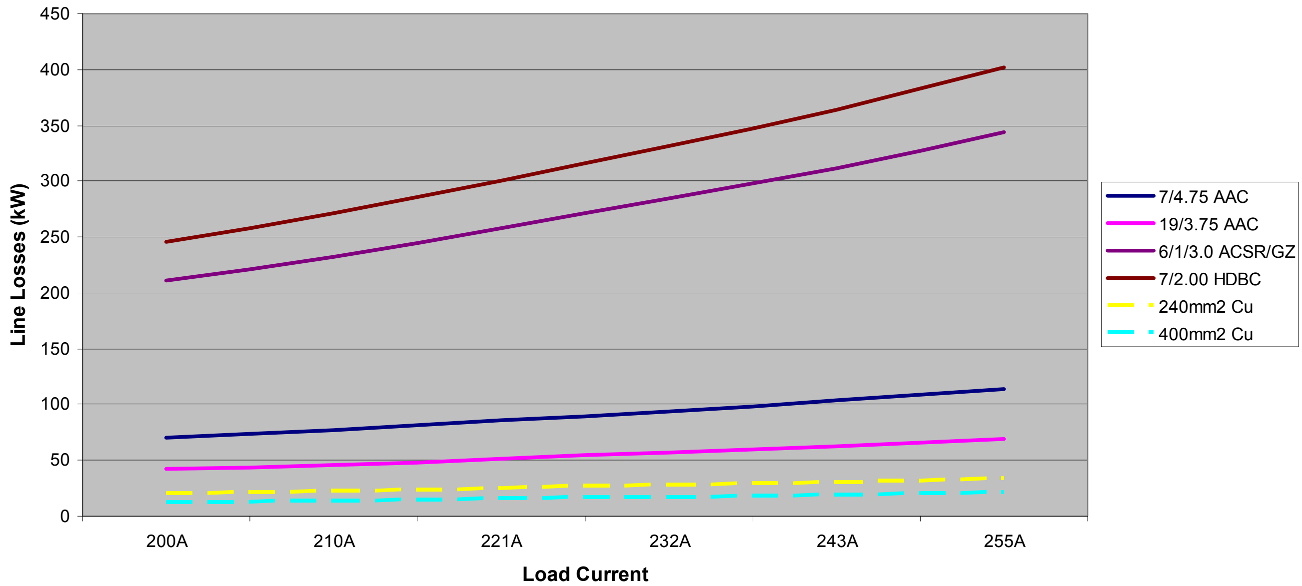


Figure 8.5 – Power Losses for Different 11kV OH Conductors and UG Cables

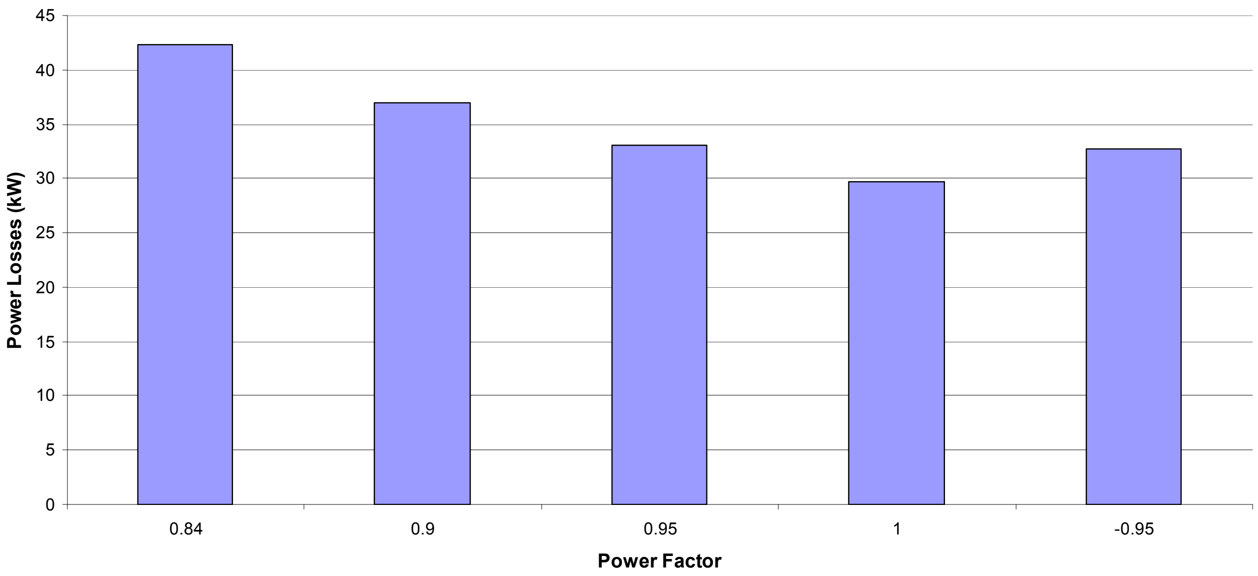


Figure 8.6 – Power Losses and Power Factor based on Load of 100A

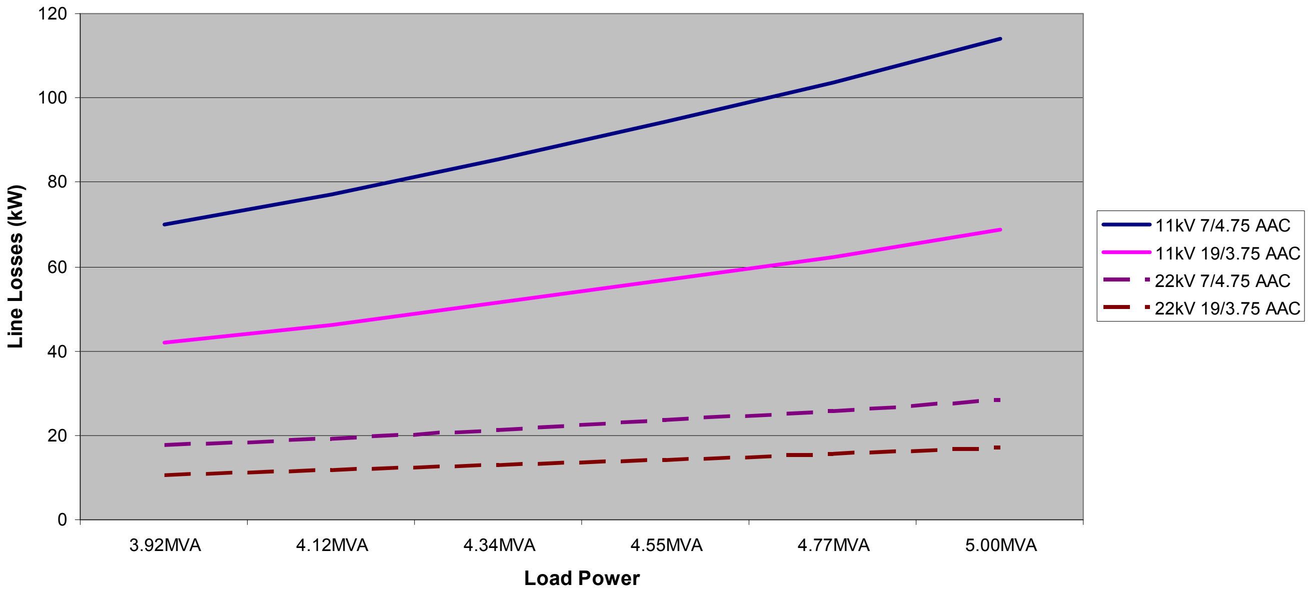


Figure 8.7 – Power Losses and Nominal Voltages

Network operation is another area where electricity utilities have opportunities to reduce power losses. The following operational considerations are standard (Ivanovich 2008):

- Regular system maintenance
- System reconfiguration and load shifting
- Closed/open loops
- Feeder balancing
- Optimal loading of distribution transformers (if possible, reduce number of light loaded distribution transformers and minimise transformer losses)
- Minimise planned outages in distribution networks (live line works)
- Economical distribution of active and reactive power flows
- Power quality improvement
    - Load balance
    - Harmonics
    - Voltage fluctuations.

Incremental loss levels during peak load conditions can be much higher than during light load periods. If some peak load can be shifted to off-peak times, savings in losses can be achieved. Electricity utilities are generally interested in flattening the load curve and this tends to increase the load factor. Consequently, an increase of load factor will result in an increase in power losses. The peak loads can be managed in a number of ways broadly known as Network Demand Management which includes:

- Load shifting from peak to non peak times of large industrial and commercial customers
- Residential customer initiatives
    - Air conditioning direct load control
    - Pool pump direct load control pilot project
    - Pool pump and filtration direct load control
    - Customer appliance and end use information
    - Hot water direct load control
    - Promotion of existing load control tariffs
    - Maintenance of existing load control relays
    - Fuel switching, such as changing from electricity to gas
    - ‘Green’ houses (‘Smart homes’)
    - Industrial energy efficiency
    - Off peak pumping/storage
    - Hot water promotion
- Power factor correction
- Distributed generation, such as stand–by generators in office buildings or photovoltaic panels on rooftops.

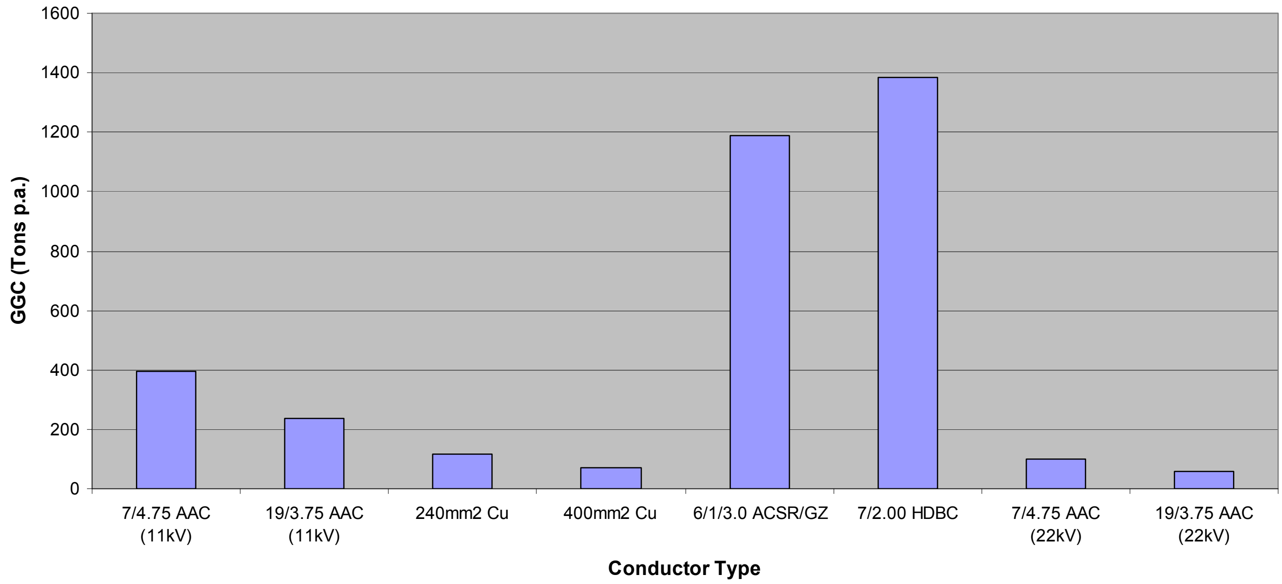


Figure 8.8 – Greenhouse Gas Emission for 5MVA Load Based on Different Conductors and Operating Voltages

Renewable and alternative energy solutions for reduction of power loses are:

- Solar energy
- Wind energy
- Geothermal energy
- Bio-energy (Biomass) technology
- Energy efficiency
- Energy conservation, Battery-to-grid and Grid Energy Storage
    - Grid Utility Support Systems (GUSS)
    - Red-Flow battery storage units
    - Thermal energy storage
    - Flywheel storage
    - Superconducting magnetic energy
    - Hydrogen Storage.

The determination of long term losses is uncertain predominantly due to unforeseeable developments and load growth. It is possible that new loading patterns could be enough to justify a change in operating voltage levels, conductor size or implementation of wide under-grounding networks. However, even if such situations were identified, no action would be taken to replace existing network simple to reduce losses unless the changes are also needed for other reasons. The network planning process must ensure minimum economic distribution losses and treat the reduction of power losses (and reduction of CO_2 emissions – Figure 8.8) as one of the most important components in justification of proposed works.

8.9 SWER Networks

The single wire earth return (SWER) line is a single conductor that may stretch for tens or even hundreds of kilometers supplying a number of SWER distribution transformers (DT). At each termination point, such as a customer's premises, current flows from the line, through the primary coil of a step-down transformer, to earth through an earth stake. From the earth stake, the current eventually finds its way back to the isolating transformer (IT), completing the circuit.

The main components of SWER schemes are:

I. Isolating transformer (installed at the start of SWER scheme provides electrical isolation of the earth return current from the 'parent' distribution feeder and prevents operation of the earth fault protection at zone substation)
II. Distribution line (high impedance conductors carrying relatively lightly load currents)
III. Distribution transformers (provides supply of LV customers)
IV. Earthing system (carrying load and fault currents)
V. Protective devices (fuses, reclosers, sectionalisers and lightning arresters).

Standard maximum demand of SWER systems is in the range between 50 and 100kVA. If more capacity is needed, a second SWER line can be run on the same poles to provide two SWER lines. It is so called Duplex SWER Scheme (25.4kV and 38.2kV) with an earthed centre tapped isolating transformers and 180 degrees out of phase. This requires more insulators and wire, but doubles the power without doubling the poles.

The conductor is usually 3/4/2.50 ACSR for the scheme backbone and 3/2.75 SC/GZ used for tee-offs and lightly loaded backbone sections. The total impedance to the far end of the line may be of the order of 1000 Ohms.

The load densities are usually below 0.5 kVA per kilometer of line. Any single customer's maximum demand will typically be less than 3.5 kVA, but larger loads up to the capacity of the distribution transformer can also be supplied.

The main advantage of SWER system is its low construction, operation and maintenance cost. It is often used in sparsely populated areas where the cost of building an isolated distribution line cannot be justified. SWER also reduces the largest component in cost of a distribution network, the number of poles. Steel's greater strength permits spans of 300 m or more, reducing the number of poles to 2.5/km (The Electricity Authority of New South West 1968).

SWER schemes are long, with high impedance conductors, so voltage drop along the line and quality of supply (voltage variations, unbalances and harmonics) are among limiting issues for special consideration.

At light load periods, due to the line charging currents the main voltage problem is actually over-voltage. Earth return charging currents for 12.7kV SWER schemes are in the range of 25mA/km and 37mA/km for 19.1kV based on 50Hz. Distributed shunt reactors are require to reduce capacitive line charging and to control over-voltage conditions. High magnetising transformers and use of lower voltages also reduce charging currents, as well as development of duplex SWER systems.

Protection of SWER schemes is another challenge for the network designers and operators. In SWER schemes the earthing carries the load and fault currents, which highlights the importance of good earthing on SWER schemes. Transformers could be individually fused or they could be sectionalised in groups and isolated during fault conditions by reclosers (placed on the SWER backbone) or sectionalisers (SWER spurs). Most faults are transient and since the network is rural, most of these faults will be cleared by the recloser.

In general, the main SWER issues and limitations for consideration are (The Electricity Authority of New South West 1968):

1. Earthing must prevent dangerous step and touch potentials
2. Telephone interference (due to harmonics from charging currents), similar to 2 wire single phase lines, worse than three-phase lines
3. Load balance problems can erode efficiency of three phase supply line
4. Voltage control can be difficult
5. Power quality can be compromised
6. Load density limitations
7. Restricted load capacity
8. Requirement for reliable low resistance earthing at isolating and distribution transformers
9. Losses due to charging currents
10. Single phase motor loads restricted to 22 kW (480V option).

Grounding is critical SWER issue, because of the significant currents on the order of 8A that flow through the ground near the earth points, so a good-quality earth connection is needed to prevent risk of electric shock due to earth potential rise near this point. Separate grounds for power and safety are also used. Duplication of the ground points assures that the system is still safe if either of the grounds is damaged.

Ground-return telecommunications can be compromised by the ground-return current if the grounding area is closer than 100 m or sinks more than 10 A of current. Modern radio, optic fibre channels and cell phone systems are unaffected.

With appropriate design and adequate maintenance, a SWER system is an economical method of supplying power in sparsely area with low load requirements. It is safe, reliable and cost effective system, simple to design, construct and maintain. Only special equipment is SWER isolating transformer and the main consideration is effective earthing. As such, it has been seen as the major way to supply rural areas of developed and developing countries.

8.10 Effects of PV Systems on Distribution Network

Impact of embedded generators on voltage regulation and power quality is extremely complex and requires specific consideration.

The connection of a distributed generator usually has the effect of raising the voltage at the PCC and this can lead to over-voltages for nearby customers. The need to limit this voltage raise, rather than exceeding the thermal capacity of the line, often determines the limiting size of generator that may be connected to a particular location. Voltage raise is often one of the main consideration for solar and wind farms connected on long rural lines with typically high impedances. Typically a raise of 1% is a concern to the network operator. Voltage raise can be controlled through the extraction of reactive power at the PCC. In combination with complexity of automatic voltage control (tap changers and line drop compensation LDC) voltage raise is definitely one of the most critical effects of embedded generators.

Impact of embedded generator on power quality is classified through deviation of standard power quality parameters. Intensity of flicker, which is voltage variation caused by the rapid changes of active and reactive power flows within the network, depends of the network characteristics, in particular the fault level and X/R ration at the PCC. So, embedded generator that cause voltage raise may also cause significant flicker.

In addition, switching a generator can cause a step change (sags and dips) in the voltage at the PCC again due to abrupt variations of active and reactive power flows. Harmonics from distributed generators usually arise from their power electronics – pulse-width-modulated (PWM) converters. Although there are examples of recorded significant harmonic distortions related to distributed generation, with improved power electronics and management of penetration of harmonics this problem now is not regarded as a particular concern. Voltage imbalance is another effect which could be efficiently managed with proper connection of distributed generators between the phases just as loads.

Control of power factor is another interesting point in the field of embedded generators. Energy from PV systems and MW size wind turbines will invariably be fed to the grid through a PMW power electronic converter which provides control of injection/extraction of reactive power at the PCC. Also, a PMW unit could be regulated to inject active power at unity power factor and eliminating reactive power.

Under certain fault conditions, the system dynamics could be so excited and it is possible that network may experience tripping. With the loss of supply from the grid, the local network runs in island mode fed solely from the generator which requires an effective active control. Theoretically, such actively managed distribution network can run autonomously in islanding mode which could increase the reliability of supply.

It is anticipated that PV systems may have effects in terms of:

- Harmonics
- Voltage distortion and regulation
- Power factor
- Safety
- Distribution protection devices and management devices and their operation.

It must also be determined if PV systems may affect the grid only during certain times, such as periods of low solar radiance, or periods where the customer load is low, and solar output is high.

In general, modern inverters used by photovoltaic systems have very little impact on power quality. Harmonic distortion is dependant on the grid and on the output of the PV system, but most inverters have a total harmonic distortion (THD) of less than 2%.

Power factor is acceptable with these inverters, however in lower-quality models the power factor can decrease with lower PV output, such as during periods of low solar radiation. Inverters can also be sensitive to voltage sags. Where a large amount of PV is installed, reverse power flow may occur, that is the output of the PV exceeds the use of the customers. Power will then flow back to the distribution transformer. This can cause voltage raise and alter short circuit impedance levels, which has implications for protection devices and ensuring that voltage levels remain within acceptable limits. This can have serious implications for future network design and is seen as a primary driver for 'smart grid'.

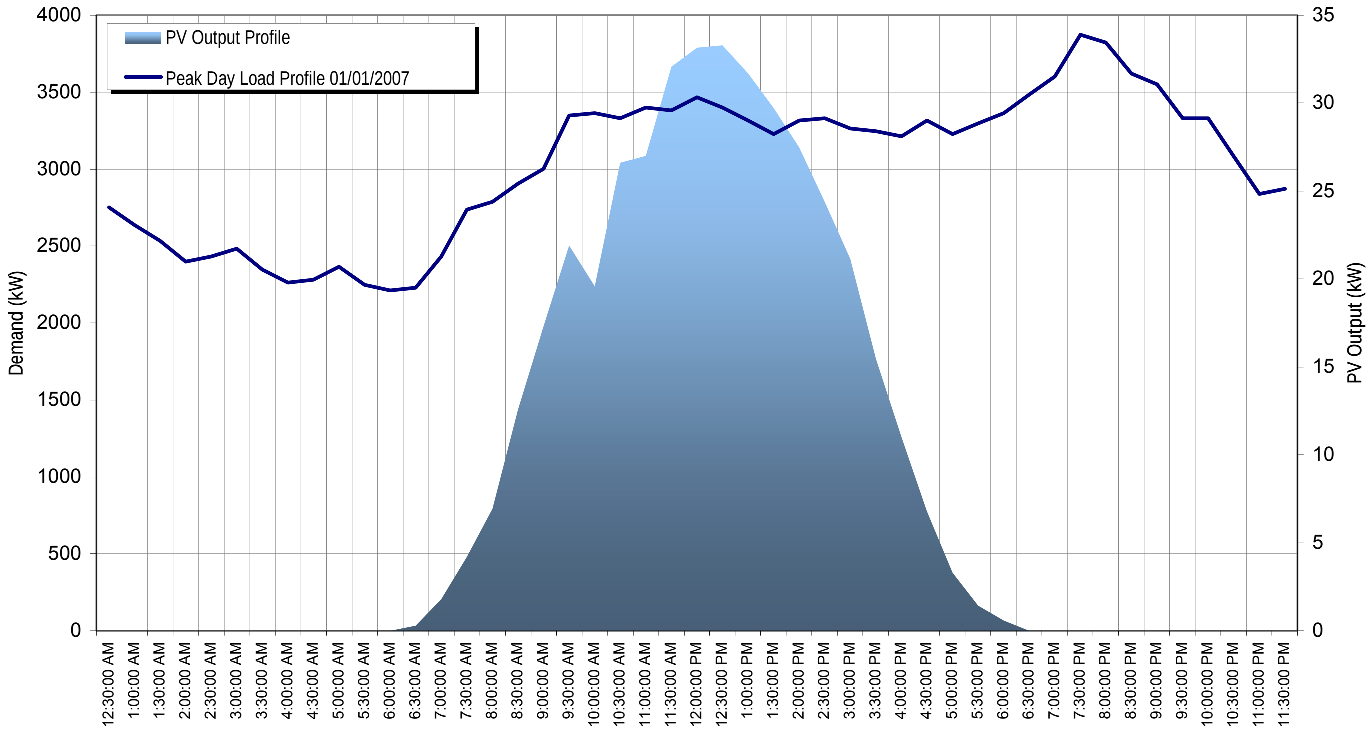


Figure 8.9 – PV Output Profile Compared to the Summer Day of Feeder Peak Demand

Traditional approach to the impact of renewable energy resources on network losses is that due to their location in the vicinity of load centres they reduce losses. However, this is not always true because there are distribution networks with extensive power losses (>20%) which means that DER has to be located very close to matching loads to reduce power loses.

For better understanding of impact of multi-size PV systems on network losses, author of this report managed studies of distribution networks with different topologies and load profiles as shown on Figure 8.10.

The objectives of these studies were:

I. How will the installation of future PV cells affect the distribution network
II. Analysed the effect on power losses by introducing PV cells
III. Three cases: CBD, Long Rural and SWER
IV. Each have similar conductors but configurations are uniquely different

V. Introduced 10kW generators into LV network

VI. Effects of PV cells on power quality and system stability – not included.

Based on these studies, PV systems reduce network losses due to improved power flows in the network and their location in the vicinity of loads.

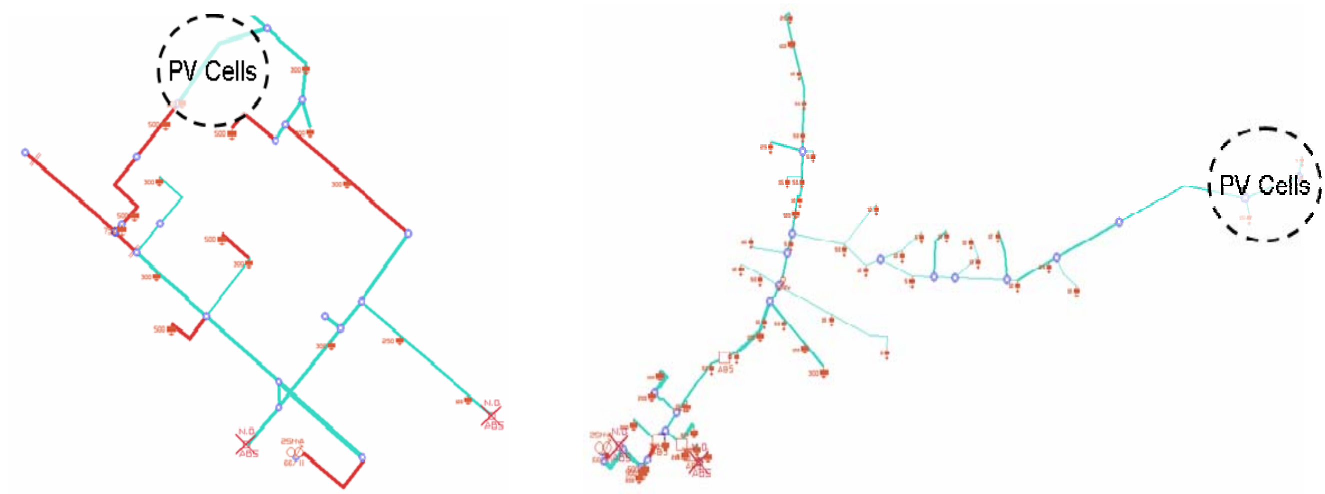


Figure 8.10 – Models of Urban (left) and Rural Distribution Feeder with PV Systems

Best results are on long and heavily loaded 11kV feeders. On studied feeders, up to a 5.6% reduction in power losses has been achieved from 3 x 10kW PV units. In this case, up to a $1,000 in loss savings and GHG savings of ~13 tons CO2 p.a. have been recorded. CBD feeders generally have higher rated conductors and are too short to see large savings, as presented in Table 10.1 (Ivanovich 2008).

Table 8.5 – Impact of PV Systems on Network Losses and Greenhouse Gas Emission

Type	Length	Number of 10kW Generators	Loss Reduction (kW)	Loss Reduction (%)	Loss Savings	GHG Reduction (Tons CO2 pa)
CBD	3.8km	1	0.4	-0.5%	$ 118	1.4
		2	0.8	-0.9%	$ 235	2.8
		3	1.3	-1.5%	$ 382	4.5
Long Rural	43.8km	1	1.3	-2.0%	$ 382	4.5
		2	2.4	-3.7%	$ 706	3.3
		3	3.7	-5.6%	$ 1,088	´2.8
Rural + SWER	38.7km	1	0.9	-0.5%	$ 285	3.1
		2	2.3	-1.2%	$ 676	7.9
		3	3.5	-1.9%	$ 1,029	´2.1

CHAPTER 9

NETWORK RISK MANAGEMENT

Network Risk Management (NRM) is one of the most important components in the distribution planning. It is critical in the study of existing and future distribution networks, where loss of electricity supply could have dramatic consequences for customers and electricity utility.

9.1 Risk Matrices

In its simplest qualitative form, the relationship between risk and its components can be considered and illustrated by means of a simple matrix. The relationship that defines the level of risk may be dominated by either consequences or likelihood or the two components may carry similar or equal weight. While a particular strength of the qualitative approach is that no attempt need to be made to understand the true consequence/probability/risk relationship, the matrix is invalid unless each possible combination is explored to ensure it accurately reflects the organisational perception of risk.

Quantitative analysis is similar in concept to semi-quantitative but with usually more rigorous use and manipulation of the values that represent the two components of risk. A 'ratio' scale is usually essential. There may still need to be some allowance to account for the human value or utility of a given consequence or perception of likelihood. The measured units should always be stated.

Consequence and likelihood tables provide definitions to rating scales so that there is a common understanding to their meaning. They should be consistent with the specific objectives and context of the risk management activity.

The number of occurrences in a time period will depend on factors like population, area or number of assets being considered. Scales are to reflect the scope defined in the context and should be consistent. The likelihood of gain or loss can be considered to be a function of both the exposure to the source of risk and the probability that the outcome will occur. They can be assessed separately. Techniques such as fault tree analysis can be used to analyse probabilities in more details (Thorpe 2007, p. 3.22).

Some applications of a matrix approach like that of Table 9.1 allocate numbers to the five categories of likelihood (for example, a 1 to 'almost certain' and a 5 to 'catastrophic') and combine them using a semi-quantitative process according to a formula.

An example of such a method would be:

Risk = (Likelihood x 2) + (Consequence x 3)

The result might be multiplied by a factor (say, 4) to produce an easily understood table. Categories like 'low', 'medium', 'high' and 'extreme' would then be allocated to risks according to their numerical value. Many risk events may arise in a variety of ways, with a range of outcomes and associated likelihoods. Usually, the minor problems are much more frequent than the catastrophic.

In many cases it is appropriate to focus of events with potentially catastrophic outcomes, as these are the ones that pose the largest threats and are often of greatest concern to managers.

Table 9.1 – Example Matrix for Determining the Level of Risk (Thorpe 2007, p.3.23)

Likelihood Label	Consequence Label				
	I	II	III	IV	V
A	Medium	High	High	Very high	Very high
B	Medium	Medium	High	High	Very high
C	Low	Medium	High	High	High
D	Low	Low	Medium	Medium	High
E	Low	Low	Medium	Medium	High

Risks are characterised by uncertainty. In some cases, the uncertainty may be uncertainty about given outcomes. In more extreme cases, there are unknown effects through casual chains or networks, or we will know about the risk at all. There may also be variability in the nature or extent of the exposure or its susceptibility. Combination of knowledge, skills and further information may reduce uncertainty. However, it is important to strike a balance between the effort required to gain further information and the value of the information in the decision process. Uncertainty and its effects on the analysis needs to be recorded and explained so that the decision makes is aware of both the level of risk and the degree of associated uncertainty.

Table 9.2 - Likelihood Definitions for Risk Events (ESAA 1995, p.33)

Likelihood	Risk ranking	Explanation / Definition
Almost certain (AC)	8	Will occur within 12 months
Expected (E)	6	Reasonable expected to occur within 12 months
Likely (L)	5	Reasonable expected to occur within 12 – 24 months
Unlikely (U)	4	Reasonable expected to occur once every 2-10 years
Rare (R)	3	Estimated to occur once every 10-100 years
Possible (P)	1	Technically feasible but not expected to occur

The likelihood – consequence – risk position matrix is presented in Table 9.3.

Table 9.3 – Likelihood - Consequence Matrix (ESAA 1995, p.34)

Consequence/ Likelihood	Almost Certain	Expected	Likely	Unlikely	Rare	Possible
Catastrophic	E	E	H	H	M	M
Major	E	H	H	M	L	L
Significant	H	M	M	L	L	I
Minor	M	L	L	I	I	I
Insignificant	L	I	I	I	I	I

As can see in Table 9.4, there are seven basic consequence levels for the loss of customer supply treated in conjunction with its exposure, outage duration, type of the customers affected with the outage, public and employee safety and reliability indices SAIDI, CAIDI, SAIFI and MAIFI.

Table 9.4 – Consequence Level of Network Loss of Supply (ESAA 1995. p.35)

Consequence level	Network Performance	Reliability	Community perception	Financial impact
Catastrophic	System black	340 minutes	Parliamentary inquire	$200M
Major	Loss of zone substation	150 minutes	Ministerial inquire	$50M
Significant	Loss of distribution feeder	50 minutes	Adverse legal procedures	$10M
Minor	Loss of multiple customers / single distribution transformer	10 minutes	Local member/local government inquire	$2M
Insignificant	Loss of individual customer supply	5 minutes	Single customer issue	$0.5M

Risk positions are (ESAA 1995):

E=Extreme	Unacceptable risk position (Board control)
H=High	Unacceptable risk position (CEO and senior management control)
M=Medium	Unacceptable risk position (senior management control)
L=Low	Acceptable risk position (medium management control)
I=Immaterial	Acceptable risk position (supervisors control).

9.2 Security of Supply

Security of supply is defined as the ability of the power system to withstand equipment failures without loss of supply. The level of security is a network design parameter that determines the extent to which loss of supply will occur in a particular part of the network given a single or multiple component failure.

The purpose of a security standard is to ensure the network is planned and designed to provide an adequate supply with an appropriate level of redundancy. Since failure of components is a regular and stochastic process (e.g. storms, ageing components, third parties) a certain level of redundancy is necessary to ensure a satisfactory level of reliability to customers. Once a security standard is established, it will directly influence the level of investment required to operate the network.

The security standard chosen should reflect the economic impact of loss of supply on customers. For this purpose it is important to classify customers into meaningful categories. The following customer categories are defined by example and are not universally inclusive.

A suggested loading range by this author is also assigned to each customer category, but is only a guide:

- CBD: Central Business District. High density, high rise offices, shops, hotels, residences, etc. in major urban centres.
- COMMERCIAL: Medium density, multi-floor offices, shops, hotels, etc. in suburban complexes.
- ESSENTIAL: Hospitals, water treatment works, water pumping stations and sewerage pumping stations. Manufacturing facilities for which unexpected and/or prolonged outages may result in public hazards (e.g. oil refineries).
- INDUSTRIAL: Manufacturing facilities in areas zoned "Industrial". Quarries and mines.
- URBAN: Single and multiple dwellings intermingled with schools, small offices, small shops, etc.
- URBAN / RURAL FRINGE: Single dwellings on large lots intermingled with schools, small offices, small shops, etc.
- TOURISM: Tourism facilities for which unexpected and/or prolonged outages may result in public hazards (e.g. theme parks).

- RURAL TOWNSHIP: Towns with schools, shops, offices, motels, single and multiple dwellings and light industrial complexes servicing rural areas.
- RURAL PRODUCTION: Energy intensive rural facilities.
- RURAL FARMING: Farms - agricultural, horticultural, feed lot, grazing, mixed.

The customer categories are then assigned to the type of network supplying them in a security matrix. For larger customers, supply arrangements to meet capacity and security requirements are subject to individual negotiation and incorporation in connection agreements. In these cases network charges are applied to recover the cost of the connection assets over their useful life. A basic guide to the security level that may be satisfactory is provided for different customer categories. The level of security provided in an interconnected transmission network is covered extensively in the National Electricity Rules (NER), including the requirements of a regulatory test specified by the Australian Energy Regulator (AER), and is not intended to be covered in this toolkit.

9.3 Security Zones

In general, there are four major security supply zones in total distribution system risk assessment which require special consideration (Figure 9.1):

- Primary switchyard (classified with risk indices α)
- Power transformer yard (β)
- Secondary switchboard (φ) and
- Distribution network (δ).

Each of elements α, β, φ and δ requires a detail risk assessment based on the following criteria:

1. Design and construction
2. Test data
3. Age and conditional factors
4. Operations
5. Protection schemes
6. Annual failure rate
7. Capacity
8. Loading
9. Contingency planning (load transfer plans)
10. External impacts and
11. Average restoration time.

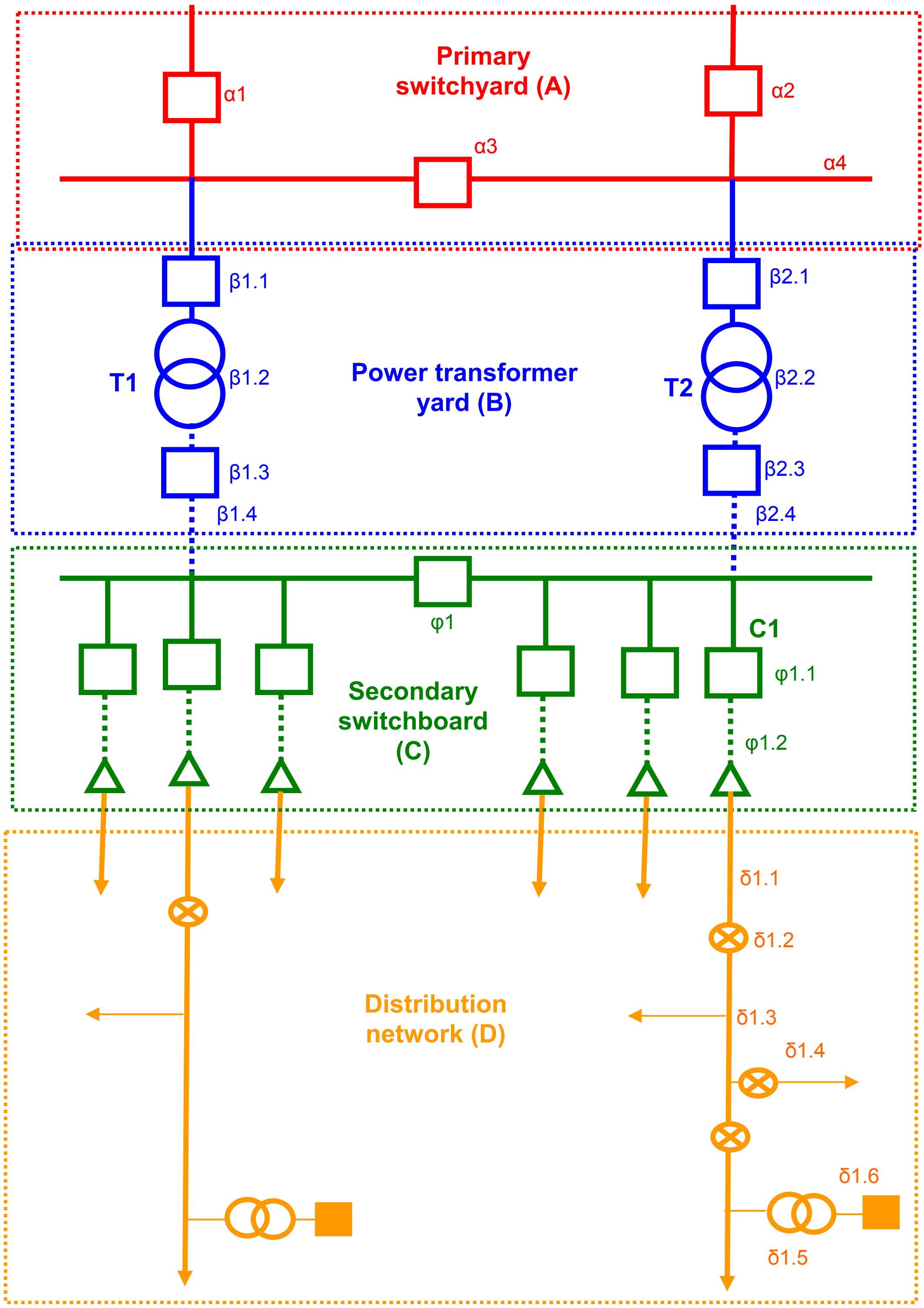


Figure 9.1 – Risk Indices and Protection Zones of Electricity Network

9.4 Interruption Durations

A pure "N-x" security standard implies that no loss of load will occur when "x" components fail. However in practice most security standards allow for some temporary loss of supply for less critical loads or for lower probability events.

