AMS 10-24 Asset Renewal Planning Guide

2023-27 Transmission Revenue Reset

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Disclaimer

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1 PURPOSE

This Asset Renewal Planning Guideline provides a framework for AusNet Services' asset renewal planning for the Victorian electricity transmission network.

2 SCOPE

This Asset Renewal Planning Guideline covers AusNet Services' regulated electricity transmission assets operating across Victoria, including:

- Transmission lines, power cables and associated easements and access tracks;
- Terminal stations, switching stations, communication stations and depots including associated electrical plant, buildings and civil infrastructure;
- Protection, control, metering and communications equipment;
- Related functions and facilities such as spares, maintenance and test equipment; and Asset management processes and systems such as System Control and Data Acquisition (SCADA) and asset management information systems (including SAP).

This guide excludes the assets and infrastructure owned by:

- Generators;
- Connected customers; and
- Other companies providing transmission services within Victoria.

3 BACKGROUND

AusNet Services' electricity transmission network serves more than 2.4 million Victorian households and businesses with more than 6,570 kilometres of transmission lines. The network is centrally located among Australia's five eastern states that form the National Electricity Market (NEM), providing key connections between South Australia, New South Wales and Tasmania's electricity transmission networks. The network served a peak demand of 10, 603 MW on 29 January 2009, which is the highest system demand recorded to date.

AusNet Services is committed to providing safe and reliable network services by investing in the upgrade and maintenance of the network and achieving the objectives set for the provision of network services through pricing determinations and other regulatory instruments.

4 VICTORIAN PLANNING FRAMEWORK

Responsibility for planning of transmission network services in Victoria is shared by the following three different parties:

- AEMO, which is the body solely responsible for planning the shared transmission network[1] and procuring network support and shared network augmentations;
- the asset owner, AusNet Services (Transmission) Ltd (referred to in this document as AusNet Services); and
- the transmission customers (distribution companies, generation companies and directly-connected customers), which are responsible for planning and directing the augmentation of their respective transmission connection facilities.

In Victoria, the transmission network augmentation planning functions are separated from the functions of ownership and operation. These arrangements differ from other states in Australia, where planning and responsibility for augmentation remains integrated with the incumbent transmission company (although independent planning oversight occurs in South Australia). The relationships between these parties and the Regulators are shown in Figure 1.

AusNet Services primary responsibilities therefore are in relation to the operation and asset management of its Victorian transmission network. AusNet Services plans and provides for the renewal of network assets in a joint planning process with AEMO which achieves an integrated network planning approach for the Victorian network.

