5.09

Cost benefit analysis for planning

Ausgrid

REVIEW

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Warning

This document will be amended as new information becomes available. Users are cautioned to check for the latest version of the document before relying of its contents.

Cost benefit analysis for Planning

Contents

1 Introduction

1.1 Purpose

The planning of augmentations of Ausgrid's network is based on cost benefit analysis of the alternative options which could be adopted to satisfy identified needs.

One of the factors of this analysis is the value of unserved energy which would result from an interruption to supply and this is determined by estimating the probabilities of the various items of equipment being unavailable for service. Other factors taken into account are safety risks, environmental risks and maintenance costs. This forms the basis of probabilistic planning.

This document sets out the detailed procedures that Ausgrid has established in order to develop a Project Investment Portfolio (PIP) plan based on probabilistic planning and cost benefit analysis (CBA).

1.2 Probabilistic planning tools

Ausgrid has developed 4 tools to assist in the probabilistic planning process

11kV Switchgear to determine the optimal replacement date for 11kV busbars and associated switchgear in Zone substations

33kV-132kV Switchgear to determine the optimal replacement date for 33kV-132kV busbars and associated switchgear

Zone Capacity to determine the optimal date to replace or augment Zone Substation transformer capacity

Subtransmission Feeder Capacity - a more general model to determine the amount of unserved energy based on probable outages of various critical items of equipment.

The purpose of the probabilistic planning process is:

1. To provide a basis for comparing investment options which would determine the most preferable investment option, whilst maximising the net economic benefit.
2. To determine if the project is a sound investment and to determine the most beneficial economic timing of the investment.

1.3 Supporting documentation

Each of these tools is described in this document together with the rational underpinning their development.

For each of the tools, separate User Guide documents have been prepared which are used to guide staff in their use.

1.4 Acronyms and abbreviations

AER	Australian Energy Regulator
AEMO	Australian Energy Market Operator
BSP	Bulk Supply Point
CBA	Cost Benefit Analysis
EPA	Environmental Protection Authority
EUE	Expected Unserved Energy
IR	Insulation Resistance
MTTR	Mean Time to Repair
NER	National Electricity Rules
PIP	Project Investment Portfolio
POE	Probability of Exceedance
SAIDI	System Average Interruption Duration Index
SAIFI	Service Average Interruption Frequency Index
STPIS	Service Target Performance Incentive Scheme

STS	Subtransmission Substation
VCR	Value of Customer Reliability

1.5 Planning criteria

1.5.1 Transmission licence conditions

During 2016, at the request of the Minister, IPART conducted a review of the transmission planning criteria which resulted in a new planning approach based on probability analysis.

This standard defines the level of redundancy required at each bulk supply point, with allowance to cater for some expected unserved energy. At each bulk supply point, a non-zero amount of load must be supplied following the outage of a single system element.

In the case of the inner Sydney Metropolitan Area, the five Inner Sydney bulk supply points (Beaconsfield West, Haymarket, Rookwood Rd, Sydney North and Sydney South) would be regarded as a single "group" acknowledging that the standard can only be achieved if TransGrid's transmission network and Ausgrid's supporting subtransmission network are considered as a single integrated network.

For Sydney Inner Metropolitan bulk supply points, TransGrid and Ausgrid must co-operate to ensure that

a. A non-zero amount of load must be supplied following the outage of a single system element (includes a single 132kV feeder, 330kV feeder or 330kV/132kV transformer)

b. A non-zero amount of load must be supplied following the simultaneous outage of a single 330kV cable and any 132kV feeder or 330/132kV transformer

c. The expected unserved energy for any bulk supply point does not exceed 0.6 minutes per year at average demand.

TransGrid and Ausgrid are not required to comply with these requirements if IPART approves a plan submitted by TransGrid and Ausgrid and that plan is implemented within the nominated time frame.

Any plan submitted in this way will contain an analysis of the cost benefit analysis (CBA) in view of maximising the net economic benefit.

It is anticipated that by mid-2018, the NSW Government will adopt the IPART recommendations and amend the licence conditions to enforce these requirements

1.5.2 Distribution licence conditions

Prior to 2014, Ausgrid's licence conditions mandated design planning criteria for the network in deterministic terms. The design planning criteria specified the number of network elements that could be removed from service without causing an interruption to supply for different parts of the network. This was referred to as the (n), (n-1) or (n-2) security standards.

The design planning standard has now been removed but Ausgrid must maintain reliability levels of SAIDI and SAIFI below minimum thresholds.

SAIDI the sum of the durations of each sustained customer interruption (measured in minutes) in a financial year divided by the total number of customers.

SAIFI the total number of sustained customer interruptions in a financial year divided by the number of customers.

The SAIDI and SAIFI standards are defined for four feeder types and for individual high voltage distribution feeders. In each case, different standards are defined for different high voltage distribution feeders.

- Sydney CBD
- Urban
- Short rural
- Long rural

In addition, the Customer Service Standards define the maximum duration and the maximum number of interruptions to a customer's premises in a financial year with separate targets for customers in metropolitan and non-metropolitan areas.

The licence provides for Ausgrid to make certain payments to customers if the number and duration of interruptions in a financial year exceeds the specified limits.

Ausgrid is required to investigate the causes for any high voltage distribution feeder exceeding the individual feeder standards and take steps to improve the performance of the network to comply with the licence conditions.

In order to comply with the licence conditions, Ausgrid now adopts a probabilistic approach to network planning.

1.6 Ausgrid regulatory environment

The Service Target Performance Incentive Scheme (STPIS) is a mechanism used by the AER to assign a value to reliability of supply to customers. The incentive scheme penalises Ausgrid financially for failing to provide supply standards, based on measurements of duration (SAIDI) and frequency (SAIFI) of power interruptions.

It has been determined that, in order to avoid unnecessary investment in capital works, the community is generally prepared to accept some interruptions to supply and the introduction of STPIS is an attempt to factor this into the planning process.

An alternative method of accounting for possible interruptions of supply is to use probabilistic planning where a dollar value (Value of Customer Reliability (VCR)) is applied to the probable amount of unserved energy resulting from equipment failures and to include this value in an overall cost/benefit analysis which includes all of the project costs. In this way, the VCR becomes a surrogate measure of STPIS.

In the longer term, as the benefits of probabilistic planning are realised, the results, measured in terms of the STPIS, will be evaluated and the factors used in the probabilistic planning process will be adjusted to more closely align the results with the STPIS targets.

1.6.1 Capacity planning

Probabilistic planning is used to determine the appropriate response to capacity shortfalls by calculating the cost/benefit of each of the possible solutions taking into account all of the costs and benefits of the option, including the value of unserved energy. One of the key factors used in this analysis is the VCR and, for the CBA assessment, the values recommended by the AER have been used. It is anticipated that this will result in the amount of unserved energy at any bulk supply point not exceeding 0.6 minutes per year at average demand as required by the licence conditions and the overall reliability of network will meet the requirements of the STPIS.

1.6.2 Replacement planning

The Asset Management Strategy Performance & Innovation Branch in the Asset Management & Operations Division monitors the condition of all equipment and identifies equipment which is approaching the stage when it should be decommissioned and accordingly develops investment plans as described in Network Standard NIS435 (Ref 3).

Major replacement investments require a comprehensive strategic approach and consequently they are included in the Area planning process (Refer section 1.7.1) conducted by the Asset Investment Branch in the Asset Management & Operations Division.

In such cases, the Asset Management & Operations Division provides a list of the required replacement needs supported by condition reports together with an indicative timeframe for the replacement/retirement to take place. The Area Plan is formulated taking these factors into account.

Currently there are two major replacement programs which involve:

- The retirement of oil filled cables. This program has already commenced and is due to be completed around 2039. This program is driven mainly by environmental and asset condition issues.

- The retirement of certain 11kV switchgear replacement program, especially oil circuit breakers and air-insulated equipment which is not fitted with earthed metal barriers. This program is driven mainly by duty of care (safety) and asset condition issues.

1.7 Planning process

1.7.1 Area planning

For the purposes of planning augmentations to the subtransmission network, Ausgrid has divided its franchise area into 25 geographic '*Areas'* and generates a sub-transmission *'Area Plan'* for each geographic *'Area'*.

The requirements of the Ausgrid *transmission/dual function network* that links TransGrid's bulk supply points to Ausgrid's distribution network are considered based on the broader Sydney Inner Metropolitan, Central Coast and Hunter regions to create three *'Transmission Area Plans'*. Each of these regions encompasses multiple '*Areas'*.

Each Area Plan is revised periodically. This process involves a detailed investigation into all the needs, constraints and possible strategic solutions for that area. It is designed to capture all of the drivers relating to the area and encompasses a ground up review of all credible strategies for meeting the network needs in that area. Following this process, the area plan defines a suite of projects that form the *preferred strategy* for that geographic area.

This process is described in detail in Network Standard "NIS419 Area Planning" (Ref 1).

1.7.2 Annual capital review process

Each year, after the load forecasts have been updated, each of the area plans is reviewed to determine if the proposed dates of all of the projects included in the plan are still appropriate and to initiate any necessary changes to the program.

This review involves running the appropriate planning models for the preferred strategies with the latest data. The models already incorporate all of the parameters required for probabilistic planning so it is appropriate to base this review on probabilistic planning.

1.8 Framework of probabilistic planning

1.8.1 Regulatory context

The Australian Energy Regulator (AER) Regulatory Test and Chapter 5 of the NER mandate a probabilistic planning approach to network investment decisions.

The Regulatory Test also specifies the assessment methodology to be used.