The duration of a temporary loss of supply depends on the level of redundancy provided and the way the network is configured. Some parts of the network have normally closed switches, or have normally open switches with or without SCADA facilities, or are configured as radial.

The durations of a temporary loss of supply have been categorised as follows:

- MOMENTARY: A momentary interruption restored automatically by SCADA equipment. Automatic sequences, which attempt to restore supply automatically after an outage, can be deployed to SCADA equipment. Examples include auto-reclose, auto restore and auto-changeover. Supply is generally restored within about 1 minute. Discussion about application of automatic sequences is beyond the scope of this toolkit. For the purposes of establishing a security standard, a momentary outage restored by an automatic sequence in one minute or less is NOT considered to be a loss of supply (as per current definitions in the National Reliability Reporting Framework). Such an event would contribute to MAIFI but not to SAIDI or SAIFI.
- SHORT-TERM: A short-term interruption restored by remote manual switching. Equipment fitted with remote control facilities can be operated remotely from the control centre. This provides an opportunity for supply to be restored by network operators by remotely identifying faulted network, opening and closing switches, operating transformer tap-changers, etc. For operators to restore supply by remote manual switching, the following are required:
  - (a) Suitable SCADA facilities;
  - (b) Adequate capacity in the unfaulted network;
  - (c) A suitable contingency plan, so the operator can quickly identify the required operations.

Restoration time by remote manual switching can range from a few minutes up to about 15 minutes depending on various factors such as how many other incidents the operator is managing, complexity of the event, etc.

- MEDIUM-TERM: A medium-term interruption restored by manual switching. A fault on a radial network causes loss of supply until the fault is isolated and ties to adjacent networks are closed to restore load. If the switches do not have remote control facilities, switching operators have to drive to site to operate them. This is typically the case on HV distribution networks. Manual switching can generally be achieved within about two hours (excluding the time required to find the fault) if switching operators do not have to travel long distances and only a small number of switching operations are required within a relatively small geographic area
- LONG-TERM: A long-term interruption restored by repairing faults or building contingency works. Some radial networks have no ties or only very weak ties to adjacent networks. This typically occurs with supplies to rural areas where it may not be cost effective to provide backup supply. In these cases, supply is generally restored by repairing or replacing the faulty equipment.

In some instances contingency works may provide faster restoration than repairing or replacing faulty equipment. Some examples are as follows:

(a) Supply may be restored after failure of a bulk supply substation transformer by energising the primary supply from the secondary supply. Sometimes pre-contingent works can be constructed to expedite connections being made after a failure occurs, e.g. a single 110kV feeder to a bulk supply substation is designed to revert to 33kV operation for a sustained fault on the single 110/33kV transformer

(b) Supply may be restored by connection of a mobile 33/11kV substation after failure of a transformer at a 33/11kV substation equipped with a single 33/11kV transformer. Limited back-up may be provided by the 11kV network until this occurs.

It may take up to 12 hours (excluding the time required to find the fault) to repair or replace the faulty equipment or provide contingency works.

Until repairs / replacement of failed assets occur the network is at a higher risk than before the event, even though the network may be in a “new” secure state. An appropriate N-x security plan should ensure the failed item is repaired or replaced within a reasonable time period, to bring the network back its original state.

The maximum durations should be based on what is considered practical to achieve given the type of asset and the relative importance of the asset to network security. Contingency plans should be developed to ensure the maximum durations are achievable, including the holding of appropriate spares.

Typical repair times for transformers and circuits and forced outage rates for OH and UG circuits are presented in Tables 9.5 and 9.6 (ESAA 1995, p.47).

Table 9.5 – Average Repair Time (hours) (ESAA 1995, p.47)

Component	132/110Kv	33Kv	11kV
Overhead circuit	8	8	8
Underground circuit	96	96	48
	132,110/33 or 132,110/11kV	33/11kV	
Tx Repair time	4400	2400	
Tx Replacement time	168	120	

Table 9.6 – Average Forced Outage Rates for Circuits (per 100km) (ESAA 1995, p.48)

System Voltage	Annual rate (8760 h)		Summer rate (5088 h)		Winter rate (3672 h)	
	OH	UG	OH	UG	OH	UG
132/110	2.3	0.38	1.7	0.22	0.6	0.16
33kV	9.5	1.3	7.1	0.76	2.4	0.54
11kV	13.4	4.3	10.0	2.5	3.4	1.8

9.5 Influencing Factors

Risk assessment is a two stage process. Firstly, it is studied in terms of the probability and frequency of outages. Secondly annual reliability indices ("Load Point Indices") based on standard transmission system indices are calculated.
Evaluation process requires detailed knowledge of various parameters:

I. Equipment rating to establish system capacity
II. Load data including load forecasts and load duration information to establish transition rates associated with partial loss of supply states (for example λ_{12})
III. Equipment outage (failure) rates
IV. Feeder outage rates including potential seasonal variations
V. Equipment operation details
VI. Equipment repair times
VII. Load transfers times and/or load restoration times
VIII. System configuration including protection details
IX. Equipment maintenance details.

The following factors, while not exhaustive, should be considered in establishing a security of supply standard:

- the significance and sensitivity of the load (customers category)
- the ratings of network assets and loading policy
- systems, policy, procedures and practices applied to the operation of the network
- capability of the network to transfer load by remote or manual switching (in general a high level of loading significantly reduces the opportunity to transfer load; and geographically dispersed load limits the opportunity to transfer loads)
- the cost / benefits to the network business and its customer of applying a level of redundancy to the network
- the likelihood and consequences of single or multiple failures on network security
- the need to schedule maintenance without causing an unacceptable risk to the supply security
- the risk appetite of a well informed business and its stakeholders
- regular risk monitoring and reporting measures to the business and its stakeholders
- sound risk management practices including comprehensive contingency plans (e.g. emergency operating procedures).

9.6 Deterministic Vs Probabilistic Approaches

Given the above influencing factors, there are two main approaches usually employed to develop a security standard:

(1) A deterministic approach which specifies a given level of redundancy in terms of "N-x" (refer below) and is consistently applied to different customer categories and/or network types in a rules based manner; where:

- "N" refers to a supply situation where sufficient capacity exists under normal operating conditions, but, if a component fails (e.g. a substation, transformer or feeder), supply to customers will be interrupted; and
- "N-x" refers to a supply situation where if x components fail, the remaining components continue to supply customers, although there may be a momentary or short term interruption as the remaining components are brought into service.

(2) A probabilistic approach which assesses the risk of failure to determine the most economically justifiable level of redundancy required based on the value of customer reliability (VCR); also referred to as the cost of non supplied load.

Both approaches have their advantages and disadvantages and both are in use in different jurisdictions throughout Australia.

In addition to the security benefits that "N-x" planning provides, it also:

- Allows the system to cope with unexpected increases in load or severe weather conditions; and
- Increases the likelihood of assets lasting up to, and beyond, their estimated useful lives.

It should be noted, however, that "N-x" planning necessarily results in a higher cost system because it builds in a level of duplication and/or redundancy which may only be drawn upon in limited circumstances. This toolkit recognises the need to balance the use of "N-x" and "N" planning as it is simply not economically feasible for an entire system to meet "N-x".

The majority of distributors use a minimum of N-1 (with very few exceptions) as the base planning criterion for their network.

9.7 Bulk Supply Substations

Bulk supply substations transform supply from transmission voltage to sub-transmission voltage (generally 66kV or 33kV). Redundancy at bulk supply substations is very important because they supply a very large number of customers and an outage can impact tens of thousands of customers. In some circumstances load can be transferred between bulk supply sub-stations in the event of equipment failure.

It is generally accepted Australian industry practice that bulk supply sub-stations should have "N-1" capability.

50%POE forecast load < N-1 ECC. Some exceptions to this are as follows:

- Where suitable load transfers can be readily achieved, bulk supply substations can be loaded to N-1 2HEC. These transfers would generally involve reconfiguration of the network by remote switching or transfer of an entire zone substation (or at least an entire zone substation transformer) to an adjacent network

- Bulk supply substations supplying urban/rural fringe and rural areas may be loaded above N-1 ECC, provided that suitable SCADA facilities are installed so that supply can be restored by remotely switching to adjacent networks. An example of this is where a single 132(110)/33kV transformer is installed as a first stage of development. Backup can be provided by the 33kV network that supplied the area before the bulk supply substation was established
- For rural areas where load is relatively small and cost of augmentation is high, bulk supply substations may be loaded above N-1 ECC. These areas may be supplied by a single 132(110)/33kV transformer. In these cases, extra care should be taken to ensure that these transformers operate reliably (e.g. appropriate inspection and maintenance programs). Backup may be provided by a weak 33kV network. In these cases, suitable SCADA facilities should be provided so that the majority of supply can be restored by remote switching within two hours.

If the 33kV network is insufficient to provide full backup, suitable contingency plans should be prepared to repair or replace faulty network components or reconfigure the network within twelve hours. An example of reconfiguring the network is the situation where the single 110kV feeder is designed to revert to 33kV operation during extended outages of the single 110/33kV transformer.

9.8 Transmission Feeders

It is generally accepted that transmission lines should have at least “N-1” capability due to the large transfers of power usually at risk. Sub-transmission feeders may “N-1” or “N” after load transfers, depending on how critical or sensitive the loads / customers are.

50%POE forecast load < N-1 ECC. Some exceptions to this are as follows:

- Where suitable load transfers can be readily achieved, transmission feeders can be loaded to N-1 2HEC. These transfers would generally involve reconfiguration of the transmission network by remote switching, or transfer of an entire substation (or at least an entire transformer) to an adjacent network
- For CBD areas, augmentation should occur when loading reaches N-2 ECC for credible N-2 contingencies. If suitable load transfers can be implemented within two hours, the transmission feeders may be loaded to N-2 2HEC. If the network is run with normally open points, then there may be a short-term loss while supply is restored by remote manual switching
- For large essential loads such as major hospitals and sewerage plants, suitable ties should be provided so that supply can be restored by remote switching following a credible N-2 contingency for transmission feeders. This may involve provision of suitable sub-transmission tie feeders to adjacent transmission networks so that supply can be restored by providing a “corridor” to these adjacent networks by using remote switching
- For rural areas where load is relatively small and cost of augmentation is high, the transmission network may be loaded above N-1 ECC. These areas may be supplied by a radial transmission network, e.g. single 110kV or 132kV feeder. In these cases, special care should be taken to ensure reliable operation of the radial feeder (e.g. appropriate inspection and maintenance programs). Backup may be provided by a weak sub-transmission network. In these cases, suitable SCADA facilities should be provided so that the majority of supply can be restored by remote switching within two hours
- If the sub-transmission network is insufficient to provide full backup at time of peak load, suitable contingency plans should be prepared to repair or replace faulty network components, or reconfigure the network, within twelve hours.

9.9 Zone Substations

Zone supply substations transform supply from transmission voltage or sub-transmission voltage to the distribution high voltage (generally 11kV or 22kV). An outage at a zone supply sub-station can impact many thousands of customers.

It is standard industry practice that zone supply substations should have “N-1” capability where these sub-stations supply large or critical customer loads, for example, urban or CBD areas.

50%POE forecast < N-1 ECC. Some exceptions to this are as follows:

- Where suitable load transfers can be readily achieved, zone substations can be loaded to N-1 2HEC. These transfers would generally involve transferring partial HV distribution feeders to adjacent zone substations
  Ideally this should be done by remote switching (e.g. ACR and load transfer switches). Manual transfers can generally only be achieved within two hours if switching operators do not have to travel long distances and only a small number of switching operations are required within a relatively small geographic area
- Zone substations supplying urban areas where there is a reasonable proportion of residential load may be loaded above N-1 2HEC. Automated plant overload protection schemes should be installed to shed suitable HV distribution feeders to protect plant until supply can be restored. Supply should generally be restored by switching within two hours. If possible, HV distribution feeders with significant commercial / industrial or essential loads should not be shed
- Some urban areas such as urban/rural fringe areas may be supplied by single transformer zone substations. In these cases, special care should be taken to ensure reliable operation of the single transformer (e.g. appropriate inspection and maintenance programs). Backup may be provided by a weak HV distribution network. In these cases, if feasible, suitable SCADA facilities should be provided so that the majority of supply can be restored by remote switching within two hours
- If the HV distribution network is insufficient to provide full backup at time of peak load, suitable contingency plans should be prepared to repair or replace faulty network components within twelve hours. One example of this is provision of a “connection kiosk” for quick connection of a mobile substation
- Rural areas should be treated similarly to urban/rural fringe areas.

9.9.1 Risk Assessment of Zone Substation Components

The reliability of an electricity supply system can be quantified in terms of the probability of system failure (loss of supply – LOS) and the frequency of system failure. These parameters can be calculated using Markov models.

Consider a simple single component system (refer Figure 9.2). The state space diagram illustrates that the system can only be in one of two states – operating (State 0 - system normal) with probability that it is operating P_0 or failed (State 1, probability P_1). Finally, there is also frequency of failure f_1.

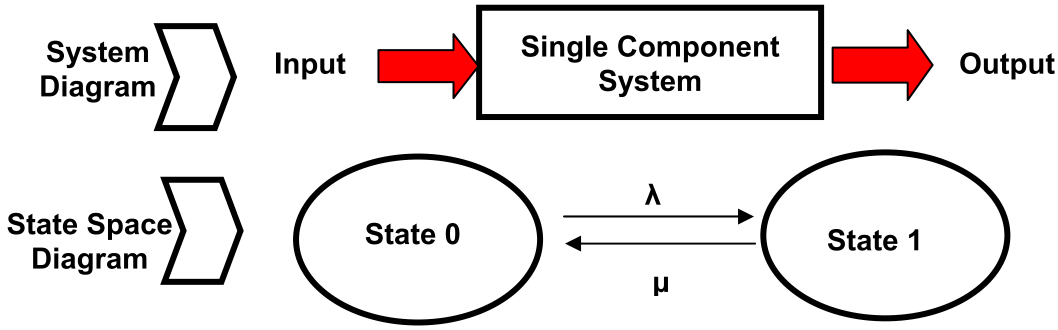


Figure 9.2 – System and State Space Diagrams (ESAA 1995, p.4)

The probabilities P_0 and P_1 indicate the average per unit of time spent in the operating and failed states respectively, e.g. if P_0=0.997, then for a one year period the system is operating for 0.997x8760 hours. The frequency of failure indicates the number of times the system resides in the component failed state.

Applying the Markov model, the values of P_0, P_1 and f_1 are readily determined in terms of the failure rate (λ) and the repair rate (μ) as follows (ESAA 1995, p.5):

$$P_0 = \mu/(\lambda + \mu) \qquad P_1 = \lambda / (\lambda + \mu) \qquad f_1 = \lambda\, \mu / (\lambda + \mu)$$

As illustrated by the single component of Figure 9.2, movements between states 0 and 1 are determined by the failure rate λ and the repair rate μ. These rates are termed transition rates with definition:

$$\text{Transition rate} = \frac{\text{(number of times a transition occurs from a given state)}}{\text{(time spent in that state)}}$$

Risk exposure of electricity network is generally a function of the following limitations:

I. Thermal rating of plant is exceeded
II. Voltage cannot be maintained within specified limits
III. System security is inadequate
IV. Fault rating is exceeded
V. Age of equipment makes continued operation uneconomic or causes a safety hazard
VI. Excessive system losses
VII. Extensive load growth.

Transformer failure rates increase with time and can be calculated using a Weibull Probability Function (ESAA 1995, p.6):

$$\lambda = \beta T^{(\beta-1)} / \gamma^{\beta}$$

where λ = transformer failure rate
β, γ = Weibull function constant
T = transformer age (in years)

Calculated values of transformer failure rates based on provided Weibull constants and specific age are listed in Table 9.7.

Typical load restoration time for faults on circuits 33kV and 11kV) or transformers (33/11kV) by manual switching is 2 hours and by remote controlled switching 0.2 hours.

Transformer failure rates are functions of risk factors which limit operation of power transformers (summarised on Figure 9.3 and Table 9.8).

Design factors are:

1. Cooling arrangements
2. Oil ducts
3. Selection of radiators
4. Sealed or unsealed system
5. Number of windings
6. Core weight to Oil volume ratio
7. Selection of accessories.

Table 9.7 – Transformer Failure Rates (Clay 2010)

Transformer age	33/11kV (β=3.9, γ=48)	110/33kV, 110/11kV (β=2.93, γ=60)
1	0.027	0.027
10	0.0009	0.0015
20	0.0064	0.0059
30	0.0208	0.0128
40	0.0479	0.0223
50	0.0915	0.0343

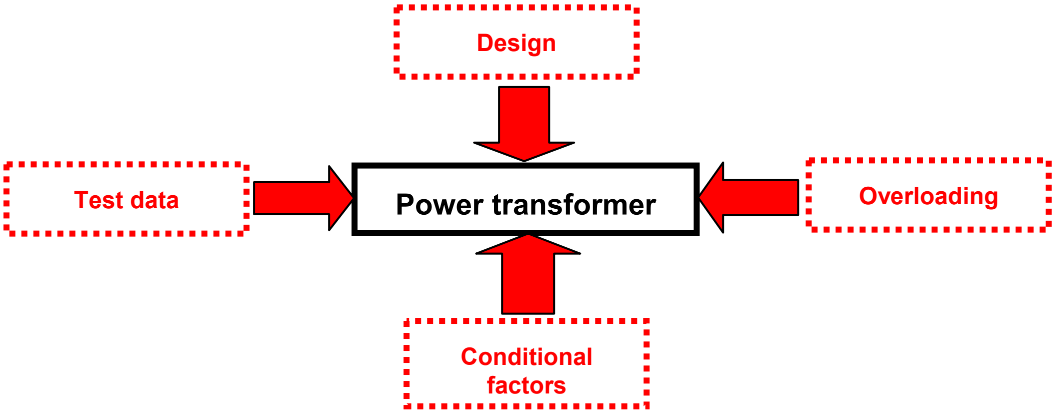


Figure 9.3 – Risk Factors of Power Transformers

Test data include availability of heat run data at max cooling and loss data.

Among conditional factors, dominant are (Clay 2010):

- Water content (WCP factor in %)
    - At WCP of 3 % and above the paper will release fibres into the oil as a result of decay of the paper due to the water
    - At WCP=4 % flashover will occur at 90 degrees
    - At WCP=5 % flashover will occur at 70 degrees.
- Oxidation
- Acidity / Particulates
- Degree of polymerisation (tensile strength of paper) (DP factor <200-400 plus)
- Weather conditions (atmospheric pressure)
- Incipient faults.

Table 9.8 – Cause of Failure for Power Transformers in the US (Clay 2010)

Electrical Disturbances	29.43%
Lightning	17.32%
Insulation issues	9.80%
Electrical Connection, Loose or High Resistance	7.38%
Maintenance issues	5.91%
Moisture	4.03%
Overload	2.01%
Sabotage	2.01%
Other	1.24%

Typical effects of overloading are:

- Heating of metallic parts
- Increase in core magnetic flux
- Voltage stability
- Increased temperature within the transformer
- Cumulative aging of:
    - the paper
    - the oil
    - the bushing
- Risk of failure due to poor joints.

Figure 9.4 – Selection of Radiators as a Design Risk Factor

9.9.2 Markov Model

Markov models for the elements of the sub-transmission systems being studied are developed as follows (ESAA 1995, p.15):

Step 1 - Define study boundaries
Step 2 - Determine single contingency based on protection diagrams
Step 3 - Establish the impact of the identified contingencies (no, partial or and total LOS)
Step 4 - Establish the response to the identified contingency (repair/replacement, switching and emergency restoration)
Step 5 - Review the system diagrams

Step 6 – Determine the states for the state space diagram
Step 7 – Determine transition rates
Step 8 – Construct the system space diagram (with State 0 – system normal conditions)
Step 9 – Review the model to determine if further simplification is appropriate
Step 10 – Based on the final state space diagram, calculate the required state probabilities.

In risk assessment of any-town zone substations, there are two major group of components used in conditional probability theory to determine the reliability for any-town zone substation. Namely, there are the independence between individual components at zone substation and the impendence between the components and the system load.

As illustrated in Figure 9.1, a zone substation can be divided into three components (or effective protected zones):

I. Component α – sub-transmission (primary) switchyard
II. Component β – power transformer yard and
III. Component φ – distribution (secondary) switchyard.

Studied zone substation is equipped with 2x10MVA power transformers (PT) and provides supply of predominantly domestic load. Its "N-1" capacity is 16MVA (which is 2 hour emergency capacity of one 10MVA PT based on domestic winter load cycle.
The identified contingencies together with the associated impact and operating responses are described in Table 9.9.

Based on the contingencies listed in Table 9.9, the following system states are selected:

State 0 – system normal (no LOS)
State 1 – One PT out of service, load > N-1 capacity (>16MVA)
State 2 – One PT, load is less or equal to N-1 capacity (16MVA)
State 3 – Two PTs out of service
State 4 – Bus fault, total LOS
State 5 – Bus fault, faulted component isolated and all load restored (no LOS, this state could be simplified by accumulating it with State 0).

Transition rates λ identified transfers between different states. For example, λ_{01} is transition rate between States 0 and 1, and include actual PT load, period of study, transformer failure rate and failure rate for all other components in the transformer zone. Other transitions rates ($\lambda_{01,}$ λ_{12},λ_{23} …) identified transfers between other states, transition between different loads (e.g. from >16MVA to > 16MVA) and refer to any failures which cause partial or total LOS.
The reliability of each of these three components is determined by using a simple two state Markov model. Similarly a two state load model can also be developed. The total system reliability is calculated by combining results from the component two state models (Fig. 9.5).

Table 9.9 – Identified Contingencies for ZSS Reliability and Risk Analysis

(ESAA 1995, p. 19)

No of Contingencies	Identified Contingency	Impact	Response
1	Fault in transformer zone	Potential partial loss of supply (LOS) if load > capacity (16MVA)	Repair time (replace PT if required)
	Fault on sub-transmission bus (including all CBs)	Total LOS	Isolate faulted section Restore supply Repair fault
	Fault on distribution bus	As there is no bus zone protection this result in total LOS	Isolate faulted section Restore supply Repair fault
2	Second fault in transformer zone (e.g. double transformer fault)	Total LOS until one PT returned to service. Potential for partial LOS	Return one unit to service ASAP Repair faults

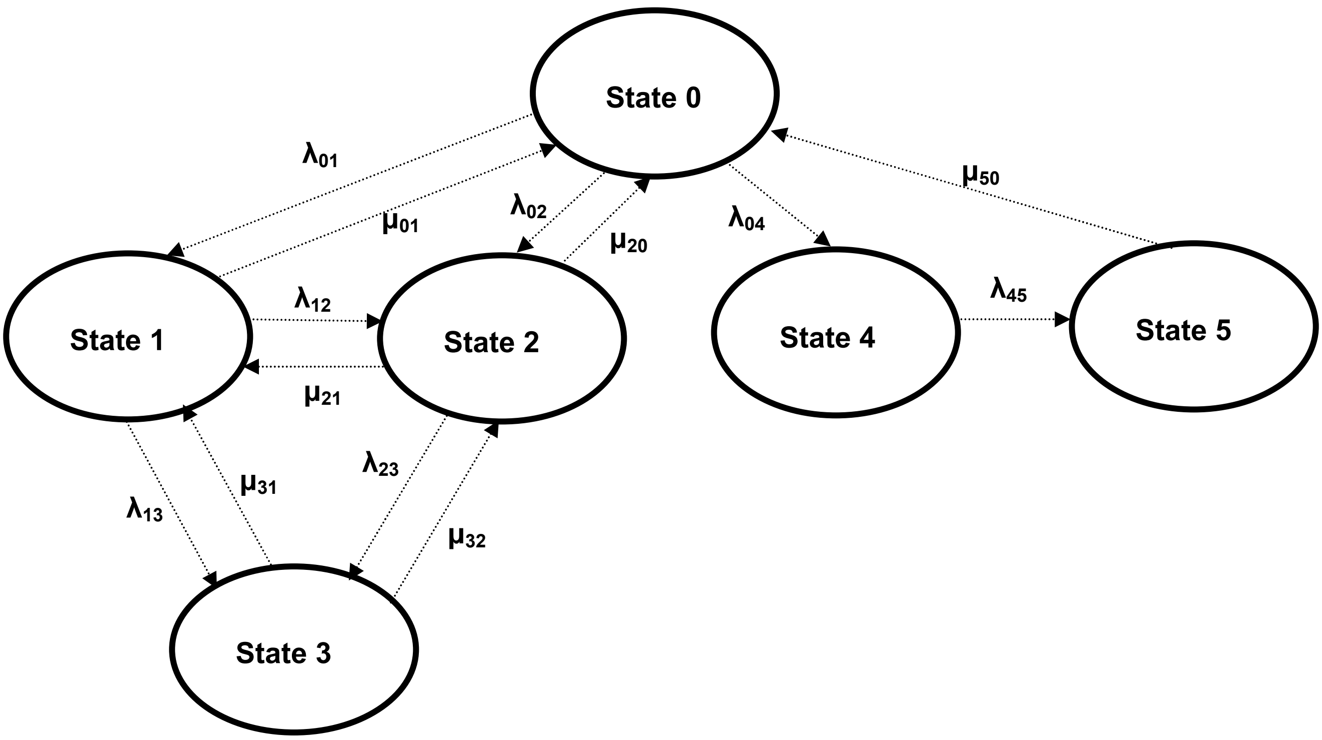


Figure 9.5 – State Space Diagram for ZSS Presented on Fig. 11.1 (ESAA 1995, P.22)

The transitional probability matrix for the state space diagrams if presented in Table 9.10.

Table 9.10 – Probability Matrix for the State Space Diagram

		To state					
		0	1	2	3	4	5
From state	0	1-(λ01+λ02+λ04)	λ01	λ02	0	λ04	0
	1	μ10	1-(μ10+λ12+λ13)	λ12	λ13	0	0
P=	2	μ20	λ21	1-(μ20+λ21+λ23)	λ23	0	0
	3	0	μ31	μ32	1-(μ31+ μ32)	0	0
	4	0	0	0	0	1-λ45	λ45
	5	μ50	0	0	0	0	1-μ50

For the six states (State 0-5) of Figure 9.5 probability is:

$$P_0 + P_1 + P_2 + P_3 + P_4 + P_5 = 1$$

For this study, states 1, 3 and 4 involve loss of supply to customers with probabilities P ad frequencies f of occurrence calculated as:

$$f_1 = P_1\,(\mu_{01} + \lambda_{12} + \lambda_{13})$$

$$f_3 = P_3\,(\mu_{31} + \mu_{32})$$

$$f_4 = P_4\,\lambda_{45}$$

As the state space diagram does not restrict transitions between states 1 and 2, or consider load transfers to adjacent zone substations, f_1 can be quite high. For comparison purposes, the combined frequency of states 1 and 2 can be calculated as the difference between frequency of encountering individual states and frequency of encounters between states 1 and 2:

$$f_{1\&2} = (f_1 + f_2) – (P_1\,\lambda_{12} + P_2\lambda_{21}) = P_1\,(\mu_{01} + \lambda_{13}) + P_2\,(\mu_{20} + \lambda_{23})$$

This represents the frequency of a single transformer outage. If calculations indicate that $f_1 > f_{1\&2}$ then partial loss of supply is predicted to occur multiple times for each transformer outage.

9.10 Sub-transmission Feeders

Standard criteria is 50%POE forecast load < N-1 ECC (Emergency Capacity). Some exceptions to this are as follows (Dalitz 2008, p.83):

- Where suitable load transfers can be readily achieved, sub-transmission feeders can be loaded to N-1 2HEC (2 Hour Emergency Capacity). These transfers should generally all be implemented by using remote switching.

  Examples of this are as follows:
    - Reconfiguration of the network, e.g. by closing normally open switches (Sometimes the network is run with normally open points to manage fault levels or power flows)
    - Transferring one or more zone substation transformers to adjacent sub-transmission networks
    - Remotely transferring partial or entire HV distribution feeders to adjacent zone substations supplied from other sub-transmission networks

  Manual load transfers may be acceptable under the following conditions:
    - Where switching operators do not have to drive long distances
    - Where only a small number of switching operations are required within a relatively small geographic area
- For CBD areas, augmentation should occur when loading reaches N-2 ECC. If suitable load transfers can be implemented within two hours, the sub-transmission feeders may be loaded to N-2 2HEC. If the network is run with normally open points (e.g. to manage fault levels or power flows) then there may be a short loss while supply is restored by remote manual switching
- For large essential loads such as major hospitals and sewerage plants, suitable ties should be provided so that supply can be restored within two hours following a credible N-2 contingency for sub-transmission feeders. This may involve provision of sub-transmission or HV distribution ties so that supply can be restored by providing a "corridor" to an adjacent network, preferably by using remote switching
- Sub-transmission feeders supplying small commercial / industrial / essential loads or medium density urban areas may be loaded above N-1 ECC. Suitable SCADA facilities should be provided so that this load can be restored by remote switching. Examples of this include normally open 11kV and 33kV ties to adjacent networks
- For urban/rural fringe areas, where there is a mixture of residential, rural / park residential and rural, it is acceptable to load sub-transmission feeders above N-1 2HEC. Plant overload protection systems or similar should be installed to shed suitable HV distribution feeders to protect plant until supply can be restored. Supply should generally be restored by switching within two hours (refer to the previous item)
- Urban/rural fringe areas should generally NOT be supplied by radial sub-transmission feeders. This is because if the radial sub-transmission feeder does not operate reliably, SAIDI for the area may actually be higher than before the zone substation was established, when it was supplied by multiple HV distribution feeders
- For rural areas where load is relatively small and cost of augmentation is high, the sub-transmission network may be loaded above N-1 ECC. These areas may be supplied by a radial sub-transmission feeder, e.g. a single 33kV feeder. In these cases, special care should be taken to ensure reliable operation of the radial feeder. Backup may be provided by a weak HV distribution network.

If the HV distribution network is insufficient to provide full backup at the time of peak load, suitable contingency plans should be prepared to repair or replace faulty network components or reconfigure the network within twelve hours.

9.11 Distribution Feeders

9.11.1 Distribution Feeders Supplying CBD Areas

50%POE forecast < N-1 ECC. Load in CBD areas are generally supplied by three-feeder mesh HV distribution networks. A three- feeder mesh network consists of three feeders connected to separate circuit breakers on separate sections of HV bus at a zone substation. The three feeders are connected in parallel at a “mesh point” such that most load remains supplied by the remaining two feeders after a feeder fault.

9.11.2 Distribution Feeders Supplying Large Commercial and Industrial Load

50%POE forecast < N-1 ECC. These are generally subject to negotiation and connection agreements.

9.11.3 Radial Distribution Network

The supply availability a customer receives from a radial distribution network depends on the risk of individual components, network configurations and capacity of any backup under contingency conditions. Augmentation options for radial distribution systems are based on factors such as:

I. Outage statistics indicating areas with poor reliability
II. Thermal overloads under normal conditions
III. System studies indicating areas with unacceptably high losses
IV. Supply to a new customer.

Risk assessment enables the risk of existing systems and proposed development options to be analysed. This enables selection of the augmentation option which provides the highest cost/benefit ratio and also enables the evaluation of non-standard strategies.
The risk management of radial distribution systems is quantified in terms of both load point and customer oriented reliability indices adopted for customer load and customer numbers. The inclusion of customer numbers ensures that reliability benefits for revised system configuration (e.g. recloser or Air Break Switch ABS replacement) are adequately reflected in risk management practises.
Risk assessment of distribution feeders (RADF) includes risk analysis of different system components summarised on Figure 9.6. Finally, based summarising individual risk exposures and probabilities, we can establish overall system reliability.

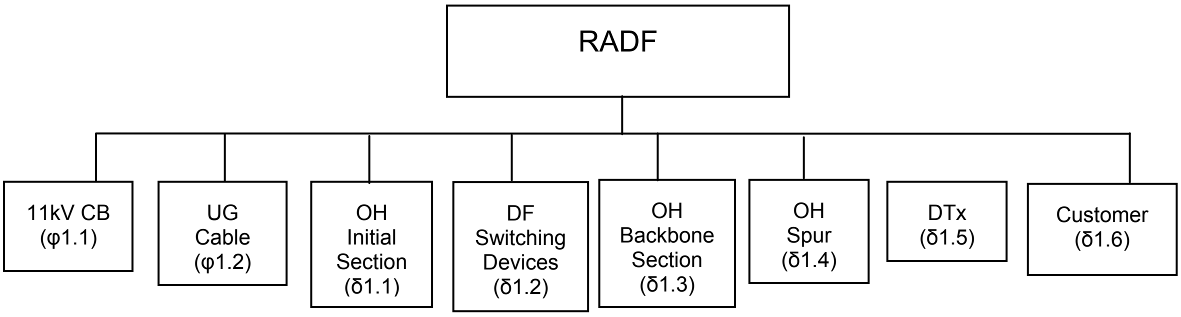


Figure 9.6 – Risk Assessment of Distribution Feeder

A composite feeder study includes a typical radial distribution feeder which supplies a distribution substation (DSS) located 7km from zone substation (Fig. 9.7) (ESAA 1995, p55). The feeder is made up of three sections (S1, 2 and 3) with different failure rates depending of section construction. The last third section is located in a high lightning area with a correspondingly higher failure rate. Distribution substation placed at end of the feeder is protected with a HV and LV fuses, as CB at the beginning of the feeder control overall feeder protection. All protection devices and ZSS in this example have 100% reliability.

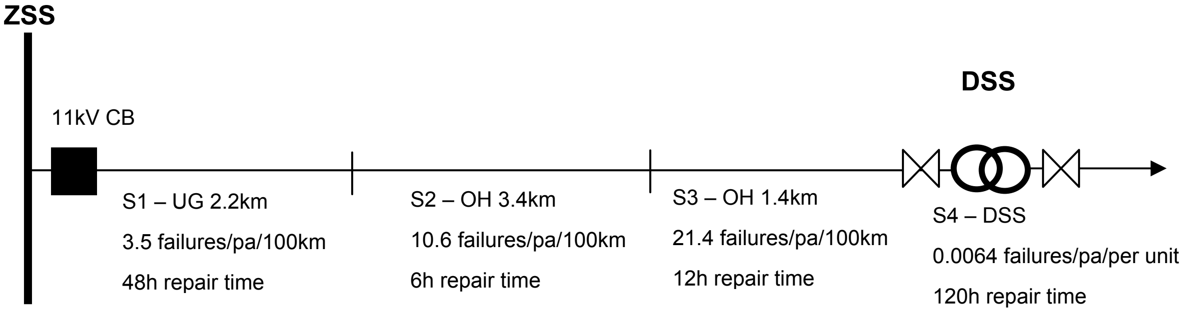


Figure 9.7 – Composite Series Feeder System (ESAA 1995, p.55)

Composite failure rate is (ESAA 1995, p.56):

λ_1 = 2.2/100 x 3.5 = 0.0770 failures per year

λ_2 = 3.4/100 x 10.6 = 0.3604 failures per year

λ_3 = 1.4/100 x 21.4 = 0.2996 failures per year

λ_4 = 0.0064 failures per year

$\lambda_s = \lambda_1 + \lambda_2 + \lambda_3 + \lambda_4$ = 0.7434 failures per year

Composite unavailability:

$$U_s = \Sigma\, \lambda_i\, r_i = (0.0770x48)+(0.3604x8)+(0.2996x12)+(0.0064x120) = 10.9424 \text{ hours per year}$$

Composite repair time:

$$r_s = U_s / \lambda_s = 10.9424 / 0.7434 = 14.7194 \text{ hours}$$

This composite feeder can now be treated as a single component in a larger system with a failure rate of 0.7434 failures per annum, unavailability of 10.09424 hours per year and a repair time of 14.7194 hours at the LV busbur.
With such risk analysis, we enter the realm of acceptable level of risks which is a definable level of supply unavailability. Electricity utilities have certain performance criteria and indices as targets.