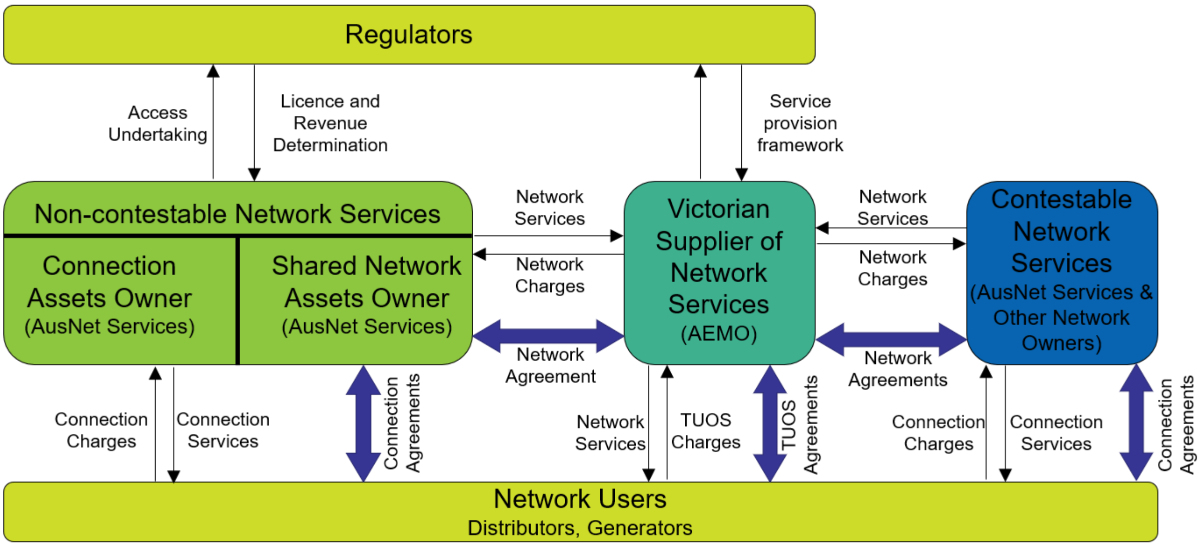


Figure 1: Regulatory and commercial relationships

5 ECONOMIC AND TECHNICAL REGULATION

The National Electricity Law (NEL) contains two overarching principles that the AER applies when performing their economic regulatory functions or powers. Under section 16(1)(a) of the NEL the AER must act in a manner that will or is likely to contribute to the achievement of the National Electricity Objective (NEO). The NEO is set out in section 7 of the NEL and repeated below:

1 The shared transmission network is the main extra high voltage network that provides or potentially provides supply to more than a single connected party with lines and tie transformers generally rated above 220 kV.

The objective of this law is to promote efficient investment in, and efficient operation and use of, electricity services for the long term interest of consumers of electricity with respect to:

- price, quality, safety, reliability and security of supply of electricity; and
- the reliability, safety and security of the national electricity system.

The AER must also take into account the revenue and pricing principles set out in the NEL when making a transmission determination[2]. Amongst other things, these principles require a TNSP to be provided with an opportunity to recover at least its efficient costs, and provided with effective incentives in order to promote economic efficiency.

The Electricity Safety Act in Victoria requires AusNet Services to “design, construct, operate, maintain and decommission its supply network to minimise as far as practicable, the hazards and risks to the safety of any person arising from the supply network”[3].

The Occupational Health and Safety Act in Victoria requires AusNet Services to “so far as is reasonably practicable, provide and maintain for employees of the employer a working environment that is safe and without risks to health”[4]

The National Electricity Rules (via clause 5.16) requires transmission network service providers to conduct a Regulatory Investment Test for Transmission (RIT-T) for both network augmentation projects and asset replacement projects where the most expensive credible option is valued at more than $6 M.

6 ASSET MANAGEMENT POLICY AND STRATEGY

AusNet Services’ Asset Management Policy[5] directs the content and implementation of asset management strategies, objectives and plans for AusNet Services’ energy delivery networks. It guides employees, contractors, suppliers and delegates in each asset management decision to achieve AusNet Services’ corporate business purpose of : “Empowering communities and their energy future”.

The Asset Management Policy states that sound risk management and the continuous improvement practices of AusNet Services’ integrated safety, health, environment, quality and asset management systems will manage the complete life cycle of network assets. The Asset Management Policy highlights the following focus areas:

- Hazards and risks to the safety of any person and their property will be minimised “as far as is practicable”.
- Consumers will be provided with information, tools and service options to facilitate their energy choices.
- Effective consultation will take place with stakeholders to comprehend and integrate their requirements in asset management decisions.
- The specification and application of assets will comply with legislation, regulation, Australian Standards and industry codes.

2 NEL, clause 16(2)(a)(i). The revenue and pricing principles are set out in section 7A of the NEL.

3 Electricity Safety Act 1998 (Vic), section 98(a)

4 Occupational Health and safety Act 2004 (Vic) Section 21 (1)

5 AusNet Services’ Asset Management Policy (July 2017)

- The national energy laws, rules and their fundamental price, performance and security principles will guide service development in the interests of customers.
- Innovation and technology will be embraced to economically reduce service risks, increase service value and manage service performance commensurate with customer's emerging needs.
- Skilled people will be developed and deployed to sustainably manage risks, increase the value of services and improve the range of services.
- Energy network development will balance the environmental, economic, and social needs of today without sacrificing the interests of future generations
- Practices, systems and facilities will be continuously improved commensurate with certification to a recognised asset management standard.

Asset Management Strategy AMS 10-01 documents AusNet Services' holistic approach to the management of the network assets and establishes the linkages with and between the underpinning detailed strategies, processes and plans. The approach seeks to deliver optimal electricity transmission network performance at efficient cost by ensuring that all decisions to replace or maintain network assets are economically justified.