> *"The purpose of the regulatory investment test for distribution is to identify the credible option that maximizes the present value of the net economic benefit to all those who produce, consume and transport electricity in the National Electricity market (the preferred option). For the avoidance of doubt, a preferred option may, in the relevant circumstances, have a negative net economic benefit (that is, a net economic cost) where the identified need is for reliability corrective action."*

> *"The regulatory investment test for distribution must be based on a cost-benefit analysis that must include an assessment of reasonable scenarios of future supply and demand; …"*

> *"The regulatory investment test for transmission must be based on a cost-benefit analysis that is to include an assessment of reasonable scenarios of future supply and demand if each credible option were implemented compared to the situation where no option is implemented; …"*

1.8.2 Probabilistic planning approach

The probabilistic planning approach involves estimating the probability of an equipment outage and determining the amount of energy which would be interrupted as a result. A value is placed on this failure by multiplying the amount of lost energy by the VCR as discussed in Section 3.7.1.

This value of unserved energy together with other risks is included in the cost benefit analysis to justify a project – both to determine the optimal project solution to address a need and to establish the appropriate date to implement the project.

This approach has the advantage that investments are not made for infrastructure that would only be rarely utilised.

2 Cost-benefit Analysis Methodology

2.1 Overview of methodology

Cost benefit analysis is used to compare options in order to determine the solution that best addresses the business needs and mitigates risks whilst maximising the net economic benefit. The following figure illustrates the general cost-benefit analysis methodology that is applied in Ausgrid's planning process.

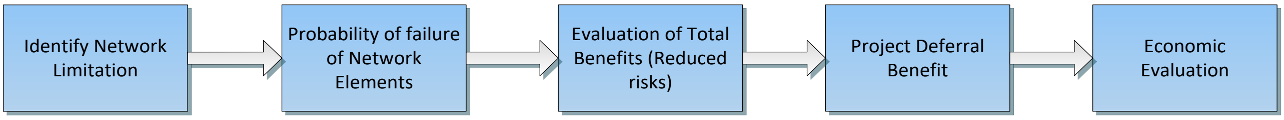

Figure 2-1 Simplified cost benefit analysis process

The methodology uses the state numeration technique[1] which generates a number of *states* that represent the status of the network with different elements out of service. The probability of each *state*, the resulting load curtailment and the associated expected unserved energy for each state is calculated. The total expected unserved energy is the sum of all expected unserved energies of all states in the system. By using an appropriate VCR, the cost of expected unserved energy can be determined. Finally, by comparing the total benefits with the project deferral benefit, the project timing of the option can be determined.

Ausgrid has developed following models to carry out cost benefit analysis.

11kV Switchgear to determine the optimal replacement date for 11kV busbars and associated switchgear in Zone substations

33kV-132kV Switchgear to determine the optimal replacement date for 33kV-132kV busbars and associated switchgear

Zone Capacity to determine the optimal date to replace or augment Zone Substation transformer capacity

Feeder Model - a more general model to determine the amount of unserved energy based on probable outages of various items of equipment.

2.2 Baseline definition

In cost-benefit analysis, all network investment options are evaluated against a common baseline – the "do nothing" option. A planning horizon of 20 years is used for this analysis.

The baseline parameters are initially defined to commence the cost-benefit analysis process, and sensitivity analysis is performed with consideration of the extent of data uncertainty and accuracy of data. Ensuring the data consistency and quality used in the baseline is a critical aspect in this process.

2.3 Data sources

Data sets used in this analysis are collected from a number of sources within Ausgrid and from other stakeholders. The major data used in this analysis are summarised below. A more detailed view of the input data and assumptions undertaken are outlined in Section 3.

- Spatial load forecast
- Network connectivity models (PSS/E)
- Condition of network elements (failure rate, repair time, repair cost etc.)
- Load transfer capability between sections
- Switching time
- Safety/environment risks evaluation parameters
- Maintenance costs
- Project cost and cash flow
- Value of Customer Reliability (VCR)

The flow chart below provides a summarised view of the input data, process and outputs that are used in the cost benefit analysis methodology. A detailed description of the process is given in the next section.

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[1] Assessment of Power System Reliability Methods and Applications, Chapter 8, Guideline for Reliability Assessment Planning ESAA DOC 006-1997, Nov 1997

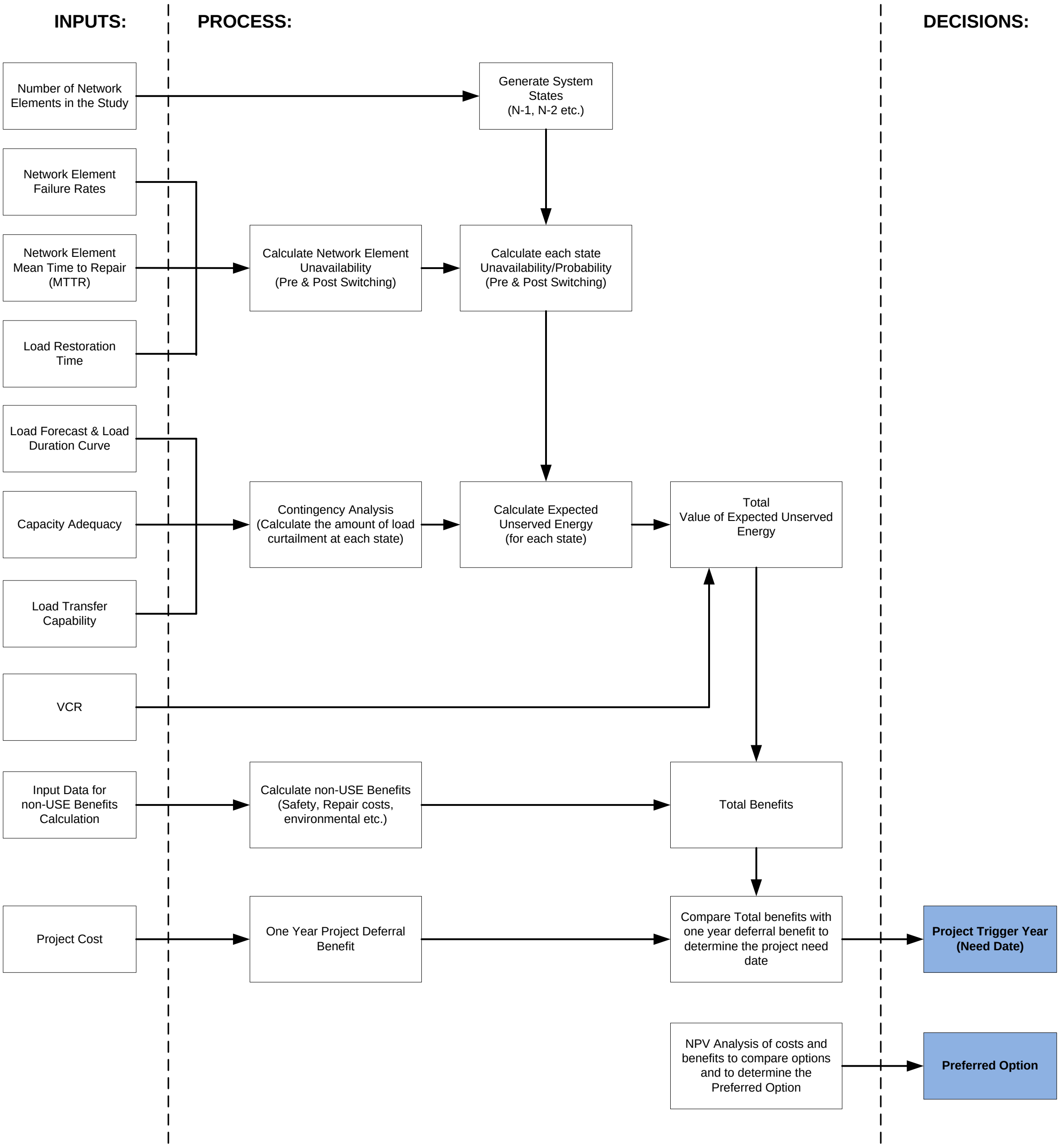

Figure 2-2 Details of input data, process and output of cost benefit analysis

The above diagram shows a number of stages that should be undertaken in succession to determine the project need date for a particular option. Given there are typically multiple options to resolve an issue, a single option (preferred option) is to be chosen. The present value of benefits associated with each option or strategy are evaluated covering the entire planning period. By comparing present value of benefits and the present value of cost, the preferred option and it its timing can be decided.

3 Input Data and Key Assumptions

3.1 Load forecast

Ausgrid develops a spatial peak demand load forecast for the next 20 years based on historical actual loads undertaking necessary adjustments such as weather corrections, rate of growth and foreseeable spot loads. These load forecasts are developed at various confidence interval levels such as POE10, POE50 and POE90. Planning studies are to be based on the POE50 forecast data and sensitivity studies are performed with other POE levels. The following diagram illustrates a load forecast at three different POE levels for a particular substation.