Risk management can be defined as the process whereby decisions are made to accept a known or assessed risk and/or implement actions to reduce the consequences or probability of the occurrence.
There are two general roles of risk management – risk assessment and detriment minimisation. As seen before, risk assessment can be broken into three parts:

- The identification of the outcomes
- The estimation of magnitude of the associated consequences of these outcomes
- The estimation of the probabilities of these outcomes.

Although there are many uncertainties in system planning (including technological and political issues), the risk that is generally estimated is that of loss of supply. By development a system using standard design procedures, it adopts an inherent failure characteristic which level determines the risk of loss of supply which is accepted or rejected. Loss of supply has many aspects, including maintenance levels, non-adequate system augmentation and spare system capacity.

Once the outcomes are identified, the consequence can be examined. For example, the failure of a large transmission line (although it is highly unlikely) would isolate a large block of load, and conversely the failure of LV conductor which is more frequent affects a few customers.

Once the probability and consequence of different outcomes has been examined, careful costing is needed. A dollar value needs to be associated with each outcome and a commonly used measure is the cost of lost energy.

Risk management can be summarised as a risk benefit analysis which includes identifying risk, calculating the probability, consequence and cost of risk outcomes, as well as cost expenditure of system augmentation and risk minimisation. It is summarised in Table 9.11 in the form of risk prioritisation evaluation.

Table 9.11 - Risk Prioritisation Evaluation

Scenario	Design criteria	Consequence	Probability of scenario and exposure of consequences		
			Exposure of consequences	Probability of scenario	Nett outcome
Low voltage complaint	Statutory limits (240V =/-6%)	Normally insignificant	Single customer - AC Local member – E	AC AC	Almost certain Expected
HV voltage regulation	Statutory limits (240V =/-6%)	10-20% insignificant >20% minor	Single customer - L Local member – E	L AC	Unlikely Expected
Feeder OL normal conditions – OH	Plant rating criteria – normal rating	<10% insignificant 10-20% significant	Single customer – R Single customer – U	U E	Possible Unlikely
Feeder OL normal conditions – UG	Plant rating criteria – normal rating	<10% insignificant	Single customer – R	U	Possible

9.11.4 Risk Ranking Methodology- Capacity and Voltage

The risk assessment template considers:

I. Network event/scenario
II. Capacity Consequences
III. Likelihood of Occurrence
IV. Risk Score based on the corporate matrix (i.e. Consequence x Likelihood)
V. Consideration of Control Measures and Risk Mitigation Options.

From the standard Current State Assessment process, constraints are identified against approved planning criteria whilst the risk ranking methodology enables the constraints to be analysed across the various asset streams.

The Distribution Network Augmentation Plan provides a list of projects that will resolve the identified constraints. Projects will be subjected to an evaluation of risk before and after augmentation to determine the full value of the proposed mitigation options.

The following figures provide the risk assessment tools used to risk score the capacity and voltage related constraints of the distribution network. Final works plans will be determined from the available resources, capital expenditure budgets and the risk ranked projects submitted by the various streams.

As an example:

Several capacity constrained urban feeders (demand utilisation > 75%) have been identified from. Based a 50PoE load forecast.

> Capacity Consequence = 3
>
> Likelihood of Occurrence = 6
>
> Risk Score based on the corporate matrix (i.e. Consequence x Likelihood) = 18

This equates to a ’High Risk’ scenario. Provided resources are available and the CAPEX budget supports scores of ‘High Risk’ and above, this project would be entered into the works plan.

Table 9.12 - Risk Tolerability and Action Requirements

Risks - *Risk Tolerability Criteria and Action Requirements*					
Risk Score	Risk Descriptor	Risk Tolerability Criteria and Action Requirements			
30 – 36	***Intolerable*** *(stop exposure immediately)*				
25 – 29	***Very High Risk***	**ALARP** Risk in this range managed to As Low As Reasonably Practicable	**Executive Approval** (required for continued risk exposure at this level)	May require a full Quantitative Risk Assessment (QRA) Introduce new or changed risk treatments to reduce level of risk Periodic review of the risk and effectiveness of the existing risk treatments	Tolerable Range
18 – 24	***High Risk***		**Divisional Manager/ General Manager Approval** (required for continued risk exposure at this level)	Introduce new or changed risk treatments to reduce level of risk Periodic review of the risk and effectiveness of the existing risk treatments	
11 – 17	***Moderate Risk***		**Group Manager / Process Owner Approval** (required for continued risk exposure at this level)	Introduce new or changed risk controls or risk treatments as justified to further reduce risk Periodic review of the risk and effectiveness of the existing risk treatments	
6 – 10	**Low Risk**				
1 to 5	***Very Low Risk***	No direct approval required but evidence of ongoing monitoring and management is required		*Periodic review of the risk and effectiveness of the existing risk treatments*	

Augmentation should generally occur when 10%POE forecast load reaches 80% of the NCC of the limiting section of the feeder. The capacity of the limiting section is taken as the lesser of the rating of the overhead line or the “stand alone” rating of the underground cable.

A value of 80% NCC (Normal Cyclic Capacity) rather than 100% NCC is specified to allow for the following:

- It allows for the possibility that the actual site specific rating of a feeder cable may be less than the “stand alone” rating. The actual rating of individual feeder cables may be very time consuming to calculate because it depends on a variety of factors including soil thermal resistivity and proximity of other cables which can cause mutual heating. Sometimes this data is difficult to obtain
- It allows for inaccuracies in the load forecast
- It allows for emergency loading during network contingencies. The 80% value is a “planning rating”. During network contingencies a feeder may be loaded to 100% of its “stand alone” capacity as an emergency rating. This includes an allowance for an increase in temperature above that used for calculating NCC.

Some exceptions to the “80% augmentation rule” are as follows:

- Where it is known that spare capacity is needed on the HV distribution feeders because it is part of an auto-changeover scheme, e.g. to a hospital or major shopping centre
- Where there are high-density loads of a common class, such as industrial estates or commercial areas. For example, traditional N-1 loading for HV distribution feeders is sometimes taken to be 66.7% of the feeder’s actual rating. Under this loading policy, it is assumed that for a worst case fault at the front end of a feeder, the load can be supplied by two adjacent feeders
- Where segmentation of the load is necessary to improve distribution SAIDI, e.g. in heavily vegetated urban areas. In such areas, the long-term objective is to reduce HV distribution feeder utilisation to 65-80% of NCC
- In some cases the sub-transmission network and/or a zone substation may be loaded above ECC or 2HEC on the basis of available HV distribution load transfers. Augmentation may be required to maintain spare capacity on HV distribution feeders to ensure that these load transfers can be implemented.

9.11.5 Distribution Transformer

Distribution transformers will be loaded to name plate rating (NPR) on the following basis:

I. For errors in the load forecast, it allows the normal cyclic overload factor as a safety

II. For extreme weather conditions, it allows the emergency cyclic overload factor as a safety margin.

The transformer may be loaded to ECC if an adjacent transformer fails and it is needed to supply additional load through low voltage ties.

9.12 Network Contingency Planning

Company reviews its contingency plans for managing network failures and events such as exceptional hot weather, on an annual basis. The contingency plans encompass a number of aspects:

1. Network contingency and load shift plans to cater for single contingencies – equipment failure
2. Strategies for spares and replacement of major plant such as power transformers
3. Emergency response procedures covering management of major network incidents, including escalation as documented in the Corporate Emergency Management Plan
4. Simulation exercises to test procedures under different scenarios
5. Application of mobile generators to provide an emergency supply in situations where it is possible
6. Use of NOMAD mobile zone substations
7. Application of available NDM options
8. Installation of on-line condition monitoring equipment on power transformers.

Network contingency plans detail what load shifts and load management are available to restore supply following a single contingency event affecting supply to bulk supply substations, zone substations and HV feeder networks.

Electricity utilities usually develop so called Annual Summer Preparedness Plan for all bulk supply substations, zone substations and 132/110/33 kV feeder networks. In cases where load shift capability was not sufficient to enable supply to be restored following a single contingency, case by case specific plans were developed. As an example, these plans involved the positioning of a spare power transformer at substations considered to be higher risk in terms of likelihood or consequence of an extended outage of a major transformer or circuit. Identified N-1 conditions are provided as input into the network development planning process.

Company has also developed a process to monitor summer loads on a weekly basis as hot weather develops and amend load forecasts if required. This process identifies emerging "hot spots" where demand growth may have exceeded the previous annual forecasts. In these cases, corrective action to avoid an overload is taken well in advance.

Network contingency plans addressing remaining capacity risks for the next 12 months have commenced.

9.12.1 Power Transformer Contingency Plan

A specific plan which tracks and manages movement of spare, existing and new transformers between bulk supply and zone substations is maintained and reviewed on a continuous basis. The objective is to ensure optimal use of all available transformers, considering the relative network risks at each location. The plan also ensures there are sufficient numbers of spares for substations that do not have N-1 capacity.

In addition to major plant such as power transformers, the plan addresses stock holding requirements for other common items such as switchgear, cable and fuses.

Another initiative could be the installation of online condition monitoring equipment on a number of key power transformers in the network. This equipment monitors a number of critical performance characteristics to provide forewarning of internal transformer problems. This information assists the deployment of spare plant and resources in advance of an actual failure.

9.12.2 Mobile and Stand-by Generators

Electricity utility has available a fleet of mobile generators that could be used to provide an emergency response to sub-transmission and distribution network failures that could not be rectified by switching. These are capable of being directly connected to the underground or overhead 11 kV networks. Contingency plans of Summer Preparedness Programme identify the amount of generator support that will be required for next summer's emergency response to sub-transmission and distribution network failures which cannot be rectified by switching.

9.12.3 Emergency Response Procedures

To ensure organisational readiness for a range of network emergencies, electricity utility reviews and exercises its emergency response procedures on an annual basis. In addition to storm emergencies, the procedures cover response to major network failures, generation and transmission deficiencies and unusual events such as extreme hot weather. Electricity utility has systems in place to allow a rapid response to most contingencies.

When hot weather is forecast, utility has procedures in place that instigate response planning in advance. The procedures are designed to ensure that operational staff are mobilised quickly in the field and that an appropriate structure is in place to manage any emergency, including communication with customers, executive management and stakeholders. As part of this process Control Centre has included NDM customer support arrangements for load at risk areas. A separate dispatch and operating protocol has been developed and tested for the Control Centre to initiate the NDM network customer support arrangements.

9.13 Project Risk Management

The management of project risk requires understanding of project management principles, an appreciation of the role of risk management in the project management and an understanding of the application of risk management principles to real projects.

Risk management is an integral component of project management, being part of each stage in project 'life cycle'. It needs to be applied early in the project management and needs to be continually monitored, reviewed and adjusted throughout the project.

'The life cycle' of distribution augmentation projects consists of the five basic components (Fig 9.8) (Gardiner 2005, p.27).

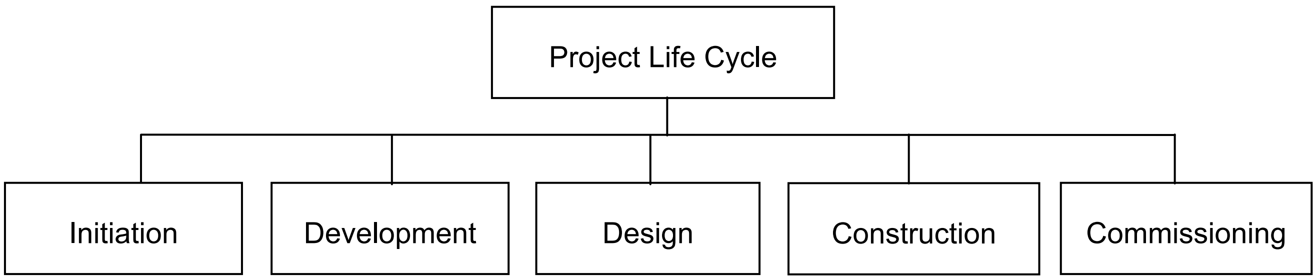


Figure 9.8 – Project Life Cycle (Gardiner 2005, p.27)

Each of the components has its own risk probabilities and risk factors which require detail assessment. In general, risks related to project management are associated with human resources problems, project structure, timetable, project budget, data availability/quality and project specifics (complexity). It is important to note that processes overlap and interact throughout a project or one of its phases.

From the timetable perspective, any of delays can cause chain of delays in entire project life cycle. These delays can cause lot of problems in delivery timetable of this and other projects. If delays are so long to exceed deployment of some of components or entire project in the period of one budget year, there is a risk of 'chain reaction' effect. Project moves into the second budget year, and as so called 'carry-over project', takes funds from projects planned in the second finance year.

Project risk management is one of the nine basic project management areas (with the project management of integration, scope, time, cost, quality, human resources, communication and procurement). It describes the process concerned with identifying, analysing and responding to project risk. It consists of the following components:

I. Risk management planning
II. Risk identification
III. Qualitative risk analysis
IV. Quantitative risk analysis
V. Risk response planning
VI. Risk monitoring and control.

Project importance and consequently priority is determined by multiple factors. One of them is affected peak load by the project and how much extra capacity is added in the system after completion of the certain project, weighted by customer segment (Table 9.13, as an example).

Table 9.13 – Project score and weighted load (a) and Customer segment and load weighting factor (b)

Project Score	Weighted load (concurrent peak MVA)
+5	>100 MVA
+4	50-100 MVA
+3	10-50 MVA
+2	5-10 MVA
+1	1-5 MVA
0	<1 MVA

Customer segment	Load weighting factor
Domestic	1.0
SME	1.5
Medium C&I	2.0
Large C&I	2.0

From distribution planning perspective, there are numerous factors which can generate risk with different impacts on the project management. In the first stage, there is a risk that planners failed to address the most critical objectives for specific project causing the failure in initiation stage. Further planning and development driven by the non-adequate objectives from the initiation stage focus on the wrong area and address recommendations which may or may not fix all problems marked among project objectives. Even if initial drivers are correct, there is a real risk that during development stage planners used methods or data not suitable for this specific project. Problems with load forecast, demographic planning, load flow analysis, basic input data, cost estimate, economic analysis and identified benefits are typical during development stage which could increase risk exposure in the project management.

Usually, design stage implements recommendations from the project scope. However, it implements more detail approach with field visits and associated surveys and sometimes change original scope and consequently project estimate. In the next stage, construction, additional changes can be expected with further cost changes and high probability of timetable modification.

Communication and co-ordination between stakeholders are critical in project management and their failure can have dramatic consequences.

Risk management should be the first port of call for the delivery of all projects to successfully manage potential and emerging risks.

Projects of every size and nature will have inherent risks. Risk management is not simply taking action to avoid or reduce the chance of something going wrong, it is also about identifying and taking opportunities to improve performance. Risk management aims to identify potential variations from what we plan or desire, and managing these to maximise opportunity, minimise loss, and improve decisions and outcomes.

Approaches used to identify risks include checklists, judgements based on experience, and records, flow charts, brainstorming, systems analysis, scenario analysis, Monte Carlo analysis and systems engineering techniques.

It is vital to apply risk management thinking generally across the project. This is especially important in the engineering process where safety in design practices are undertaken continuously, with various workshop techniques used to audit outcomes. Ensuring risk management forms a web between the various disciplines being used on the project will enable cross-disciplinary learning in relation to potential and emerging issues.

Climate change is one such risk factor. It presents a range of special challenges, including managing corporate and supply chain greenhouse gas 'footprints', exposure to national and international emissions reporting and trading regimes and risks from the physical impacts of climate change. There is also the growing challenge of converting the massive flow of related information into knowledge and better decisions.

The risk of not accounting for the impacts of climate change on a project could be significant.

The assessment of risks and opportunities associated with natural climate variability and human-induced change should be an integral part of all major projects. This assessment could simply consist of asking questions to assess risk and vulnerability as part of the design scoping discussion, or it could be a more specific and comprehensive plan tailored to specific aspects of a project.

The vulnerability of a project to climate risks reflects its:

- Sensitivity to climate – the degree to which change in or extremes of climate will affect the project
- Exposure to climate – the magnitude of natural variability and/or extent of projected human-induced changes in temperature, water availability, likelihood of floods and storms, and/or sea levels etc
- Capacity for adaptation to change – either in planning and design or through the project's life.

Climate variability and climate change contain risks and opportunities that will manifest at all stages of the project lifecycle – from planning to decommissioning. Climate risks must be considered over a range of planning horizons, and for some projects, across multiple spatial scales. This requires a robust understanding of how the climate currently operates and of how this might change in the future.

It also requires an understanding of the design and operational flexibility to manage risk. Although uncertainty will always be part of any assessment, tools are now available to assess and adapt to climate risk.

Managing project risk should be at the forefront of every project commencement. Recognising, assessing, managing and monitoring current and emerging issues are central aspects of successful project management and delivery. Keeping abreast of trends and developments in risk identification and management is essential for every project.

In project risk ranking process, there are the following four standard steps (ESAA 1995, p.73):

- Step 1: Identify objectives
- Step 2: Rank objectives
- Step 3: Rate projects against objectives
- Step 4: Rank projects based on score from Step 3.

The following seven objectives are typical for sub-transmission and distribution augmentation projects:

Cap - Capacity exceeded (thermal limits or voltage regulation)

QS - Quality of supply

H – Hazard (Safety)

RS - Reliability of supply

F - Financial

E - Environment

GO - Government objectives.

The second step requires that objectives be given a rank score between 1 (the least important objective) and 10 (the most important objective) with comparison of objectives using Priority Setting Matrix and the following weighting scores:

4 – Strong preference

3 – Preference

2 – Weak preference

1 – Equal.

In Table 11.15, Cap /4 indicates that Capacity (Cap) is a preferred compared with Quality of supply (QS) with number 4 (strong preference compare with QS) added to the Cap raw score.

H/4 indicates that Hazards/Safety (H) has strong preference (4) compare with either Capacity (Cap) or Quality of supply (QS). RS/2 indicates that Reliability of supply (RS) is a weak preference (2) compared with financial (F) and E/1-GO/1 indicates that these two compared objectives (Environment and Government objectives) are equal.

When the priority setting matrix is complete, raw scores for each objective are calculated as the sum of all scores listed in the matrix. For the example of Table 9.14, Hazards (H) has scores 4, 4, 4, 4, 3 and 3 giving a total score of 22.

Table 9.15 provides all raw scores for this example with rank score normalised (1 to 10) so that the highest weighted objective (H) receives a score of 10. Other objectives have scores multiplied by 10/22 and rounded to give an integer result.

Table 9.14 – Priority Setting Matrix (ESAA 1995, p. 74)

	QS	**H**	**RS**	**F**	**E**	**GO**
Cap	Cap/4	H/4	Cap/2	Cap/3	E/2	GO/3
	QS	H/4	RS/4	F/2	E/4	GO/4
		H	H/4	H/4	H/3	H/3
			RS	RS/2	E/2	GO/3
				F	E/3	GO/3
					E	E/1-GO/1
						GO

Table 9.15 – Rank Scores for Selected Objectives

Code	Raw Score	Rank (1-10)
Cap	9	4
QS	0	1
H	22	10
RS	6	3
F	2	1
E	12	5
GO	14	6

The final project ranking is carried out to in a similar fashion to objective ranking. Each project is examined to determine how it contributes to the identified objectives using a satisfaction rating which indicates the effective contribution (or negative impact) of the project toward the objective (Table 9.16).

Table 9.16 – Objective Satisfaction Ratings

Satisfaction rating	Description
5	A key element is satisfying objective
4	Strong impact
3	Significant impact
2	Some impact
1	Minor impact
0	No impact
-1 to -5	Minor to a major negative impacts

9.14 Project Risk Assessment – A Case Study

Let's do a risk assessment for one of augmentation projects. The project scope consists of purchasing and installation of a new 132/33kV power transformer 63MVA at one Bulk Supply Substation to use back up for 132/110kV, 30MVA power transformer and 110/33kV transformer to feed peak load at one of the towns of 27MVA.

In addition to standard project info (project title, timing, cost and project number), the project scope includes the following major components:

- Existing Asset Attributes
    - Description of asset type, age and condition (1 x new 132/33 KV, 63 MVA transformer, existing 30 MVA T/F in series with 2 x 20 MVA 110/33 KV T/Fs and 2 x 20 MVA regulators)
    - Number of Customers (7800)
    - Customer Base (C&I)
    - Critical Installation
    - Significant Load Increase (2.6MW in 2010; 1MW in 2012)
    - Rating of Equipment(s) (Single 132/110kV Transformer is 30MVA, 2x110/33kV TF-Regulator in series each with 20MVA capacity)
    - Political Issues
    - Environmental Issues
    - Safety Issues
    - Public Relations Issues
    - Any other pertinent information (110kV line which is back up supply for BSS is converted to 33kV to supply customer "X". In a contingency (loss of 132/33kV power transformer) customer "X" can be removed and 110kV back up supply restored in up to 24hrs time)

- Project Drivers
  - Load Forecast (MVA) (26MVA in 5yr time)
  - Network Topology (meshed and radial)
  - Customer Complaint History
  - Outage History (2 outages of 132/110 kV transformer are reported in 2004, totalling to 1.5 million lost customer-minute and one outage of 110/33kV transformer in 2004 with lost customer-minutes of 163,000)
  - Equipment Type Issues (Transformers are in satisfactory condition. No major rating issues)
  - Operational Issues (Single transformer point. Transformer maintenance is critical issue)
  - Feeder Category & Ranking
  - Power Quality Issues (33KV voltage problem)
  - Any other pertinent information (33kV Line VR in poor condition and may needs replacement. Present loads at BSS have reached the 33KV network capacity in terms of voltage regulation and any new load connections require extensive 33KV network augmentation)
- Risk Factors
  - Restoration time (All switching is manual. Phase issues between two BSS substations. Customer 'X' connected at 33kV on backup 110kV line. Extensive works required to reinstate at 110kV under contingency conditions)
  - Transfer capacity (Minimal – voltage constrained)
  - T/F age & condition
    - 132/110 KV (30 MVA) T3 1985 and estimated remaining life is 26 years
    - Bay 1: 110/33 kV T1 (20 MVA) 1953
    - Regulator 1, 20 MVA, 1962
    - Bay 2: 110/33 kV T2 (20 MVA) 1953
    - Regulator 2, 20 MVA, 1962
  - Load Profile (Load is greater than 80% of peak load for only 1% of time)
- Network Controls
  - Sub-transmission Network Transfer Capability (110kV line can pickup 20-25MVA. Requires customer 'X' to be disconnected and line works to re-energise at 110kV)
  - Distribution Network Transfer Capability (Existing distribution load transfer is minimal as voltage constrained)
  - Mobile Sub, Generation, Replacement Capability, Load shedding (Contingency plan to install spare 132/110kV, 30 MVA, transformer to replace existing transformer. 48hrs or more to replace failed unit)
  - Maintenance / Operating Instructions
  - Customer Connection Agreements (33kV connection can be removed if required)
  - Media and any other pertinent information.

After detail assessment of existing and future limitations, project drivers, risks and network control factors risk analysis continues based on the following four major risk categories:

- Safety
  - Initiating Sequence: Transformer bushing failure
  - 2nd Stage: Protection will operate
  - 3rd Stage: Bushing failure results in flying debris
  - 4th Stage: Personnel in BSS
  - 5th Stage: Struck by debris
  - 6th Stage: Single fatality
  - Total risk score: 10 (low)
- Environment
  - Initiating Sequence: 132/110kV Transformer Failure with tank rupture
  - 2nd Stage: Protection operates
  - 3rd Stage: Oil spill (no bunding)
  - 4th Stage: Sloping site, but oil spill contained to site, requiring outside assistance
  - Total risk score: 8 (low)
- Reliability
  - Initiating Sequence: Failure of 132/110kV transformer
  - 2nd Stage: Protection will operate to isolate transformer
  - 3rd Stage: 7800 customers, 25MVA load off
  - 4th Stage: Transfer 4MVA of load to adjusted BSS - 6hrs
  - 5th Stage: Re-energise 110kV to pick up 20-25MVA of load (24hrs)
  - Total risk score: 18 (high)
- Capacity
  - No capacity scenario
  - Total risk score: 1 (very low).

Table 9.17 – Summary of Risk Assessment

Driver	Score	Descriptor
Safety	10	Low
Environment	8	Low
Reliability	**18**	**High**
Capacity	1	Very Low

CHAPTER 10

ECONOMIC ANALYSIS OF DISTRIBUTION AUGMENTATION PROJECTS

This chapter explains the major components of economic studies in distribution planning. It also sets out the guidelines proposed to be adopted for the economic analysis requirements of planning investigations.

10.1 Present Value

The requirement is to have all of the dollars involved in the project, both inflows and outflows, valued at one point in time. To arrive at the present value for future cash flows, the future cash flows are discounted. A dollar today is worth more than a dollar tomorrow, because today's dollar can be invested immediately and starts earning interest. This discounting relates to the time value of money and not to the uncertainty associated with the projects and the associated projections.

Present Value or Principal (P) of total development expenditures is calculated based on (QUT EEP208 2002):

$$P = FV / (1+i)^n$$

where:

FV = the future value of the amount

i = the rate of interest per compounding period (10%)

n = the number of compounding periods

If a future sum of money is known, its worth can be calculated by discounting the future sum by the appropriate discount rate. The future value (FV) formula can be rearranged to do this function.

10.2 Net Present Value

The Net Present Value (NPV) or Internal Rate of Return (IRR) of an investment is the discounted value of the net cash inflows from the investment less than discounted value of the investment outlays.

The NPV technique recognises the time value of money and does not suffer from the defects of the other techniques. Of the available techniques, the NPV stands out as the most applicable for general use.

The NPV rule to be followed in the evaluation of a project, from an economic viewpoint, is to accept each project if it has a NPV that is positive (QUT EEP208 2002).

The general formula for NPV is:

$$NPV = \sum_{t}^{\infty} \frac{X_t}{(1+k)^t} - I$$

This means that the NPV equals the sum of (Σ) all future cash flows (X_t) discounted $(1+k)^t$ for time and risk minus the original outlay (I). The IRR formula is similar except that we set NPV to zero and solve for k.

Parallel with the idea of present value, there are also two additional and very important aspects to NPV technique - the concentration on the discounted cash flow and the concept of the discount rate.

10.3 The Discounted Cash Flow

The NPV rule is unconcerned with the calculation of profit or loss for purposes such as the end of year accounts of the enterprises or its divisions, but concentrates on the flows of cash relevant to the project. The non cash concept of depreciation is irrelevant to the examination of the whole of the life of a project. Its inclusion would be double counting because the outlay of the project is included in the calculation of the NPV in the form of a negative cash flow.

The timing of the cash flows is important. A Discounted Cash Flow (DCF) analysis is used in economic evaluations to take into account the time value of money. The risk associated with the cash flows needs to be identified and the risk is reflected in the discount rate used in the analyses.

10.3.1 The Discount Rate

The role of Discount Rate is to enable costs and benefits which accrue in future time periods to be expressed in comparable “present value” terms. The rate of discount used may affect the identification of the most desirable alternative because of the differences in the time profile of the respective projects’ cash flows.

10.3.2 Costs and Benefits

All relevant costs must be identified and included in the analyses including indirect and incidental costs of operation. In the costs’ structure there are the two following major components to be identified:

- Labour costs (including all costs associated with labour component of every project stage like development, design, construction and commissioning)
- Material costs.

In relation to the benefits, there are five main areas valued in dollar savings for consideration in distribution project planning:

I. Labour savings
II. Revenues
III. Reduction of network losses
IV. Reliability improvement (in the form of saved customer loss minutes converted to the dollar value)
V. Benefits arising from the capability to supply new load (based on the type of supplied load and tariff structure).

These savings are summarised in Annual Saving (AS) figure for entire project.

As one of project justification indicators Distribution Planning Engineer can use Benefits/Cost Ratio (BCR) as the ratio between Annual Savings and Annual Capital Cost (ACC).

For example:

AS=$111,049 and

ACC=$32,984

⇨ BCR = AS / ACC = $111,049 / $32,984 = 3.37.

10.4 Sensitivity Analysis

Sensitivity analysis is a variation on scenario analysis that is useful in pinpointing the areas where forecasting risk is especially severe. The basic idea for a sensitivity analysis is top freeze all of the variables except one and then see how sensitive our estimate of NPV is to changes in that one variable. If our NPV estimate turns out to be very sensitive to relatively small changes in the projected value of some component of project cash flow, then the forecasting risk associated with that variable is high.

Sensitivity analysis is useful in pinpointing variables that deserve the most attention. If we find that our estimated NPV is especially sensitive to a variable that is difficult to forecast, then the degree of forecasting risk is high.

Because sensitivity analysis is a form of scenario analysis, is suffers from the same drawbacks. Scenario analysis is useful for pointing out where forecasting errors will do the most damage, but it does not tell us what to do about possible errors.

An example of sensitivity analysis is presented on Figure 10.1. Two options (Option 1 and 2) are compared based on capital cost in Year 1 ($200,000 for Option 1 and $300,000 is capital cost of Option 2), maintenance cost (2% of capital cost), discount rate of 7.5% and loss savings of $100,000 (Option 1) and $80,000 (Option 2). Payback period for Option 1 occurs between Year 4 and Year 5 and for Option 2 after Year 7. Further improvement of NPV sensitivity analysis is possible with additional benefits (e.g. implementation of reliability improvements and supply of new loads due to increased system capacity).

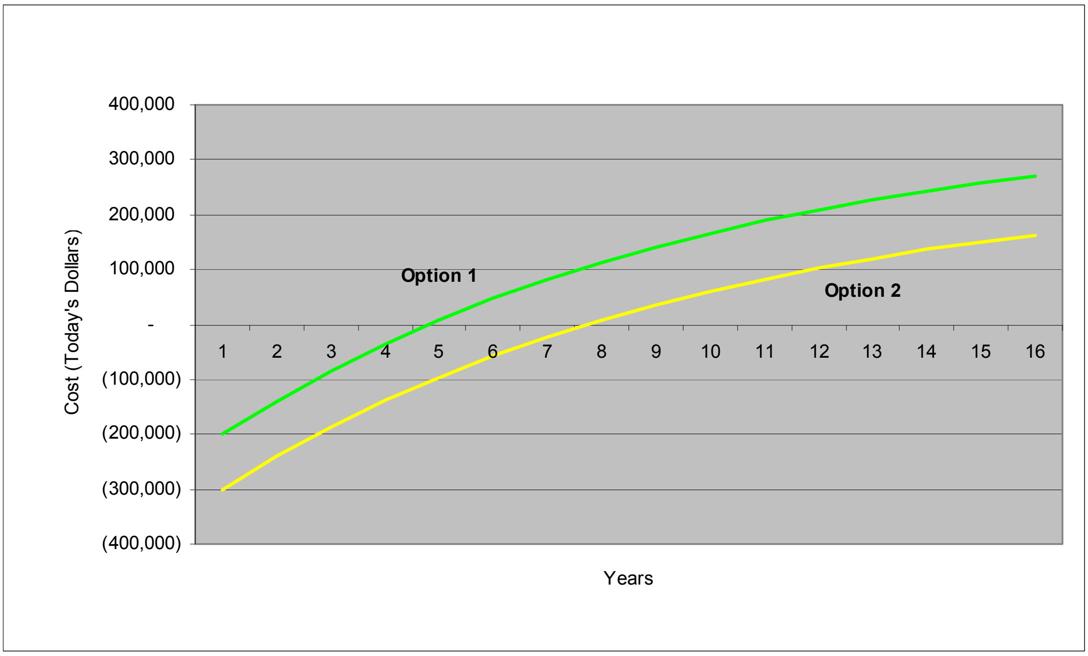


Figure 10.1 – NPV Sensitivity Analysis

Payback is the period of time it takes to recoup the initial outlay. As an accept/reject decision tool, the project with the shortest payback (Option 1 on Figure 10.1), or with a payback below some arbitrarily chosen time period is accepted.

There are tow major problems with payback. Firstly, there is a risk that unequal projects may be ranked equally. Secondly, payback does not take into consideration the risk of the project, nor the cash flows that occur after the payback period. Management needs to set an arbitrary time frame for that payback period.

10.5 Methods for Economic Comparisons

In economic comparisons carried out within the electricity industry, a minimisation of costs is the main driver. Within this context, the return on an investment is simply the reduction in costs we expect to achieve by pursuing one alternative project rather than another.

The main objective is to establish the envelope for cost minimisation and the variety of methods of economic analysis attempt to do this with different effectiveness. The reasons usually given for favouring one method of analysis over any other are not at all clear. An additional 'unknown' component in this equation is that the 'benefits' that may occur from capital investment in the electricity industry are considered as the ultimate benefits rest with the consumers.

Since tariffs are determined by costs, the tariffs (or expected future tariffs) simply measure costs incurred within the industry and do not measure benefits to the consumer.

Parallel with minimisation of capital cost of project, a detail analysis of economical benefits is necessary to be undertaken in comparison of different development options. Economical benefits (positive NPV and short payback period), with technical improvements (system capacity, its efficiency, security, availability and reliability) and positive climate change impacts are the main components in justification of recommended works and selection preferred option.

10.6 Cost of Losses

In assessing a cost of losses, the electricity supply industry in Queensland should be regarded as a single economic entity. In this context, the cost of losses should be taken as the complete marginal cost of supplying additional demand and energy in terms of the marginal costs of generation, transmission, sub-transmission and distribution, as well as marginal staffing costs throughout the supply system.

The bulk supply tariff reflects cost in excess of the marginal costs and use of the Bulk Supply Tariff would induce us to select alternatives with lower losses than would otherwise be the case. Invariably lower losses imply greater capital investment and this is not in the best interests of minimising costs to the consumer.

10.6.1 Hierarchy of Network Losses

The cost of the losses occurring in each level of the network must include the capacity costs for losses passed through the higher levels of the upstream network. However, in the diverse network design used at Ergon, not all levels of the network described below are utilised for any given location.

1) **Transmission Lines and Bulk Supply Substations** must feed all losses in the system following (in some areas of Ergon, HV distribution network emanates from Bulk supply directly)

2) **Sub-transmission lines** must feed all subsequent sub transmission line and Zone sub, HV distribution line Distribution transformer and LV Network losses

3) **Zone substations** must feed all subsequent HV distribution line, Distribution transformer and LV Network losses

4) **HV distribution lines** must feed all subsequent Distribution transformer and LV Network losses

5) **Distribution transformers** must feed all subsequent LV Network losses

6) **LV Network** must provide capacity for the customers' load and losses in the network within the voltage limits prescribed.

10.6.2 Methodology

The methodology below is based on a marginal cost approach. It considers the question "what is the cost of providing one more kW of load (in the form of losses)". For simplicity in calculation, the $\$/kW_{loss\ peak}$/year is used as discussed below, as $kW_{loss\ peak}$ may be calculated for the network most readily using analysis tools for the peak load (Ergon Energy 2008).

The formula takes into account two elements:

- the cost of the energy lost and
- the cost of the additional network capacity required as a result of system losses.

Hence we can consider:

Total cost of losses ($\$/kW_{loss\ peak}$/year) = $C_e + C_n$

Where:

C_e = Cost of Energy (including generation capacity), expressed in \$/kW at peak periods, but modified by the loss load factor for series losses, as above.

C_n = Cost of network capacity, expressed in $\$/kW_{loss\ peak}$ pa for losses at peak periods, applying without loss load factor as this capacity must be applied irrespective of light load periods, ie we must add capacity to meet the system maximum demand.

As set out below, we may have a co-incidence factor applied for diversity between transformer loads/feeder and feeder/zone substations, normally about 0.85 but = 1 for standing {parallel or iron} losses.

The first element Ce is the generation cost component, which includes both generation capacity plus the cost of energy. Under a market environment the average pool price provides a representation of this cost. An average pool price over a significant period is proposed to remove any short term fluctuations in the pool price. Ideally a 2 year moving average pool price should be used. In the short term this is obviously not feasible and pool price predictions may be used.

The second of these elements Cn is the cost of provision of additional network capacity for both transmission and distribution. The average cost of this capacity at each voltage level in the system is represented by the network price at that level. The marginal cost of new network at any voltage level can be derived from the network price and by adjusting for the difference between average and marginal network cost. From work carried out by IPART in NSW an initial estimate of 75% of the network price is used. That is, the marginal cost of network provision is about 75% of the average cost.

The typical usage of the value of losses is applied to system peak conditions and it will vary depending on the voltage level where it is to be used. The formulae below make adjustments for both of these factors.

The formulae are as follows:

Total cost of losses (\$/kW/year) = Ce + Cn

where: Ce = Ppool * LFtx * LFdist * 8760 * LLF

Ce = Cost of Energy (including gen. capacity), expressed in \$/kW at peak periods

Ppool = Average pool price, \$/kWh

LFtx = Average transmission loss factor

LFdist = Distribution loss factor to appropriate voltage level

LLF = System loss load factor.

This formula takes the average pool price and scales the price by transmission and distribution losses to achieve an equivalent energy cost at the required voltage level.

The use of the 8760 and the LLF multiplier adjusts this average cost figure to a cost applicable at peak periods and on an annual basis.

Also:

Cn = Pnetwork * MPF * 8760 * LF

Cn = Cost of network capacity, expressed in $/kW at peak periods

Pnetwork = Network price at the voltage level, expressed in $/kWh

MPF = Marginal network cost / average network cost

LF = Load factor at the voltage level.

This formula adjusts the average voltage based network price to a marginal cost and then adjusts by 8760 and the load factor to convert this to a demand based amount which can be applied to system peak on an annual basis.

The example calculation below for a low voltage (LV) value of losses is based on the following assumptions (indicative numbers only):

Ppool = 0.04 $/kWh

LFtx = 1.05

LFdist = 1.05 for LV

LLF = 0.35.

Ce = 0.04 * 1.05 * 1.05 * 8760 * 0.35 = $135/kW/year

Pnetwork = 0.045 $/kWh (LV)

MPF = 0.75

LF = 0.5.