7 ASSET RENEWAL STRATEGY

7.1 Asset Renewal Objectives

The objective of asset renewal is to achieve sustainable outcomes in:

- Safety of customers, the community and workers
- Quality, reliability and security of supply of electricity transmission services
- Compliance with codes, licences, contracts, industry standards and obligations
- Minimising total life cycle costs through the consideration of capital costs, operational costs, retirement costs and operational risk costs
- Stabilising volatility of renewal works and associated material, skill and revenue requirements
- Minimising project delivery risks and the potential impact of renewal works on network availability, market participants and connected parties

7.2 Asset Renewal Criteria and Drivers

The key drivers for transmission asset renewal decisions are discussed in this section.

7.2.1 Compliance

AusNet Services' network and asset management practice must comply with all relevant electricity transmission codes, licences, contracts and prescribed industry standards. Currently, these obligations include 22 regulatory instruments involving some 350 mandatory obligations and 260 event driven obligations relevant to the Victorian electricity transmission network.

Of particular significance are several legislative obligations relating to worker safety. Under the Occupational Health and Safety Act AusNet Services is required to so far as is reasonably practicable maintain for employees a working environment that is safe and without risks to health. The Electricity Safety Act requires AusNet Services to operate its electricity transmission network to minimise, so far as is practicable, hazards to the safety of any person.

These Acts require AusNet Services to have regard to the likelihood, harm and what is known or should be known about safety hazards. AusNet Services must also consider the availability and suitability of ways to eliminate or mitigate safety hazards. AusNet Services is then further obliged to have regard to the cost of removing or mitigating the safety hazard or risk.

7.2.2 Network Performance

If equipment performance trends indicate that contractual performance requirements (relating to the respective codes and licences) will not be met, or will be unreasonably compromised, or the existing service provision is no longer efficient, planned (proactive) renewal is investigated.

Maintenance, refurbishment and replacement plans are developed using an underlying strategy of condition-based remediation. This strategy uses risk management principles that take into account criticality, reliability and the prudence of adopting a particular course of action.

The risk and consequence of plant failure, including unserved load and reduced network performance are assessed as part of each asset management decision. Asset management is also balanced with a longer-term perspective on capital and network access requirements and indicators such as the Weighted Average Remaining Life (WARL) of the assets.

While assets are generally managed as a discrete ‘fleet’, each decision to replace or refurbish items of plant is taken on a case-by-case basis.

When assets are unable to operate at their full rating, this tends to place operational restrictions on network configuration and capability and can result in poor utilisation of associated major plant (for example power transformers). To address this, planned replacement of minor plant items (for example, disconnectors) is often combined with other plans (like AEMO augmentation plans) to optimise network capability and node to node load transfers.

7.2.3 Asset Condition

AMS 10-13 Condition Monitoring describes AusNet Services’ strategy and approach to monitoring the condition of assets as summarised in this section.

Asset condition is measured with reference to an asset health index, on a scale of 1 to 5. The 1 to 5 condition range is consistent across asset types and relates to the expected remaining asset life. The table below provides a simple explanation of the asset condition scores.

Table 1: Condition score definition and recommended action

Condition Score	Likert Scale	Condition Description	Recommended Action	Remaining Service Potential %
C1	Very Good	Initial service condition	No additional specific actions required,	95

C2	Good	Relatively new, no known issues identified.	continue routine maintenance and condition monitoring	70
C3	Average	Average condition, some minor defects identified. Early signs of deterioration and condition or performance.		45
C4	Poor	Advancing deterioration – life ending failure highly likely within 10 years without remedial action.	Remedial action/replacement within 2-10 years	25
C5	Very Poor	Extreme deterioration – life ending failure highly likely within 5 years without remedial action.	Remedial action replacement within 1-5 years	15

Asset condition is a key driver of asset renewal activities. As equipment condition deteriorates its design safety margins and performance can gradually decline below network operating requirements. Assets require a margin which allows them to operate during foreseeable abnormal network operating conditions, caused by network faults, surges, plant outages, and high ambient temperatures. This margin determines asset reliability and security.