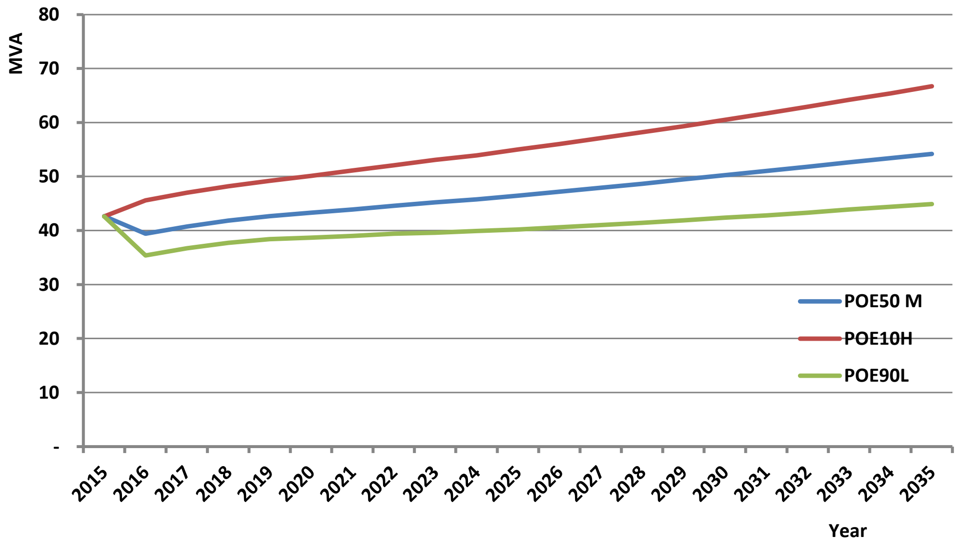

Figure 3-1 Load Forecast

The load forecasts shown above are calculated for both peak summer and winter loads at a substation. However, it should be noted that, at most times, the substation load is much lower than the peak load. As a result, the load duration curve of a substation is considered to be appropriate in order to estimate unserved energy at various load levels as part of the cost-benefit analysis. This provides an estimation of the unserved energy, noting that load curtailment may not be required at lower load levels. The load duration curves are developed using the historical data expressed in per unit values. The diagram below shows a set of typical load duration curves which have been developed based on the categorisation of Ausgrid's standard load cycles.

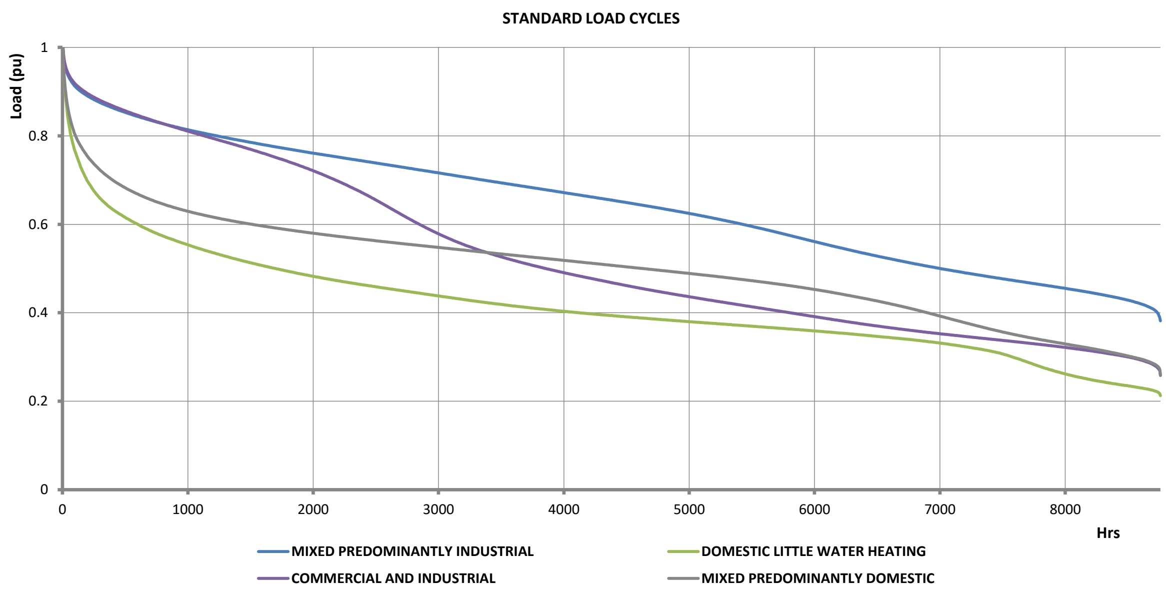

Figure 3-2 Load Duration Curves

At critical locations, the results of the studies were confirmed by running the models using actual load duration curves which were extracted from recorded metering data.

Assumptions:

- The maximum load is determined based on summer or winter peak at the zone substation.
- One of the above load duration curves is assigned to a zone substation. In Ausgrid's RIC system, a load cycle has been assigned for each transformer group with the most appropriate one used to represent the zone substation's load profile.
- For detailed analysis in some situations, actual load duration curves using historical loads for a particular substation are used.
- The identical per unit load duration curve is assigned for future years.

3.2 Project costs

During the initial development of Area Plans, options for addressing the needs are identified and for each option involving capital expenditure, the estimated cost of the works is estimated using Ausgrid's BPC project cost estimating system. These costs are expressed in current day dollar values and separate values are provided for each year of the construction period.

During the annual review process, each preferred solution is reviewed undertaking a cost benefit analysis based on new or updated input parameters.

A breakdown of the project costs can be found in the Project Investment Portfolio (PIP).

3.3 Discount rate

The Discount Rate used in the calculations is determined by the Investment Management section in the Asset Investment branch.

3.4 Ratings of equipment

The capacity of network elements are based on thermal ratings calculated within Ausgrid's Ratings & Impedance Calculator (RIC). In general, normal and emergency ratings are calculated for each network element in the Ausgrid network.

3.5 Load transfer

3.5.1 Capacity

The load transfer capability at a substation is considered to be the amount of load normally supplied from a faulty section of busbar that can transferred to a healthy section of busbar within the same station or to an adjacent zone substations via the existing 11kV feeder network. The extent of transfer capacity is dependent upon the availability of network connectivity and the capacity that can be taken from the alternative supply without causing any equipment to be overloaded.

3.5.2 Switching time

To evaluate network consequence (unserved energy), it is essential to consider the time taken to do the necessary switching to effect the load transfer.

Investigations have shown that following a major incident such as a busbar failure, it takes approximately 2 hours for staff to travel to the site, then to analyse the fault and plan the necessary switching. Each actual switching operation takes approximately ½ an hour which is due mainly to the time taken to travel between the various sites where the switching isolations must occur.

Figure 3 illustrates how the effect of load transfers is modelled taking into account the time taken to do the necessary switching.

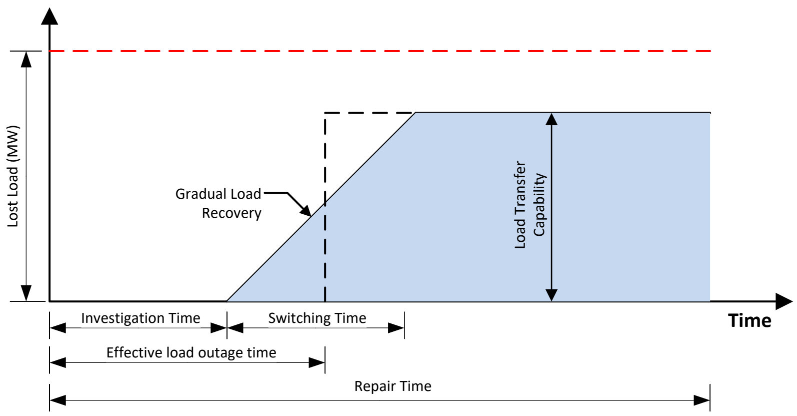

Figure 3-3 Load Transfer (Effective Switching Time)

Where load transfers are done automatically or can be done by remote switching, it is assumed that the load is transferred immediately.

3.6 Failure statistics

3.6.1 Data sources

Ausgrid has a history of over 100 years and it represents an amalgamation of many different organisations that have had many different systems to collect information relating to the performance of the equipment. It is anticipated that as the data requirements for probabilistic planning are refined, Ausgrid will update its existing systems to ensure that the appropriate data can be extracted.

3.6.2 11kV zone substation switchgear

The following diagram shows typical 11kV switchgear arrangements found in Ausgrid's network. Normally, the sections of bus bar are not operated in parallel. The failure of a bus section would result in the loss of supply to all feeders connected to that bus section. In many stations, there are systems to automatically close a bus section breaker if supply is lost to any section of busbar but this is only useful in the event of a failure of the transformers supplying that busbar and is of no benefit it there is a fault on the busbar itself.

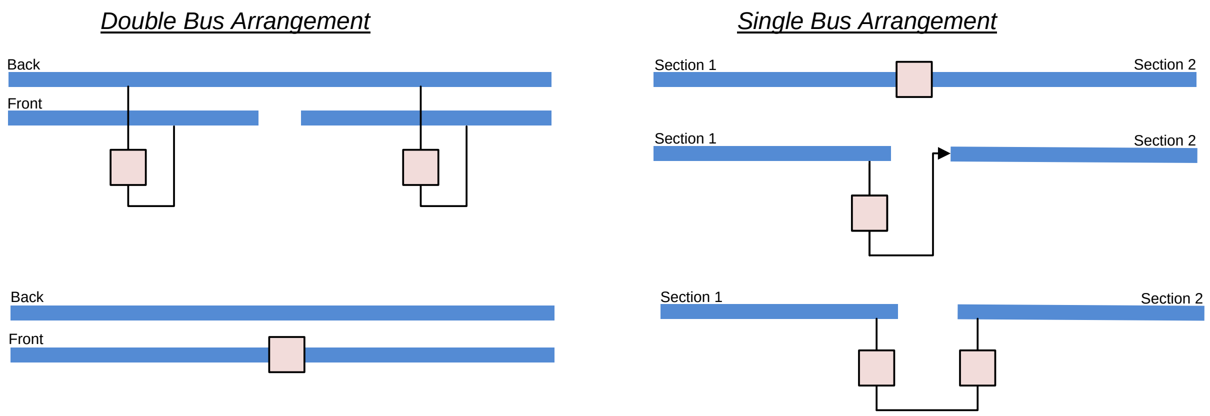

Figure 3-4 11kV Bus Section Arrangements

The condition of 11kV switchgear is determined through periodic testing of both the switchgear and circuit breakers. Consistent with industry practice, the tests performed in Ausgrid are Dielectric Dissipation Factor (DDF), Partial Discharge and Insulation Resistance. Through these tests and historical failure rates, the replacement of these assets is prioritised. The condition information is applied to the generic failure rate parameter β weighted with the specific condition factors and adjusted within a 95% confidence interval on the population switchboard panel distribution. The Strategic Asset Prioritisation (Ref 4) document stipulates these requirements.