Cn = 0.045 * 0.75 * 8760 * 0.5 = $148/kW/year

Ctotal = 135 + 148 = $283/kW/year.

10.7 Economic Analysis Requirements of Planning Investigations

The following guides sets out the rules in economic analysis of distribution planning studies:

- Distribution Planning is responsible to recommend system development which provides the option with the lowest project present worth cost over the appropriate study period. All options considered must technically satisfy requirements. It is management's responsibility to consider political implications such as what is the impact if an outage occurs to overturn the most cost effective development for an alternative. The Planning Engineer however should alert management to these concerns if appropriate
- Benefits arising from the capability to supply new load are not currently evaluated and therefore a slightly different approach should be used in the economic analysis for works related to limitations which include overloads under system normal conditions and safety
- The proposed development options is chosen as the lowest project present worth scheme and supported if applicable by the lowest initial capital cost development. Should these two items lead to an inclusive determination, the technical advantages of the schemes must be used in the determination
- Benefits arising from loss savings are evaluated by determining losses trough load flow analysis and supplying the appropriate loss cost ($/kW)
- Benefits from reliability improvement need to be determined in two steps, firstly if a failure results in loss of supply until switching is completed (e.g. radial systems) and secondly if a failure results in insufficient system capacity remaining to supply the load (evaluated under a Markov model or equivalent). For loss of supply evaluated for average loads such as outages of radial feeders, the following community cost of unsupplied energy to be used (SEQEB 1997):

    $2 per kWh for Domestic load

    $6/kWh for Mixed Domestic/Commercial and Industrial load

    $10/kWh for Commercial and Industrial load.

For loss of supply calculated for probabilistic techniques requiring load shedding at peak periods the following costs of unsupplied energy are used:

    $6 per kWh for Domestic load

    $10 per kWh for Mixed Office, Commercial and Industrial Load

    $14 per kWh for Commercial or Industrial Load

The capital cost used in economic comparisons is the direct cost only. The standard discount rate to be used is 10%. Sensitivity analysis is to be undertaken where necessary.

The analysed cost of recommended works is to be calculated by applying an annualised cost factor to the direct cost of works and which comprises a component to recover capital costs and a component to recover maintenance and operational costs. The capital recovery component is to be based on a 10% discount rate applied over a period corresponding the standard life as used in the asset valuation associated with network pricing. This period must be reduced accordingly if it is known that the asset will become stranded in a lesser period. The default value to be used for maintenance and operation costs is 2% of direct cost.

The annualised cost factors for varying standard lives are presented in Table 10.1.

- The recommended timing of non discretionary projects is just prior to the twelve month period when annual benefit exceeds annualised costs
- The associated payback periods are to be used to support the recommended works. The standard spreadsheets for simple projects evaluate payback periods which use the lower average cost of unsupplied energy and do not escalate the benefits for subsequent years. Payback periods up to ten years are appropriate
- If non discretionary works are being undertaken, benefits associated with supplying load under system normal conditions must be included with appropriate consideration given to valuing energy at the rates of community costs of energy not supplied.

Table 10.1 – The Annualised Cost Factors (Ergon Energy 2008)

Standard Life (years)	Discount Rate (%)	Annualised Capital Recovery Factor	Annualised Maintenance and Operative Recovery Factor	Total Annualised Cost Factor
15	10	0.131	0.02	0.151
25	10	0.110	0.02	0.130
30	10	0.103	0.02	0.126
35	10	0.104	0.02	0.124
40	10	0.102	0.02	0.122
45	10	0.101	0.02	0.121
50	10	0.010	0.02	0.121
60	10	0.100	0.02	0.120

CHAPTER 11

APPLICATION - AIRPORT DISTRIBUTION NETWORK STRATEGIC PLANNING

The author developed application of the following planning methodology to achieve best planning results discussed in this chapter. These works are pioneering in the field of long-term planning of the big airport's distribution networks worldwide. They are implemented in the author's report prepared for one of the companies managing electricity infrastructure of one of the largest airports in Australia (Ivanovich 2005).

The author implemented the modern principles of strategic distribution planning in development of different scenarios, considering network planning criteria, risk management, quality and reliability of supply, load growth and the airport demographic planning. The author conducted an extensive research and collection of confidential data from one of the major Australian airports during works on this report.

Chapter 11 represents application of modern planning principles which gives another specific dimension of this Master Dissertation thesis. Finally, recommendations from Chapter 11 are technically implemented in development programme of one of the major Australian airports as part of its standard capital expenditure plan.

Due to these reasons, Chapter 11 of this Dissertation should be considered as highly confidential and any utilisation of provided materials (text, figures and tables) must be co-ordinated only with the author.

By nature of the fact that they are among the largest public facilities in the world, airports play significant roles in shaping the economic, political and social landscapes of the communities they serve. The quality of airport infrastructure, which is a vital component of the overall transportation network, contributes directly to a country's international competitiveness and the flow of foreign investment.

Airports also represent a country's window on the world. Passengers form their first impressions about a nation from the state of its airports. They can be effectively used as symbols of national pride, if we pay sufficient attention to their quality and maintenance. Airports need to be integrated with other modes of transport like Railways and Highways, enabling seamless transportation to all parts of the country.

Considering the forecasts made by different organisation and taking a reasonably pragmatic view, the expected traffic scenario up to the year 2016-17 has been projected by the Foundation for Aviation and Sustainable Tourism. During the next twenty years, there is a quantum jump in the projected traffic - four times in passenger and six times in cargo traffic. It will, therefore, be necessary to take a host of measures so that the ground infrastructure keeps pace with the growth of traffic.

ICAO forecasts predict worldwide growth in air traffic at 5% a year or doubling in the volume of traffic once in 14 years. The Asia Pacific region is set for higher than average growth.

According to an AUTC study, it might account for more than 50% of the world air traffic by the year 2010. It is imperative that our procedures improve and facilities grow to match the increase in volume of traffic.

It is expected that adequate capacity will be deployed by the operators to meet the growth cargo traffic requirements in the years to come. Capacity induction in this sector is expected to be determined by market forces. The only aspect which needs to be planned and developed is the infrastructural facilities at the airports to handle various types of cargo traffic with efficiency and speed.

As such, airport management must assume the responsibility for leading the airport in positively contributing to the local economy, maintaining good relations with the airport's users and surrounding community while minimizing the impact that airports have on the natural environment. Maintaining this balance of roles is perhaps equally as challenging as maintaining the operations of the airport itself. From this perspective, strategic planning and development of the airports, including electricity network as one of the foundation of successful operation of the airports, is of extreme importance and requires implementation of specific analytical methods and philosophies.

The capable, reliable and well planed distribution network supplying increasing and more demandable load is of critical importance, especially considering the following factors associated with the modern airports:

- Speed is the essence of air transport. The AAI will set standards of performance in various areas of passenger and cargo handling, so that both ICAO standards as well as comparable standards at similar airports around the world, are achieved. For this purpose, procedures will be simplified, regulations which delay or restrict movement of traffic reviewed and efforts made to reduce ground delays to a minimum

- Dwell time of passengers and cargo will be drastically reduced, thus enhancing capacity at existing airports. The short-term objective will be to clear incoming international passengers within 45 minutes of arrival and clear departing passengers in 60 minutes including check-in-time. Similar targets of 30 and 45 minutes respectively, will be laid down for domestic flights

- Technological and other improvements will be made by introduction of automation and computerisation, mobile check-in counters, improvement in emigration/immigration and security checks, mechanisation of baggage and ground handling services, provision of aero-bridges, introduction of better systems of passenger transfer between terminals, improvement in cargo terminals, reduction in bunching of flights and contracting out of operating and maintenance facilities. New approaches in airport design will be required to accommodate technological innovations like the New Large Aircraft. Construction technology and architectural inputs will also need to be updated to standards applicable globally

- Efforts will be made to upgrade the facilities, manpower, equipment, etc., by concerned departments and institutions like customs, immigration, meteorology, oil companies, etc., so that these keep pace with the upgrade of airports, enabling the users to experience the optimum benefits of airports as 'cohesive' transit points

- Apart from the AAI and the national carriers, private agencies will also be encouraged for providing ground handling services

- Special attention needs to be given to the speedy handling of cargo and reducing its dwell time. The objective will be to reduce dwell time of exports from the present level of 4 days to 12 hours, and of imports for the present level of 4 weeks to 24 hours to bring us in line with internationally achieved norms. Cargo clearance will be on 24-hour basis

- Infrastructure relating to cargo handling like satellite freight cities with multi-modal transport, cargo terminals, cold storage, automatic storage and retrieval systems, mechanised transportation of cargo, computerisation and automation, etc., will be set up on top priority basis. Such facilities have to come up at smaller places too

- The Electronic Data Interchange systems will be developed and linked amongst all stake-holders in the trade (Wells & Young 2003).

11.1 The Airport Components

An airport is a complex transportation facility, designed to serve aircraft, passengers, cargo, and surface vehicles. Each of these users is served by the different components of an airport. The components of an airport are typically placed into two categories – the airside and the landside components (Fig. 11.1).

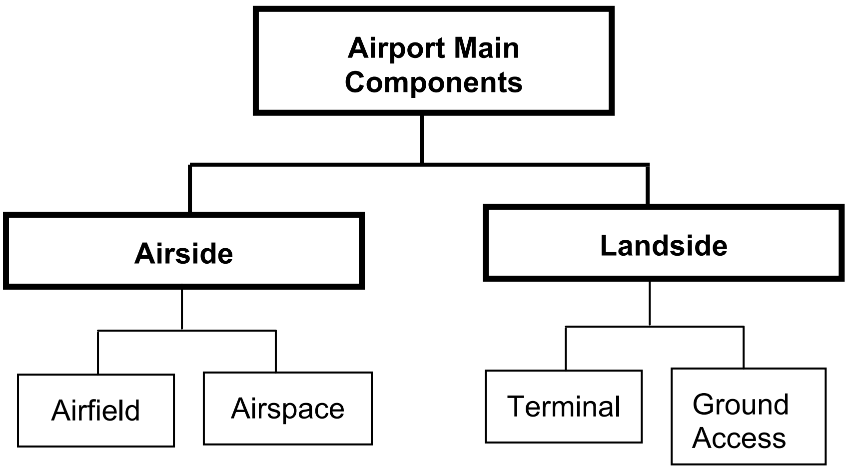


Figure 11.1-The Main Components of an Airport (Wells & Young 2003, p.101)

The airside of an airport is planned and managed to accommodate the movement of aircraft around the airport, as well as to and from the air. It is further categorized into two major sub-components - the airport's airfield and the airspace. The airport's airfield includes all the facilities located on the physical property of the airport to facilitate aircraft operations. The airspace surrounding an airport is the area, off the ground where aircraft manoeuvre, after takeoff, prior to landing, or even merely to pass trough on the way to another airport.

The landside components of the airport are planned and managed to accommodate the movement of ground-based vehicles, passengers and cargo. The components are categorized into two groups. The airport terminal sub-components facilitate the movement of passengers and luggage from the landside to aircraft on the airside. The airport's ground access sub-component accommodates the movement of ground-based vehicles to and from the surrounding metropolitan area, as well as between the various buildings found on the airport property.

The airport's components are planned to allow proper 'flow' between components. The most prominent facilities located on an airport's airfield are runways (as the single the most important facility), taxiways, aircraft parking areas, navigational, lightning system, signage, marking and air rescue and fire fighting facilities. One of the most important components of an airport's airspace area is air traffic control towers with air traffic control system command centre (Wells & Young 2003).

The airport terminal areas are comprised of passenger and cargo terminal buildings, aircraft parking, unloading, and service areas as passenger service facilities, automobile parking, and public transit stations (Figure 11.2).

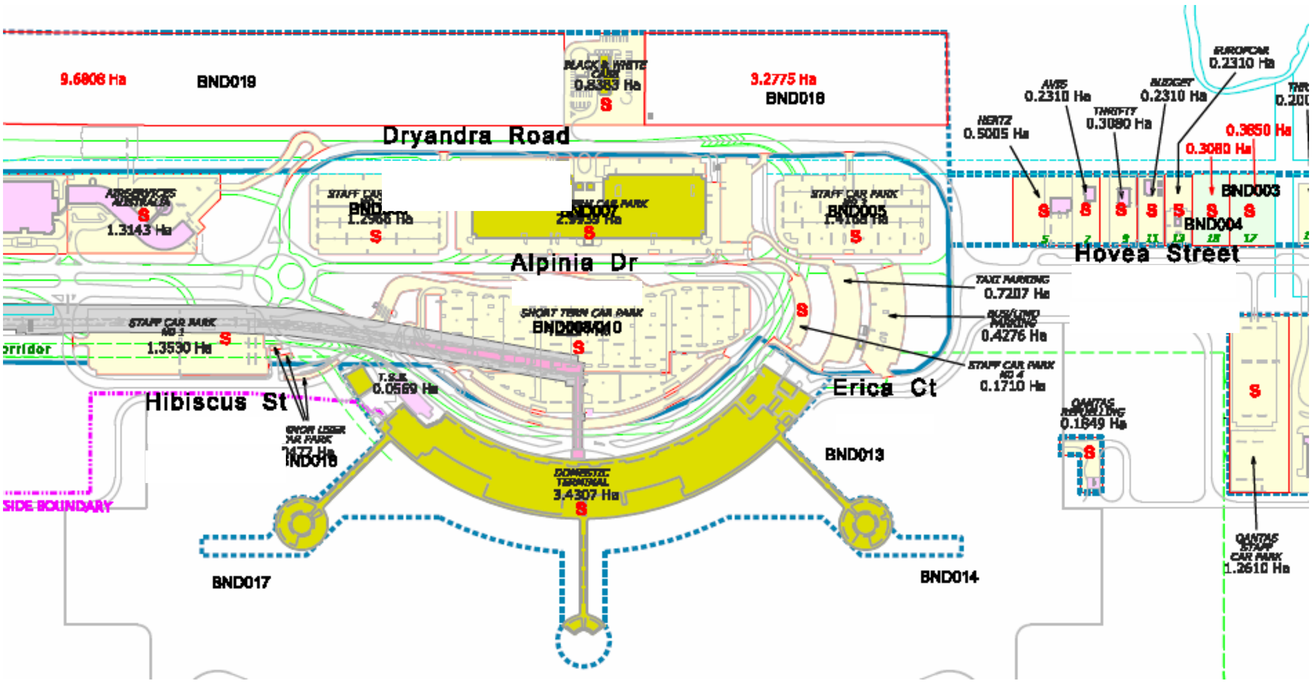


Figure 11.2-The Modelled Airport Terminal Area

11.2 Modelled Airport Area Development

All components mentioned in Chapter 11.1 have been included in the Modelled Airport (MA). For the purpose of this study, the total MA area of almost 1000 Ha is separated into 12 development areas specifically abbreviated as (Figure 11.3):

ND - planned for the future runway

APN - area for technical services

IDA - area for various developments related to the management of future runway

DT – Domestic Terminal

BP - area for various buildings

IT - International Terminal

APS - area for technical services

EPW - area for different storage facilities

AIP – industrial services

AD – area planned for future development of commercial facilities

EP - area for different storage facilities

EPE - area for different storage facilities

Consumers of electricity power located in each of these areas could be categorized into the four major groups:

1. Technical facilities
2. Industrial infrastructure
3. Terminal services and
4. Commercial buildings.

Typical technical facilities like lightning and control and navigation systems are extremely important for the critical functions of the airport. Industrial infrastructure includes various services like hangars for maintenance and tests of the airplanes and fuel storage facilities. Terminal services incorporate numerous airplane ports and gates and complex infrastructure for transfer of passengers to or from the airplane. Also, there are numerous commercial facilities used by travellers at the airport. Finally, among the major customers of electricity are commercial buildings, shopping centres, hotels, large storage facilities (like Post Services or collection centres for different companies), petrol stations and offices.

Compare with the customers in standard distribution networks, the airport systems require continuous and reliable electricity with maximum quality. Any block-outs and power outages, even the shortest ones, would have serious consequences on the operation of the airport, airplanes in taking-off or landing phases and the general airport safety.

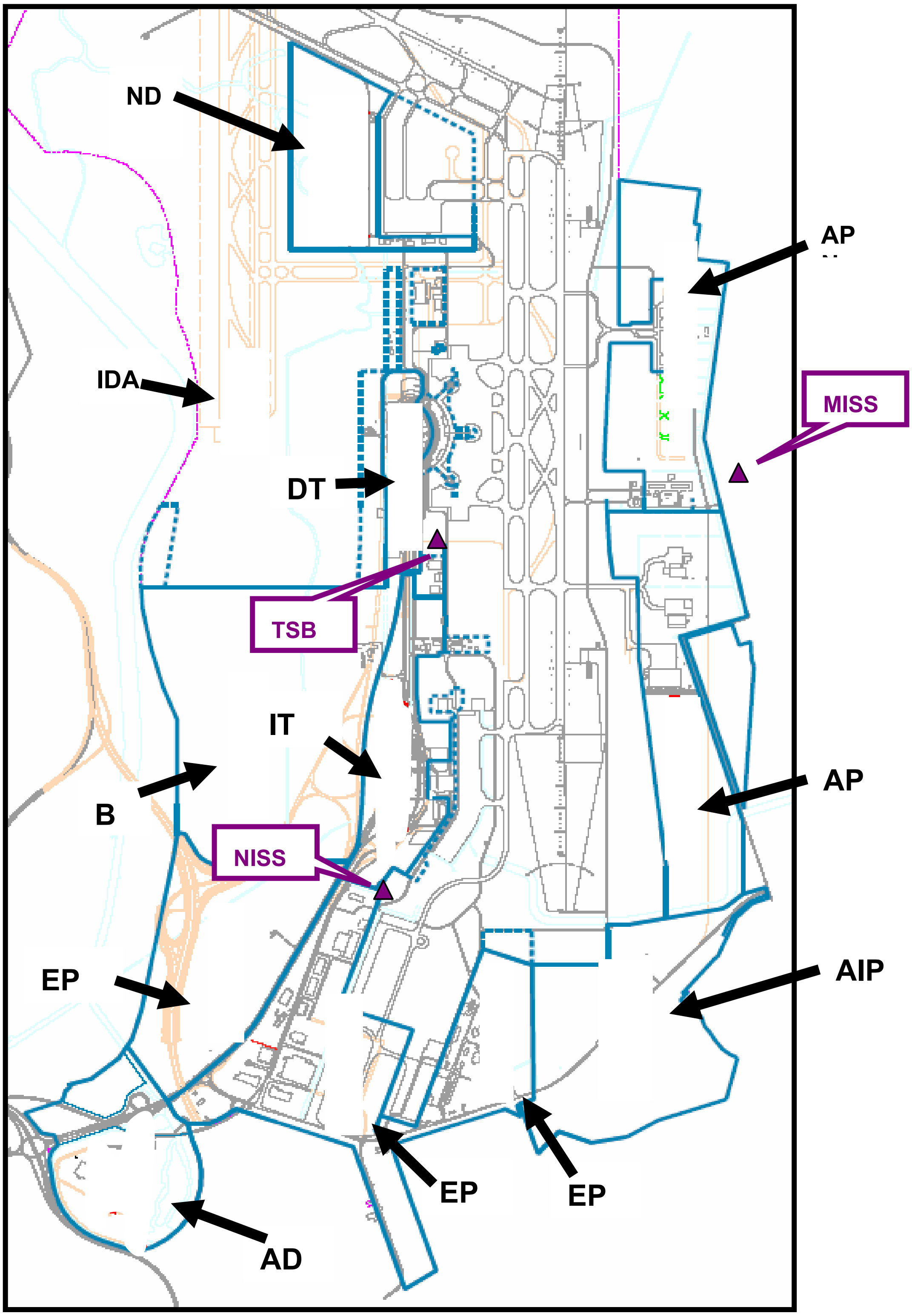


Figure 11.3 – The Modelled Airport Precincts Layout

11.3 Basics of the Airport Distribution Network Study

As every strategic planning study of electricity networks, the airport planning is a combination of different methodologies and techniques conducted during the following stages:

I. Data collection and analysis
II. Development of studied distribution system model
III. Load flow analysis and simulations
IV. Development of load and voltage profile of studied distribution system
V. Determination of network constraints and limitations
VI. Development of different planning scenarios
VII. Technical and economical comparison of studied options
VIII. Recommendations including timing and capital expenditure.

This process starts with collection of data using different internal and external sources. Among them very important are the local airport corporations managing the airport infrastructure (including the airport electricity network), local electricity utilities managing transmission and sub-transmission networks and set of planning criteria, processes and planning procedures. In this stage extensive communication and co-ordination of works are critical for the success to the study. It is recommended to form few teams co-ordinated by the Network Planner. One of the teams is under direct management of the Network Planner, as other teams operate in the Airport Corporation Company and other transmission utilities providing electricity supply services to the airport.

In the second stage, using available data distribution planner develops model of electricity networks, sub-transmission (outside or at the airport) and the airport distribution system. Each components of electricity network should be modelled properly and numerous simulating tests should take place to identify any anomalies and problems in running load flow analysis. In this stage it is extremely important proper distribution of loads between distribution transformers using electricity consumption, billing data, number of connected customers, ADMD techniques, transformer rating and info from the local electricity staff responsible for operation of electricity system.

The third stage includes serial of load flow analysis to determine load profile and system dynamics and stability for different operational regimes. Simulating covers normal system operations, as well as different contingency conditions which address system constraints and limitations. It is also extremely important to determine adequate (real) rating of each distribution component for different loading, design and the weather conditions.

Based on these data, simulations and load flow analysis, in the fourth stage, distribution planner develops electricity system's load/voltage profile.

In the fifth stage the constraint profile is developed and all limitations addressed.

Typical limitations are:

- Capacity constraints – existing or in the future, under normal and contingency conditions
- Load transfer capabilities
- Connection of the major loads
- Voltage regulation
- Fault levels
- Quality of supply.

To overcome these limitations, different options are studied and compared from different perspectives – technical, operational, reliability, economical and financial. Recommended option is superior based on these criteria. If necessary, based on load and energy forecast Network Planner can recommend stage development with clear distinction between stages represented in the form of NPV Sensitivity Analysis.

11.4 Airport Load Forecast Principles

Load forecast for any modern airport is based on the Airport Development Plan, existing load profiles and load history (preferable in the last 10 years). There are three major groups of load data important for the airport load forecast - zone substations and the airport distribution network load data and data about future connections.

Usually, zone substations supplying the airport are managed by the local electricity utilities. They provide supply for so called Intake Substations (switching stations) which distribute power to the different areas of the airport. Thus, it is necessary to collect load records from the local electricity utility managing zone substations and the Airport Corporation managing the airport infrastructure including electricity network. Also, zone or bulk substations load forecasts provided from the local electricity utilities with development plans related to the airport area are important for the airport load forecast.

For more details related to load forecasting methodology please refer Chapter 4 of this thesis.

11.5 Airport Power System Analysis

After collection of load data, the next step in the airport network planning is to develop accurate model of the airport electricity system using some of standard power flow packages. This study had been carried out in 2005 using developed DINIS model of the airport distribution network.

Modelled airport electricity network is consisting of the following major components:

- Two 33/11kV zone substations (ZSS) SSMTN and SSNGE managed by the local electricity utility
- Zone substation's 11kV distribution system of four feeders (also managed by the local electricity utility) supplying the airport intake substations
- Three airport intake substations (ISS)
- The airport 11kV distribution network emanating from ISS and supplying the airport services. Model consists of three ISS, 28 distribution feeders, 66 distribution substations, 130 switching devices and approximately 60km of distribution network (predominantly UG).

This model is sufficient to provide an accurate representation of the airport distribution system, and an indication of the likely implications of distribution system developments on the sub-transmission system.

Network limitations have been identified using this load flow model. Various scenarios have been tested to ascertain their viability and to identify the most effective technical solutions to the limitations found.

Two DINIS models have been developed:

- Existing distribution network to conduct existing and future load flow analysis, system performance studies, fault level studies, determination of level of constraints and contingency planning
- Proposed system consisting of three zone substations (BAPSS, LMDSS and PAVSS), three major switching stations (MISS, TSB and BLV SW/S), 50 distribution feeders and all expected distribution substations at the end of 2019/20.

11.6 Airport Growth Rate

Commercial and industrial development at the modelled airport (MA) until 2020 has been identified based on the Precinct Development Plan. Up to 2014 expected total new connected ADMD is approx. 50MVA. The highest growth is expected before 2012/13.

Calculation of ADMD in this case also has specifics related to development adjacent to an aerodrome – so called “Sky-park”. It is a residential development adjacent to an aerodrome, with direct access for aircraft from larger allotments (to accommodate aircraft hangers), as well as a conventional road network. They may be reticulated with either overhead or underground electricity supply, but usually the latter.

Issues for the Distribution Planner for such developments are:

- Large lot size (typically 1400m2 to 200m2) means larger frontages per lot which may require the use of 300mm2 LV cable to minimise voltage drop
- These are normally ‘prestige’ developments, so a higher per lot ADMD may be appropriate, also providing for electrical loads in hangers
- Full cut-off street light lanterns may be appropriate to avoid confusion with runway lights
- There may be a height restriction on poles or streetlight columns, requiring closer spacing.

11.7 Airport Distribution Network Risk Assessment

Development of the high level risk profile of airport distribution network includes the following major steps:

I. Determination of the root causal factors that affect failure of one or group of network assets

II. Determine the likely life of an asset based on statistical profiling

III. Develop a base line predictive model for asset life

IV. Factor into the developed model for asset life and external factors

V. Risk budgeting and costing.

11.8 Economic Analysis and Cost Estimate

Cost models for a range of development options have been built up using standard project estimating techniques and unit prices presented in Appendix B.

These have been built up to represent ±10% accuracy for the purpose of selecting the most economic augmentation option.

The preferred developments have been selected on the basis of being technically acceptable in the first instance. The selection is then based on the net present value of the capital cost and operating costs (i.e. losses) cash flow stream over time using discounted cash flow analysis.

11.9 Modelled Airport Electricity Infrastructure

The MA distribution network is supplied by four 11 kV incoming feeders from two zone substations SSMTN and SSNGE. Electric power is distributed to the local distribution network via three major intake switching stations MISS, NISS and TSB – Figure 11.4.

Two feeders for MTNSS (MTN03 and MTN08) located approx. 1.7km south of MISS have UG (2x300mm^{2}Cu 3C PLYSWS) and OH components (19/3.75AAC Pluto@75^{o}C). Summer continuous capacity of each 2x300Cu cable is 768A (~14.6MVA). Pluto OH section has SD-NC of 553A (~10.5MVA).

Feeders NGE10 and NGE17 from NGESS have UG 3x33kV 400mmCu 1C PLYHDPE both length of approx. 3.2km in duct. Cables with summer continuous rating of 437A (~8MVA) each are presently energised at 11kV and will be re-energised at 33kV when BAPSS is commissioned.

Distribution feeders out of MISS, NISS and TSB have UG cable exits in duct out of substations at an average depth of approx. 1m. Size of UG cable exits is 95mm^{2}Cu (e.g. ISS06, ISS07, NISS04, and NISS07), 185mm^{2}Cu (e.g. ISS08 and NISS05), 240mm^{2}Cu (e.g. ISS10, NISS08 and NISS09) and 300mm^{2}Cu (e.g. ISS05, ISS09 and NISS06).

Three feeders out of TSB have UG cable exits size only 25mm^{2}Cu. Two feeders (ISS06 and ISS08) have in their structure OH conductors (7/2.5AAC and 7/.173AAC), as well.

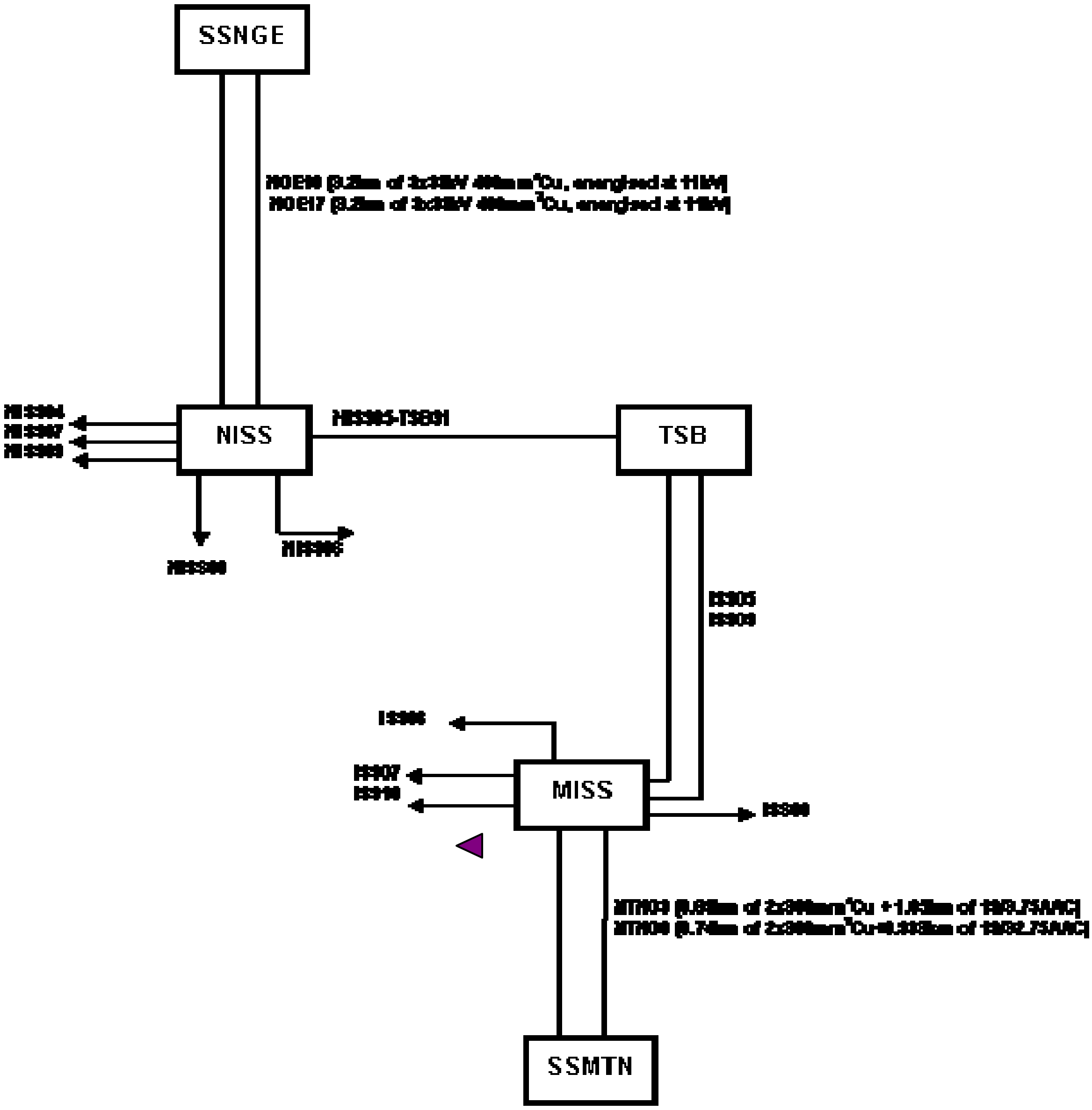


Figure 11.4 – Modelled Airport Distribution System

The system is presently loaded to approx. 20 MVA (Fig.11.5) and supplies 21 distribution feeders and 66 distribution substations 11kV/LV. The MA daily peak load curve is presented in Fig. 11.6.

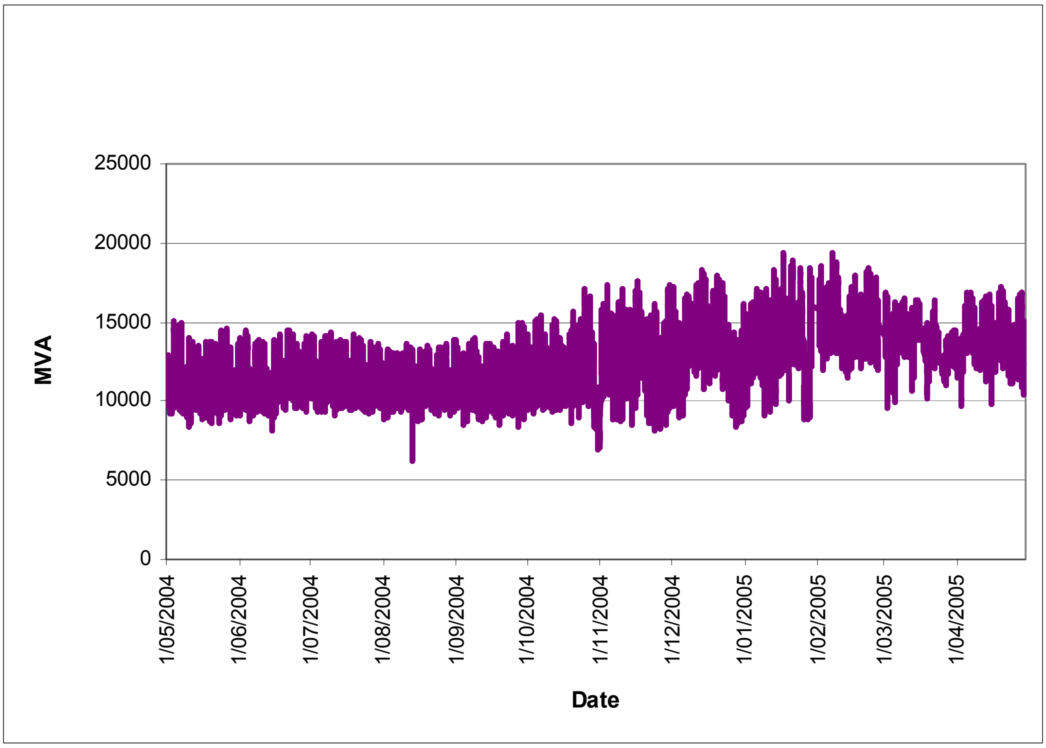


Figure 11.5 – Modelled Airport Load Profile

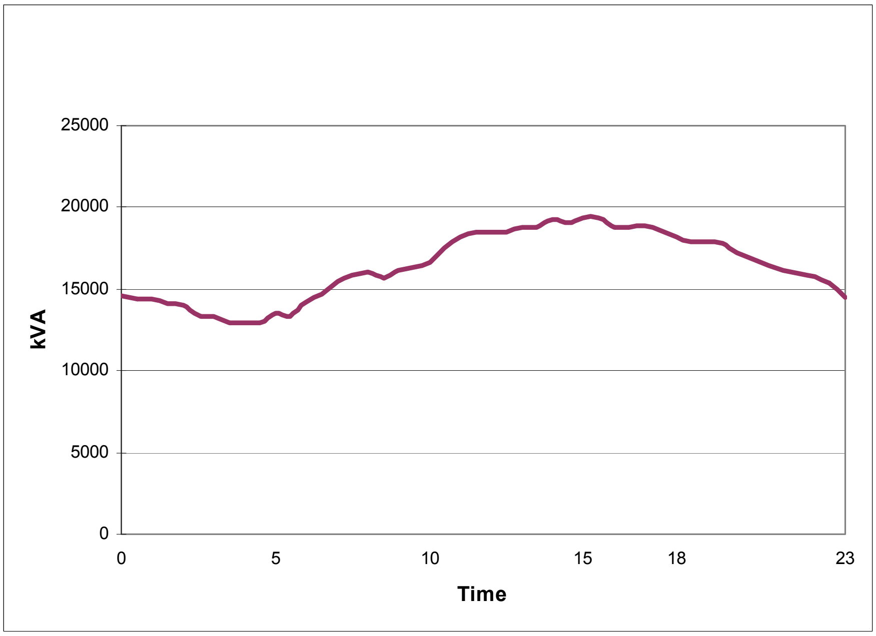


Figure 11.6 – Modelled Airport Daily Load Curve

The MA is experiencing period of rapid growth especially in the areas of AD (supplied by NISS) and APS (MISS).

For each precinct development plan for period 2005-2020 has been established. This plan is summarised in Appendix E and Figure 11.7.

A detailed examination of the commercial and industrial developments planned and forecast for the MA supply area has been conducted.

In the supply area of NISS, apart from the IT (>6MVA additional ADMD), it is expected that most of the new loads (>15MVA) will be attracted to the areas located in the western parts of the MA. This is due to available land and well developed infrastructure such as road access, water supply, sewerage etc. Also, it is expected additional ADMD of >12MVA in areas of EP and EPW.

But, the largest development at the MA is expected in the APS area, west of MISS. An additional ADMD of >20MVA will be installed at the end of 2019/20.

In 2009/10, 2010/11 and 2012/13 based on the Development Plan total additional ADMD at the MA will exceed 9MVA.