Failure Modes Effect Analysis (FMEA) is the principal technique used to gain knowledge about the modes and rates of deterioration of each asset type. Benchmarking with other transmission network service providers and liaison through industry associations such as CIGRE brings additional data, experience and insight. Using this knowledge, condition is assessed through a wide range of activities including online condition monitoring, regular inspections, planned maintenance and issue-focussed testing.

Condition profiles for a fleet of assets aid comprehension of the extent and the rate of deterioration. The analysis also provides input to asset risk models used to compare future risk forecasts with historical and current risk positions.

Condition ranking each asset within a fleet of its peers identifies individual assets having the greatest probability of failure and targets intensive inspection, testing to determine any recommendations and potentially, renewal activities.

7.2.4 Asset Criticality

The consequence of plant failures, including loss of service is established for each major asset and combined with the probability of such events to enable the evaluation of risk costs for individual assets. Asset condition and asset criticality are considered in the asset renewal decision, where asset criticality is based on the consequence of an asset failure. The key risks considered in establishing the consequence of an asset failure (asset criticality) are described in Section 9.3 and includes loss of supply, health and safety impact, financial impact, environmental impact and plant collateral damage.

Asset failure risk information flows from AusNet Services' condition-based reliability centred maintenance (C-RCM) methodology to guide optimal replacement timing. This approach considers performance requirements and actual failure data to determine failure rates of individual network assets or classes of assets.

Failure Mode Effect Criticality Analysis (FMECA) based on historical asset performance data is undertaken to determine typical root causes of functional failures, and the resulting effects these causes have on key performance measures including safety, reliability and availability. Asset condition data collected during scheduled maintenance and asset inspection tasks is used to determine dynamic time-based probability of failure and the expected remaining service potential of the asset in that lifecycle phase.

7.2.5 Life Cycle Costs

Increasing operational cost is a consideration for asset renewal and is considered in the economic cost-benefit analysis and asset renewal decision. Contributors to increasing operational costs may include increasing maintenance costs and network losses.

7.2.6 Future Customer Requirements

Asset renewal plans are integrated with the shared network augmentation plans developed by AEMO and the connection network augmentation plans developed by distribution network service providers to optimise economic benefits. The integration of these plans may advance or defer asset renewal plans or introduce new options to consider in the planning decision.

7.2.7 Spares and Technical Support

A contingency strategy is developed when a manufacturer no longer offers technical support and spare parts for key assets. Depending on the level of technical support and spares available from within AusNet Services and plant criticality to the network, this strategy may involve the replacement of one asset which would generate spares for the maintenance of other assets in less critical areas of the network. This strategy generally results in an improvement in asset restoration time during a failure, but not to the overall network reliability and availability.

8 ASSET RENEWAL PLANNING PROCESS

The main planning activities are discussed in this section of the report and consist of the following steps:

1. Identify assets presenting high failure risks using the criticality scores stored in SAP. Criticality scores are determined based on risk calculations performed by reliability modelling tools.
2. Assess asset health and performance indices to calculate asset condition scores for critical assets requiring asset renewal planning. Develop asset failure rate curves, establish assets remaining service potential and calibrate to history.