By using historical failure data and the average repair times, the unavailability of 11kV switchgear can be modelled enabling the expected value of unserved energy to be determined.

3.6.2.1 Failure Parameters of 11kV circuit breakers

There are two types of 11kV circuit breakers, namely oil and vacuum. Due to the fire risk associated with oil circuit breakers, the current strategy is to replace these with vacuum circuit breakers. At some of the older substations, vacuum circuit breakers cannot be accommodated in the existing switchgear. In these substations, the oil breakers will be retained until the replacement of the complete switchgear can be justified.

During many years of service, the vacuum breaker technology has proven to be extremely reliable and, unlike the experience with oil circuit breakers, there has not been any incident where a failure of a vacuum circuit breaker has led to a major failure of the associated busbar.

For this reason, the failure of a vacuum circuit breaker will result in a minimal loss of supply and hence the failure of vacuum circuit breakers is not considered in the model. On the other hand, the failure of oil circuit breakers can cause significant damage to the associated busbar, and these probabilities are included in the analysis.

The following input data is used to describe the circuit breakers. Minor failures described in the table below are assumed to be negligible and therefore not included in the model.

Table 3-1: Oil circuit breaker parameters

Description		**Category**
Circuit Breaker Type		Oil or Vacuum
Condition		Good, Average or Poor
Failure Rate	Minor	Estimated number of failures per year (negligible)
	Major	Estimated number of failures per year that lead to a busbar failure (constant rate)
Mean Time to Repair (MTTR)		Number of hours to repair the bus and put back into service

3.6.2.2 Failure Parameters of 11kV busbars

For the purpose of this analysis, most failures of 11kV bus sections are assumed to be repairable/replaceable, and that the busbar can be put back in to service after necessary repair works or replacement of damaged parts are undertaken. Two types of failures, minor and major are considered in the analysis. Minor failures are characterised by relatively short duration repair times and are represented by constant failure rates, whereas major failures are 'end-of-life' and non-repairable, and would take a longer time to replace (typically in days or weeks) and it is assumed that the failure probability can be defined in terms of the Weibull distribution. With this distribution, the probability of failure varies with time with an increasing probability as the equipment ages.

The following input data is used to describe 11kV busbars.

Table 3-2: Switchboard parameters

Description		**Category**
Busbar Type		Air or Compound
Condition		Good, Average or Poor
Failure Rate	Minor	Estimated number of failures per year
	Major	Based on Weibull parameters β – Shape factor μ – Scale factor

Mean Time to Repair (MTTR)	Number of hours to repair the bus and put back into service
Age	Based on the commissioned date

The Weibull function is denoted as $f(t)$, where t is expressed in years and the parameters of the function have been derived by analysing the following statistical information.

- The age of Ausgrid's in service 11kV switchboards
- The age of functional failure for Ausgrid's failed switchboards
- The age of retirement for Ausgrid's switchboards that were retired before the point of functional failure

A typical probability distribution function $f(t)$ is shown below in Figure 3-5 (shape = 8, scale = 65)

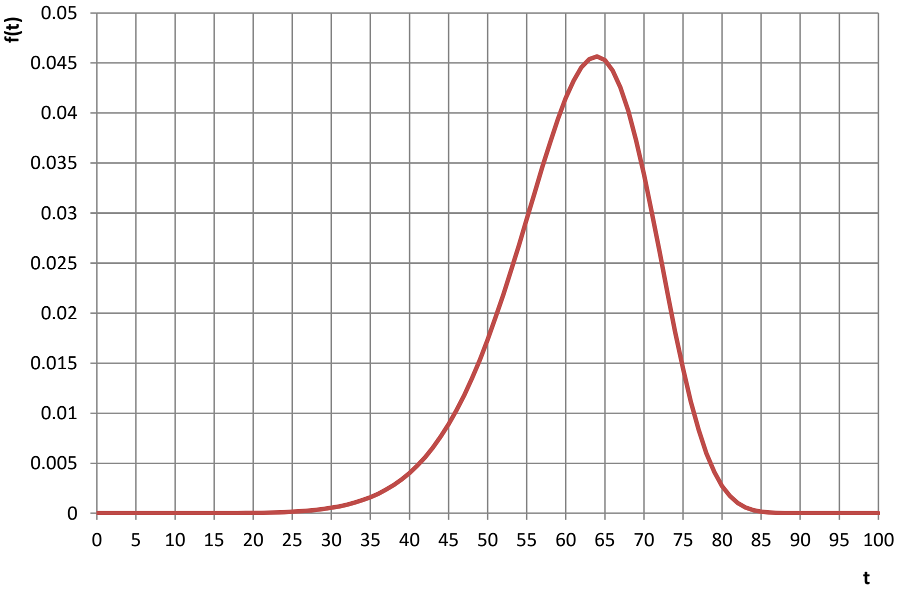

Figure 3-5: 11kV switchboard probability density function

The probability distribution function represents the failure intensity for age t. The concept of conditional probability is applied to evaluate the likelihood of failure. The probability of a failure of an asset occurring within the next year, after having survived for t years, is be calculated by the following equation[2]

$$P_f = \frac{\int_t^{t+1} f(t)dt}{\int_t^{\infty} f(t)dt} \tag{1}$$

Figure ***3-6*** shows P_f when the above equation is applied to the probability distribution function $f(t)$ shown in figure 3. Year by year P_f is used in the evaluation of risk in the cost benefit analysis.

[2] ***Wenyuan Li****, Risk Assessment of Power Systems, Wiley and Sons, Vancouver, 214 (pg 20)*

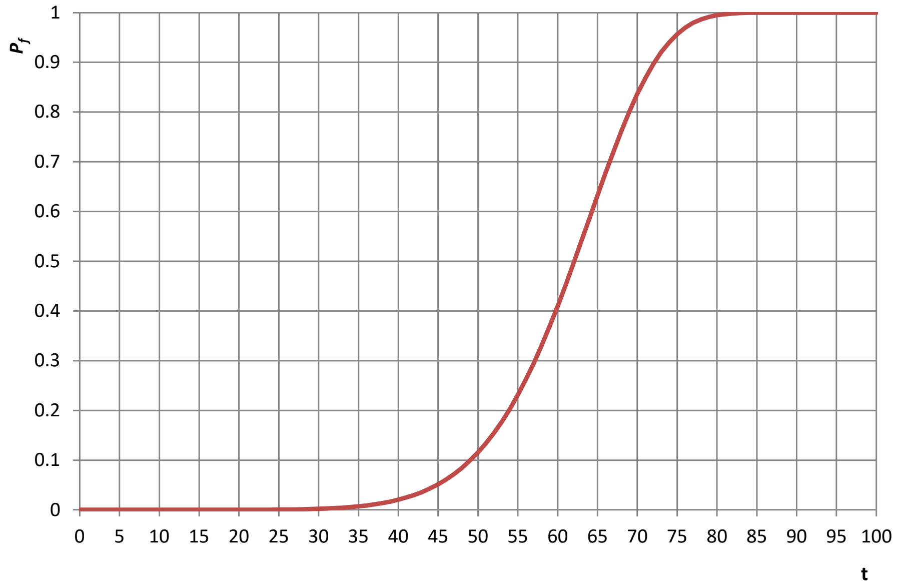

Figure 3-6: 11kV switchboard cumulative distribution function

The Weibull Parameters are determined by the Asset Risk & Performance section based on analysis of the performance of the large population of equipment in the Ausgrid network. To simplify the process of collecting and entering data into the models, separate sets of parameters were provided depending on whether the equipment was in GOOD, FAIR or POOR condition.

The condition of the equipment in the different stations was ranked according to the maintenance test results.

Assumptions:

- All the circuit breaker and switchboard failures are repairable/replaceable as necessary.
- The failure of either front or back bar of double bus arrangement will not be propagated to the other bus which will be in service.
- The failure of vacuum circuit breakers would not cause an outage of corresponding busbar sections.
- The failure of circuit breakers between bus sections would take out both sections which are connected, except in the case of a single bus arrangement when bus sections are connected via two circuit breakers.
- There have been no explosive failures of a vacuum circuit breaker so the safety risk due to vacuum circuit breakers is assumed negligible.
- The condition of similar type of switchboards at a single zone substation is assumed identical.

3.6.3 Failure Parameters of high voltage cables

There are predominantly four types of cables used in the Ausgrid network which are described in Table 3-3.

Table 3-3: Ausgrid's cable types

Type	Category
XLPE	Used for all new 33kV, 66kV and 132kV feeders since 1980s
HSL	Installed from 1960s to 1980s (typically in 33kV)
Gas Pressurised	Installed from 1960s to 1980s (typically in 33kV)
Self-Contained Fluid Filled (Oil-Filled)	Installed from1960s to 1980s (typically in 33kV, 66kV and 132kV)

Ausgrid models cable failures as a non-homogeneous Poisson process where all failures are repairable. A power law model[3], commonly known as the Crow-AMSAA model, is used to describe this process for a population of cables of a particular type (XLPE, HSL, Gas or Oil-filled). The model assumes a cable segment that has failed can be repaired multiple times over its lifetime. The Crow-AMSAA model has a Weibull intensity function given by:

$$z(T) = \lambda \beta T^{\beta-1} \qquad (2)$$

Where:

$z(T)$ is the current failure intensity at time T (per km)

T is the cumulative time (i.e. age of the cable at failure, in years)

β is the shape parameter

λ is the scale parameter

The above process is carried out for various failure modes, namely;

- corrective actions;
- breakdowns; and
- third party damage.