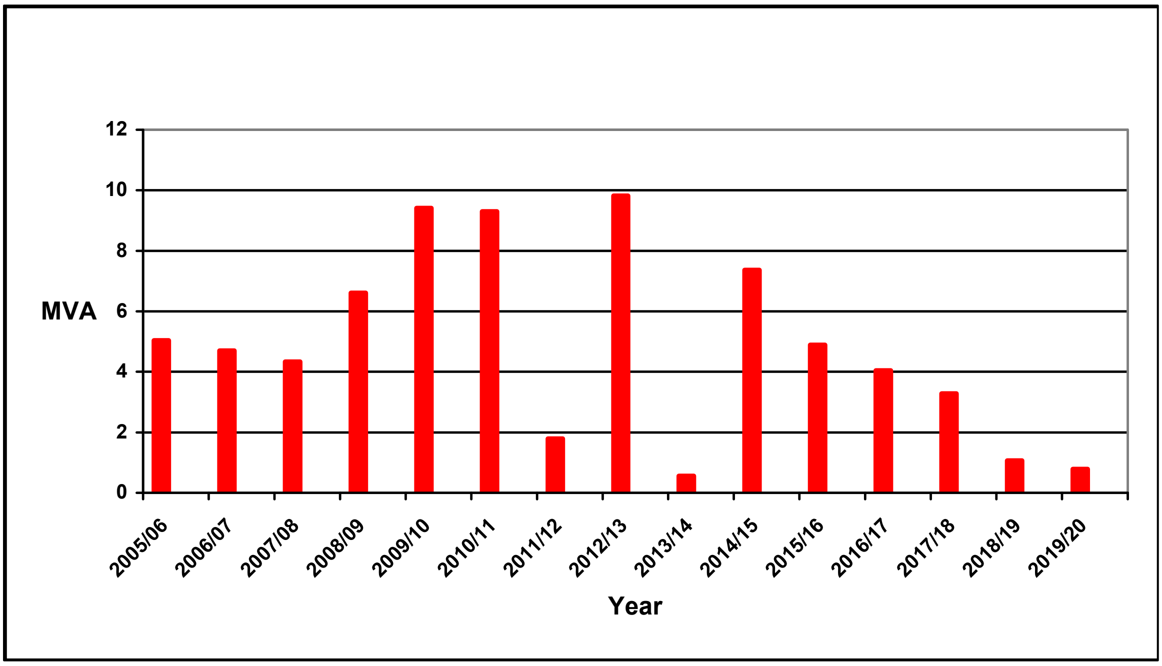


Figure 11.7 – Future Load at the Modelled Airport

11.10 MISS Intake Switching Substation

Two main feeders (MTN03 and MTN08) provide supply for the MISS. Summer continuous capacity of both feeders is 16MVA respectively. The MISS provides supply for six distribution feeders and there is one spare feeder bay (ISS04). Two feeders (ISS09 and ISS05) are dedicated UG cables supplying the TSB switching station. The largest customers supplied from MISS are airplane servicing hangars with a total capacity of 6.5MVA.

Modelled one year load curve of MTN3 and MTN8 is presented on Fig. 11.8.

The peak load details of distribution feeders ISS06, ISS07, ISS10 and ISS08 are provided in Table 11.1.

As ISS05 and ISS09 provide supply for TSB, data related to power losses and Greenhouse Gas Contribution (GGS) are included in peak load details for TSB feeders.

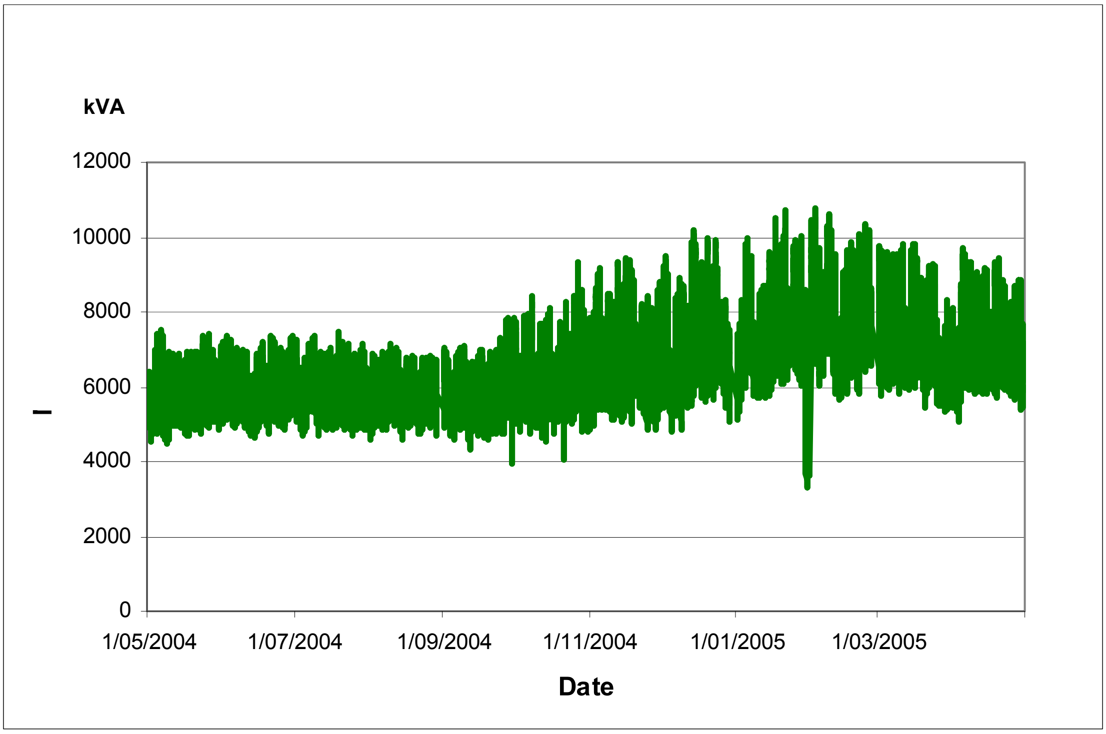


Figure 11.8 – MISS – One Year Load Profile

Table 11.1 – MISS - Existing Feeder Peak Load Data

Feeder	SD[1] Peak Load (A, MVA)	Peak Load Voltage Drop (%)[5]	Peak Load Losses (kW, %)	Loss Penalties ($/p.a.)[2]	Greenhouse Gas Contribution (t/p.a., CO_2)
ISS06	103 (1.73)	+0.1%	24.9 (1.9%)	$7,320	86
ISS07	52 (1)	+1.8%	1.8 (0.2%)	$529	6
ISS10	185 (3.6)	+1.4%	13.6 (0.5%)	$3,998	47
ISS08	150 (2.92)	+0.7%	14.3 (0.5%)	$4,204	49
ISS05-TSB05[3]	247 (4.7)	0%	8.9 (0.2%)	$2,616	31
ISS09-TSB09[3]	247 (4.7)	0%	8.9 (0.2%)	$2,616	31

Note: 1 - SD-Summer Day; 2 - $294/kW [1]; 3 –Three months available load readings data for ISS05 and ISS09 have 174A. Load flow study has been done based on maximum potential demand at the Domestic Terminal; 5 – Voltage drop colour code: Green – no voltage constraints

11.11 NISS Intake Switching Substation

NISS is supplied by two feeders NGE17 and NGE10 with summer continuous capacity of 10MVA each. The NISS provides supply for six distribution feeders. One of them (NISS005) is a back-up feeder for TSB switching station. Feeder NISS06 provides supply for IT Building. There is only one tie with MISS between NISS08 and ISS06.

The largest modelled customers supplied from NISS are IT Building with a total capacity of 8.5MVA and Flight Simulator (3MVA).

One year load curve for NGE10 and NGE17 is presented on Fig. 11.9.

The peak load details of distribution feeders NISS04, NISS07, NISS09, NISS08 and NISS06 are provided in Table 11.2. Load flow study has been conducted based on DINIS standard figures for actual load on distribution substations.

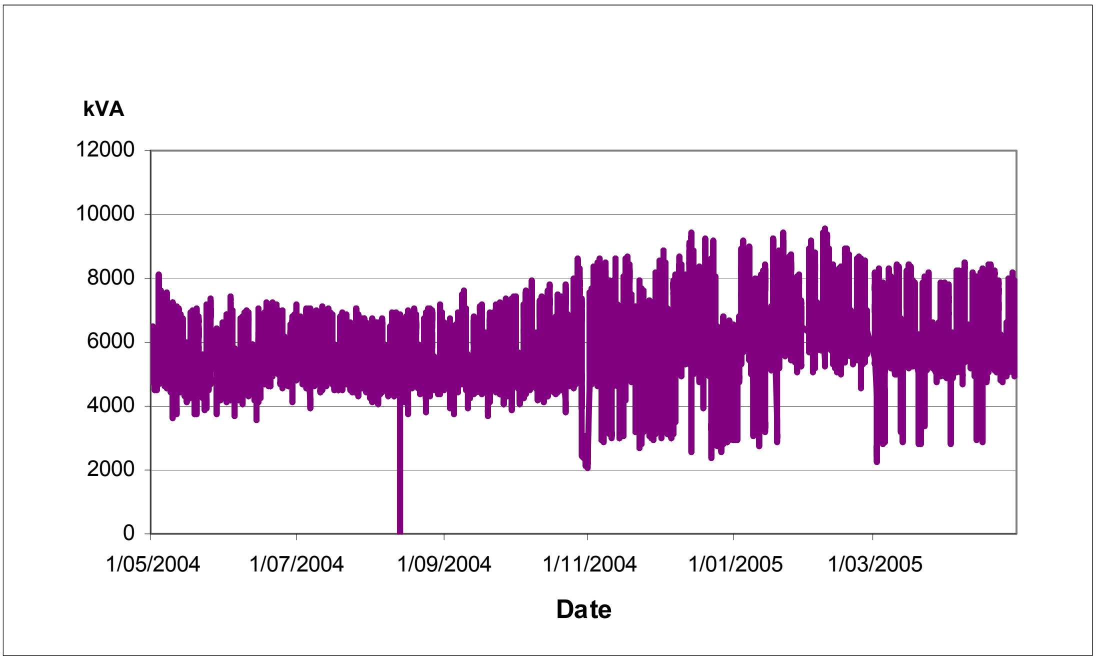


Figure 11.9 – NISS – One Year Load Profile

Table 11.2 – NISS - Existing Feeder Peak Load Data

Feeder	SD[1] Peak Load (A, MVA)	Peak Load Voltage Drop (%)[3]	Peak Load Losses (kW, %)	Loss Penalties ($/p.a.)[2]	Greenhouse Gas Contribution (t/p.a., CO_2)
NISS04	275 (5.2)	-1.7%	174.5 (3.6%)	$51,303	602
NISS07	46 (0.9)	+1.9%	0.4 (0.1%)	$118	1.4
NISS09	148 (2.9)	+1.7%	4.8 (0.2%)	$1,411	16.6
NISS08	128 (2.5)	+1.9%	0.4 (0.1%)	$118	1.4
NISS06	292 (4.76)	+1.4%	45 (0.9%)	$13,230	155
NISS05-TSB31[4]	N/A	N/A	N/A	N/A	N/A

Note: 1 - SD-Summer Day; 2 - $294/kW [1]; 3 – Voltage drop colour code: Green – no voltage constraints; 4- Back-up supply for TSB

11.12 TSB Switching Substation

TSB Switching Station is supplied with two dedicated feeders from ISS (ISS09 and ISS05).

Summer Day continuous capacity of both feeders from ISS is 406A (SD cyclic capacity is 487A), and feeder NISS09 from NISS has SD continuous capacity of 318A (SD cyclic capacity is 382A).

One feeder from NISS (NISS05) with 2x185mm^{2}Cu UG cables provides back-up supply for TSB and/or ITB.

The TSB provides supply for 13 distribution feeders. Four feeders (TSB20, 15, 12 and 13) supply the DT Building, the largest customer at the MA (9.5MVA total install capacity). Feeder TSB32 is a back-up feeder for the International Terminal (8.5MVA).

From transfer capabilities point of view it is important to notice that there are only two ties between TSB and ISS systems (between TSB08 and ISS08) and only one tie with NISS (between NISS07 and TSB06).

The peak load details of distribution feeders out of TSB are provided in Table 11.3.

Table 11.3 – TSB - Existing Feeder Peak Load Data

<table>
<tr><th>Feeder</th><th>SD[1]
Peak Load (A, MVA)</th><th>Peak Load Voltage Drop (%)[3]</th><th>Peak Load Losses (kW, %)</th><th>Loss Penalties ($/p.a.)[2]</th><th>Greenhouse Gas Contribution (t/p.a., CO_2)</th></tr>
<tr><td>TSB08</td><td>109 (2.1)</td><td>-0.5%</td><td>6.7 (0.4%)</td><td>$1,970</td><td>23.1</td></tr>
<tr><td>TSB06</td><td>113 (2.2)</td><td>0%</td><td>6.2 (0.3%)</td><td>$1,822</td><td>21.4</td></tr>
<tr><td>TSB14</td><td>126 (2.4)</td><td>-0.1%</td><td>3.2 (0.1%)</td><td>$941</td><td>0.96</td></tr>
<tr><td>TSB13[4]</td><td>116 (2.25)</td><td>0%</td><td rowspan="4">7.8 (0.1%)</td><td rowspan="4">$2.293</td><td rowspan="4">26.9</td></tr>
<tr><td>TSB12[4]</td><td>68 (1.3)</td><td>0%</td></tr>
<tr><td>TSB15[4]</td><td>118 (2.24)</td><td>0%</td></tr>
<tr><td>TSB20[4]</td><td>77 (1.47)</td><td>0%</td></tr>
<tr><td>TSB 18/21</td><td>16 (0.)</td><td>0%</td><td>0 (0%)</td><td>0</td><td>0</td></tr>
<tr><td>TSB23</td><td>8 (0.15)</td><td>0%</td><td>0 (0%)</td><td>0</td><td>0</td></tr>
<tr><td>Total TSB</td><td>495 (9.43)</td><td>0%</td><td>17.8 (0.2%)</td><td>$5,233</td><td>61.4</td></tr>
</table>

Note: 1 - SD-Summer Day; 2 - $294/kW [1]; 3 – Voltage drop colour code: Green – no voltage constraints; 4- DTB feeders

11.13 Modelled Airport Distribution Network Contingency Planning

Contingency plan to eliminate load at risk during abnormal conditions in distribution network of the MA has been developed for every existing 11kV distribution feeder. The contingency plan takes into consideration peak load conditions, feeder capacity and O/C settings.

For every feeder a load transfer and switching operations blocks (LT&SOB) have been developed. The structure of LT&SOB presents summer day maximum demand during contingency conditions on affected feeders, their spare capacity and O/C settings, switching operations, multiple load transfers, load at risk and potential changes for improvement of contingency operations (e.g. increase of O/C settings). As an example a LT&SOB for ISS06 feeder is presented in Appendix F.

11.14 MISS Intake Switching Station Contingency Plan

11kV distribution feeders transfer capacity of MISS is summarised in Appendix G.

Based on the existing distribution system load flow study is has been identified load at risk of 62A (33%) on ISS10 feeder supplying APS area. Other feeders out of MISS do not have contingency conditions constraints.

11.15 NISS Intake Switching Station Contingency Plan

11kV distribution feeders transfer capacity of NISS is summarised in Appendix H.

Based on the existing distribution system load flow study is has been identified load at risk of 102A (69%) on NISS09 feeder supplying EP area west of NISS. Other feeders out of NISS do not have contingency conditions constraints.

Two 1000kVA generators at IT provide back-up supply in the case of NISS06 or NISS05-TSB31-TSB31 failure.

11.16 TSB Contingency Plan

11kV distribution feeders transfer capacity of TSB switching station is summarised in Appendix I.

As feeders TSB14 and TSB23 do not have ties with any adjacent feeders, load at risk on both feeders is 100%, or 57A on TSB14 and 16A on TSB23. Other feeders out of TSB do not have contingency conditions constraints.

Two 1070kV generators at TSB provide back-up supply for TSB loads during potential loss of supply from MISS (ISS05-ISS09) or NISS (NISS05-TSB31).

11.17 Fault Levels

Bus fault levels are presented in Fig. 11.10 and Table 11.4. Figures are based on a 100MVA and 1.1pu Voltage.

11 kV source impedances at MISS and NISS Intake substations for the network for summer 2005/06 are:

- MISS: (pu on 100 MV.A base)

  +ve seq - (0.0484 + j0.5668), zero seq - (7.4567 + j0.4136)
- NISS: (pu on 100 MV.A base)

  +ve seq - (0.0240 + j0.5771), zero seq - (7.4515 + j0.4797)

Three phase fault contours around MISS have values between 10.14kA (at MTNSS bus) and 1.4kA at DSS-825 in the ND area. Fault levels on sections between 810-3 and 815-1 (25mm^{2}Cu UG in APN), 840-3 and 830-2 (7/2.5HDBC OH in TSB-Domestic Terminal) and D50 and D60 (TSB-Domestic Terminal) exceed the 1s fault rating of the cable (Table 11.5).

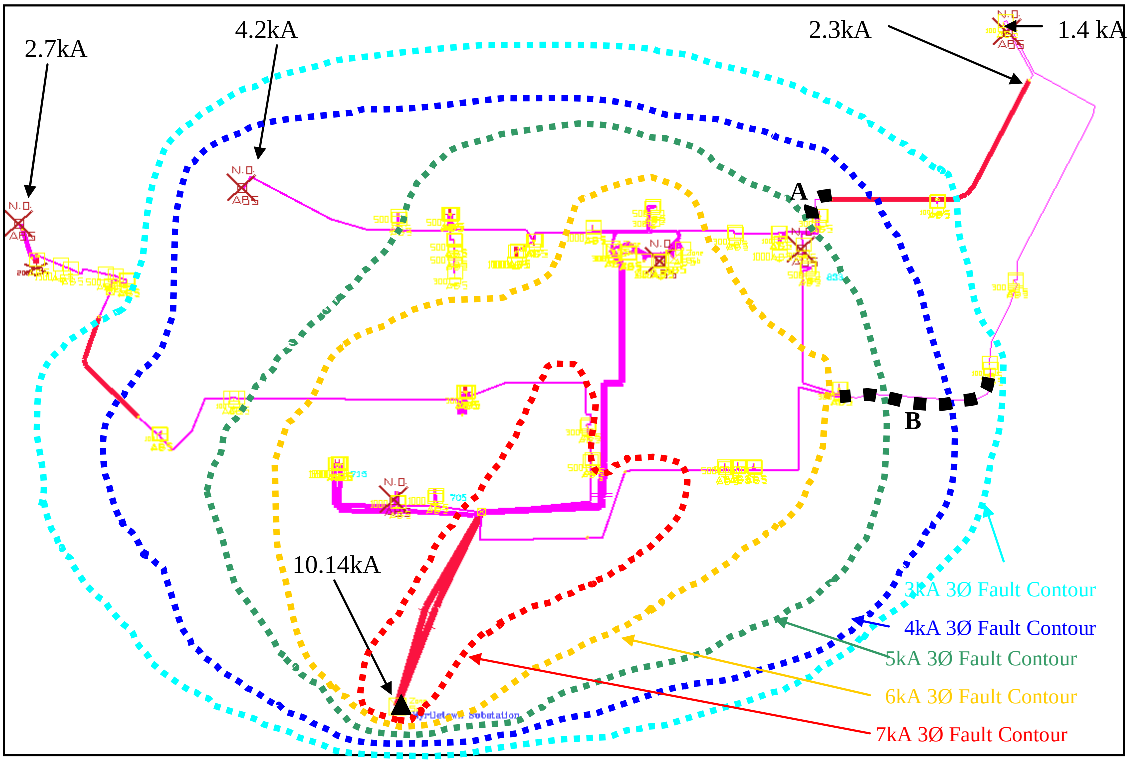


Figure 11.10 – MTNSS and TSB 3Ø Fault Contours

Table 11.4 – Bus Fault Levels

NISS 11kV Bus Fault Levels [A]	
L-G	2257
L-L-L-G	9977
MISS 11kV Bus Fault Levels [A]	
L-G	2246
L-L-L-G	10146
TSB 11kV Bus Fault Levels [A]	
L-G	1788
L-L-L-G	6408

A replacement program is recommended for these sections, currently consisting of 3 core 25mm^2 XLPE cable. Data from OLEX Cables indicates that these cables have a conductor 1 second fault carrying capacity of 3.57kA (for 3 core screened and HR-PVC sheathed cable).

Table 11.5 – Summary of Fault Level Constraints

Cable Section From	Cable Section To	Feeder Designation	Distance (m)	Cable Fault Rating (1s)	System fault level on cable (high end)	System fault level on cable (low end)
TSB	D50	TSB18 & TSB21	2x20	3.57Ka	6.4Ka	6.4kA
TSB	D60	TSB23	444	3.57kA	6.4Ka	5.3kA
840-3	7/2.5 HDBC O/H	8-3040	310	3.57kA	5.0kA	4.4kA
810-3	815-1		1380	3.57kA	5.9Ka	3.2kA

Auto-reclose and protection clearing times, which have not been considered in this study, have the potential to further decrease fault carrying capacity. A possible consequence of this is that further sections of cable downstream from 815-1 (APN) might need replacement.

Fault contours between 9.98kA (NGESS) and 4.3kA at DSS-462 in AD area have been identified in distribution system supplied by NGESS.

11.18 Load Forecast

Based on the Development Plan, a load forecast for each distribution feeder at the MA has been developed. The 11kV incoming feeders' peak load forecast is presented in Appendix J. The following limitations have been identified:

MTN03 11kV Feeder: the summer day peak load presently exceeds 50% of its OH conductor continuous rating. In 2011/12 peak load exceeds N-1 capacity of OH conductor (19/3.75AAC Pluto@75^{o}C).

MTN08 11kV Feeder: the summer day peak load presently exceeds 50% of its OH conductor continuous rating. In 2009/10 peak load exceeds N-1 capacity of OH conductor (19/3.75AAC Pluto@75^{o}C).

NGE10 11kV Feeder: the summer day peak load presently exceeds 66% of its UG exit cable continuous rating (N-1).

NGE17 11kV Feeder: the summer day peak load exceeds 66% of its UG exit cable continuous rating (N-1) in 2006/07.

Load forecast for distribution feeders out of MISS is summarised in Appendix K and he following limitations have been identified:

ISS08 11kV Feeder: the summer day peak load exceeds 50% of its UG cable exit continuous rating. In 2008/09 peak load will exceed N-1 capacity of UG cable exit (185mm^{2}Cu)

ISS06 11kV Feeder: the summer day peak load will exceed 50% of its UG cable exit continuous rating in 2008/09. In 2010/11 peak load will exceed N-1 capacity of UG cable exit continuous rating (95mm^{2}Cu)

ISS07 11kV Feeder: the summer day peak load will exceed 50% of its UG cable exit continuous rating in 2015/16. In 2016/17 peak load will exceed N-1 capacity of UG cable exit continuous rating (95mm^{2}Cu)

ISS10 11kV Feeder: the summer day peak load presently exceeds 66% (N-1) of its UG cable exit continuous rating (240mm^{2}Cu)

ISS05 11kV Feeder: the summer day peak load presently exceeds 50% of its UG cable exit continuous rating. In 2010/11 peak load will exceed N-1 capacity of UG cable exit (300mm^{2}Cu)

ISS09 11kV Feeder: the summer day peak load presently exceeds 50% of its UG cable exit continuous rating. In 2010/11 peak load will exceed N-1 capacity of UG cable exit (300mm^{2}Cu).

Load forecast for distribution feeders out of NISS is summarised in Appendix L and the following limitations have been identified:

NISS09 11kV Feeder: no constraints

NISS07 11kV Feeder: no constraints

NISS08 11kV Feeder: the summer day peak load will exceed 50% of its UG cable exit continuous rating in 2009/10. In 2014/15 peak load will exceed SD-NC capacity of UG cable exit continuous rating (240mm^{2}Cu)

NISS04 11kV Feeder: the summer day peak load presently exceeds SD-NC of its UG cable exit continuous rating (95mm^{2}Cu)

NISS06 11kV Feeder: the summer day peak load presently exceeds 66% (N-1) of its UG cable exit continuous rating. In 2007/08 peak load exceeds SD-NC capacity of UG cable exit (300mm^{2}Cu)

NISS05 11kV Feeder: this feeder provides back-up supply for TSB (with TSB32) and/or International Terminal Building (with TSB31). In this configuration (NISS06 out of service, NISS05 supplies TSB/ITB) the summer day peak load presently exceeds 50% of NISS05 UG cable exit continuous rating. In 2008/09 peak load will exceed N-1 capacity of each of UG cable exit (2x185mm^{2}Cu).

Load forecast for distribution feeders out of TSB is summarised in Appendix M. Based on the existing distribution system load flow study and load forecast summarized in Table M.1, capacity constraints on TSB06 feeder supplying BP area and Fuel South DSS have been identified. The summer day peak load presently exceeds 50% of its UG cable exit continuous rating. In 2012/13 peak load will exceed N-1 capacity of UG cable exit (95mm^{2}Cu) and in 2016/17 its SD-NC capacity.

11.19 Modelled Airport Development

The airport area management and development is responsibility of the local airport corporation which control all major services and infrastructure at the airport, including electricity system. As seen, planning and development of each of the airport areas and individual components depends of electricity supply. It is why strategic planning of adequate power and distribution capacities is one the most important segments in the airport corporation business.

11.19.1 Stage Development

The studied developments provide a strategy for meeting the expected load increases in the MA airport area. The new substations and feeder assets that are proposed will provide the MA with the capacity and flexibility to meet future load developments well beyond 2020.

According to the load forecast, all distribution feeders at the MA in 2019/20 will be loaded below 50% of their UG cable exits cyclic capacity which could be actually sufficient up to period 2035-2040 without any major distribution augmentation.

Recommendations include development of 11kV distribution network at the MA in the following stages:

Stage 1 - Immediate Augmentation

- Upgrade distribution network to improve transfer capabilities and fault levels

Stage 2 (2007/08) - BAP Zone Substation

- Complete establishment of the BAP Zone Substation (BAPSS)
- Improve supply of the MA International Terminal (IT) from BAPSS.

Stage 3 (2007/08-2014/15) – LMDSS Zone Substation

- Establish LMD Zone Substation (LMDSS)
- Develop a distribution network out of LMDSS in period between 2006/07 and 2014/15 to supply a new switching station at No 1 AD and the areas of EP, EPW and DV.

If LMD Zone Substation is established with transformation of 33/11kV rather than 110/11kV which is a more realistic option, it is expected at a late stage to establish a 33kV ring at the MA. This will require the installation of 33kV bus at the BAPSS, reinforcement of 33kV supply from NGESS and further development of 33kV UG network to provide supply for the new zone substations.

Stage 4 (2007/08-2010/11) - BLV Switching Station

- Establish the BLV Switching Station (BLV SW/S)
- Develop distribution network out of BLV SW/S in period between 2006/07 and 2010/11 to supply No 1 AD area.

Stage 5 (2007/08) - BAPSS, BIT, TSB and BP

- Reconfigure the distribution network out of BAPSS to supply TSB and BP
- Establish a new dedicated feeder for the BIT.

Stage 6 (2008/09–2016/17) - PAV Zone Substation

- Establish PAV Zone Substation (PAVSS)
- Develop the distribution network out of PAVSS in period between 2008/09 and 2016/17 to supply APS and AIP areas.

Stage 7 (2009/10) – MISS Intake Switching Station

- Re-arrange 11kV network out of MISS Intake Switching Station in APS and AIP areas
- Establish a new feeder to supply APN area.

11.19.2 Capital Expenditure

Total approximate quote estimate for all recommended development stages of the MA distribution network, including new zone substations, switching station and associated distribution network in period 2005/06 – 2016/17 is around $38M for 33/11kV option for LMDSS and $40M for 110/11kV option.

Preliminary budget estimates indicate that the distribution and substation works under consideration at the MA can be completed at the following estimated costs:

Stage 1 - Immediate Augmentation - 2005/06: ~$1.8M
Stage 2 - BAP Zone Substation - 2005/06: ~$2M
Stage 3 and Stage 4 - LMD Zone Substation and the BLV Switching Station - 2006/07-2014/15: ~$16.5M-$18M (33/11kV option) or ~$18M-$20M (110/11kV option)
Stage 5 – BAPSS, BIT, TSB and BP-2007/08: ~$1.5M
Stage 6 - PAV Zone Substation - 2008/09–2016/17: ~$11.4M-$12M
Stage 7 – MISS Intake Switching Station - 2009/10: ~$1.3-$1.5M.

11.19.3 Proposed immediate augmentation

Except recommendations associated with long-term network major augmentation, this planning study includes two additional programs for urgent upgrade of distribution system.

- Immediate Development to urgently relieve some of overloaded feeders and improve feeder transfer capacity and fault levels before establishment of new zone substations
- Development of new database, load recordings, GIS and new methodology of monitoring and controlling the MA distribution network.

11.19.4 MISS immediate augmentation and re-arrangement

Total immediate augmentation cost for MISS during 2005-2006: ~$1.3M.

To improve transfer capacities between distribution feeders in MISS network and between MISS and NISS systems, replacement of OH section with an UG cable and establishment of UG ring system between ISS06, ISS07 and ISS10 distribution feeders have been recommended for the MISS immediate development/re-arrangement:

- **ISS06-2005/06** - Replace 900m of 7/2.50AAC OH conductors (6-2023) with UG cable 240mm^{2}Cu (~$0.36M, based on $400,000/km)
- **ISS06-2005/06** [Establish ring system between ISS06, ISS07 and ISS10]:
  - Install an interconnection (~0.55km of UG 240mm^{2}Cu) between ISS06 and ISS10&ISS07 between 715-1 and 710-2 (NOP) in the vicinity of DSS-715 (~$0.22M)
  - Install RMU between 715-1 and 710-2 (NOP) in the vicinity of DSS-715 (~$50,000)

ISS06 total immediate augmentation cost for 2005-2006 is ~$0.65M.
To improve fault levels of distribution feeders out of MISS the following augmentation is recommended:

- **ISS08-2005/06** - Replace 1.4km of UG section 8-1015 (25mm^{2}Cu) between 810-3 and 815-1 (APN area) with 95mm^{2}Cu (~$0.6M, based on $400,000/km)

ISS08 total immediate augmentation cost for 2005-2006 is ~$0.6M.

11.19.5 NISS immediate augmentation and re-arrangement

Total immediate augmentation cost for NISS during 2005-2006: ~$0.

To improve transfer capacities between distribution feeders in NISS network upgrade O/C settings of the following feeders have been recommended for the NISS immediate development/re-arrangement:

- **NISS08-2005/06** - Increase O/C from 160A to 300A
- **NISS09-2005/06** - Increase O/C from 300A to 400A
- **NISS04-2005/06** - Increase O/C from 200A to 230A.

11.19.6 TSB immediate augmentation and re-arrangement

Total immediate augmentation cost for MISS during 2005-2006: ~$0.5M.
To improve fault levels of distribution feeders out of TSB the following augmentation is recommended:

- **TSB08-2005/06** - Replace 770m of OH section 8-3040 (7/2.50HDBC) with UG cable 95mm^{2}Cu between 840-3 and 830-2 (~$0.3M)
- **TSB-D50- 2005/06** - Replace both UG cables (25mm^{2}Cu) TSD50(A) and TSD50(B) from TSB (TSB18 and TSB21) to D50 with 95mm^{2}Cu (~$20,000)
- **TSB-D60-2005/06** - Replace 444m of UG cable (25mm^{2}Cu) TSD60 from TSB (TSB23) to D60 with 95mm^{2}Cu (~$180,000).

Proposed new zone substations and future loads at the MA are presented in Appendix N.

Figures 11.11-13.14 present the 11kV arrangement for different development stages and Tables 11.6-11.8 their proposed load forecast. Network models and load flow analysis are presented in Appendices O and P.

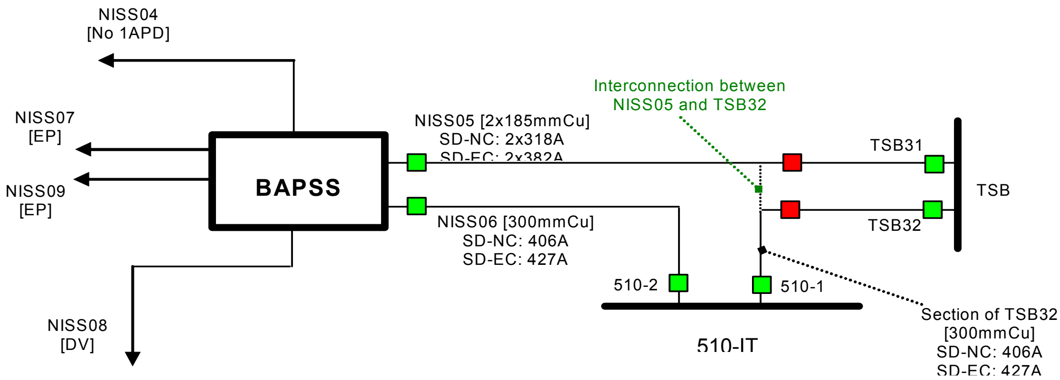


Figure 11.11–Stage1 - 11kV Arrangement of BAPSS until Establishment of LMDSS

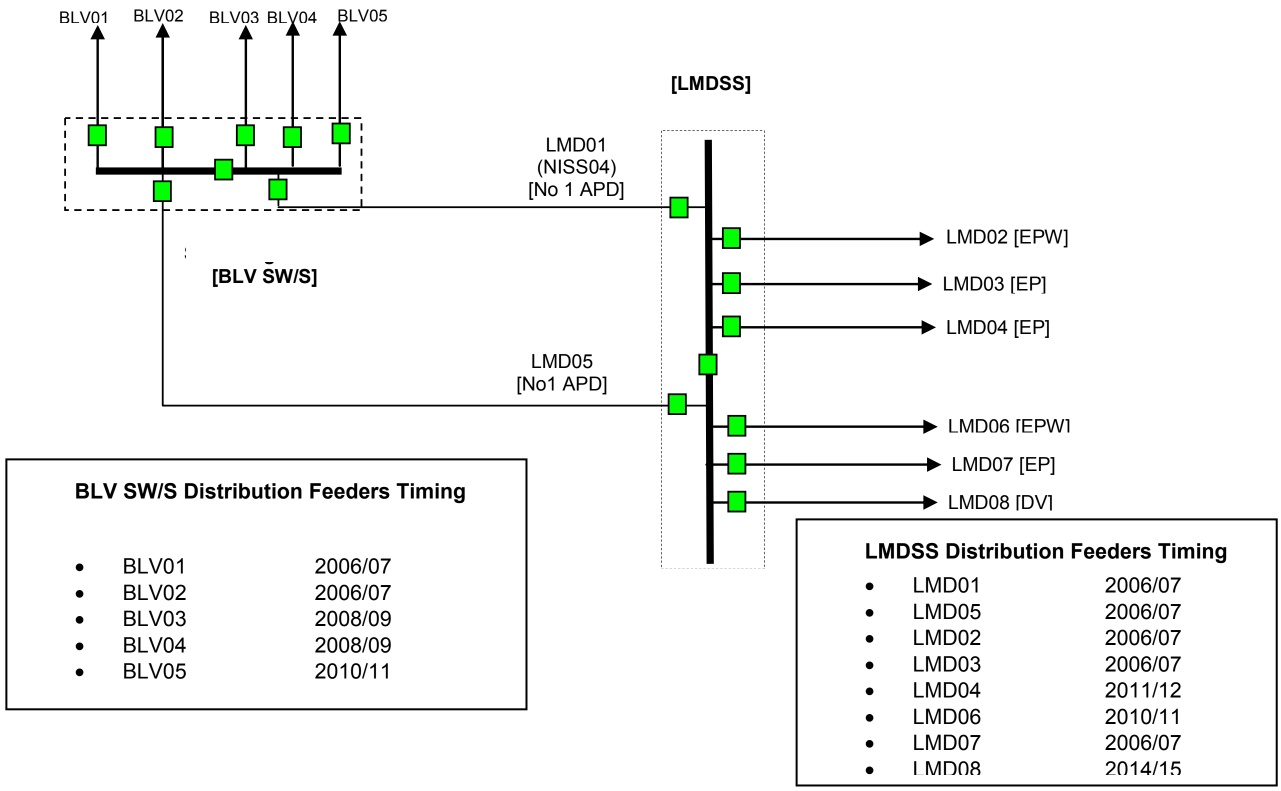
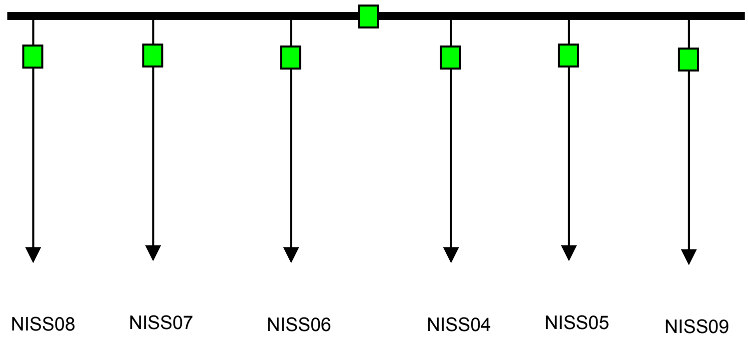


Figure 11.12–Stage 2 and Stage 3- 11kV Arrangement of LMDSS and BLV SW/S

Table 11.6 – LMDSS and BLVSS 11kV Feeders Peak Load Forecast Based on Supply Areas (A) Proposed System