3. Quantify the base line risk based on the probability and consequence of asset failure and verify whether the base line risk has reached a level where a “Do nothing” asset management approach would compromise efficient service provision. The main hazards or effects that should be included are safety, reliability and security of supply, environmental impact and collateral plant damage.
4. Develop asset management options based on risk ranking, plant strategies, transmission line strategies and system strategies. Consider non-network options including demand side options as well as efficient integration of replacement and outage requirements. Consider brownfield or greenfield type replacement, staged replacement, and refurbishment (opex) versus replacement (capex) trade-offs. Consider the future need for the assets and the economic feasibility of all proactive asset renewal options given uncertainties in demand growth, new generation connections, generation retirements, etc.
5. Assess the need to undertake a regulatory investment test (RIT-T) and make provision for the time required to undertake a RIT-T in the renewal planning process.
6. Develop scope of work and cost estimates for each credible option.
7. Select asset renewal solutions including deferred replacement when the base line risk is small, and the asset can be managed without the need for refurbishment or replacement (“do nothing”). Run to failure should only be considered for assets that do not present significant safety or environmental hazards and whose failure can be rapidly and economically recovered.
8. Consult with AEMO and the respective Distribution Business regarding their long-term augmentation plans and update the ultimate planning requirements for terminal stations and transmission lines. Integrate asset renewal and augmentation projects and plans.
9. Select the most economic solution that complies with the asset management strategies, the future augmentation planning requirements and is consistent with the objectives of the network performance incentive scheme (AER Service Target Performance Incentive Scheme - STPIS). Ensure compliance with technical limits, planning philosophies, regulatory criteria and guidelines, reliability and quality of supply standards and asset management strategies.
10. Use scenario planning techniques to establish the robustness of each option; including testing the economic viability of each option for asset stranding risk. Calculate the regret for options that are selected based on selection criteria that minimises the upfront cost, but places less economic value on achieving longer term planning outcomes, i.e. the horizon year plan.
11. Undertake sensitivity studies to establish the economical project timing considering changes in demand forecast, discount rate, cost of capital and asset failure rates.
12. Prepare an asset renewal planning report documenting all considerations and recommendations.
13. Prioritise the different transmission asset renewal projects based on the assessed failure risk, the company’s business strategy and regulatory funding decisions.
14. Integrate network plans and projects to ensure efficient project and program delivery
15. Document plan and include it in the Annual Planning Reports. Initiate projects with RIT-T where thresholds require.