Once the Weibull intensity function parameters are known for each cable population and each failure type, the β parameter is weighted by a condition score for each cable based on the historical oil leaks and IR test results for that cable. The weighting can vary the β parameter within the 95% confidence interval determined for the population parameters. In this way the cable failure model incorporates measures of condition other than age which is commonly used as a proxy for condition.

For each cable and failure type, Weibull parameters are determined as shown below.

Table 3-4: Underground cable parameters

Description	Category
Cable Type	XLPE, HSL, Gas or Oil-filled
Failure Mode	Corrective actions, breakdowns and third part damage
Failure Rate	Based on Weibull intensity function parameters β – Shape factor λ – Scale factor
Mean Time to Repair (MTTR)	Number of weeks to repair the cable and put back in to service (for each cable type and failure mode)
Age	Based on the commissioned date
Length	Length of each cable type in a feeder

Assumptions:

- All cable failures are repairable.
- All cable failures can be categorised as either Corrective Actions, Breakdowns, or Third Party Damage.
- Failures for equipment that do not have a deteriorating failure model are assumed to be sufficiently rare that they can be ignored. Ausgrid's subtransmission feeders have a deteriorating failure model.

[3] See AS IEC 61164-2008 Reliability growth - Statistical test and estimation methods

- When cable failures overload the network, the minimum amount of load is shed to relieve those overloads.
- Conditional feeder ratings are applied, where available, to maximise the capacity of the transmission feeder network. Ausgrid utilises conditional feeder ratings for underground cables where a higher throughput rating can be tolerated during outages of parallel cables.
- The unavailability of associated feeder circuit breakers is not included.

3.6.4 Failure parameters of HV switchgear – 33kV to 132kV

The types of switchgear for voltages 33kV to 132kV used in the Ausgrid network which are described in Table 3-5.

Table 3-5: Ausgrid's Switchgear Types for all Subtransmission Voltages

Type	Category
Outdoor Circuit Breakers (OCB)	Bulk Oil Vacuum GIS Live or Dead Tank (132kV)
Outdoor Isolating and Earthing Switches	Air
Outdoor Busbar	Air
Post Current Transformers	Bulk Oil
Post Voltage Transformers	Bulk Oil
Indoor Switchgear	GIS Air (33kV)

Failures of any of the above switchgear types in table 3.4 are assumed to be repairable/replaceable, and that the equipment can be put back in to service after necessary repair works or replacement of damaged parts are undertaken. Ausgrid models these failures by assuming constant unplanned (forced) failure rates. These Unplanned Failure rates and Mean Time to Repair are available by switchgear category voltage and manufacturer where available. In the case of failure data not being available industry standard failure rates[4] have been used.

3.6.5 Failure parameters of overhead transmission lines

In comparison with high voltage cables, the repair time for failures of overhead transmission lines is generally quite short and it would not be possible to justify the replacement or reinforcement of a line purely on the basis of expected unserved energy. For this reason, the models do not consider the unavailability of overhead transmission lines.

In the very few situations where the failure of an overhead transmission line will have significant impact, Ausgrid has developed contingency plans to minimise the impact of any possible failure.

3.6.6 Failure parameters of transformers

The failure rate of transformers is expressed in terms of the Weibull distribution with sets of parameters for the different transformer types.

This information has been provided by the Asset Risk & Performance section based on the service history of the large number of transformers in the Ausgrid network.

[4] Industry Standard Failure Rates available from the ENA Guide on Reliability Planning (ESAA DOC 006 – 1997 – Guidelines for Reliability Assessment Planning)

3.7 Other inputs and assumptions

3.7.1 Value of customer reliability (VCR)

The Value of Customer Reliability is a measure of the value that the customer places on the reliability of supply and measured in dollars per MWh.

This figure cannot be "measured" but must be estimated based on surveys and discussions with customers.

There have been many attempts to determine appropriate value(s) of VCR and there are a number of estimates in the public domain – including those produced by AEMO and the AER.

Ausgrid has also undertaken a comprehensive analysis to determine appropriate values of VCR.

However, for the current regulatory review, the values of VCR produced by the AER have been used in the analysis:

Ausgrid notes that the values of VCR proposed by the AER do not take into account factors such as:

- Location
- Length of interruption
- Time of interruption (day/night/weekday/weekend etc.)

It is understood that VCR is dependent on the length of interruption seen by the customer. The Ausgrid models have some capability to include a range of VCR values based on some of these factors, but the models may need to be modified if the AER elects to publish a range of VCR values which take these factors into account.

3.7.2 Direct cost of equipment failures

For switchboard failures, these costs are estimated based on following tasks to be undertaken in the event of an outage.

- Access investigation
- Causal analysis
- Engineered solution (T & D)
- Manufacture/repair engineered solution
- Implement engineered solution
- Ancillary works, testing etc.

For cable failures, these costs are estimated based on following tasks to be undertaken in the event of an outage.

- Labour costs
- Material costs
- Contracted services
- Jointing works
- Traffic control
- Protection & earthing

4 Evaluation of Benefits

4.1 Evaluation of benefits

The cost benefit analysis used to justify capital expenditure must take into account certain "risks" which can have an influence on planning decisions.

The benefits that are evaluated within the modelling methodology include:

- Reduced Expected Unserved Energy
- Reduced safety risk
- Reduced maintenance and repair cost
- Reduced environmental Risk

The following sections discuss each of above items.

4.2 Reduced expected unserved energy

4.2.1 Failure Rates

11kV Switchboards:
The following equation is used to calculate the yearly major failure rates based on the Weibull parameters related to the condition of the switchboard.

$$f = \left(\frac{\beta}{\mu}\right) \times \left(\frac{t}{\mu}\right)^{(\beta-1)} \qquad (3)$$

Where:

f is the failure rate

β is the shape parameter

μ is the scale parameter

t is the age (years)

Cables:
The frequency of corrective action, failure or third party damage can be determined by applying the equation below to each cable segment.

$$f = L\lambda(t_2^{\beta} - t_1^{\beta}) \qquad (4)$$

Where:

f is the frequency of failures

L is the length of the cable segment (km)

λ is the shape parameter

β is the scale parameter

t_1 is the age of the cable segment at the start of the year (years)

t_2 is the age of the cable segment at the end of the year (years)

The Expected Unserved Energy (EUE) is the probability weighted average amount of load that would need to be involuntary curtailed due to system limitations. These limitations arise from the unavailability of network elements and the resulting reduction in network capacity to supply the load.

4.2.2 Unavailability

The element unavailability (hours/year) is calculated by applying equation 5.

$$U = f \times MTTR \tag{5}$$

Where;

f is the average failure frequency of an element (failures/year)
$MTTR$ is the mean time to repair (hours)

As the load transfer via switching is included in the analysis, the unavailability is split into two components, namely pre-switching unavailability and post-switching unavailability. The equations below calculate these unavailability values.

$$U_{pre-switching} = f \times Switching\ time \tag{6}$$

$$U_{post-switching} = f \times (MTTR - Switching\ time) \tag{7}$$

In the case of feeder analysis, a feeder is generally comprised of multiple cable segments. The each cable segment unavailability is calculated taking the union of the corrective actions, breakdowns and third party damage unavailability values as shown in Equation 8. Then, the feeder unavailability is calculated by taking the union of all the respective segment unavailability values.

$$U_{total,segment} = U_{corrective\ actions} \cup U_{failures} \cup U_{TPD} \tag{8}$$

$$U_{total,feeder} = U_{segment\ 1} \cup U_{segment\ 2} \cup \dots \tag{9}$$

The probability of outage of an element (unavailability) is the proportion of time that an element is not available to supply the load. This can be calculated for each state (pre-switching and post-switching) as equation 10.

$$P = \frac{U}{8760} \tag{10}$$

Where;

8760 is the number of hours in a 365 day year

The Expected Unserved Energy has been calculated by enumerating all the system states that result in an inability of the network to service the load. This is performed for a discrete set of load levels obtained from the load duration curve for each substation. The probability of residing in each state is calculated from the unavailability of each component. Therefore the probability of residing in each state is given by equation 11.

$$P(s) = \prod_{i=1}^{N_d} PF_i \prod_{i=1}^{N-N_d} (1 - PF_i) \tag{11}$$

Where:

N is the total number of components
N_d is the number of failed components
PF_i is the unavailability of ith component

4.2.3 Load curtailment & energy at risk

Under a contingency event, the load may need to be curtailed to avoid the other elements of the network being overloaded (system limitations). The operator takes necessary actions to shed partial load until the constrained network element is relieved. In addition, there may be situations where the load will be tripped off automatically due to the nature of the contingency event (switchboard failure). This is related to the availability of network connectivity and design configuration at the substation.

The load duration curve at a substation is used to determine the amount of load curtailment required at certain loading levels. Using a discrete number of load points and the capacity adequacy at the substation, the load curtailment can be determined. As seen in the figure below, at some loading levels, load curtailment is not required. These low loading levels may represent off peak times such as night time and holidays. For a major contingency event, it is assumed that the control room will take necessary actions to switch on and off loads depending on the loading levels. Energy at risk is the area under the curve as shown below.

The following diagram illustrates the load curtailment due to overloads and the treatment of load transfer capability. During an overload condition, initially the necessary amount of load is shed, and then partial load is restored via available load transfer opportunities to surrounding zone substations.

Energy at risk due to overloads of the network is illustrated in the diagram below.