Feeder	LMD01 (Ex NISS04)	LMD05	BLV01 [NISS04]	BLV02	BLV03	BLV04	BLV05	NISS04 [LMD02 in 2010/11]	LMD06	LMD03 [NISS04]	LMD07 [NISS09]	NISS07 [LMD04 in 2011/12]	NISS08	LMD08
SD-NC [A]	370 [850]	850	370 [485]	485	485	485	485	226 [485]	485	226 [485]	370 [485]	226 [485]	370 [485]	485
SD-N-1 [A]	244 [561]	561	244 [320]	320	320	320	320	149 [320]	320	149 [320]	244 [320]	149 [320]	244 [320]	320
SD-EC [A]	444 [1011]	1011	444 [582]	582	582	582	582	230 [582]	582	230 [582]	444 [582]	230 [582]	444 [582]	582
Year														
2004/05	0	0	138	0	0	0	0	0	0	0	0	46	128	0
2005/06	204	0	199		0	0	0	17	0	71	189	86	148	0
2006/07	181	181	199	163	0	0	0	17	0	141	189	86	148	0
2007/08	202	202	199	206	0	0	0	17	0	159	204	107	150	0
2008/09	286	286	5	206	202	160	0	68	0	159	204	107	150	0
2009/10	400	400	173	206	202	160	60	68	0	161	204	107	150	0
2010/11	438	438	173	206	202	160	136	68	193	164	204	125	161	0
2011/12	439	439	173	206	202	160	136	92	193	164	204	125	170	0
2012/13	444	444	183	206	202	160	136	92	193	173	213	125	170	0
2013/14	449	449	183	206	202	160	146	92	193	173	213	125	181	0
2014/15	454	454	183	206	202	160	156	146	193	173	213	125	181	148
2015/16	459	459	183	206	202	160	166	146	193	173	213	125	187	149
2016/17	459	459	183	206	202	160	166	154	193	173	213	125	195	152
2017/18	464	464	193	206	202	160	166	154	193	173	213	125	202	153
2018/19	464	464	193	206	202	160	166	154	193	173	213	125	202	160
2019/20	464	464	193	206	202	160	166	162	193	173	213	125	202	182

Note:
2005/06 - LDM01: 199+5 (from DSS455) = 204A
2005/06 - NISS07 - Tranfer of 40A from NISS04 to NISS07; MD on NISS07 86A
2008/09 - Upgrade LMD01 to 1000mmCu (SD-NC: 850A)
2008/09 - After establishment of BLV03&BLV04 transfer 2x1MVA from BLV01 to BLV04, and 113A to BLV03
2008/09 - Establish BLV03 and reduce load on BLV01 for major load in 2009/10. MD on BLV03 is 113A (existing)+(1509.02+384)kVA=212A
2008/09 - Transfer DSS 460 (2x1MVA, or 2x0.8MW) from BLV03 to BLV04. MD on BLV04 is: 1600/19.03 (existing) + 1620kVA = 169A
2009/10 - Install 3253.34 on BLV01; new MD on BLV01 is 173A - DINIS
2010/11-Establish LMD02 (ex NISS04) and LMD06 - 400mmCu
2011/12 - Transfer NISS07 from NISS to LMDSS and establish LMD04; replace 95mmCu with 400mmCu on LMD04 (ex NISS07)
2012/13 - Upgrade UG cable on LMD03 with 400mmCu
2012/13 - Upgrade UG cable on LMD07 with 400mmCu
2014/15: LMD08 takes 240.91kVA from Export Park and 3248.55kVA from Da Vinci
2017/18-Replace UG cable on BLV01 with 400mmCu
2017/18-Replace UG cable on NISS08 with 400mmCu



BAPSS (NISS) Distribution Feeders Timing

- NISS08 Existing
- NISS07 2011/12
- NISS06 Existing
- NISS04 2011/12
- NISS05 2011/12
- NISS09 2007/08

Figure 11.13–Stage 4- 11kV Arrangement of BAPSS

Table 11.7–BAPSS 11kV Feeders Peak Load Forecast Based on Supply Area (A) Proposed System

Feeder	TSB06	NISS07	NISS06	NISS09	NISS04	NISS05	NISS08	ISS08
SD-NC [A]	226	226	406 [12/13-705A]	705	705	2x318	370	318
SD-N-1 [A]	149	149	270 [12/13-465A]	465	465	2x210	244	210
SD-EC [A]	230	230	487 [12/13-840A]	840	840	2x382	444	380
Year								
2004/05	113	0	292	0	0	0	128	113
2005/06	113	0	295	0	0	0	148	118
2006/07	113	0	295	0	0	0	148	120
2007/08	113	0	202	202	0	0	150	122
2008/09	113	0	219	219	0	0	150	122
2009/10	113	0	219	219	0	0	150	127
2010/11	113	0	219	219	0	0	161	127
2011/12	140	41	219	219	203	203	170	127
2012/13	140	41	280*	280	203	203	170	127
2013/14	140	41	280	280	203	203	181	127
2014/15	140	41	280	280	209	209	181	127
2015/16	140	57	280	280	217	217	187	127
2016/17	140	84	305	305	217	217	195	127
2017/18	140	84	305	305	224	224	202	127
2018/19	140	88	305	305	227	227	202	127
2019/20	140	88	305	305	291	291	202	127

Note * - In 2012/13 upgrade UG cable NISS06

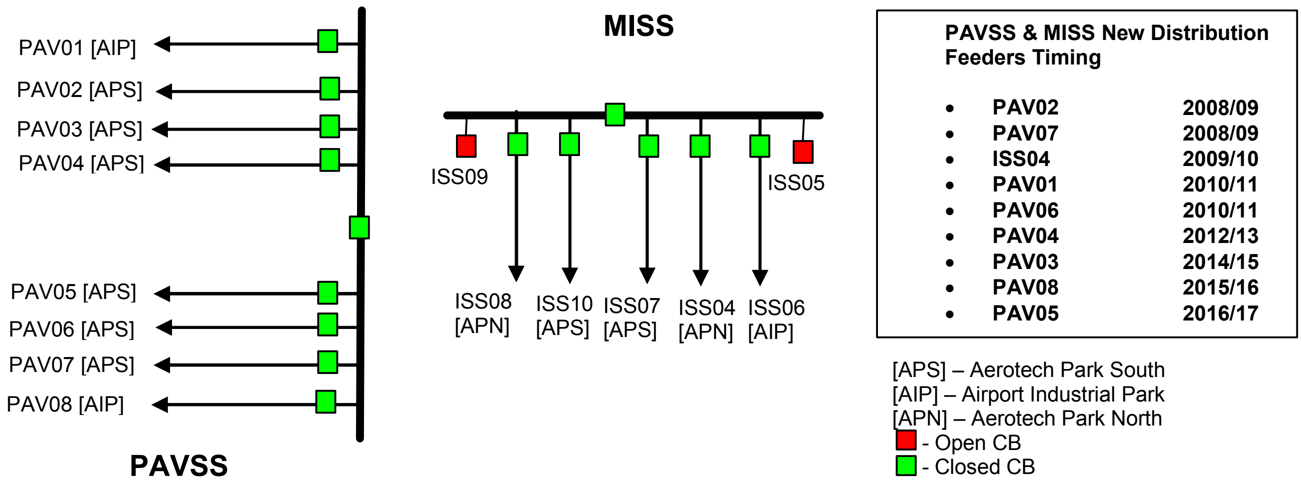


Figure 11.14–Stage 5 and Stage 6 - 11kV Arrangement of PAVSS [A] and MISS [B]

Table 11.8–PAVSS and MISS 11kV Feeders Peak Load Forecast Based on Supply Area (A) Proposed System

Feeder	ISS10	ISS07	PAV02	PAV03	PAV04	PAV05	PAV06	PAV07	ISS06	PAV01	PAV08	ISS08	ISS04
SD-NC [A]	370	226 [480]	480	480	480	480	480	480	226	480	480	318	480
SD-N-1 [A]	245	150 [318]	318	318	318	318	318	318	150	318	318	210	318
SD-EC [A]	382	230 [580]	580	580	580	580	580	580	230	580	580	382	580
Year													
2004/05	185	52							103			150	0
2005/06	222	113							104			182	0
2006/07	222	113							104			182	0
2007/08	222	113							104			189	0
2008/09	99	113	123					90	130			228	0
2009/10	130	113	123					155	130			135	135
2010/11	86	113	123				166	172	53	162		137	137
2011/12	86	113	123				166	172	53	165		140	140
2012/13	125	113	123		153		166	172	118	165		146	146
2013/14	125	113	123		153		166	172	118	165		146	146
2014/15	125	113	123	109	153		166	172	118	165		158	158
2015/16	145	113	155	153	153		166	172	118	165	130	163	163
2016/17	173	25	155	153	153	146	166	172	118	165	130	163	163
2017/18	158	184	155	153	153	146	166	172	118	165	130	163	163
2018/19	158	184	155	153	153	146	166	172	118	165	130	177	177
2019/20	158	184	155	153	153	146	166	172	118	165	130	177	177

11.20 Financial Consideration

Economic analysis of recommended developments at the MA is based on:

I. The lowest project present worth cost over the appropriate study period and

II. Technical satisfaction of recommended option.

As 95% of modelled network is constructed as UG, peak load losses (PLL) for the MA distribution system are only 316kW. Annual loss penalties (ALP) are $92,000 and greenhouse gas emission contribution (GHGC) to supply network losses at the MA are 1101 t,CO_2,pa.

Due to stage development over the period of fifteen years, proposed network losses are evaluated based on simulated network and peak load conditions in 2019/20 (PLL=400.5kW, ALP=$117,423 and GHGC=1377 t,$CO_2$,pa).

In the second step, proposed losses are compared with 'existing' losses (PLL=640kW, ALP=$188,810 and GHGC=4485 t,$CO_2$,pa) predicted for 2019/20 for the 'Do Nothing Option'.

Annual loss savings (ALS) in 2019/20 of 200kW is distributed over the study period (ALS=13kW), with annual loss benefits (ALB) of $4,800 and annual Greenhouse Gas Emission Reduction (GHGR) of 91 t,CO_2,pa.

Benefits arising from the capability to supply existing and new load installed during the study period are not evaluated. The main reason for their exclusion is a high risk of failure in NPV sensitivity study due to uncertain financial, tariff and energy consumption structure in future.

However, financial consideration of all recommended development stages at the modelled airport in period 2005/06-2019/20 is presented in Table 11.9 and could be included as an indicator of expected capital expenditures over the study period for the utility managing development of distribution system.

Table 11.9–Expected Expenditure of Development Stages at the MA

Year	Additional Load [MVA]	Immediate Development	Stage 1	Stage 2	Stage 3	Stage 4	Stage 5	Stage 6	Total $/pa
2005/06	5.036	$1.8M	$2.2M						$4.0M
2006/07	4.694			$12.9M	$1.5M	$0.3M			$14.7M
2007/08	4.336					$1.05M			$1.05M
2008/09	6.603			$0.9M	$0.4M		$8.1M		$9.4M
2009/10	9.405							$0.9M	$0.9M
2010/11	9.317			$1.05M	$0.2M		$0.2M		$1.45M
2011/12	1.788			$0.2M		$0.5M	$1.0M	$0.2M	$1.9M
2012/13	9.810			$0.75M			$0.1M		$0.85M
2013/14	0.555								
2014/15	7.362			$1.1M			$0.1M		$1.2M
2015/16	4.891						$2.0M		$2.0M
2016/17	4.044						$0.1M	$0.4M	$0.5M
2017/18	3.288				$0.2M				$0.2M
2018/19	1.066								
2019/20	0.789								
Total	72MVA	$1.8M	$2.2M	$17M	$2.3M	$1.85M	$11.6M	$1.5M	$38.2M

11.21 Alternative Options

A number of alternative options based on introduction of sub-transmission network 33kV and extensive 11kV augmentation works have been considered:

- **Option 2 (~$71M)** – Establish BAPSS (33/11kV) and PAVSS (33/11kV). BAPSS will provide supply for BIT, TSB, EP, EPW, No 1 APD and EPE areas via 11 new distribution feeders of a total length of ~33km. Also, six existing feeders (NISS04, 05, 06, 07, 08 and 09) will remain in service. Recommended works for PAVSS are the same with those recommended under preferred option. Total expected distribution costs are approx $31M. Based on the average cost of $15M per standard 33/11kV zone substation (with two power transformers 20MVA) and $4M/km for UG 33kV cables, Option 2 is 2.3 times more expensive than Option 1, as in return provides same benefits

- **Option 3 (~$52M)** – Establish BAPSS (33/11kV), LMD SW/S (11kV) and PAVSS (33/11kV). BAPSS will provide supply for BIT and TSB and via two 11kV feeders supply LMD SW/S. Note that LMD SW/S is established under Option 3 as an 11kV switching station. From the LMD SW/S eight distribution feeders are developed at a total length of approx. 8km. These feeders with four existing feeders from BAPSS (NISS04, 07, 08, 09) supply APD, EPW, EP and DV areas. In addition, two express-feeders will be established to provide N-1 supply for BIT and TSB. Recommended works for PAVSS are same with those recommended under preferred option. Expected cost of approx. $52M for Option 3 includes new zone substation 33/11kV and 33kV UG cable works. Due to much higher capital, this option is not considered as preferred one

- **Option 4 (~$70M)** – Establish BAPSS (33/11kV) and PAVSS (33/11kV) at the site of MISS. BAPSS will provide supply for BIT, TSB, EP, EPW, No 1APD and DV areas via 11 new distribution feeders at a total length of ~33km. Also, six existing feeders (NISS04, 05, 06, 07, 08 and 09) will remain in service. Expected cost of new UG distribution works in BAPSS system is ~$13.2M, and augmentation of NISS04, NISS07 and NISS06 ~$1.9M. PAVSS is established at the site of MISS with eight new feeders. Total length of new distribution network is ~21km. Total expected cost of development of new distribution network out of PAVSS at the site of MISS is ~$8.5M. Total expected distribution costs are approx $30M. Based on the average cost of $15M per standard 33/11kV zone substation (with two power transformers 20MVA) and $4M/km for UG 33kV cables, Option 4 is 2.3 times more expensive than Option 1, as in return provides same benefits..

In addition to 33kV options, introduction of new transmission and distribution voltages (110kV and 22kV) have also been investigated, but excluded due to complex network conversion process, project management limitations, an extended use of generators during construction stage and consequently extensive capital costs in the range above $100M.

In comparing investigated options the selection comes down to the following 2 options:

- Option 1 (proposed): Establish BAPSS, LMDSS, BLV SW/S and PAVSS in period 2005/06-2008/09 or
- Option 2 (alternative): Establish BAPSS and PAVSS in period 2005/06-2008/09.

In the context of expected growth rate, network constraints, future network development in all areas of the MA and expected capital expenditure, Option 1 is preferred to Option 2.

For future development of the distribution network Option 1 provides enough capacity, transfer capabilities, acceptable voltage regulation, high reliability and improved quality of supply in this area well beyond 2016/20. As majority of distribution feeders will have maximum demand less than 50% of their summer day normal capacity, Option 1 provides enough capacity for the MA areas without any additional distribution augmentation until at least 2035-2040.

The choice to recommend Option 1, in terms of the development of distribution and sub-transmission networks, is prefer for the following reasons:

1. New substations are in the close vicinity of major load centres
2. Security of supply major customers such as BIT, TSB and the Domestic Terminal
3. No further major distribution augmentation works are required well beyond 2019/20
4. Security of supply of maximum potential growth load at the MA
5. Better operational flexibility and load management
6. Better transfer capabilities (N-1 is provided beyond 2019/20)
7. Less technical risk for the utility managing the airport distribution network
8. Possibility of establishment of 33kV ring at the MA
9. Financial advantages of Option 1 (Fig. 11.15).

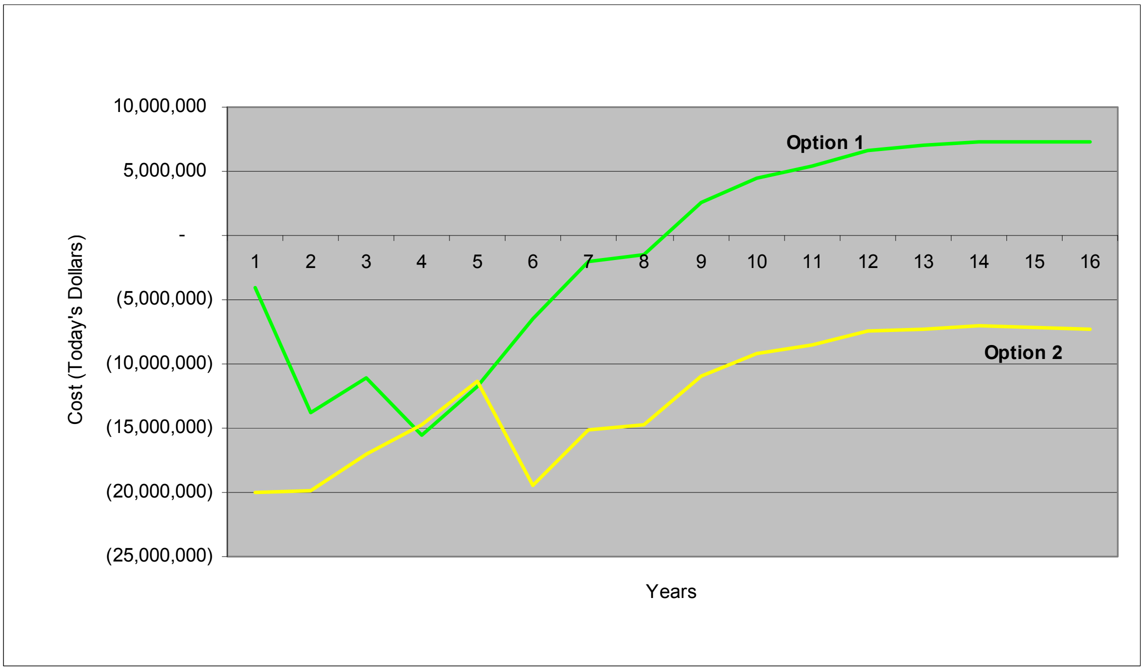


Figure 11.15–NPV Sensitivity Analysis of Options 1 and 2

Other alternative network options have been discounted due to the following reasons:

- Location of load centres. Major developments are in the areas of AS and AD. In addition a rapid growth is expected in the areas of AIP, EP, EPW and IT. With exception of IT, all these areas are distant from BAPSS. Development of long and robust distribution network provides a limited supply for expected developments
- Capacity constraints. Due to system exposure and location of major load centres remote from BAPSS, it is expected capacity constraints on proposed network to take place before end of study period
- Operational flexibility, transfer capabilities, load management and technical risk. Due to system configuration, remote areas (e.g. AD, EPE, API and segments of EP) will have load at risk during contingency conditions. System flexibility and its operational effectiveness is much lower compared with preferred option
- Strategic development beyond the study period. Due to system configuration, its operational flexibility and power losses, alternative options do not provide enough capacity for normal and contingency conditions for developments and future load increases at the MA beyond 2019/20
- Cost. As development of 33kV sub-transmission network (or 110kV transmission network and conversion of 11kV distribution network to 22kV) consisting of the new zone substations and sub-transmission (transmission) UG cables for alternative options is much more expensive, NPV sensitivity analysis as shown on Figure 11.15 below does not provide positive return during the standard NPV period of 15 years. Also, for future development, it is expected additional expenditure associated with distribution augmentation beyond 2019/20.

In addition to standard 'network' options, one potential renewable option with introduction of large and medium size PV systems had been considered. The following three types of PV systems had been suggested to the Airport Corporation:

I. Thin film laid directly onto the roof

II. Glass panels laid flat onto the roof

III. Glass panels mounted on structures, angled to the sun.

However, in light of extensive developments, load increases well above capacity of standard roof PV technologies, huge initial (>$4M/MW) and operational costs and potential impact on landing operations, the Airport Corporation management rejected this plan and decided to include at this stage only standard network augmentation options for the future development of studied airport.

CHAPTER 12

CONCLUSIONS

The aim of this project was to develop a new concept of distribution planning processes that incorporates improved management and control of all stages in the network planning. The new concept also considers transition from ‘traditional’ to ‘modern’ distribution planning with implementation of ‘non-network’ solutions as standard investigation options. After a review of relevant publications, concept of modern distribution planning is adopted for the project and some of its main components elaborated.

In the last part of this dissertation, this concept has been demonstrated on the airport electricity network development project which is now well in the construction stage.

The new concept of distribution planning processes is developed due to the following major limitations of old network planning methodologies:

- Lack of interfaces with sub-transmission components of the network
- Partially understanding of voltage regulation specifics
- Use of static system planning
- Exclusion of dynamic plant ratings and scientific validation of weather parameters
- Lack of energy and load driven reliability indices
- Ignorance of importance of energy forecasts and weather correction parameters
- Impact of network topologies and load profiles on power losses and climate change
- Position of risk assessment and project quote estimate at end of the distribution planning study
- Exclusion of renewable and alternative energy solutions
- Position in relation to project management.

The adoption of new processes in distribution planning is essential for the achievement of the new required standards of system security, reliability and economy in general. The information contained within this Dissertation is the result of extensive investigation by the author and discussion with the variety of the network planning’s stakeholders. The Dissertation has attempted to incorporate the best of the existing network planning practices studied in different electricity utilities in order to formulate processes which meet the future requirements.

12.1 Discussions

The challenges facing by the network planners in these times are significantly different to those of former years. While energy demand and growth are still strong, the environment is changing at a global level placing climate change at the top of Government and community priorities.

The nature of electricity networks is changing as well. Different energy supply and delivery models are evolving. The ability of electricity systems to cope with growing energy demand in future years combined with their major role in Climate Change Response is providing engineering and financial challenges for those who plan, maintain and operate electricity networks.

Globally utilities are trying to maximize the utilization of their existing transmission and distribution assets through the introduction of new network solutions. Distributed generation using renewable and alternative energy sources and “smart grid” technologies and initiatives will become key enablers.

Also, it is the time to change our traditional understanding of electricity customers. The modern customers want to know much more about energy consumption, how to use energy efficiently and above all how to reduce their electricity bills. In addition, the new generation of customers is now entering the electricity market. It is a combination of customers who consume electricity and small, medium and large scale generators who distribute energy back to the grid.

Network demand management, rather than supply augmentation solutions will start to become more common and our business will broaden from standard network solutions to working on the other side of the customer meter.

Penetration of PV systems, energy storage devices and other renewable and alternative distributed energy resources, implementation of network demand management solutions and development of micro-grids convert traditionally ‘passive’ networks into more dynamic, ‘active’ systems with reverse power flows which may have a big impact on system stability and performances of distribution networks. If such technologies are combined, the nature of the future distribution network may decline into a minimum infrastructure system providing only occasional energy delivery.

The evaluation of reliability when distributed generators are present is a topic that is gaining importance. The general unpredictability and frequent variations of generated power that characterizes most renewable energy sources requires that past reliability assessment techniques based on deterministic principles must be modified to account for the probabilistic nature of embedded generation.

An actively managed distribution network with locally generated power that approximately balances the demand could theoretically be run autonomously if connection to the mains were to be lost to a fault. Such operation would require some sophisticated local control actions to maintain stability of the network and then to reconnect the islanded system back to the mains when the fault is cleared. Also, the island capability during fault conditions could increase the reliability to the local consumers.

A fundamental rethink will be needed of the way electricity is generated and distributed in the power systems of the future. Variable generation in feeds coupled with bi-directional network flows will become commonplace.

This rethink does not only require the adoption of new technologies but also a 'cultural' change of power system engineers

Implementation of new methodologies and philosophies in planning of distribution networks are now more relevant than ever. This dissertation is an attempt to address the most important issues in management of the future distribution network planning processes and help the next generations of network planners, graduate engineers and students of electrical engineering in facing the challenges ahead.

The distribution network is the main subject in the focus of Distribution Planning. However, the Network Planner considers entire electricity system and interactions systems with between different operating voltages maintaining a strong interdisciplinary approach.

In relation to application of modern distribution planning principles this Dissertation provides numerous research opportunities for strategic study of electricity network supplying large airports:

- Investigation of different network planning methodologies and advanced tools for planning and operation to meet challenges of future electricity systems including smart grids, the growing area of distributed and diversified energy resources
- Research in the variety of electricity system planning including the areas of real-time planning and network modelling, reliability and power quality, dynamic system rating and utilization, smart grid technologies and controls, integrated communication infrastructure, standards and economic analysis
- Development of risk assessment models for different networks to address potential worst case scenarios and develop adequate contingency plans
- Development of standard models acceptable for the study of electricity network of large airports
- Development of standard models to improve business plans between electricity industry and major customers
- Transition of methodologies, principles and philosophies from the electricity industry into the company with well developed electricity network
- Development of electricity network contingency models
- Development of electricity network reliability models
- Improvement of Project Management
- Development of quality of supply models
- Development of more accurate ADMD models for specific customers
- Development of customer/demographic plans
- Risk assessment of the airport's electricity systems and proposed long term development
- Climate change effects generated by the operation of the airport distribution system.

Investigation of interaction between development of electricity network and associated airport infrastructure (roads, gas lines, water supply system, civil plans etc) is another research opportunity.

12.2 Effective Transition of Graduate Electrical Engineers in Electricity Industry

It is intended that this Dissertation serve as a working reference for policy, procedures and information in the field of Distribution Network Planning, as well as providing methods and solutions for many of planning problems with may arise. Because the Dissertation gives a broad description of most components of distribution system, it may also be useful in the induction stage of the new and existing technical staff.

Although effective management of Graduate Engineers and Co-operation Engineering Students during transition from University to Electricity Industry is not the primary objective of this thesis, it is expected that this Master Degree Dissertation can assist in more effective preparation of future generations of electrical engineers which is shown in Figure 12.1.

This author has a long experience in supervision, management and mentoring of Vacation Students, Co-operation Engineering Students and Graduate Electrical Engineers employed in Ergon Energy and is in position to address the major problems and provide adequate solutions.

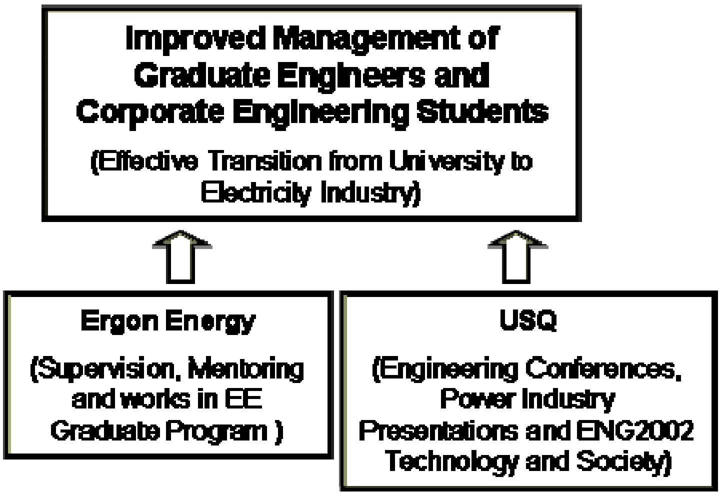


Figure 12.1–Improved Management of Graduate Engineers

The major problems in the initial stage of employment of Graduate Electrical Engineers are:

- Introduction/induction process, as a very important stage in development of an electrical engineer is too long; for Graduate Electrical Engineers in their first rotation it takes between 2 and 4 months. During the following rotations in other business units usually this process lasts 1-3 months depending upon their business models, structures and deliverables
- The length of introduction process is driven by different ‘external’ and ‘internal’ issues. One of the typical ‘external’ reasons is that transition process of Graduate Electrical Engineers from university to the electricity utility is not considered in detail in the last stages of their studying at the university. Graduate Electrical Engineers usually are not well prepared for the challenges after the graduation. On the opposite side, electricity utilities are traditionally not well prepared for all introduction/induction challenges of the new Graduate Electrical Engineers.

  Despite extensive and continuous support provided by supervisors, mentors and Learning and Development departments, Graduate Electrical Engineers traditionally have problems to become familiar with critical planning processes and techniques. One of the typical reasons for that is lack of process documentation, manuals and adequate guidelines

- Due to the length of introduction process, supervisors spend lot of time and energy managing Graduate Electrical Engineers which is an additional pressure in an environment with limited resources, extensive business activities and deliverables based on strict deadlines
- The first major deliverables are usually expected few months after the commencing of Graduate Electrical Engineers (Fig. 12.2). Sometimes unfortunately planning reports are completed just before completion of rotation period or even not completed and must be transferred to the next Graduate Electrical Engineers or completed by the supervisor. There are two critical consequences caused by the delay in planning report deliverable:
  - Technical, financial and business problems, as elaborated below and
  - Time and resource management and the deadline changes in the business model

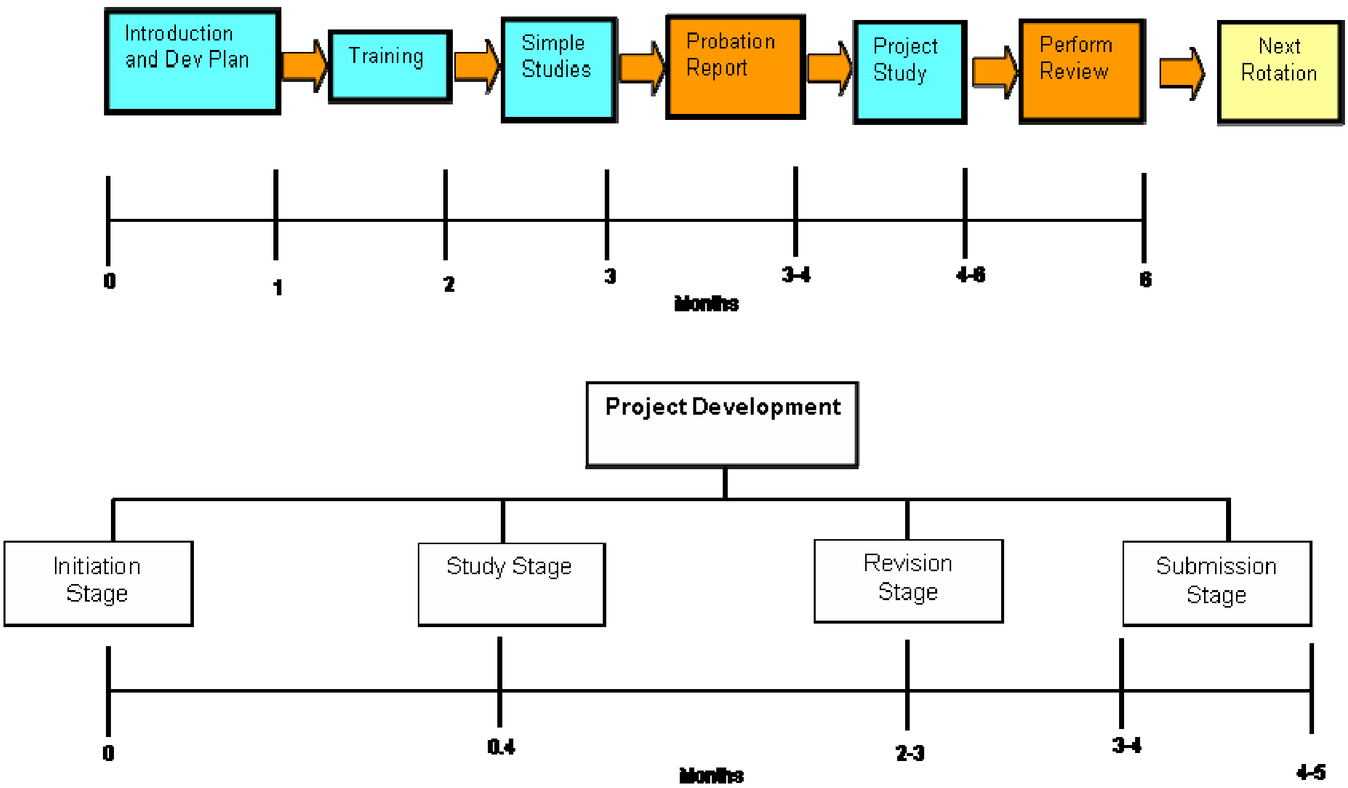


Figure 12.2–Graduate Engineer Rotation Period and Project Development Stage

- The planning environment is a very sensitive and specific space which requires considerable analytical and technical skills, as well as knowledge of planning processes and principles. Planning deliverables in the form of the major projects have a critical impact on business of any electricity utility from technical and financial perspective. In addition, working on different development scenarios, Network Planners are involved in variety of activities typically managed by other business units, like protection, reliability, quality of supply, network data, communication and control, operation, project management, renewable and alternative energy solutions, network demand management, demographic planning, load forecasting, economic analysis, even climate change challenges. Planning process includes intensive communication and co-ordination activities which is another issue in the development of Graduate Electrical Engineers
- As planning reports are at the beginning of project life cycle, any delay in their deliverables cause delays in the further project stages – design, material purchase, construction and commissioning
- Delay in project completion has serious consequences from technical and general business perspective. Technical aspect includes limitations in network capacities for future load growth, reliability issues, risk management, power quality, voltage regulation stability and other critical network performances. Consequences related to the general business include finance component (in the case of capital projects usually in the range of million of dollars) and impact on global project management and budget process.

12.3 Future Works

Future distribution planning principles must follow development and operation of distribution networks, with consideration of expected changes in supply options of future customers. Consequently, different operation scenarios, together with open market, new regulation models, renewable and alternative solutions and smart grid technologies will pursue the search for new comprehensive methods for planning of future distribution networks.

Based on the author expectations, almost every component of distribution planning processes will experience some kind of modification to meet future challenges.

Based on the author expertise, almost every area in the distribution network planning will require some kind of future improvements. The history of the planning methodologies and techniques come along with the history of electricity industry. The distribution network, especially its LV part is the most dynamic component of power systems mostly affected with the penetration of new renewable and alternative technologies. Consequently, their management and planning will require additional adjustment and improvements of the distribution network planning processes in future.

Among variety of the distribution network planning areas, the author suggests the following fields for future improvements:

- Implementation of dynamic loading in distribution network planning processes is one of the most important segments of the network planning which require intensive future works. Aspect of dynamic loading is very important from different perspectives. Firstly, it provides load profile in a real time. In conjunction with ambient conditions it also provides a real time capability of distribution feeder. On the opposite side, new and more accurate ADMD figures per customer and distribution transformer could be applied based on real time energy consumptions

- Network modelling tools and simulations techniques provide wide spectrum for future improvements. Existing simulation techniques are based on static network models and treatment of all loading, weather and plant rating variables using single static mode. Implementation of dynamic models in distribution network planning is a paradigm of future works. Also, existing simulation methodologies separate modelling of different network topologies from town planning development plans during system modelling. In another words, the network planner actually does two separate analysis (load simulation and demographic/town planning). In the last stage of network modelling, the network planner joins these two simulations which is high time consuming process with sometimes wrong results
- Same observation is valid for load and energy forecasting. Future works in this area include development of adequate methods and algorithms for full implementation of accurate temperature (and weather) data, future customer connections, positive and negative loads, distributed energy resources, alternative energy solutions and economic and demographic figures. As noted, implementation of town planning development plans and future economics and climate specifics in the existing network models is critical for effective planning of future load growths and in general for better understanding of future load dynamics between different areas
- In the field of risk assessment and project prioritisation there are two critical components to be considered in future works. One is related to comprehensive plant risk assessment and the second to risk assessment of related augmentation projects. Development of both models requires considerations from different angles. Future risk models must include comprehensive assessment of technical and physical conditions of network assets, especially major components like power transformers, UG cables and transmission OH lines. Also, they must include accurate plant rating performances addressed in conjunction with asset conditions, installation specifics and existing and future load profiles
- Network planning data management is wide area which also requires intensive works in future. In the absence of accurate data, the network planner must to extend accountabilities and collect data using all available different sources. It requires intensive time and energy lost and consequently reduces the length of planning stage. Future business model of distribution network planning must include variety of reliable and available data, sorted, classified, interfaced and archived based on network planning needs. For example, future customer connection data (size of load, supply point, location, time of connection and load category) must be linked with existing load profile of a particular feeder based on summer day and night and winter day and nigh conditions. With this interface the network planner will be able to analyse future load growth and develop the most accurate models of future network topologies. Also, there should be a continuous interaction between ambient and load/energy data for better understanding of load patterns and potential peak load shifts during 24 hours and seasonal periods. Some of the areas have strong summer peaks, as some may have typical winter peaks. Finally, there are areas with peaks drifting from time to time between summer and winter, even between day and night conditions based on change of load categories
- Penetration of renewable and alternative energy resources and smart grid technologies requires variety of different and multidisciplinary actions on improvement of the distribution network planning processes. All above mentioned fields, as well as power quality, protection, reliability, fault levels and many more planning components will be affected and require comprehensive analysis in near future

- Impact of plug-in electric vehicles (PEV) on distribution HV and LV networks is another very important area which requires specific consideration. Unfortunately, there is no comprehensive study which addresses all aspects of massive penetration of charging points for electric vehicles. Future works must cover all components of PEV initiatives including impact on electricity networks as well as on business, economics and regulatory model of electricity utilities
- In the field of plant rating, future works must include implementation of high temperature and dynamic line rating technologies in the distribution network planning. With the growing demand and continuous pressure on electricity utilities to reduce capital planning expenditures and extend network utilization levels, introduction of super-conductor cryogenic technologies in UG and OH networks with much higher capacities than standard conductors and cables is highly expected
- Global understanding of network power losses in the new business environment is another paradigm of effective management of electricity utility. This author has developed sophisticated model of assessment of network power losses which however requires extensive works in future to cover all components of this important subject. Specifically it is an imperative to develop planning criteria which will include power losses as a standard component. Future works must include understanding of power losses of different network topologies, their effective reduction and their greenhouse gas emission parts. Finally, although this author has completed preliminary studies of impact of PV systems on network power losses for different system configurations, penetration of renewable and alternative energy solutions and energy storage devices must be assessed from network power losses perspective, as well
- Impact of global climate change on electricity networks and consequently on the distribution network planning processes is another important area which must be studied in future from different angles. On one side, global climate change may have physical impact on existing networks (especially overhead lines and zone substations). On the opposite side higher average temperatures, more extreme hot days and extended dry periods may have big impact on load patterns and peak load conditions. In addition to increased maximum demand (predominantly due to operation of air-conditioning systems), higher ambient temperatures reduce rating of overhead lines and power transformers which is another serious issue for consideration. Finally, driven by the federal polices global climate change may also have a big impact on business economics and regulations related to management of greenhouse gas emissions in future
- As noted in Chapter 14.2 another interesting area for future works is educational aspect of this and similar projects. Educational aspects could be included in a future Master Degree Dissertations which could assess these issues from different angles – educational, economical, social, cultural, religious, communicational, professional, structural, psychological, business related and technical. These factors are outside of the scope of this Master Degree Dissertation. It addresses only two, but very important aspects:
    - Lack of adequate planning documentations, business models and procedures for the Graduate Electrical Engineers at the Universities and in the electricity utilities
    - Application of planning methodologies into a real project.