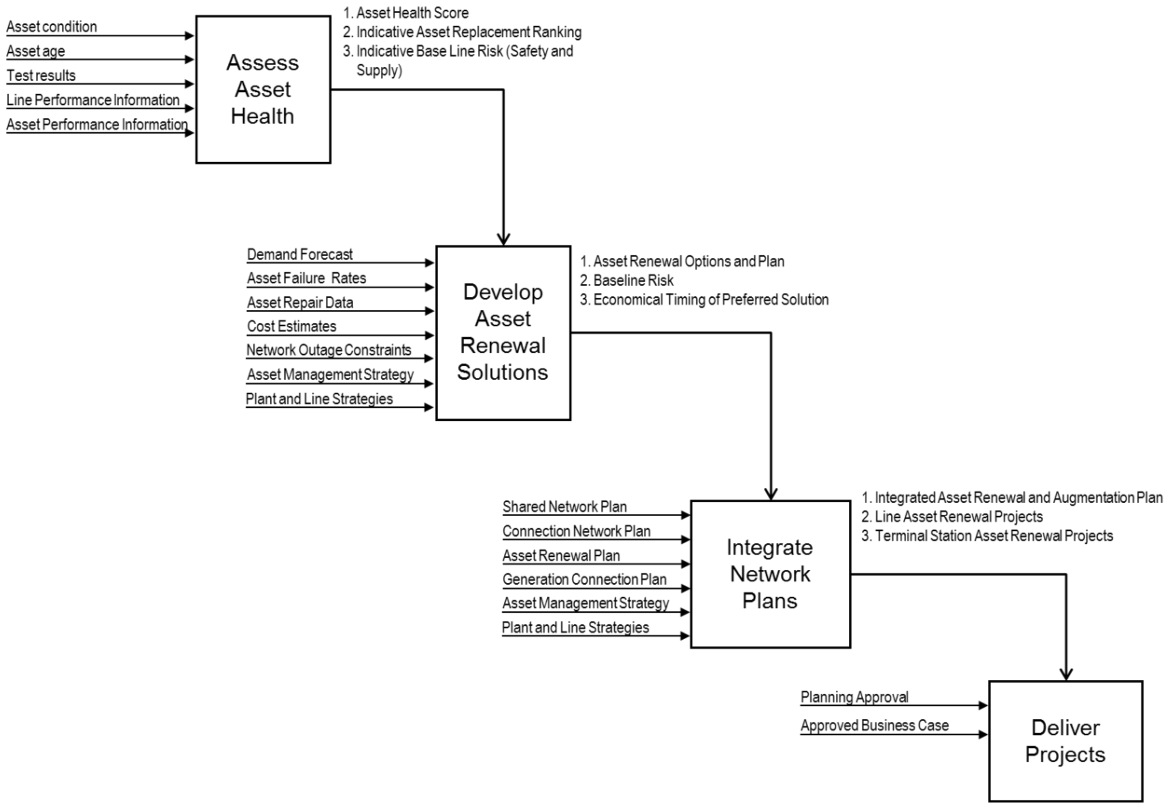


Figure 2: Asset Renewal Planning Process

9 ASSET RENEWAL OPTIONS

The asset renewal objectives described in Section 5.2 are met by either asset refurbishment or replacement, or a combination of refurbishment and replacement.

9.1 Refurbishment

This asset management strategy involves refurbishing plant to extend its reliable service life. This is sometimes the most economic option and allows deferral of the more expensive asset replacement alternative when the future need for the asset is uncertain. However, in many cases it is reliant on spare equipment being available while deteriorated plant is being refurbished and the economics of this option are predicated on the probability that known technical issues can be addressed.

In general, refurbishment addresses specific, known problems that would, if no remedial action were taken, lead to failure and shorten the service life of the asset. Generally, refurbishment improves the declining reliability of the plant but does not extend its useful service life. In most cases, refurbishment has only a minor impact on maintenance costs because refurbishment tends to stabilise rising future costs rather than dramatically reducing costs below historic levels.

This strategy requires careful analysis as benefits are unique to each refurbishment and are highly dependent on stabilizing or reducing a rising failure rate, with a secondary benefit of a small extension in reliable service life.

9.2 Replacement

This asset management strategy involves replacing plant to ensure continued reliable service. While this strategy often has the highest up-front costs it also tends to lead to the largest reductions in failure risk and maintenance costs. Replacement also presents an opportunity to modernise plant which can avoid costs associated with obsolete equipment and may inherently improve the level of service.

Replacement is often the preferred option when the reliability of an asset is critical, when asset outages and spares are not available for refurbishment, or refurbishment is simply an ineffective means for addressing poor reliability.

A primary requirement for asset replacement planning is knowledge of asset condition and other factors that will affect the remaining technical life of the assets. This technical life assessment is undertaken in accordance with AMS 10-101 Asset Life Evaluation Strategy.

Plans for asset replacement look for efficiencies over the entire planning period for example, by integrating the augmentation needs of AEMO and those of distribution network service providers with AusNet Services' replacement plans. This approach optimises engineering and construction resourcing and minimises project risks and network outages for construction purposes.

The following options are considered in the asset renewal evaluation:

1. **Replace-upon-Failure** is only employed in circumstances where the impact of asset failure on network performance, health, safety and the environment is insignificant or non-existent, and where the asset has a short procurement and replacement lead-time.
2. **Renewal on Risk** optimises the asset's lifecycle cost with due consideration for health, safety and environmental factors as well as community cost based on asset performance. This strategy requires sufficient asset condition and performance monitoring to predict deterioration of the respective plant with sufficient lead-time to enable renewal prior to failure.
3. **Renewal by Asset Class** is employed when a class of asset has either a higher-than-acceptable failure rate or exhibits a greater degree of deterioration than other asset types. This approach avoids widespread deterioration in network performance due to multiple asset class-related failures.
4. **Renewal on a Bay-by-bay (or Scheme/Network)** basis is employed when it is economic to replace all primary plant and equipment within a specific station switch bay or scheme. This strategy is often adopted for terminal station renewals where outage restrictions apply.
5. **Replacement of Whole Station in Existing Location (Brownfield redevelopment)** is employed when it is economic to replace all assets in a single, coordinated project within the existing station or location. This is normally when station assets are approaching the end of their life and there are advantages in station reconfiguration.
6. **Replacement of Whole Station in New Location (Greenfield redevelopment**) means constructing a replacement station on a new site. This is a more expensive strategy than undertaking works within an existing

station as it requires procuring new land, establishing key infrastructure, and relocating associated transmission and distribution lines. It is usually only economic when the existing infrastructure is inadequate or in poor condition, or when replacement works cannot occur without sustained supply disruption due to limitations at the existing site.