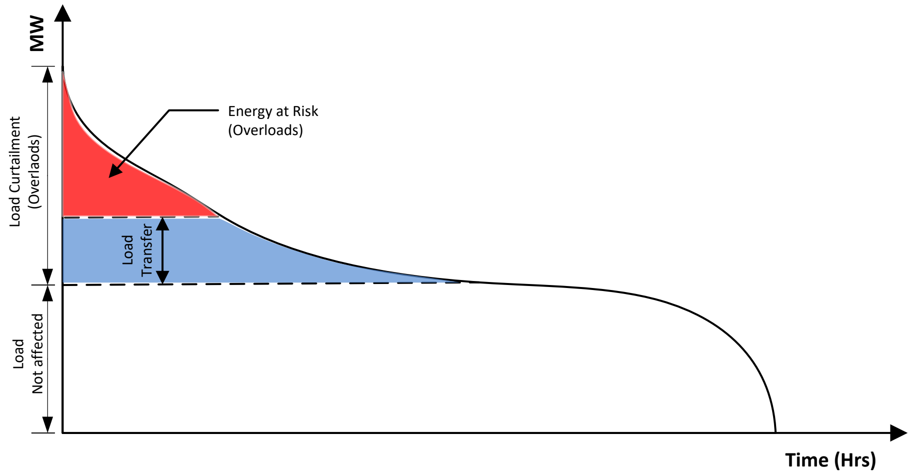

Figure 4-1 Illustration of Load Curtailment

$$Energy\ At\ Risk\ (Overloads) = Area\ of\ the\ curve\ (as\ shown\ above) \quad (12)$$

If the load cannot be supplied due to network connectivity[5], the supply to the load will be lost regardless the size of the load, and hence the entire load duration curve will be used in the estimation.

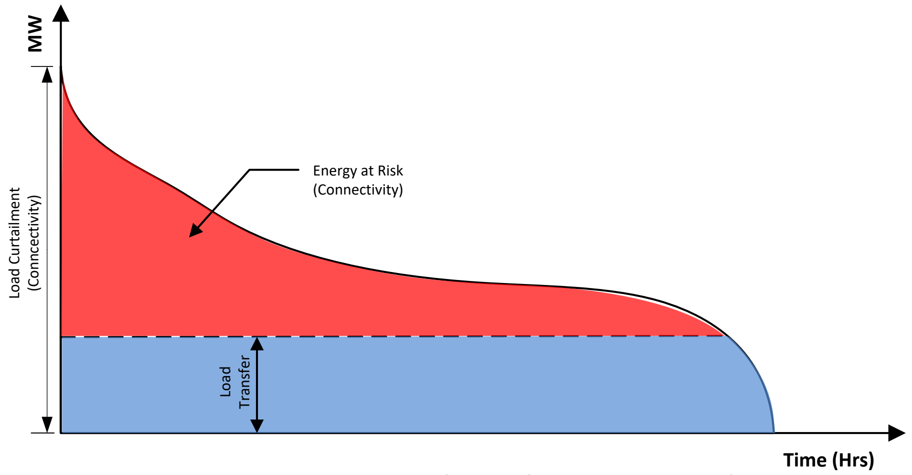

Figure 4-2 Illustration of Load Curtailment/Transfer

$$Energy\ At\ Risk\ (Connectivity) = Area\ of\ the\ curve\ (as\ shown\ above) \quad (13)$$

[5] The connectivity is defined as the complete loss of supply to a bus section, and no possibility to recover the load apart from 11kV connections to surrounding substations.

4.2.4 Expected unserved energy

The Expected Unserved Energy (EUE) is the probability weighted average amount of load that would need to be involuntarily curtailed due to system limitations. These limitations arise from the unavailability of network elements and the resulting reduction in network capacity to supply the load.

The expected unserved energy is the sum of product of energy at risk and probability of each state.

$$EUE = \sum_{n-1}^{n} energy\ at\ risk \times P(s) \qquad (14)$$

Where;

n is the number of states
$P(s)$ is the probability of each state

The value of expected unserved energy is the product of expected unserved energy and the value of customer reliability.

This can be represented by equation 14.

$$Value\ of\ Expected\ Unserved\ Energy = (EUE \times VCR)_{pre-switching} + (EUE \times VCR)_{post-switching} \qquad (15)$$

4.3 Reduced safety risk

Most busbar faults are cleared successfully in which case there is no risk to personal safety. However, there is a possibility that some busbar failures could be explosive and, under these circumstances it is possible that personnel in the vicinity could be injured or even killed.

The probability of this occurring is extremely low since, for most of the time, the substation is unattended and, even if there were persons at the station at the time of a failure, there is only a remote probability that they would be close enough to the failed switchgear to be affected.

This is converted into a dollar value based on the Corporate Risk Management Plan.

The quantification of safety risk is undertaken as shown below.

$$Safety\ risk\ cost = F\ \times S \times \beta \qquad (16)$$

Where;

F is the failure rate of the equipment
S is the safety consequence (as per corporate risk matrix)
β is a factor calculated based on the conditional probability and the exposure rate

The β factor is provided by the Asset Risk & Performance section based on an engineering assessment of the probability of a failure of the equipment resulting in a safety incident. This assessment is based on the type of equipment (air insulated equipment without phase segregation pose a greater safety risk), the regularity at which staff visit the site and the proportion of time that such staff would be in close proximity to the equipment.

4.4 Reduced maintenance and repair cost

The replacement of old equipment with new equipment will normally reduce the costs of routine maintenance. Where this difference is significant, it is included in the analysis.

In the event of a serious failure of an 11kV busbar which would require the equipment to be replaced, temporary repairs would need to be done to maintain supply until the replacement busbar is commissioned. As this cost is avoided if the busbar is replaced before any failure takes place, this repair cost represents a saving and is factored into the cost benefit analysis.

The following equation is used to calculate the impact of repair cost.

$$Repair\ cost = F \times D \qquad (17)$$

Where;

F is the failure rate
D is the repair cost per event

4.5 Reduced environmental risk

Ausgrid has experienced major leaks from oil filled cables and some Ausgrid cables leak smaller amounts of oil into the environment that are difficult to locate and repair. Ausgrid policy is to minimise environmental impact to the extent it is practical. Regardless, oil leaks expose Ausgrid to a risk of liability under the Protection of the Environment Operations Act 1997 (NSW), particularly in relation to pollution of water and pollution of land.

The quantification of environmental risk is carried out using the method shown below.

It is necessary to include the environmental risk in the cost benefit analysis as the continued service of oil-filled cables will result in further deterioration in condition and an increasing number of failures that are random in nature. These failures have the potential to cause damage to the environment.

The quantification of environmental risk is undertaken as shown below.

$$Environmental\ risk\ cost = F \times EC \times \beta \quad (18)$$

Where;

F is the failure rate of the equipment
EC is the environmental criticality
β is a factor calculated based on the conditional probability of ground water impacts from an oil leak

The Environmental Criticality (EC) is calculated for the three feeder failure types described in section 3.6.3, namely;

- corrective actions;
- breakdowns; and
- third party damage.

Each failure type is made up by a group of possible failure modes. For each failure type, the Mean Time To Repair (MTTR) is determined by taking the average of the repair times for each failure mode assuming equal likelihood for each failure mode within that failure type. The proportion of the year that would be impacted by a single equivalent failure is then used to weight the monetised consequence of a significant oil leak to produce the Environmental Criticality for each failure type.

$$Environmental\ Criticality = \frac{MTTR}{52} \times Sig.oil\ leak\ cost \quad (19)$$

Where;

$MTTR$ is the Mean Time To Repair in weeks

$Sig.oil\ leak\ cost$ is the monetised worth of a detectable oil leak of 5L per day for one year multiplied by $3,000/L[6] (5L x 365 days x $3,000 = $5.475M) plus an amount of $21,198 being a weighted tier two and/or three fine under the POEO Act.

Table 4-1: Environmental Criticality for each failure type

Environmental Criticality		
Corrective Action	**Breakdown**	**Third Party Damage**
$103,468	$916,033	$581,328

[6] (D16/1028628) NSW EPA's Regulatory Impact Statement – Proposed Protection of the Environment Operations (Underground Petroleum Storage Systems) Regulation 2014 – states "*Petroleum can contaminate large volumes of groundwater. For example, according to Environment Canada, one litre of gasoline can contaminate 1,000,000 litres of groundwater.. If water used for domestic purposes is priced at about $3,000/ML (Deloitte Access Economics 2013)…*"

5 Evaluation of Costs & Economic Analysis

5.1 Cost benefit analysis

During the Area Planning process, a great deal of engineering knowledge and experience is applied to identify options and to assess all the factors which will impact on the selection of the appropriate solution. It should be recognised that the assessment is complex and requires a great deal of inputs.

The probabilistic models which are described in this report are just some of the tools which can be used to assist in the work, but the final decision will take into consideration economic and other requirements.

When comparing options at this stage, the NPVs of the various options are evaluated which take into account the time value of money.

During the annual review of the capital investment, where there is no material change in the need, the only factor that is considered is the timing of the preferred strategy and the models described in this report have been specifically designed to support this work.

5.2 Project cost

The project costs for all options are calculated based on constant dollars (no time variation in value), and to compare the costs with benefits, one year deferral of the project is calculated as below equation.

$$One\ year\ deferral\ benefit = \frac{rY}{1+r} \tag{20}$$

where;

Y is the initial project cost
r is the discount rate

5.3 Need date (economic) evaluation

The total benefits are compared with the one year deferral benefit to trigger the project as shown in the Figure 5-1 below.

The timing of projects is chosen to maximise the net economic benefit to those who produce, transport and consume electrical energy. This is done by considering the potential timing of the proposed project cash flows and monetised benefits. When the benefits of a particular project outweigh the possible savings from deferring capital expenditure, and those benefits are forecast to continue, the project is said to be "needed" at that time. Where projects involve the installation of network assets with nominal lives in excess of the planning window of twenty years, a terminal value may be used in the Net Present Value calculation to account for benefits beyond the planning window. Because forecasts beyond the twenty year planning window are uncertain, the terminal value is calculated by depreciating the project capital cost using straight line depreciation. Some projects that are said to be needed towards the end of the planning window may be sensitive to variation in the terminal value. In these cases it is important to reassess the need each year so that a greater proportion of the benefits are based on explicit forecasts.