  As such, this Master Degree Dissertation can serve as an interface between electricity utilities and the future generations of students of electrical engineering and Graduated Electrical Engineers.

APPENDIX A
Classification of Distribution Feeder Capability and Voltage Regulation

Accepted basic planning criteria considerations and colour codes for feeder constraints have been classified to the following:

- Red: Constraint has emerged whereby there is a notable excursion of distribution planning limits during the period of consideration:
  - **Voltage Drop** within feeder exceeds:
    - **7.0%** for urban feeders (or the large urban townships sections of rural feeders),
    - **8.0%** for rural feeders (with LV reticulation surrounding rural transformers) and
    - **12.0%** for rural feeders (e.g. SWER, no LV reticulation).

  Note: Assumed nominal set point of Zone Sub transformer to be fixed on 1.05puV; tap setting plan for distribution transformers close to Zone Substations are set at nominal or buck, therefore customers close to Zone Substation should not suffer regulation issues under any normal network conditions.

  Furthermore, fixed tapped distribution transformers at the feeder extremities need to be taken into account to ensure that customers do not suffer over-voltage under network minimum loading conditions (20-30% MD conditions – conventional urban and rural feeders).

  Bus voltage at peak load depends on the system under investigation and does vary from the 1.05puV level between regions. Bus voltage set points and LDC settings of associated regulating devices will affect tap-setting plans.

  - **Capacity** for distribution feeders exceed:
    - **Rural Feeders: 100%** of feeder nominal conductor rating (at specific temperature design for feeder)

      The maximum acceptable load of a typical rural distribution feeder is limited to 90% of the overcurrent setting.

    - **Urban Feeders: 75%** of feeder nominal conductor rating (at specific temperature design for feeder).

      The maximum acceptable load of a typical urban distribution feeder is limited to 60% of the overcurrent setting.
  - **90%** of **Fault level** rating (1 second) of the equipment supplying the feeder from the zone substation is exceeded or conductor/cable within the immediate area of the Zone Substation has exceeded **90%** of its fault rating for the relevant backup protection clearing time.

- Yellow: Constraint is emerging whereby an excursion of distribution planning limits is likely shortly after the period of consideration:
    - **Voltage Drop** within feeder exceeds:
        - **6.0-7.0%** for urban feeders (or the large urban townships sections of rural feeders),
        - **7.0-8.0%** for rural feeders (with LV reticulation surrounding rural transformers) and
        - **11.0-12.0%** for rural feeders (e.g. SWER, no LV reticulation).

Note: Assumed nominal set point of Zone Sub transformer to be fixed on 1.05puV; tap setting plan for distribution transformers close to Zone Substations are set at nominal or buck, therefore customers close to Zone Substation should not suffer regulation issues under any normal network conditions.

Furthermore, fixed tapped distribution transformers at the feeder extremities need to be taken into account to ensure that customers do not suffer over-voltage under network minimum loading conditions (20-30% MD conditions – conventional urban and rural feeders).

Bus voltage at peak load depends on the system under investigation and does vary from the 1.05puV level between regions. Tap setting plans will be affected by bus voltage set points and LDC settings of associated regulating devices.

-
    - **Capacity** for distribution feeders exceed:
        - **Rural Feeders: 80%** of feeder nominal conductor rating (at specific temperature design for feeder).

          The maximum acceptable load of a typical rural distribution feeder is limited to 80% of the over current setting.

        - **Urban Feeders: 50%** of feeder nominal conductor rating (at specific temperature design for feeder).

          The maximum acceptable load of a typical urban distribution feeder is limited to 40% of the overcurrent setting.
    - **80%** of **Fault level** rating (1 second) of the equipment supplying the feeder from the zone substation is exceeded or conductor/cable within the immediate area of the Zone Substation has exceeded **80%** of its fault rating for the relevant backup protection clearing time.
- Green: Feeder does not exhibit any constraints, i.e. if none of the above limits are exceeded as described.

Classification of Overall Substation Capability

Accepted basic planning criteria considerations and colour codes for substation constraints have been classified to the following:

- Red: Constraint has emerged whereby there is a notable excursion of distribution planning limits during the period of consideration:
  - Greater than 50% of the substation feeders suffer the particular constraint (i.e. overhead capacity, underground capacity, protection setting capacity or voltage).
  - At least one of the substation feeders suffers the particular constraint and greater than 50% of the feeders are either suffering or nearing the constraint.
- Yellow: Constraint is emerging whereby an excursion of distribution planning limits is likely shortly after the period of consideration:
  - No substation feeders are suffering the constraint and greater than 50% of the feeders are nearing the particular constraint (i.e. overhead capacity, underground capacity, protection setting capacity or voltage).
- Green: Substation feeders do not exhibit any constraints, i.e. if none of the above limits are exceeded as described.

Feeders without the particular construction (i.e. a feeder may not have any overhead construction) are not included whether 50% of the substation feeders exceed or a nearing constraints.

APPENDIX B
Pricing Methodology of Distribution Augmentation Projects

The following pricing list has been used to build the cost estimates of proposed works. As different contractors may have different labour costs (overheads) and contingency factors there is possibility that these price units may differ. However, in general they reflect approximate cost of some of standard distribution augmentation projects.

Table B.1 - Estimating Sheet, Base Rates (2008 rates)

Type	Works Unit Description	Unit	Unit Cost
UG Heavy CBD	11kV, 400Cu-CBD	km	$1,350,000
UG Heavy Urban	11kV, 400Cu-Urban	km	$1,000,000
UG Light CBD	11kV, 240Cu-CBD	km	$1,150,000
UG Light Urban	11/22kV, 185Al-Urban	km	$550,000
OH New Feeder Urban	11/22kV Pluto-Urban	km	$160,000
OH Reconductoring Urban	11/22kV Pluto-Urban	km	$100,000
RMU	RMU Installation	Each	$50,000
P/M Transformer	Pad-mount Installation	Each	$80,000

APPENDIX C
SWER Network

The major advantages of SWER networks (Ivanovich & Turner 2008, p.69):

- One conductor
- Less pole top equipment
- Long, hilltop to hilltop spans (~300m)
- Less poles (2.5-4 poles/km)
- Design Simplicity
- Easy and Speed of Construction
- Good reliability
- Fewer switching and protection devices
- Low maintenance costs
- Reduced bushfire hazard – no conductor clashing.

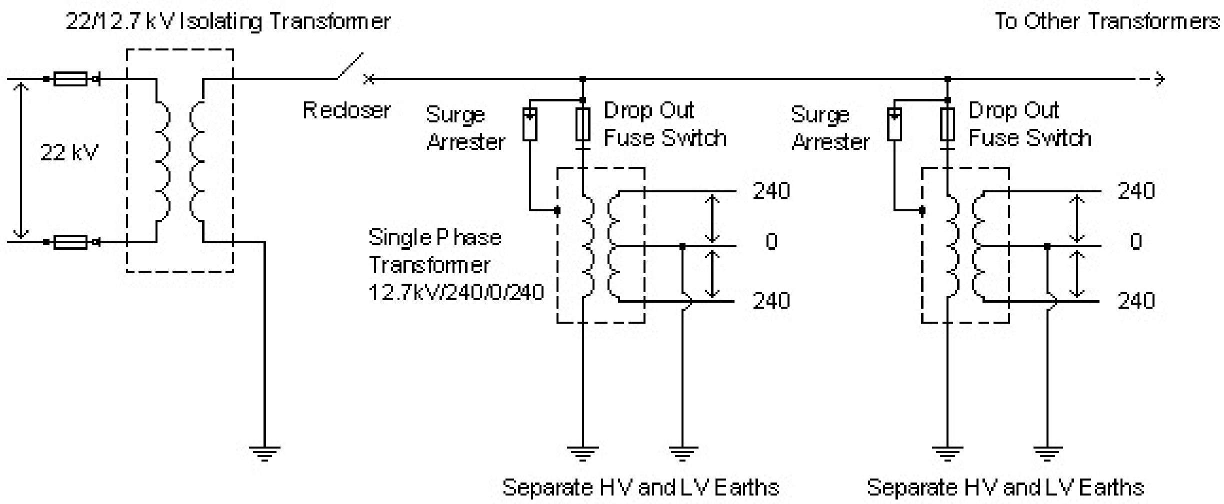


Figure C.1 – System Diagram of SWER Network (Ivanovich & Turner 2008, p.70)

APPENDIX D

Photovoltaic Systems and Smart Grids

Renewable generators are embedded in the distribution network as shown in Figure D.1. They break the traditional one-direction power flow from higher to lower voltages or from generators to the customers. Connection of embedded generator occasionally can cause a variety of problems. Firstly, connection of numerous embedded generators complicates determination of the point of common coupling (PCC). Secondly, the fault level at the PCC is very important because it largely determines the effect that the generator will have on the network. For example, a low fault level implies high network source impedance, and a relatively large change in voltage at the PCC caused by injection of active or reactive power. The nominal voltage of connection depends of its rated capacity. On LV network maximum capacity of embedded generator is 50kVA, as at the LV busburs of distribution substations (DSS) it goes up to 250kVA. On 11kV distribution network maximum capacity of embedded generator is 3MVA (8MVA on11kV busburs). These figures are approximate but still ensure acceptable level of voltages at the PCC.

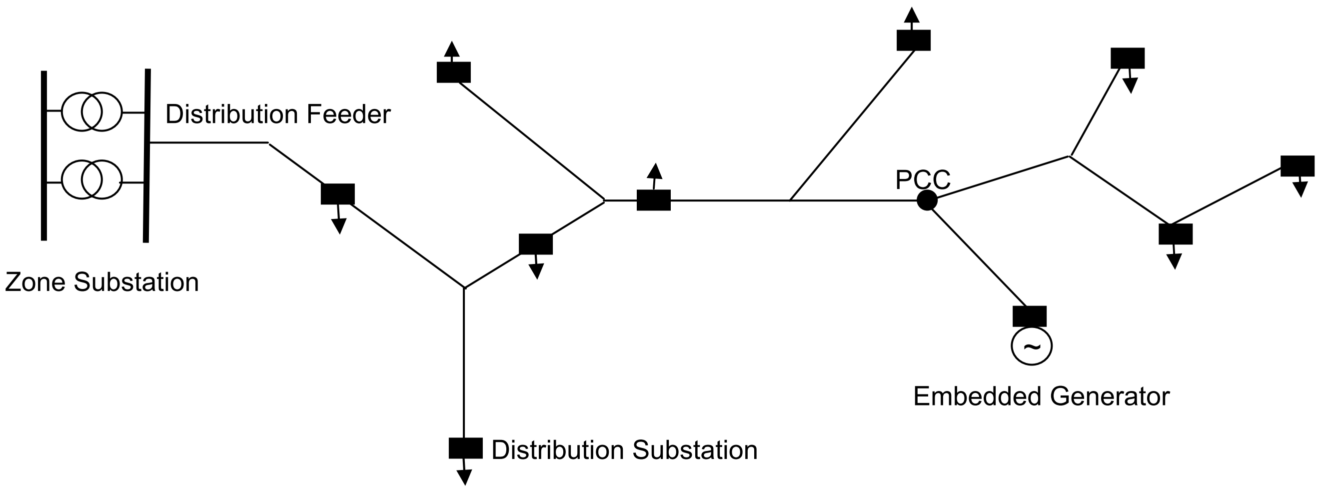


Figure D.1 – Distributed Generator on Distribution Network

Under certain fault conditions, after connection of embedded generators (like PV systems) the system dynamics could be so excited and it is possible that network may experience tripping. With the loss of supply from the grid, the local network runs in island mode fed solely from the generator which requires an effective active control. Theoretically, such actively managed distribution network can run autonomously in islanding mode which could increase the reliability of supply.

It is anticipated that PV systems may have effects in terms of:

- Harmonics
- Voltage distortion and regulation
- Power factor
- Safety
- Distribution protection devices and management devices and their operation.

It must also be determined if PV systems may affect the grid only during certain times, such as periods of low solar radiance, or periods where the customer load is low, and solar output is high.

In general, modern inverters used by photovoltaic systems have very little impact on power quality. Harmonic distortion is dependant on the grid and on the output of the solar system, but most inverters have a total harmonic distortion (THD) of less than 2%. Power factor is also good with these inverters, however in lower-quality models the power factor can decrease with lower PV output- such as during periods of low solar irradiation. Inverters can be sensitive to voltage sags. This can have flow-on effects such as over-currents and current oscillation, and may lead to reduced lifetime of the components. Sag sensitivity in inverters is a current area under review (Goonaverdana 2009).

Where a large amount of PV is installed, reverse power flow may occur- that is the output of the PV exceeds the use of the customers. Power will then flow back to the distribution transformer. This can cause voltage raise and alter short circuit impedance levels, which has implications for protection devices and ensuring that voltage levels remain within acceptable limits. This can have serious implications for future network design and is seen as a primary driver for 'smart grid'.

D.1 Harmonics

Total harmonic distortion (THD) calculated to the 50th harmonic under AS4777 is stipulated to not exceed 5%. It is speculation as to whether there is THD for inverter grid connected systems may be excessively high under increase PV penetration, particularly in weaker rural networks, or whether a specific harmonic frequency may find resonance on these schemes. The harmonic limits for AS4777 standard were derived from the IEEE 929 - 2000 standard recommended practice for utility interface of Photovoltaic (PV) systems. Under IEEE929 -2000 standard, Clause 4.4 states ' The PV system output should have low current-distortion levels to ensure that no adverse effects are caused to other equipment connected to the utility system. The PV system electrical output at the PCC should comply with Clause 10 of IEEE Std 519-1992 and should be used to define the acceptable distortion levels for PV systems connected to a utility. The total injected harmonic current is dependent on the number of individual customers injecting harmonic currents and the size of each customer. Therefore, a reasonable approach to limiting the harmonic currents for individual customers is to make the limits dependent upon the customer size.

Increasing levels of harmonic distortion are brought about by the use of inverter systems in PV-DG. Thus, it is important for grid utility operations that connected inverters do not interfere quality of supply at the connection point. The THD content for most modern PWM sine wave inverters is typically 3% below the allowable 5% of its full rated current as per AS4777. A study conducted by Intelligent Energy Europe (Chant 2009) suggests 'inverters combined harmonic current emissions may lead to voltage harmonics (especially the 11th harmonic frequency) exceeding tolerated limits.

This is because the impedance and resonance frequencies of the grid may be altered, and a non-sinusoidal shape of the grid voltage may increase the harmonic currents produced by an inverter where the current control electronics is not able to cope adequately'.

As noted, the harmonic output of PV systems is largely affected by the quality of the inverter used. In older or low-quality inverters, the power quality of the output, including the THD, can change significantly depending on the PV output. This is because when input power to the inverter is low, there is non-continuous conduction which results in high harmonics. It was found that when the inverter output power was low (20% of rated power), the THD was as high as 7.2%. However, when the inverter was operating at 75%, the THD was reduced to 2%. This is confirmed by the manual of the Sunny Boy 1100 inverter, which states that the harmonic output of the inverter is under 4%, so long as the inverter output is greater than 50% of the nominal power output (Goonevardana 2009).

In a system where higher-quality inverters were installed, the THD introduced by the PV system was consistently less than 2%, even with a large number of inverters on the same phase in simulation and in practice. For one of PV systems in Denmark, where the installed PV totalled 60kW, or 30% of the feeding transformer's rated capacity, greatest harmonic distortion was experienced at night, between 6.30 and 11 pm, and was attributed to other harmonic sources.

However, in one of the oldest PV project (Gardner PV Project), the system despite being almost 20 years old, also exhibited THD increased by less than 1% after the installation of 56kW of PV on one phase of a three-phase feeder. This was attributed to high-quality inverters being used. It should be noted that harmonics are cumulative, so where many inverters – particularly of low quality – are used, it can be anticipated that THD will increase.

In one study, it was found that, the maximum acceptable penetration was 27%, or 47 PVIS units. With improved filtering, this was increased to 38% or 67 PVIS units (Chant 2009). This highlights the importance of using an inverter with a filtered output.

The impact of PV inverters on the power quality of the grid depends on the impedance of that grid. $THD_{voltage}$ has strong grid dependence. $THD_{current}$ has low influence on $THD_{voltage}$ if grid impedance is low.

D.2 Voltage Regulation

For a typical distribution network, load voltage is defined by the following parameters:

I. Voltage held constant by tap changer of distribution substation
II. Voltage drop due to load on the distribution feeder
III. Voltage boost due to taps of distribution substation
IV. Voltage drop in LV feeder

The above parameters are manageable within acceptable voltage tolerance by correct tap settings and load management. However, with growth in DG, power flow becomes more complicated with the increase and nature of PV generation. This feeds directly from the LV into the HV networking causing undeniable over-voltage situations under correct conditions such as that of light load and increased power generation from DG. This situation is considerably likely under increased penetration levels during maximum solar luminosity and light loads such as midday for residential loads. Studies conducted in Germany have shown to accept about 6 kW per household with no major voltage dips and swells from passing clouds cover, because of an averaging effect over large areas. Voltage dips have shown to cause nuisance tripping of protective functions in inverters. Considering the installed PV capacity of more than 2 GW, there is a concern that this sensitivity can amplify grid instability under overload conditions (Chant 2009).

A study conducted by Intelligent Energy Europe into the management of PV-DG in the United Kingdom, Germany, Spain, Netherlands and Austria discovered the 'main concern in nearly all countries is voltage rise from strong generation near end-of-feeder. This effect is being noticed. However, in strong grids it is not critical. It may become critical in terms of violation of power quality standards, or reduction of produced power due to voltage imitation, or costs for grid strengthening mainly in rural areas with higher impedance networks' (Chant 2009).

D.3 Voltage Distortion

It has been found that all inverters introduce some DC current into the grid. This is minimised in inverters with a LF (low-frequency, switches at grid-frequency) transformer, here the maximum DC current is generally ±0.04A. For inverters with a HF (high-frequency) transformer, the DC current is up to 0.09A, and transformer-less inverters can have up to 0.175A DC injection.

Where there is a large amount of PV installed, the reverse power flow to the higher voltage power system will substantially increase during periods of light load and maximum daylight. This may have a number of effects, such as causing the voltage at the customers' terminals to exceed the statutory limits.

Many inverters can be very sensitive to voltage sag, even when shallow and for a short period of time. As such, minor voltage sag can cause the disconnection of a large amount of distributed generation, which can cause serious power quality problems.

D.4 Voltage Unbalance

Voltage unbalance problems are related to increased penetration of single phase DG. If PV cells are installed on certain houses, it is possible to overload a single phase with only load on the system and unload other phases with increased DG. Distribution utilities will be required to ensure each phase is loaded correctly and the neutral current is minimised for this new operating condition. Single phase DG on every house would have the same effect as single phase load on every house in terms of unbalance, and is likely to cause less of a problem than single phase load concentrated on a single phase, with load on an adjacent phase.

D.5 Power Factor

Power factor seems to be heavily affected by the performance of the inverter. During high solar radiation, and therefore high PV output and inverter output, power factor could be very close to unity. However, at low solar radiation, when input to the inverter was around 20% of the rated value, the power factor could drop to 0.965 and phase angle as high as -12°. For some situations, it may be beneficial to operate the PV with a leading power factor. Examples of this include cases where the voltage at the customer's terminals may exceed the upper statutory limit. Leading power factor can prevent this voltage rise without reducing the effective power output. Of course, if all PV systems on the line are producing a leading power factor, the power of the entire line may be degraded. Older inverters are typically line-commutated. Line commutated inverters receive their switching signal from the utility waveform. As such, they require significant reactive power from the utility during the conversion. Typically they have a lagging power factor, in some cases so poor that the peak VAR demand of the inverter would more than double the maximum demand that would be expected for a normal home. Modern inverters such as the SMA Sunny Boy are also line commutated, and utilise PWM to shape the ac waveform and have a power factor of close to 1 and so do not require large VAR input (Chant 2009).

D.6 Islanding and Safety

Under AS 4777.3 islanding is defined as any situation where the electrical supply from an electricity distribution network is disrupted and one or more inverters maintains electrical supply, be it stable or not, to any section of the electricity distribution network. Islanding, present safety issues for power system operation as opposed to quality of supply and management issues. The known conditions which islanding can occur are:

1. A match between load and generation at the same time as a loss of mains supply occurs
2. The inverter protection must fail to detect the loss of mains condition.

AS4777-3 stipulates grid protection including anti-islanding protection shall be installed provided by a grid protection device. Grid protective devices shall operate under varying conditions governed by the grids operation. Thus if supply to the grid is disrupted, to prevent islanding the device should isolate the system from grid operation. Protective devices shall also operate If the grid is outside preset parameters for voltage and frequency. Under clause 5.3 of AS4777 the voltage and frequency limits (passive anti islanding protection stipulate the following:

'The grid protection device shall incorporate passive anti-island protection in the form of under- and over-voltage and under- and over-frequency protection. If the voltage goes outside the range Vmin to Vmax or its frequency goes outside the range fmin to fmax, the disconnection device shall operate within 2 s, where settings of the grid protection device shall not exceed the capability of the inverter (Chant 2009).

Although unlikely to pose a problem unless on mass, the failure of the anti-islanding device at a customer premise would not be detected by the utility, which does need some consideration given the criticality of this function. Islanding has a main issue regarding safety. In the case of grid failure, the PV system may continue to feed the grid, unbeknownst to line workers. Although most inverters have islanding detection to prevent this, with higher penetration, it can be anticipated that the chance of islanding occurring will increase, and as such, better islanding detection is required.

D.7 Distribution Protection Devices and their Operation

Power system protection deals with security of utility and privately owned assets from a range of adverse network conditions outside of specified operating conditions. Current protection systems assume power flows from generation to the low voltage network, with discrimination (time delays and over current settings) defined between upstream and downstream relays. Discrimination ensures a downstream fault is cleared by the closest relay at the source end of the feeder unless a malfunction occurs].

Part 3 of AS4777 details grid protection requirements for individual PV systems. A grid protection device must operate under the following conditions:

- If supply from the grid is disrupted, or
- When the grid goes outside the present parameters, or
- To prevent islanding (Chant 2009).

If a large number of customers on a particular branch have installed PV systems, there may be reverse power flow to the distribution transformer. In addition, there may be a significant voltage rise in the distribution lines. As such, the PV systems will supply a part of the fault current in the event of a distribution line fault. This additional fault current will decrease the fault current flowing at the substations and might cause fault detection relays in substations to malfunction. Depending upon site and PV penetration on the distribution system, fault levels may raise or decrease depending upon the location of the fault and generation. Unpredictable nature of PV penetration including system load makes fault levels increasingly hard to detect or monitor.

Larger generators connecting to higher voltage networks, such as the sub-transmission network, are required to have their protection coordinated with electricity utility's equipment, often in the form of inter-trips, but smaller scale generation has no control in this form. The reason for this is the perceived lower contribution to fault current and lower impact of mal-operation. The problem with this is scenarios with low fault levels, or unusual network topology, where a high penetration of DG may have a similar network impact as a single larger generator.

D.8 Planning of Smart Grids

Numerous definitions exist as to what constitutes a smart network. However, at the highest level there is a stark comparison between:

- The electricity networks of today—transporting energy from major generation sources using mostly non renewable fuels, to consumers who have limited knowledge of their consumption, where outages affecting customers are largely unknown until the customer alerts the network operator; and
- A future smart network—serving as a dynamic network for two-way energy flows; linking widely dispersed micro-level renewable energy sources at the customer level and large-scale energy sources; providing more dynamic information to customers; facilitating greater customer choice about energy source and level of consumption; and providing real-time information on the performance of the network and optimising the network operations (EPIC 2006).

The smart grid has five key objectives to:

1. Change the relationship with customers, transforming their role from uninformed and non-participative to informed, active and involved, stimulating demand-side response
2. Accommodate connection of widely distributed, renewable energy sources across the network and in particular at customer premises, providing an 'energy clearing house' function
3. Facilitate market interactions, providing customers access to products and services with choice, based on price and environmental concerns
4. Accommodate new energy storage technologies, enabling customers to choose the source of their energy and optimise the efficiency of their use of energy, and
5. Continue to improve the performance of the network by:

    a) using greatly enhanced data gathering capabilities
    b) detecting and responding to problems automatically
    c) strengthening interconnections, and
    d) optimising replacement investment (EPIC 2006)

D.9 Characteristics of a Smart Grid

The US Department of Energy developed a paper titled *The Smart Grid: an Introduction*. The following Table 10.2 is an extract from that paper which perfectly describes the smart network of the future (ENA 2009, pp 11-15). In 10 or 20 years time possible transformation which may occur are presented in Table D.1 and Figure D.2.

Table D.1 – Transformation of Electricity Networks (ENA 2009, p.11)

Characteristic	Today's grid	A future smart grid
Enables active participation by consumers	Consumers are uninformed and non-participative with power system	Informed, involved, and active consumers—demand response and distributed energy resources
Accommodates all generation and storage options	Dominated by central generation—many obstacles exist for distributed energy resources interconnection	Many distributed energy resources with plug-and-play convenience focus on renewable energy
Enables new products, services and markets	Limited wholesale markets, not well integrated—limited opportunities for consumers	Mature, well-integrated wholesale markets, growth of new electricity markets for consumers
Provides power quality for the digital economy	Focus on outages—slow response to power quality issues	Power quality is a priority with a variety of quality/price options—rapid resolution of issues
Optimises assets and operates efficiently	Little integration of operational data with asset management—business process silos	Greatly expanded data acquisition of grid parameters—focus on prevention, minimising impact to consumers
Anticipates and responds to system disturbances (self-heals)	Responds to prevent further damage—focus is on protecting assets following fault	Automatically detects and responds to problems—focus on prevention, minimising impact to consumer
Operates resiliently against attack and natural disaster	Vulnerable to malicious acts of terror and natural disasters	Resilient to attack and natural disasters with rapid restoration capabilities

The following provides additional comment on the smart network characteristics described in this table:

- Active participation of consumers occurs through the provision of two-way communications and information that gives the consumer the ability to make informed decisions to both consume and provide energy
- Achieve 'self-healing', or automatic fault response, the integration of devices and sensors with a secure communications network to automatically recover unaffected sections and isolate those elements in need of repair
- Enable generation and storage options at the macro and micro-level by way of participatory networks established at all levels of the network, allowing individual and industrial customers the ability to contribute to the environmental agenda
- Optimise asset use and minimise operating costs through peak shaving (deferring capital expenditure) and reduced operating and maintenance costs, harnessing the information provided by sensing and monitoring devices and automatic switching capability
- Detect and address emerging problems before they impact service
- Make protective relaying will be the last line of defence
- Respond to local and system-wide inputs and know much more about broader system problems
- Incorporate extensive measurements, rapid communications, centralized advanced diagnostics, and feedback control that quickly return the system to a stable state after interruptions or disturbances
- Automatically adapt protective systems to accommodate changing system conditions.
- Re-route power flows, change load patterns, improve voltage profiles, and take other corrective steps within seconds of detecting a problem
- Enable loads and distributed resources to participate in operations
- Be inherently designed and operated with reliability and security as key factors.

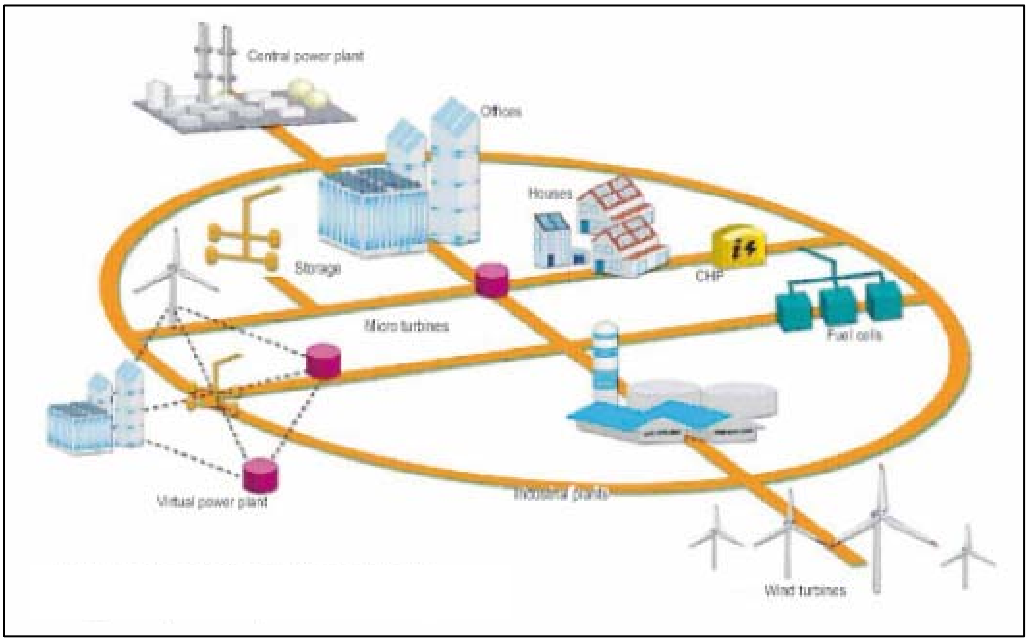


Figure D.2 – The Basic Model of Smart Grid (ENA 2009, p.15)

D.10 Smart Grid Performance

Performance of the Smart Grid will support the grid's key success factors and take many forms. Near-term actions would include engineering, operations, maintenance, and emergency response. Long-term term actions would include system planning and the resulting system capacity additions, new technology applications, and other activities with extended development cycles. For example, the Smart Grid could accommodate new breakthrough technologies such as a hydrogen economy or other advanced fuels in the future.

The following are performance characteristics of a Smart Grid (ENA 2009, p.11).

- Emergency - Grid operators take responsive action in the face of grid emergencies to minimize loss, protect major equipment from destruction, and initiate the first wave of restoration. In the future, this will change as advanced analytical technologies will provide predictive capabilities
- Restoration - In cases of emergency, grid operators take action to recover the damaged or compromised sections of the grid from major events, like cascading outages. Restoration from major events usually requires days and weeks to affect the necessary repairs, replacements, and reconfigurations to return the damaged grid to full operation. In the Smart Grid model, new data sets and geographical based information could be available to assist operators in the restoration process, improving restoration times
- Routine operations - During the course of a normal day, grid operators manage planned changes to the grid configuration, manage understood transients, and respond to small upset conditions, typically from losses of single components. Activities can include the start-up and shutdown of generators, injections and withdrawals of megawatts (MW) for bulk power movement, and diurnal load changes
- With Smart Grid technologies and strategies, the role of the grid operator could change as advanced visualization tools and decision support capabilities are provided to help them better understand system conditions and make decisions on actions to be taken
- Optimization - During the course of a normal day or week, grid operators fine tune the grid, minimizing unnecessary congestion, unnecessary power generation, reducing the total cost of generation, and maximizing overall grid efficiency. The Smart Grid could provide grid operators advanced tools to increase their effectiveness in optimization
- Systems planning - Grid engineers and planners analyse intermediate and long-term issues, newly planned generation, and projected growth in supply and demand to determine courses of action. The Smart Grid could allow planning processes to become more effective as improvements in data collection and modelling provide more accurate historical demands and enable more accurate load forecasts.

APPENDIX E
Airport Precincts Development Plan

Table E.1 - Airport Precincts Development Plan (kVA)

Year	AD	EPW	BP	EP	IT	DT	ND	EPE	AIP	APS	AP N	Total
2005/06	1344	0	0	653.6	65.64	93.94	0	384	12	1872	610.98	5036.16
2006/07	3106	0	0	1540.43	0	0	36.12	0	12	0	0	4694.55
2007/08	872	0	0	1020.8	2048	264	0	0	0	0	131.32	4336.12
2008/09	1620	968.63	0	0	631.95	0	36.14	423.97	484.4	1704.08	734.08	6603.25
2009/10	6286.3	968.63	0	66.88	0	0	0	46.22	0	1236.96	800.83	9405.82
2010/11	1440	3665.42	0	615.35	0	0	95.14	22.26	609.47	2802.21	67.31	9317.16
2011/12	0	451.52	0	185.26	0	0	0	22.26	1009.05	0	120.55	1788.64
2012/13	192	0	1378.05	177.91	2298.38	360	0	61.91	1376.88	3734.08	231.57	9810.78
2013/14	192	0	0	240.91	0	0	0	50.4	72	0	0	555.31
2014/15	192	1025.89	0	280	0	0	0	3248.55	91.68	2074.32	449.59	7362.03
2015/16	192	0	305.93	168	0	24.96	0	25.2	2067.79	1899.65	208.28	4891.81
2016/17	0	153.38	519.37	308	958.16	0	0	59.7	0	2045.52	0	4044.13
2017/18	0	0	0	168	0	0	0	25.41	0	3095.2	0	3288.61
2018/19	0	0	77.08	168	0	288.96	0	0	0	0	532.4	1066.44
2019/20	0	153.38	0	455.6	0	179.96	0	0	0	0	0	788.94
Total [kVA]	**15437**	**6418.22**	**2280.43**	**6048.74**	**6002.13**	**1211.82**	**167.4**	**4369.88**	**5735.35**	**20464**	**3886.91**	**72021.88**

APPENDIX F
Contingency Planning

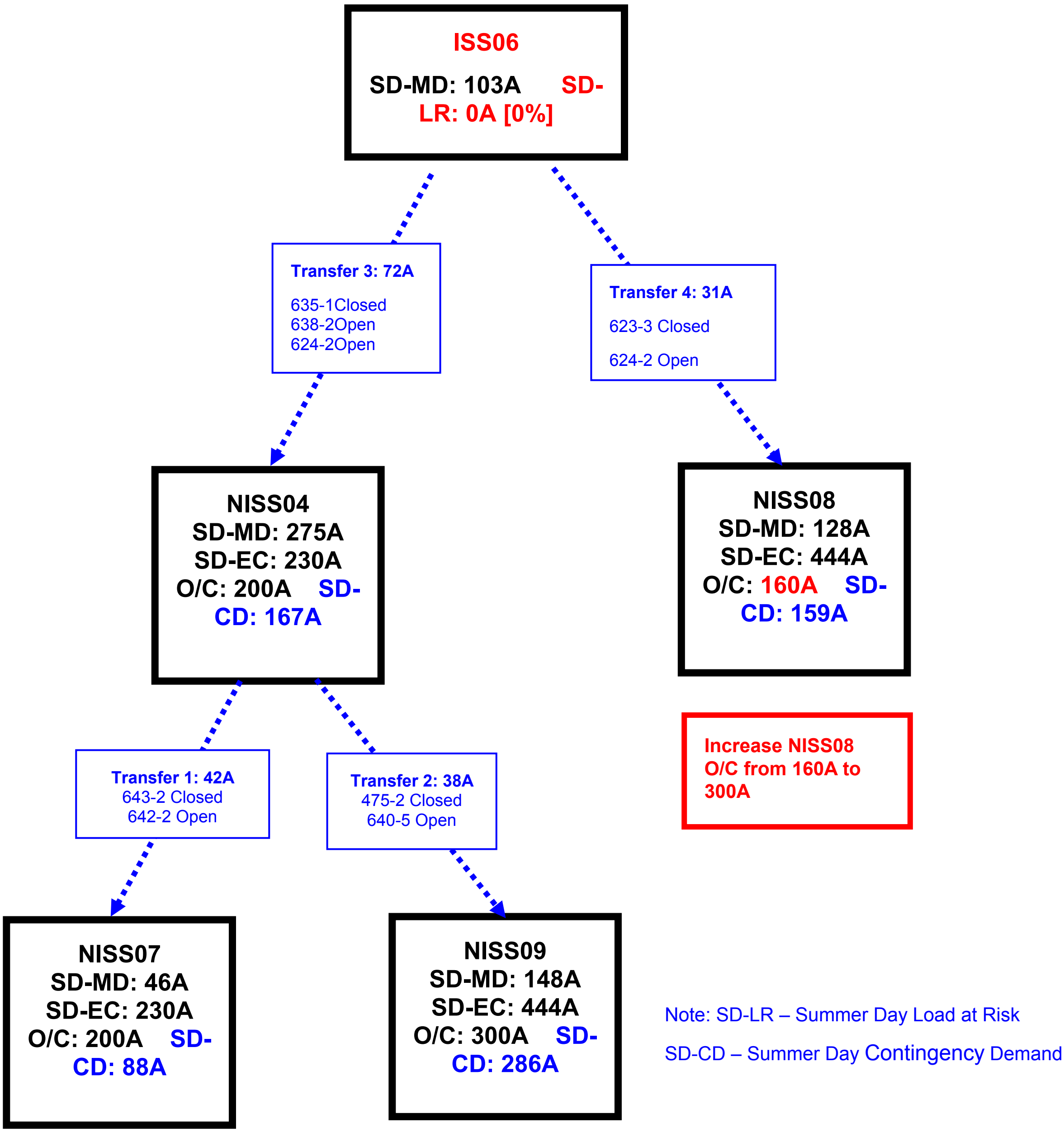


Figure F.1 – Load Transfer and Switching Operation Blocks

APPENDIX G
MISS – Existing System 11kV Transfer Capacity

Table G.1 – MISS – Existing System 11kV Transfer Capacity

Loss of Feeder	SD Peak Load (A)	Tie Feeders (Indirect Tie Feeders for Multiple Load Transfers)	Tie Feeder Capacity (A)					Load Transfer to Adjacent Feeders[6] (A)	
			Tie Feeder Summer Day Capacity				Load Transfer to Adjacent Feeders based on DINIS model	Summer Day	
			MD[3] (A)	EC[4] (A)	O/C[5] (A)	Spare Capacity (A)	A	A	%
ISS06	103	NISS04 [635-1]	275	230[1]	200[2]	0	0	**103**	**100%**
		NISS08 [623-3]	128	444	160[2]	32	103		
ISS07	52	ISS10 [710-2]	185	444	300	115	52	**52**	**100%**
ISS10	185	ISS07 [710-2]	52	230[1]	200[2]	126	124	**124**	**67%**
ISS08	150	TSB08 [835-2] - [825-2]	90	382	300	210	150	**150**	**100%**