10 ECONOMIC PLANNING CRITERIA

AusNet Services undertakes economic appraisals of all asset renewal options and asset renewal investment decisions and the economic planning criteria are described in this section.

AusNet Services applies probabilistic planning methods to determine the economic viability of asset renewal. The baseline risk is first calculated to quantify the following hazards/risks:

- Health and safety risk presented by assets that could fail explosively or present a fire risk due to their design (e.g. porcelain bushings, oil used as an insulating medium, etc.)
- Security of supply risk to consumers or the electricity market when asset failure could result in supply interruptions or network constraints
- Financial Risk Cost. Upon failure of an asset, it is assumed that the asset is replaced and the financial consequence arising from the failure of the asset is calculated as per the Australian Energy Regulator (AER) Industry practice application note – Asset replacement planning, Section 5.1.2[6].
- Environmental risk, for example due to oil spillage
- Collateral plant damage risk for plant that could fail explosively, resulting in damage to adjacent plant and consequent costs for litigation, media liaison, emergency operational action and site clean-up

The monetised baseline risk is compared with the annualised cost of the asset renewal options to establish whether proactive asset renewal strategies are required to manage the asset failure risk instead of continuing with reactive asset management strategies such as "Business as usual" or "Do nothing" approaches[7]. Figure 3 illustrates the methodology used to calculate the baseline risk, which is the probability weighted risk cost presented by asset failure.

6 Australian Energy Regulator, "Industry practice application note for asset replacement planning," available at https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/industry-practice-application-note-for-asset-replacement-planning.

7 This approach is only used to provide a high level indication of whether investment may be economical as it assumes that the investment will mitigate all the base line risks identified.

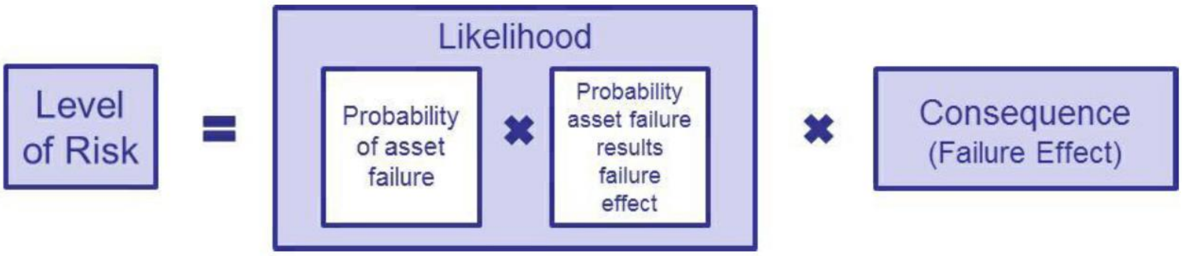


Figure 3: Baseline Risk Calculation

10.1 Identifying the Assets at Risk

Asset health index scores and asset failure rate (hazard) curves are assigned to key assets, such as power transformers, circuit breakers and instrument transformers and documented in the risk models for these major assets.

The asset health index score provides an indication of asset health and candidates for replacement are first identified by ranking the assets with the highest condition scores (i.e. C4 and C5). The initial baseline risk calculation of an asset or group of assets provides evidence of the need for a more rigorous assessment.

The need for asset renewal is identified by quantifying the asset failure risk (where expected cost is a function of consequence and probability) and by undertaking an economic evaluation of credible asset renewal options. The objective of the economic evaluation is to identify the option with the highest net present benefit or lowest expected present value (PV) cost and the timing by when the asset renewal would be economical.

10.2 Asset Unavailability

Asset unavailability is calculated from the asset failure rate and Mean time to recovery information for the particular asset. The asset failure rate information for transformer, circuit breakers and instrument transformers are described in the failure rate curves in the risk models for these assets.