When assessing several competing options, the timing of each project within each option is chosen using the approach that has been described. Then the option with the greatest net economic benefit is chosen as the preferred option. An exception to this selection criterion may be made in cases where there are significant benefits that have not been quantified which can reasonably be outlined to support the selection of a different option or project timing.

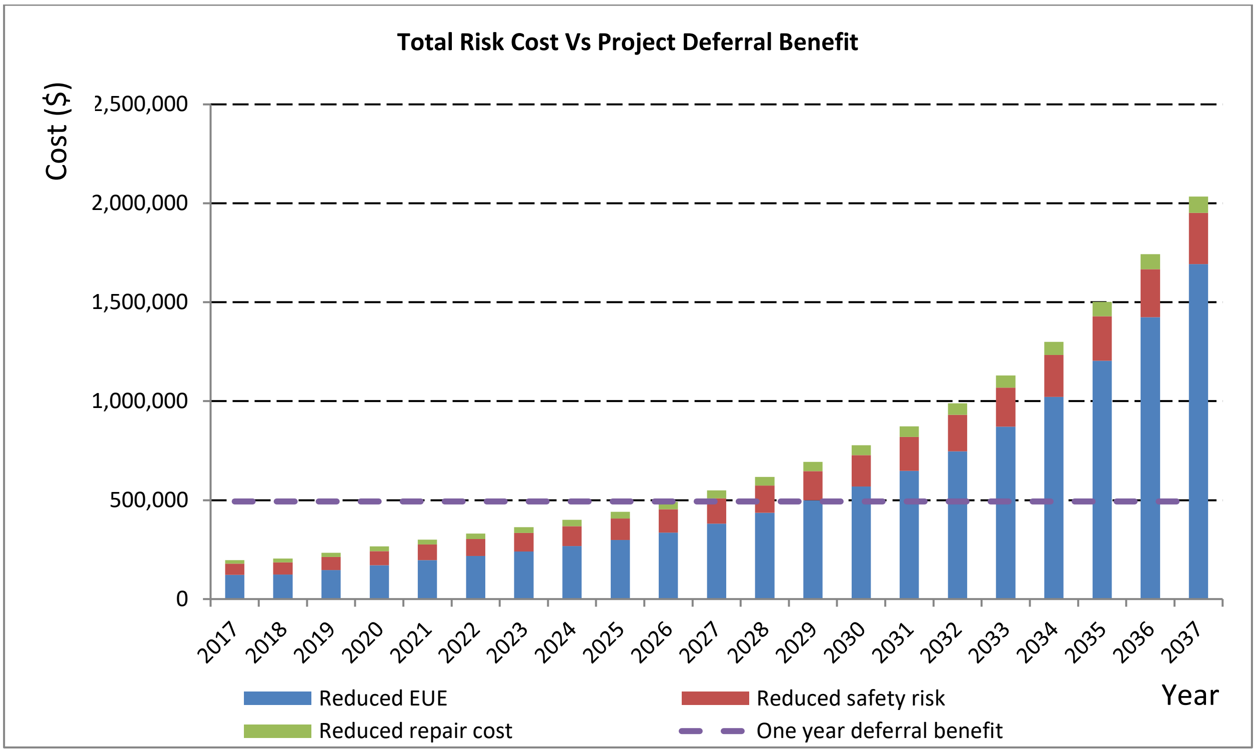

Figure 5-1 Need Date Assessment

The above graph shows an output of sample cost-benefit analysis carried out for an 11kV switchgear replacement project. As can be seen, the crossover point where the annualised benefit exceeds the benefit of deferring the project by one year is taken as the trigger for the project to be completed, that is known as the network need date. Generally, the commencement date of the project is four to five years ahead of the trigger year.

During the Area Plan review, the timing of the each option is determined in accordance with the above process. The net economic benefit of each option is calculated as illustrated in the graph below. The option which has the maximum net economic benefit is chosen as the preferred option.

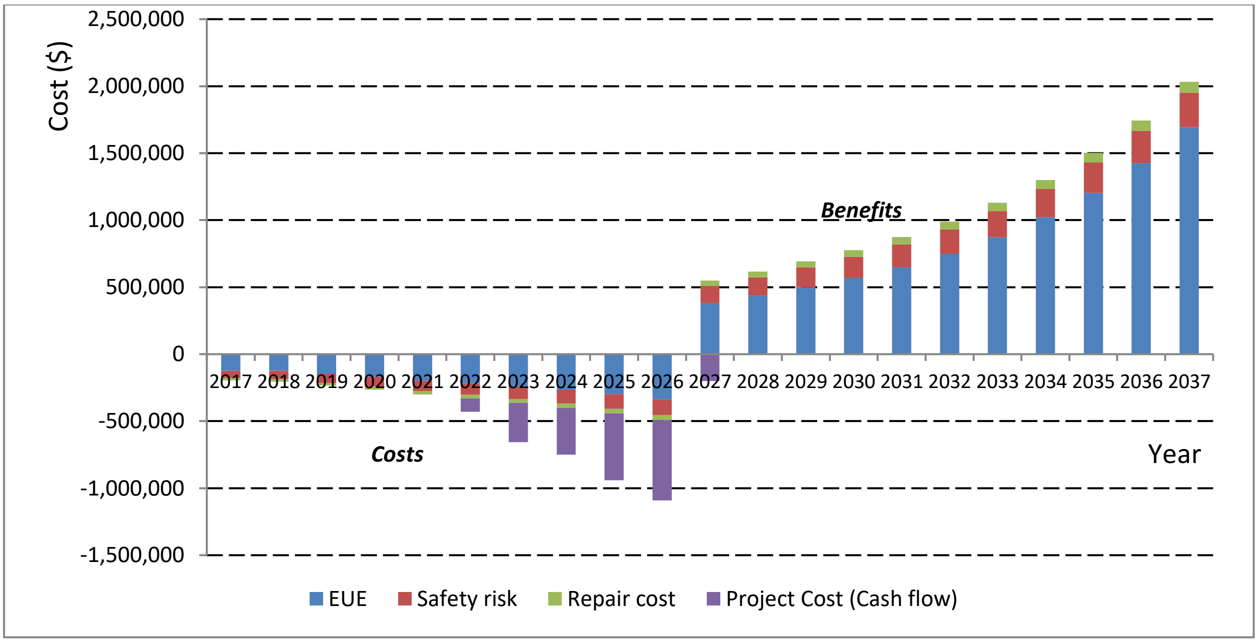

Figure 5-2 NPV Analysis for Options Comparison (sample data)

6 Sensitivities & optimisation

6.1 Sensitivity analysis

Sensitivity analysis is undertaken in order to gain an understanding of the investment decision by changing input parameters given in the baseline definition. The assumptions that are subject to the highest degree of uncertainty have been selected for inclusion in the sensitivity analysis.

In general, the following input parameters (predetermined low, base and high values) are included in the analysis.

Table 6-1: Sensitivity Analysis

Parameter
Value of Customer Reliability
Discount Rate
Project Cost
Load Forecast
Failure statistics and Repair times

The sensitivity analysis gives a range of dates (band) to be selected as the trigger year, as illustrated in the figure below. A careful consideration of the risks associated with the equipment and the considerations outlined in Section 6.2 are undertaken in order to select the optimum need date.

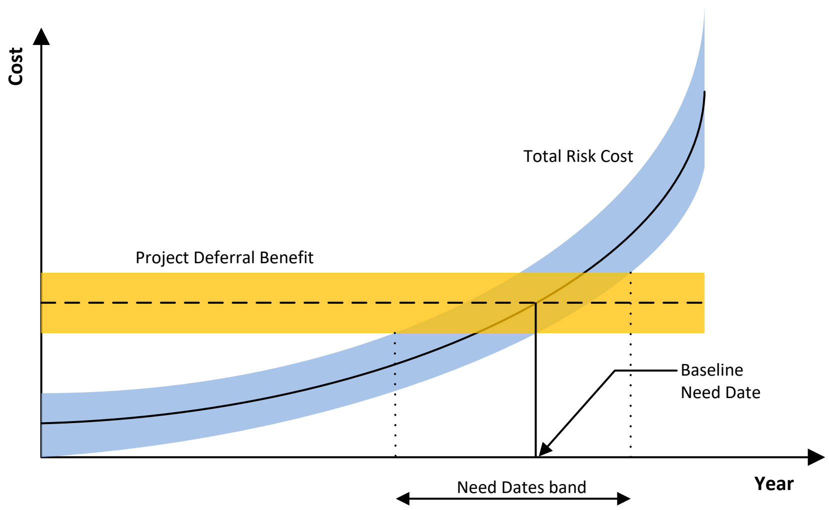

Figure 6-1 Illustration of need dates band

6.2 Optimisation

The cost benefit analysis for a proposed network investment is carried out during both the annual review and the Area Plan stage. A decision on the project need date (the date the project needs to be completed to address the need for the project) is made at this stage. The sensitivity analysis is also aimed at the identification of the effect of deferral or advancing the baseline need date. Once the suite of projects is developed, the next step is to understand the practicality or cash flow lumpiness which may require smoothing the need dates. Essentially, the project timing may be re-arranged in accordance with other priority requirements. These are:

- Fulfil other obligations such as environmental act requirement, regulatory requirement etc.
- Smoothing the project delivery plan.
- Dependency on the projects.

- Unexpected change/deterioration of condition of equipment which requires immediate replacement.
- Demand management analysis outcomes.