Note:

1 – Limited by UG cable exit capacity

2 – Limited by O/C protection settings

3 – MD – Maximum Demand

4 – EC – Emergency Capacity

5 – O/C – Over-current protection settings

6 – Colour code: Red – there is load at risk; Green – no load at risk

APPENDIX H

NISS Intake Switching Station Contingency Plan

Table H.1 – NISS – Existing System 11kV Transfer Capacity

Loss of Feeder	SD Peak Load (A)	Tie Feeders (Indirect Tie Feeders for Multiple Load Transfers)	Tie Feeder Capacity (A)					Load Transfer to Adjacent Feeders (A)	
			Tie Feeder Summer Day Capacity				Load Transfer to Adjacent Feeders based on DINIS model	Summer Day	
			MD[3] (A)	EC[4] (A)	O/C[5] (A)	Spare Capacity (A)	A	A	%
NISS04	275A	ISS06 [635-1]	103	230[1]	200[2]	97	47	**275**	**100%**
		NISS09 [475-2]	148	444	300	152	170		
		NISS07[643-2]	46	230[1]	200[2]	154	58		
NISS09	148A	NISS04 [475-2]	275	230[1]	200[2]	0	46	**46**	**31%**
		{ISS06} [635-1]	103	230[1]	200[2]	97	47		
		{NISS07} [643-2]	46	230[1]	200[2]	154	42		
NISS07	46A	NISS04 [643-2]	275	230[1]	200[2]	0	46	**46**	**100%**
		{ISS06} [635-1]	103	230[1]	200[2]	97	47		
		{NISS09} [475-2]	148	444	300	152	138		
NISS08	128A	ISS06 [623-3]	103	203[1]	200[2]	97	128	**128**	**100%**
		{NISS04} [643-2]	275	230[1]	200[2]	0	67		
		{NISS09} [475-2]	148	444	300	152	138		
NISS06	292A	TSB32 [510-1]	0	487	400	400	292	**292**	**100%**

Note:

1 – Limited by UG cable exit capacity

2 – Limited by O/C protection settings

3 – MD – Maximum Demand

4 – EC – Emergency Capacity

5 – O/C – Over-current protection settings

6 – Colour code: Red – there is load at risk; Green – no load at risk

APPENDIX I
TSB Contingency Plan

Table I.1 – TSB – Existing System 11kV Transfer Capacity

Loss of Feeder	SD Peak Load (A)	Tie Feeders (Indirect Tie Feeders for Multiple Load Transfers)	Tie Feeder Capacity (A)					Load Transfer to Adjacent Feeders[8] (A)	
			Tie Feeder Summer Day Capacity				Load Transfer to Adjacent Feeders based on DINIS model	Summer Day	
			MD[5] (A)	EC[6] (A)	O/C[7] (A)	Spare Capacity (A)	A	A	%
TSB08	90	ISS08 - [835-2] [825-2]	150	382	300	150	90	90	100%
		TSB13 [D12-4]	110	271	200	90			
		TSB12 [D12-4]	125	271	200	75			
TSB06	120[3]	NISS07 [656-2]	46	230[1]	200[2]	154	120	120	100%
TSB32 [505, 510]	80[3]	NISS06 [510-1]	292	487	400	108	80	80	100%
TSB14 [DS20]	57	N/A	N/A	N/A	N/A	N/A	0	0	0%
TSB13 [D43,DTB]	110[3] [16A+93A]	TSB08 [D12-4]	90	382	300	200	110	110	100%
		TSB12	125	271	200	75			
		TSB15	93	271	200	107			
		TSB20	93	271	200	107			
TSB12 [D92,DTB]	125A[3] [30A+93A]	TSB08 [D12-4]	90	382	300	200	125	125	100%
		TSB13	110	271	200	90			
		TSB15	93	271	200	107			
		TSB20	93	271	200	107			
TSB15 [DTB]	93[3]	TSB08 [D12-4]	90	382	300	200	93	93	100%
		TSB13	110	271	200	90			
		TSB12	125	271	200	75			
		TSB20	93	271	200	107			
TSB20 [DTB]	93[3]	TSB08 [D12-4]	90	382	300	200	93	93	100%
		TSB13	110	271	200	90			
		TSB15	93	271	200	107			
		TSB12	125	271	200	75			
TSB18 [D50]	16[3]	TSB21	16	154	50	34	16	16	100%
TSB21 [D50]	16[3]	TSB18	16	154	50	34	16	16	100%

TSB23 [D60]	16[3]	N/A	N/A	N/A	N/A	N/A	0	**0**	**0%**
TSB30 [TSB11]	217	TSB11	217	382	630	165	NOP-Bus feeder[4]		
TSB11 [TSB30]	217	TSB30	217	382	640	165	Bus feeder[4]		

Note:

1 – Limited by UG cable exit capacity

2 – Limited by O/C protection settings

3 – SD-MD based on system diagram load allocation

4 – TSB30 and TSB11 are interconnected bus feeders with TSB30 NOP

5 – MD – Maximum Demand

6 – EC – Emergency Capacity

7 – O/C – Over-current protection settings

8 – Colour code: Red – there is load at risk; Green – no load at risk

APPENDIX J

11kV Incoming Feeders Load Forecast

Table J.1 – 11kV Incoming Feeders Peak Load Forecast (A) – Existing System

Capacity	MTN3				MTN8				NGE10				NGE17			
	SD	SN	WD	WN	SD	SN	WD	WN	WD	WN	WD	WN	SD	SN	WD	WN
Year	553	752	678	815	553	752	678	815	437	437	488	488	437	437	488	488
2005/06	299	297	254	250	323	319	273	268	312	285	231	221	302	276	222	212
2006/07	310	307	262	258	334	330	282	277	409	373	303	289	398	363	293	279
2007/08	317	315	269	265	342	338	289	284	514	469	381	363	503	459	370	352
2008/09	338	335	286	282	364	360	307	302	595	543	441	421	584	533	429	409
2009/10	349	346	296	291	376	371	317	312	615	561	456	435	604	551	444	423
2010/11	362	359	307	303	390	385	330	324	636	580	471	450	624	570	459	437
2011/12	371	368	314	310	399	395	338	332	657	600	487	465	645	589	474	452
2012/13	380	377	322	317	409	404	346	340	679	619	503	480	666	608	490	466
2013/14	389	386	330	325	419	414	354	348	701	639	519	495	687	628	505	481
2014/15	399	395	338	333	430	425	363	357	723	659	535	511	709	647	521	497

Note 1 - Colour code: Red - Peak load > N-1 (66% of Cable Rating); Yellow - Peak load > 50% of Cable Rating; Green - Peak load < 50% of Cable Rating

APPENDIX K
MISS Load Forecast

Table K.1 – MISS 11kV Feeders Peak Load Forecast (A) – Existing System

Feeder	ISS08	ISS06	ISS07	ISS10	ISS05	ISS09
SD-NC	318	226	226	370	406	406
SD-N-1	210	150	150	245	268	268
SD-EC	382	230	230	382	487	487
O/C	300	200	200	200	400	300
Year						
2004/05	150	103	52	185	247	247
2005/06	182	104	52	283	248	248
2006/07	182	104	52	283	255	255
2007/08	189	104	52	283	256	256
2008/09	228	130	52	373	256	256
2009/10	270	130	52	438	258	258
2010/11	273	162	57	580	258	258
2011/12	280	215	57	580	304	304
2012/13	292	287	96	737	304	304
2013/14	292	291	96	737	304	304
2014/15	315	296	96	846	313	313
2015/16	326	404	117	926	326	326
2016/17	326	404	165	985	326	326
2017/18	326	404	327	985	336	336
2018/19	354	404	327	985	341	341
2019/20	354	404	327	985	437	437

Note 1 - Colour code: Red - Peak load > N-1 (66% of Cable Rating); Yellow - Peak load > 50% of Cable Rating;
Green - Peak load < 50% of Cable Rating; Black – Peak load > SD-NC

APPENDIX L
NISS Load Forecast

Table L.1 – NISS 11kV Feeders Peak Load Forecast (A) – Existing System

Feeder	NISS09	NISS07	NISS08	NISS04	NISS06	NISS05*
SD-NC	370	226	370	406	406	406
SD-N-1	245	150	245	268	268	268
SD-EC	444	230	444	487	487	487
O/C	300	200	150	400	400	300
Year						
2004/05	148	40	128	275	292	
2005/06	158	40	148	550	295	
2006/07	158	40	160	621	295	
2007/08	174	61	160	784	403	
2008/09	174	61	182	830	436	
2009/10	174	61	186	966	436	
2010/11	174	79	198	1296	436	
2011/12	174	79	209	1564	436	
2012/13	183	79	212	1588	557	
2013/14	183	79	215	1598	557	
2014/15	183	79	400	1608	557	
2015/16	183	79	410	1672	557	
2016/17	183	79	430	1682	607	
2017/18	183	79	440	1690	607	
2018/19	183	79	449	1690	607	
2019/20	183	79	466	1690	607	

Note 1 - Colour code: Red - Peak load > N-1 (66% of Cable Rating);
Yellow - Peak load > 50% of Cable Rating; Green - Peak load < 50% of Cable Rating;
Black – Peak load > SD-NC
* - NISS05 back-up supply for TSB/International Terminal

APPENDIX M
TSB Load Forecast

Table M.1 – TSB 11kV Feeders Peak Load Forecast (A) – Existing System

Feeder	TSB08	TSB06	TSB14	TSB13	TSB12	TSB15	TSB20	TSB18	TSB21	TSB23
SD-NC	318	226	226	226	226	226	226	318	226	226
SD-N-1	210	150	150	150	150	150	150	210	150	150
SD-EC	380	230	230	230	230	230	230	380	230	230
O/C	300	200	200	200	200	200	200	300	200	200
Year										
2004/05	113	113	126	118	68	118	77	8	8	8
2005/06	118	113	126	118	68	118	77	8	8	8
2006/07	120	113	126	118	68	118	77	8	8	8
2007/08	120	113	126	121	71	121	80	8	8	8
2008/09	122	113	126	121	71	121	80	8	8	8
2009/10	122	113	126	121	71	121	80	8	8	8
2010/11	127	113	126	121	71	121	80	8	8	8
2011/12	127	113	126	121	71	121	80	8	8	8
2012/13	127	185	126	121	71	121	80	8	8	17
2013/14	127	185	126	121	71	121	80	8	8	17
2014/15	127	185	126	121	71	121	80	8	8	17
2015/16	127	202	126	122	72	122	81	8	8	17
2016/17	127	229	126	122	72	122	81	8	8	17
2017/18	127	229	126	122	72	122	81	8	8	17
2018/19	127	233	126	125	75	125	84	9	9	17
2019/20	127	233	126	128	78	128	87	9	9	17

Note 1 - Colour code: Red - Peak load > N-1 (66% of Cable Rating); Yellow - Peak load > 50% of Cable Rating; Green - Peak load < 50% of Cable Rating; Black – Peak load > SD-NC

APPENDIX N
Future Loads

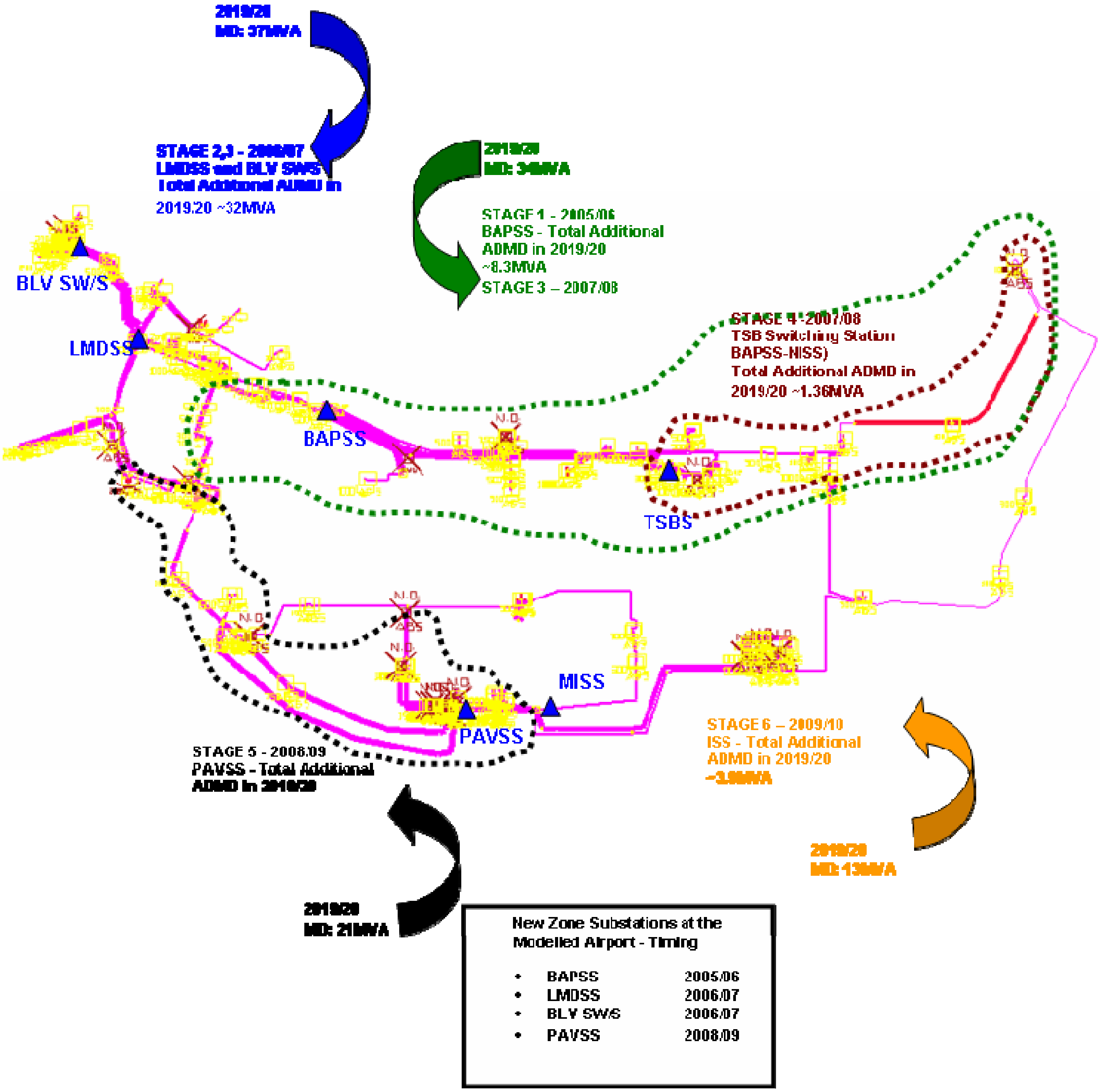


Figure N.1 – Future Load and New Zone Substations at the Modelled Airport

APPENDIX O

LMDSS and NISS Network Models

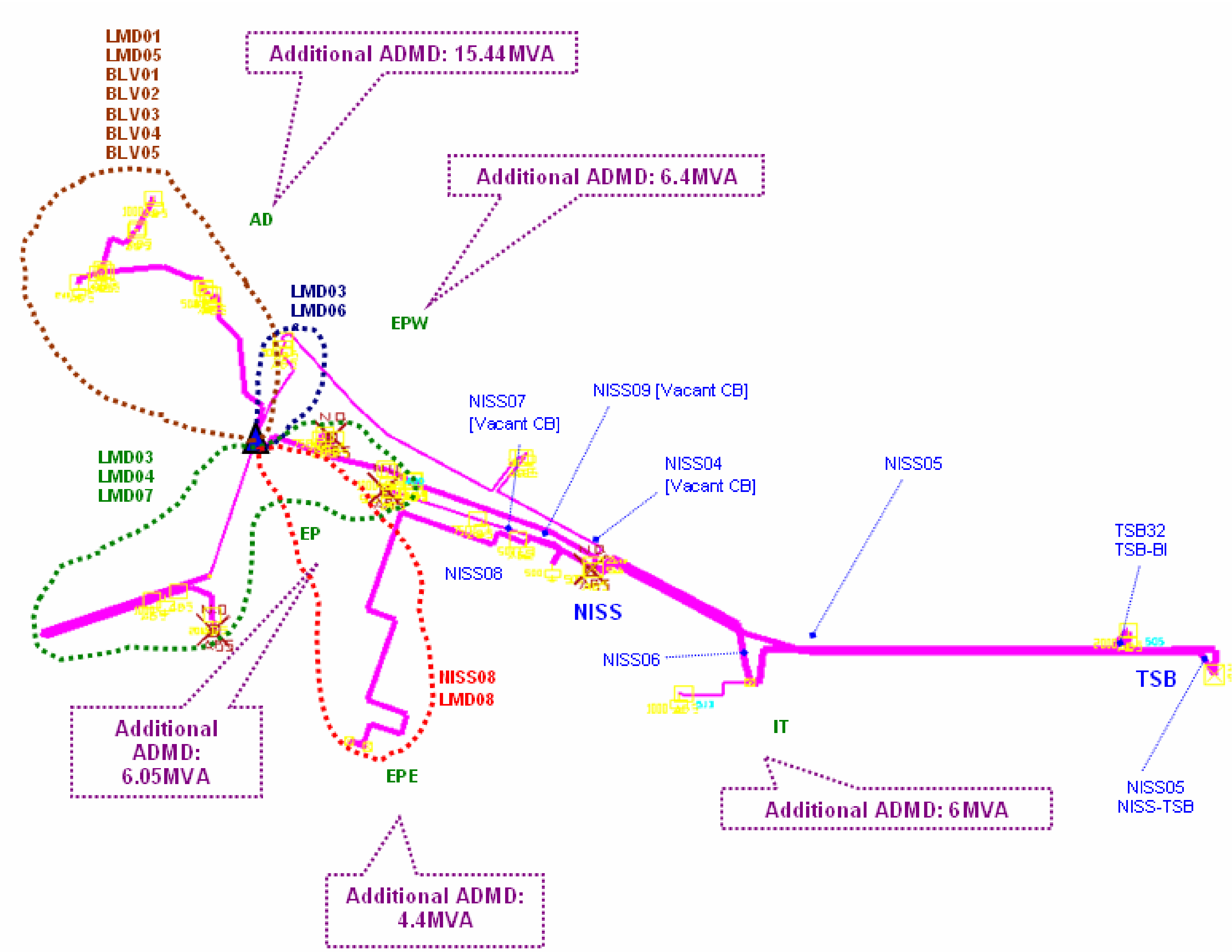


Figure O.1– LMDSS and NISS Network Models

APPENDIX P
LMDSS Load Flow Study – 2019/20

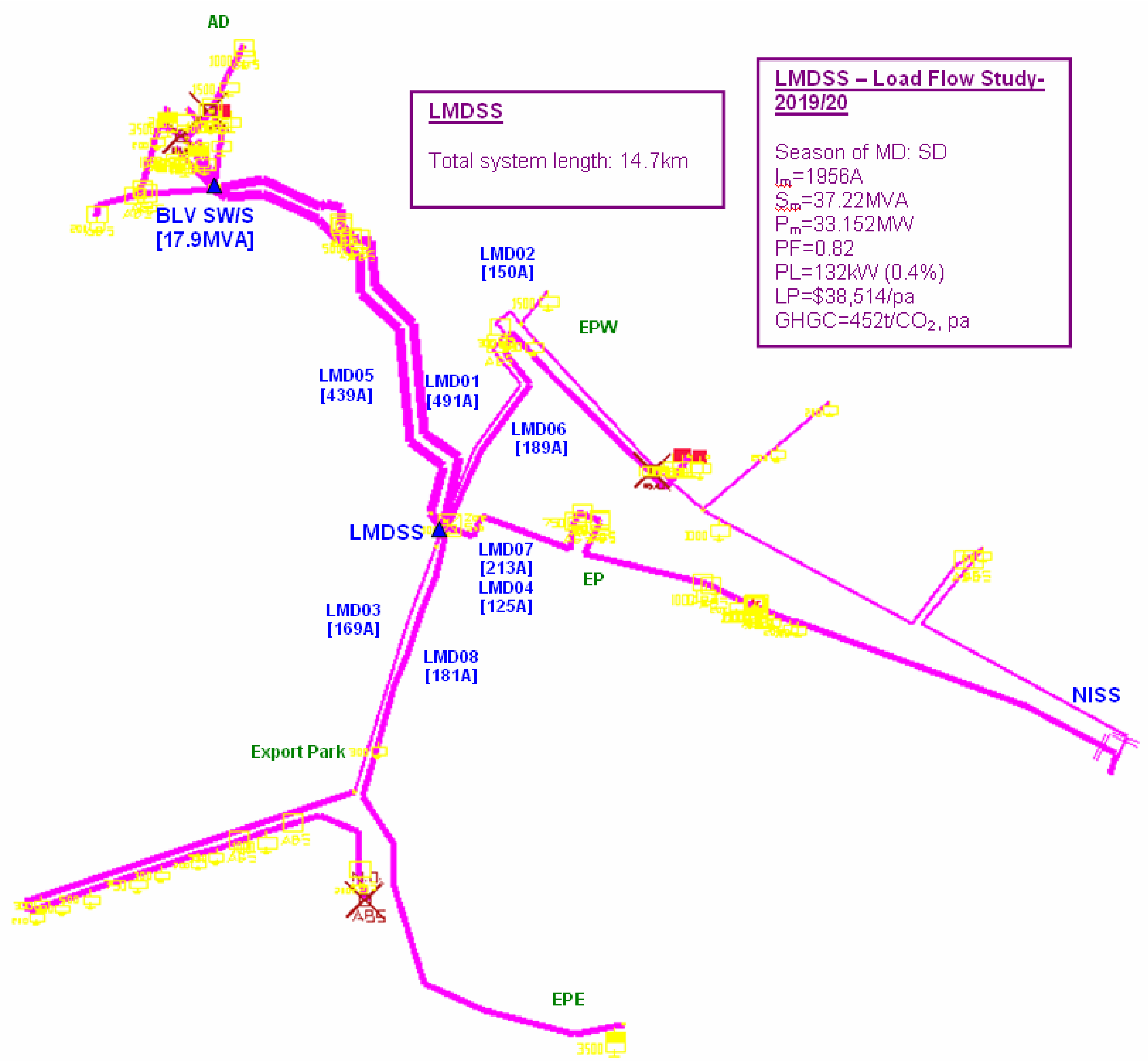


Figure P.1– LMDSS Load Flow Study – 2019/2020

REFERENCES

Abdallah, J 2007, *Distribution Network Planning and Design Using Branch and Bound Methods*, American Journal of Applied Science 2 (3): 644-647, ISSN 1546-9239, Science Publications

ACIL Tasman 2010, *System Maximum Demand Guidelines*, Common Forecasting Methodology prepared for Ergon Energy and Energex, Brisbane

ACIL Tasman 2010, *System Energy Guidelines*, Common Forecasting Methodology prepared for Ergon Energy and Energex, Brisbane

ACIL Tasman 2010, Spatial De*mand Guidelines*, Common Forecasting Methodology prepared for Ergon Energy and Energex, Brisbane

ALSTOM 2002, *Network Protection and Automation Guide*, 1^{st} edn, ALSTOM, Paris

Anders, GJ 1990, *Probability Concepts in Electric Power Systems*, John Wiley & Sons Inc, New Jersey

Anders, GJ 1997, *Rating of Electric Power Cables*, McGraw Hill, IEEE Press, New York

Anders, GJ 2005, *Rating of Electric Power Cables in Unfavourable Thermal Environment*, IEEE, Power Engineering, John Wiley & Sons Inc, New Jersey

Armstrong, P 2000, *Single Wire Earth Return (SWER)*, Course presentation, MERITEC, Wellington

AS 2279 1991, *Disturbance in mains supply networks*

AS 3000 1981, *SAA Wiring Rules*

AS 3008.1 1989, *Electrical Installations, Selection of cables, 2^{nd} edn*

AS/NZ 61000 1999, *Electromagnetic Compatibility – Part 6-4: Generic Standards*

Australian Government, *The Smart Grid: An Introduction,* viewed on 27 August 2009, <http://www.energy.gov>

Australian Government 2009, *Smart Grid, Smart City – a new Direction for a new energy era*, Barton, ACT

Burkes, J 2002 *Hard to Find Information about Distribution Systems*, ABB Reference material, 5^{th} Edition

Caamaño, E, Suna, D, Thornycroft, J & Cobben, S 2007, *Utilities Experience and Perception of PV Distributed Generation*, PV Upscale, Intelligent Energy Europe

Caamaño, E, Thornycroft, J, De Moor, H & Cobben, S 2007, *State-of-the-Art on Dispersed PV Generation: Publications review on the impacts of PV Distributed Generation and Electricity networks*, PV Upscale, Intelligent Energy Europe

Canadian Electricity Association 1982, *Distribution Planner's Manual*, CEA/CEATI, Montreal

Carrter-Brown, CG 2005, *ESKOM Distribution Network Planning, a Quantum Leap to Meet Increased Load Growth and Improved Network Reliability*, ESKOM, <http://www.ameu.co.za>

CEPG 8044, *Ferroresonant over-voltage risk limitations on distribution transformers*

CEM7097 1997, *Overhead design manual*

Chant, T 2009, *Impacts of Increased Solar Panel Utilisation on Utility Grid Operations,* Planning thesis CQ University & Ergon Energy, Rockhampton

Christ, R 2009, *Planning Guideline to Fault Study,* Distribution Network Planning Manual NP&D, Ergon Energy

Clay, W 2010, 'Zone Substation Plant Rating Programme', conference paper presented on the IV Network Conference, Ergon Energy, Townsville

CRA International 2008, Assessment of the Value of Customer Reliability (VCR), Report prepared for VENCorp, Melbourne

Distribution Planning, viewed on 18 May 2010, <http://www.adea.net.au/planning.html>

Dikgale, O 2006, "Comparison of approaches to Distribution Network Planning and Design", Master thesis, University of Cape Town

Dalitz, C 2008, 'A Distribution Planning Manual for Country Energy', Country Energy, conference paper presented on the III Network Conference, Ergon Energy, Rockhampton

EEE Std. 1243-1997 1997, *IEEE Guide for improving the lightning performance of electric power overhead transmission lines*

ENA 2009, *Smart Networks,* Position Paper, Barton, ACT

Energex 1999, *Plant Rating Manual,* Energex, Brisbane

Energex 2004, *Criteria for Loading of the Electricity Network,* Energex, Brisbane

Ergon Energy 2003, *Interim Report on After Diversity Maximum Demand,* NP&D, Ergon Energy

EPIC 2006, *San Diego Smart Grid Study*, Final Report, University of San Diego

Ergon Energy 2003, *Network Planning Criteria Version 3.04,* NP&D, Ergon Energy

Ergon Energy 2003, *Planning guideline to voltage regulation,* NP&D, Ergon Energy

Ergon Energy 2009, *Smart Grid, Smart City,* Pilot Project, Ergon Energy

Ergon Energy 2010, *Guide to Distribution Planning Reliability*, System Development, Ergon Energy

ESAA 1989, *ESAA Guide to the installation of UG cables*, C/b/2

ESAA 1995, *Guidelines for Reliability Assessment Planning,* Melbourne

Freris, LL & Infield, DG 2009, *Renewable energy in power systems*, Wiley & Sons, Chichester,UK

Gardiner, PD 2005, *Project Management - A Strategic Planning Approach,* Palgrave Macmillan, New York

Goonaverdana, S 2009, *Effects of PV and CFL on the Grid,* Desktop Study, Ergon Energy

Hermann, L 2010, 'A Non Asset Weather Based Solution for Applying Dynamic Line Rating', conference paper presented on the IV Network Conference, Ergon Energy, Townsville

Howarth, P 2008, 'Distribution Planning 'The Swinging Pendulum', Energy Australia, conference paper presented on the III Network Conference, Ergon Energy, Rockhampton

Integral Energy 2003, *Network Parameters*, Special Report No. 67

Ivanovich, GS 2000, *Desktop Study: Reliability study of Distribution Feeders,* Energex, Brisbane

Ivanovich, GS 2004, *Desktop Study: Typical DF Daily Load Curves,* Ergon Energy, Toowoomba

Ivanovich, GS 2005, *Airport Strategic Review*, Ergon Energy, Toowoomba

Ivanovich, GS 2008, *Distribution Network Planning Manual,* Version 1.0, Ergon Energy

Ivanovich, GS 2006, *Desktop Study: Distribution Feeder Overloading Risk Assessment,* Ergon Energy, Toowoomba

Ivanovich, GS 2007, *Desktop Study: NPV Sensitivity Analysis,* Ergon Energy, Toowoomba

Ivanovich, GS 2009, *Desktop Study: Concept of DER,* Ergon Energy, Toowoomba

Ivanovich, GS 2008, *Desktop Study: Distribution Feeder Fault Contours,* Ergon Energy, Toowoomba

Ivanovich, GS 2008, *Desktop Study: Dynamic Line Rating Report,* Ergon Energy, Toowoomba

Ivanovich, GS 2008, *Desktop Study: Modelling ZSS Load,* Ergon Energy, Toowoomba

Ivanovich, GS 2008, 'Distribution Network Power Losses', paper presented on III Network Conference, Ergon Energy, Rockhampton

Ivanovich, GS 2009, *Desktop Study: Ergon Energy Smart Grid Pilot Project,* Ergon Energy, Toowoomba

Ivanovich, GS 2009, *Desktop Study: Project Risk Assessment – a Case Study,* Ergon Energy, Toowoomba

Ivanovich, GS 2009, *Desktop Study: Risk Assessment of Distribution Augmentation Project,* Ergon Energy, Toowoomba

Ivanovich, GS 2009, *Desktop Study: UG Cable Rating Philosophy,* Ergon Energy, Toowoomba

Ivanovich, GS 2010, *Desktop Study: DP Process,* Ergon Energy, Toowoomba

Ivanovich, GS & Turner J 2008, *The Basics of Single Wire Earth Return System,* Transmission and Distribution magazine, Issue 4

Ivosevic, N 1970, *Elektroenergetika, Osnovni principi i energetsko-ekonomske Informacije*, (Power Engineering, The Basic Principles and Energy and Economic Information), Institut za Naucno-Tehnicku Dokumentaciju i Informacije (Institute for Scientific and Technical Documentation and Information), Beograd (on Serbian)

Jain, V, Connor T & Bose C, 2005, *Greenfield Planning for Distribution Network of Megacities – Basis for Reduction of Losses, Costs and Assets*, viewed on 21 January 2010, <http://www.sg.cier.org.uy/cdi/cier-zeus.nsf>

Jain, V, Connor, T & Bose, C, 2008, *Greenfield Planning for Distribution Network of Megacities – Basis for Reduction of Losses, Costs and Assets*, Siemens Service Department's paper, Mumbai

Johnson, G & Scholes, K 2002, *Exploring Corporate Strategy*, 6th edn, FT Prentice Hall, Essex

Leyland, B 2006, *Rural Electrification: Economy, Efficiency and Project Planning*, <http://www.bryanleyland.co.nz>

Laukamp, H, Diaz J, Erge, T & Ebert, G 2007, *Grid Effect of Large, Distributed PV Capacity in a Modern Urban Settlement*, paper presented on the Renewable Conference, Milano

Laukamp, H, Thoma, M, Meyer, T & Erge, T 2007, *Impact of a Large Capacity of Distributed PV Production on the Low Voltage Grid*, paper presented on the Renewable Conference, Paris

Mandeno, L 1947, *Rural Power Supply – Especially in Back Country Areas,* The New Zealand Institution of Engineers, Ferguson & Osborn Printers, Wellington

Mielczarski, W 1997, *Quality of Electricity Supply and Management of Network Losses,* Energy Optimal Solution, Melbourne

McGraw-Edison Company, Power System Division 1974, *Distribution System Protection Manual,* McGraw-Edison, Canonsburg

McAllister, D 1982, *Electric Cables Handbook*, Granada Pubishing Ltd, Forgmore, St Albans

National Oceanic and Atmospheric Administration (NOAA), *Return Stroke*, viewed 15 March 2009, <http://www.nssl.noaa.gov/primer/lightning/ltg_bascis.html>

NSW Ministry of Energy and Utilities 2005, *NSW Network performance reports, 2004-2005,* NSW ME&U, Sydney

Naimane, V & Andersson, G 1999, 'Distribution Network Reinforcement Planning: A Dynamic Multi-Criteria Approach', Proceedings of the PowerTech Electric Power Engineering International Conference, Budapest, p 260

Naimane, V, Sauhats, A, Vempers, G, Tereskina, I & Bockarjova, G 2008, 'Approach for Energy Supply System Planning Based on Cooperative Game Theory', *IEEE Electronic Literature*, viewed 20 April 2010, <http://ieeexplore.ieee.org>

Naimane, V 2001, 'Distribution Network Planning Based on Statistical Load Modelling Applying Genetic Algorithms and Monte-Carlo Simulations'

NSW Department of Water and Energy 2006, *NSW Service and Installation Rules, Code of Practice,* NSW DW&E, Sydney

NSW Ministry of Energy and Utilities 2005, *Design, Reliability and Performance License Conditions Imposed on Distribution Network Service Providers by the Minister for Energy and Utilities,* NSW ME&U, Sydney

NSW Ministry of Energy and Utilities 2003, *NSW Statement of System Opportunities*

O'Flynn, D 2008, 'Distribution 11kV Load and Utilisation Forecasting and Development Planning', Energex, conference paper presented on the III Network Conference, Ergon Energy, Rockhampton

Oberthur, JC 1966, *Distribution System Planning in Suburban Brisbane*, Brisbane Division Technical Papers Vol 7, No.3

OLEX 2000, *High Voltage OLEX Cables*

Patroni, D 2008, 'Proactive LV Network Planning', Western Power, conference paper presented on the III Network Conference, Ergon Energy, Rockhampton

QUT Postgraduate Electricity Supply Training Course 2002, *EEP208 Economic Analysis for Power System Engineers*, Brisbane

QUT Postgraduate Electricity Supply Training Course 2003, *EEP209 Harmonics*, Brisbane

SCC 1970, *Plant Rating Manual*, Sydney County Council

SECV-DISTNET 1993, *Cable Current Ratings and Earthing*

SEQEB 1992, *Plant Rating Manual*, SEQEB, Brisbane

SEQEB 1997, *Economic Analysis Requirements of Planning Investigations*, SEQEB, Brisbane

Sinclair Night Merz 2001, *Ergon Energy Conductor/Cable Rationalisation,* Brisbane

Skilling, HH 1974, *Electric Networks, Willey International Edition,* New York

SKM 2009, *Advice on Development of a National Framework for Electricity Distribution Network Planning and Expansion*, SKM, Report for AEMC

Stephens, G 2004, 'UG Cable Sizing and Capacity', conference paper presented on the I Network Conference, Ergon Energy, Rockhampton

Stretton, A 1994, *A Short History of Modern Project Management,* The Australian Project Manager, vol. 14

Stojanovic, D 1989, *Problematika gubitaka elektricne energije in snage (Problems of Energy and Power Losses)*, Technical Report, Elektrotehnicki Fakultet Nikola Tesla (Nikola Tesla Faculty for Power Engineering), Pristina (on Serbian)

SynerGEE, *Distribution Planning*, viewed 10 May 2010, < http://www.adea.net.au/planning.html>

The Electricity Authority of New South Wales 1968, *High Voltage Earth Return Distribution for Rural Areas*

Thorpe, D 2007, *Management of Technological Risk – Study book*, USQ Faculty of Engineering and Surveying, Toowoomba

Turner, RJ 1999, *The Handbook of Project-Based Management,* McGraw-Hill, Berkshire

USQ 2005, *Management of Technological Risk – Selected readings*, USQ Faculty of Engineering and Surveying, Toowoomba

VENCorp Final Report 2003, *The Value of Unserved Energy to be Used by VENCorp for Electricity Transmission Planning*

VENCorp 2003, *Electricity Transmission Network Planning Criteria,* VENCorp, Melbourne

Watt, M 2004, *The Value of PV in Summer Peaks*, Centre for Photovoltaic Engineering, University of New South West, Sydney, viewed 4 June 2008, <http://www. unsw.edu.au>

Wells, AT & Young, BS 2003, *Airport Planning and Management* – 5th edn, McGraw-Hill, New York

Wikipedia, *Photovoltaics,* viewed on 26 August 2009, <http://en.wikipedia.org/wiki/Photovoltaics 2009>

Wikipedia, *Wind Power,* viewed on 26 August 2009, <http://en.wikipedia.org/wiki/Wind power>

Wishart, M 2010, *SWER Line Capacity Improvement through Utilisation of Non-embedded Distributed Generation Resource*, QUT, Australian Strategic Technology Programme

Zhou, JB 2010, 'HV Underground Cable Ratings', conference paper presented on the IV Network Conference, Ergon Energy, Townsville