7 Planning Models

7.1 Introduction

Four computer based models are used to assist in the calculation of the expected value of unserved energy and to perform the cost benefit analysis. They are:

11kV Switchgear - to determine the optimal replacement date for 11kV busbars and associated switchgear in Zone Substations

33kV-132kV Switchgear - to determine the optimal replacement date for 33kV-132kV busbars and associated switchgear

Zone Capacity - to determine the optimal date to replace or augment Zone Substation transformer capacity

Feeder Capacity - a more general model to determine the amount of unserved energy based on probable outages of various critical network elements.

7.2 11kV switchgear model

The 11kV Switchgear model has been designed to determine the optimal replacement date of 11kV switchgear in Zone Substations.

The 11kV network is typically a radial network and any failure of an 11kV busbar will result in a loss of load until the network is switched to supply all or part of the load from another source. In these circumstances, it is not necessary to undertake load flow calculations to determine the value of lost load.

The model has been developed in the form of a single Access Database which contains all of the information relating to all of the Zone Substations in the Ausgrid network.

The busbar arrangement for each of the substations has been entered into the database and facilities are provided to load the following information relating to each substation which has to be sourced from various Ausgrid corporate systems.

Table 7-1: Input data for 11kV Switchgear Model

Data Type	Description
Load forecasts	MW and MVAr for 20 year planning horizon
Transfer Capacity (MVA)	Transfer capacity and Switching Steps
Project Cost ($)	Solution cost

The model determines the optimal switchgear replacement date by determining the first year when the total costs of expected unserved energy, maintenance and safety risk exceeds the value of a one year deferral of the project.

Note that this model does not make provision for environmental risks as such risks are inconsequential in the analysis.

7.3 33kV to 132kV switchgear model

The Switchgear model for all voltages 33kV to 132kV has been designed to determine the optimal replacement date of switchgear of these voltages in Zone and Subtransmission Substations.

The subtransmission network has been designed to N-1 network security. An initial screening test to determine the value of lost load involves undertaking loadflow calculations to determine loading at worst case N-1 contingencies. If 100% utilisation is not exceeded under these conditions, then it is very unlikely that any significant unserved energy will be calculated. Thus the model is not tested under these conditions.

For situations where it is found that 100% peak load exists, then the Switchgear model is tested to determine the value of lost load.

For condition based asset drivers, the model is tested to determine unserved energy at locations where condition based asset drivers have been identified by the Asset Risk & Performance section.

The model is programmatically implemented in Matlab and can be easily converted into any programming language. The table below shows all the required input data.

Table 7-2: Input data for 33 to 132kV Switchgear Model

Data Type	Description
Load forecasts	MW and MVAr for 20 year planning horizon
Transfer Capacity (MVA)	Transfer capacity and Switching Steps
Equipment Failure Rates	All constant failure rates for the study required
Equipment MTTR	All equipment Mean Time to Repair figures required
Substation Outage Type	All substation outage types considered are to be input in this model
Project Cost ($)	Solution cost

The model determines the optimal switchgear replacement date by determining the first year when the differential between the base case and solution exceeds the value of a one year deferral of the project.

Note that this model does not make provision for environmental risks as such risks are inconsequential in the analysis.

7.4 Zone capacity model

Based on deterministic planning, zone substations were planned to have an (n-1) level of redundancy where there will be no interruption to supply following the failure of a single transformer. The “firm” capacity of the station was defined as the load the station could supply with one transformer out of service.

If the load was forecast to increase beyond the firm capacity of the station, the planner would investigate a range of options to address the situation – including the transfer of load to other stations – but, if the load continued to grow, then a project to add a new transformer or replace the existing transformers with higher rated units would ultimately be required to achieve the required level of reliability.

To apply probabilistic planning, it is necessary to calculate the probable value of unserved energy that would occur if the load was in excess of the firm capacity of the station should a transformer failure occur and a project to augment the capacity of the station would only be initiated when the annualised benefit exceeds the benefit of deferring the project by one year. The Zone Capacity Model calculates the value of unserved energy based on the forecast loads and the failure statistics for the transformers and compares this with the project cost - being the cost of the works identified by the planner as the least cost option to address the need.

7.5 Subtransmission feeder model

7.5.1 Structure

The Feeder Model has been developed in two components. The first component is designed to calculate the amount of expected unserved energy resulting from the failure of an element in a meshed network. In these cases, it is necessary to undertake a load flow analysis for each case to determine the amount of load lost in the event of the failure of specific elements. The load could be lost due to islanding of the network or the need to shed load to avoid overloading in-service elements.

7.5.2 Component 1 – PSSE model

The model is based on PSSE software (the system Ausgrid uses for network studies) and with a specially designed “front end” to facilitate data entry. This front end has been programmed in Python which runs on a normal PC.

The main input to the models is a set of PSSE “.sav” files which accurately define the network being considered. There are two files for each of the study years – one containing forecast summer loadings and the other containing forecast winter loadings. These files are used in the normal planning process and are known to produce accurate results.

The planner then prepares a number of files to define the contingencies he/she wishes to study.

These files are:

Table 7-3: Input files for Feeder Model

Files	Description
Unavailability	Elements which are to be 'failed' in the study, and the estimated unavailability of each element
LDC	Load Duration Curves for each of loads
Auto Closing	Switching operations

When the model is "run", the load flow is "solved" for each combination of possible outages for each year. Where the model indicates that load is lost – either to avoid overloading and in-service elements or as the result of "islanding" a part of the network – the model calculates the estimated amount of unserved energy based on the unavailability of the relevant elements and the load duration curve of the affected loads.

A summary spreadsheet is generated which gives the total estimated amount of unserved for the study period measured in MWh.

7.5.3 Component 2 – spreadsheet model

The details of the amounts of unserved energy are copied into a spreadsheet model which is designed to:

- Compare alternative options for addressing the need
- Determining the optimum date for implementing each of the options

Apart from the values of unserved energy derived from the PSSE model, the following additional data is entered into the model

- VCR
- Project Costs
- Failure rates

Taking into account the

- Value of unserved energy
- Changes in maintenance costs
- Changes in the environmental risk
- Cost of implementing each of the augmentation options

The model calculates the optimal date for implementing each option based on the first year when the total costs of doing nothing exceed the value of deferring the implementation of the option for one year.

The model then determines the NPV of each of the options based on the optimal implementation date determined previously.

8 Other methodologies

The following methodologies were considered during the investigation stage but did not proceed further. The cost and benefit analysis methodology was selected as Ausgrid's preferred planning methodology as it aligns with the AER's regulatory investment guideline and provides the most economical justification for the network investment decision.

8.1 Cost effectiveness analysis

In this method, the benefits are not assigned a monetary value rather benefits are expressed as outcomes (effects) and compared with the relative cost which focuses on maximising the level of the outcome. This method is widely applied to situations where the social benefits cannot be easily monetised or be reluctant to place a monetary value of some of outcomes.

If this method is applied to electrical infrastructure projects, the potential outcomes can be defined as below.

- Reduced number of customer interruptions
- Reduced number of safety incidents
- Reduced number of environmental impacts

Cost effectiveness ratio is a measure to compare the investment options, and is defined as:

$$CE = \frac{\Delta C}{\Delta E}$$

Where,

ΔC is the relative cost

ΔE is the improvement relative to base case

In terms of electrical infrastructure projects, the cost of the project is compared with the potential reduction of customer interruptions as a result of implementing the project. The objective is to minimise the cost effectiveness ratio which then the preferable option can be chosen. There are some drawbacks of this method in trying to apply to electrical infrastructure projects. The money spent on the project is not recognising as to whether the customer is willing to pay to achieve such network reliability. Customer willingness can be varied from location to location which is not a consideration in the cost effectiveness analysis. Further, safety and environmental impacts are significantly varied depending on the extent of the incident and the severity. In general, the cost effectiveness analysis is not focused on the 'scale effect' of outcomes and hence this method is not considered over cost benefit analysis.

The cost effectiveness analysis is more applicable to 'safety' projects where the effect is distinctly identified such as 'saving lives'. The introduction of a dollar value for numbers of lives saved would be quite difficult.

8.2 Cost benefit analysis based on STIPIS

The Service Target Performance Incentive Scheme (STPIS) is a mechanism used by the AER to assign value to reliability of electrical supply to customers. The incentive scheme penalises Ausgrid financially for failing to provide supply, based on measurements of duration (SAIDI) and frequency (SAIFI) of power interruptions.

The use of STPIS as a basis for assigning a value to the reliability of supply for the purpose of cost benefit analysis has been considered by Ausgrid. However, it has been determined that the use of expected unserved energy (EUE), in conjunction with a value of customer reliability (VCR, $/MWh) is a more appropriate and relevant for the following reasons:

- Major events are often excluded from STPIS statistics, and these are often the contingency events that threaten network security and drive appropriate investment.

- Measurements of frequency and duration of interruptions do not take into account the size of supplied load, and can distort the relative customer benefit from investment. The use of EUE overcomes this limitation.

- The use of VCR and EUE is endorsed by the Australian Energy Market Operator (AEMO) who has conducted customer surveys to determine an appropriate value for VCR and has published these findings for use by Network Service Providers.

Attachment A – Reference documents

This table includes relevant supporting information for the processes and data used in Area Plan and annual capital investment reviews.

	Document title	Version	Location
1	Area Planning NIS419	1.0	TRIM record no. D15/512608
2	Capacity Planning NIS439	1.0	TRIM record no. D15/379683
3	Replacement Planning NIS435	1.0	TRIM record no. D15/54269
4	Strategic Asset Prioritisation	2.1 (Apr 2013)	
5	Switchboard Risk for Planning		
6	FFC Environmental Risk Assessment	2.0	TRIM record no. D15/801516