The following definitions are used to define asset unavailability:

- Failure Rate ($\lambda(t)$) is defined as the anticipated number of times an item will fail in a specified time period, t.
- Mean time to Recovery (MTTR) is defined as the total amount of time spent performing corrective repairs, replacement or any other recovery option. It is the expected span of time from a failure (shut down) to the recovery completion.
- Unavailability (Pr(f)) is the probability that the component is in the failed state.

$$\mathbf{Pr}(\boldsymbol{f}) = \frac{\boldsymbol{MTTR}}{\boldsymbol{MTTR} + \frac{\mathbf{1}}{\boldsymbol{\lambda}}}$$

- A simplified version of the above formula, when the MTTR is small in comparison with the mean time to failure (MTTF), is as follows:

$$\mathbf{Pr}(\boldsymbol{f}) = \boldsymbol{MTTR} * \boldsymbol{\lambda}$$

Example:

A major transformer outage in a particular network's fleet is expected to occur once per 100 transformer-years. Therefore, in a population of 100 terminal station transformers, you would expect one major failure of any one transformer per year. The major outage rate for transformers (λ) = 1%.

On average, 2.6 months is required to repair the transformer and return it to service, during which time, the transformer is not in service. Mean time to recovery (MTTR) = 2.6 months.

On average, each transformer would be expected to be unavailable due to major outages for 0.217% of the time, or 19 hours in a year. The calculation of the transformer unavailability is as follows:

$$\Pr(f) = \frac{MTTR}{MTTR + \frac{1}{\lambda}} = \frac{\frac{2.6}{12}}{\frac{2.6}{12} + \frac{1}{1\%}} = 0.2162\%$$

or

$$\Pr(f) = MTTR * \lambda = \frac{2.6}{12} * 0.01 = 0.2167\%$$

10.3 Consequence of Asset Failure

The key risks to be considered in the calculation of the monetised baseline risk are the following:

- **Supply Security Risk:** Load at risk that would not be supplied in the event of an asset failure, evaluated based on AEMO's or the Distribution Businesses' terminal station demand forecast and the latest value of customer reliability (VCR). Network constraints (generation constraints) that also impact on the National Electricity Market (NEM) are assessed through market simulations.
- **Health and Safety Risk:** Hazards to the safety of any person in an event of asset explosive failure or failure that involves fire, e.g. Human injury and fatality.
- **Financial Risk Cost** is calculated based on the following: The cost to reactively replace the failed asset and the asset failure rates, as determined by the condition-based age of the assets
- **Environmental Risk:** Threat of adverse effects on the environment, e.g. environmental impacts due to oil leaks.
- **Plant Collateral Damage Risk:** Potential collateral damage of adjacent plants due to an asset explosive failure.

10.3.1 Supply Security Risk

Demand Forecasts

AusNet Services uses the distribution businesses' terminal station demand forecast and AEMO's connection point forecast for asset replacement planning. These two demand forecasts provide the maximum active power and reactive power demands forecast to occur (or exceed) for summer and winter on average one year in two (50% probability of exceedance (POE)) and one year in ten (10% POE) for each of the financial years in the ten-year planning period.

The terminal station demand forecasts are used to assess the amount of load at risk under asset outage conditions, both for single and multiple contingencies.

Value of Customer Reliability

The value of customer reliability (VCR) is the value that customers place on avoiding electricity service interruptions. The VCR varies widely between customer types, between countries and across time. In probabilistic transmission asset renewal planning, a VCR is used to value the economic benefits of a proposed asset renewal that is expected to reduce the unserved energy, so that this economic benefit can be compared with the cost of the asset renewal.

AusNet Services uses the latest VCR rates derived by AER and as weighted by the DBs based on the load composition for each individual terminal station. The average VCR across Victoria for 2019 is $41,210/MWh ($41.21/kWh).

Table 2: Victorian VCR estimates by sector (AER Values of customer reliability 2019)

Business customer segment	AER 2019 business VCR ($/kWh)	AEMO 2014 business VCR ($/kWh) real $2019
Agriculture	37.87	51.34
Commercial	44.52	48.16
Industrial	63.79	47.45

Energy at Risk

Energy at risk (EAR) can be defined as the estimate of the amount of energy that would not be supplied during a component failure or system constraint.

The capacity of a terminal station with one transformer out of service is referred to as its “N-1” rating. The capability of the station with all transformers in service is referred to as its “N” rating.

The graph below shows the annual load duration curve for the specific system under evaluation and the EAR for a N-1 contingency.

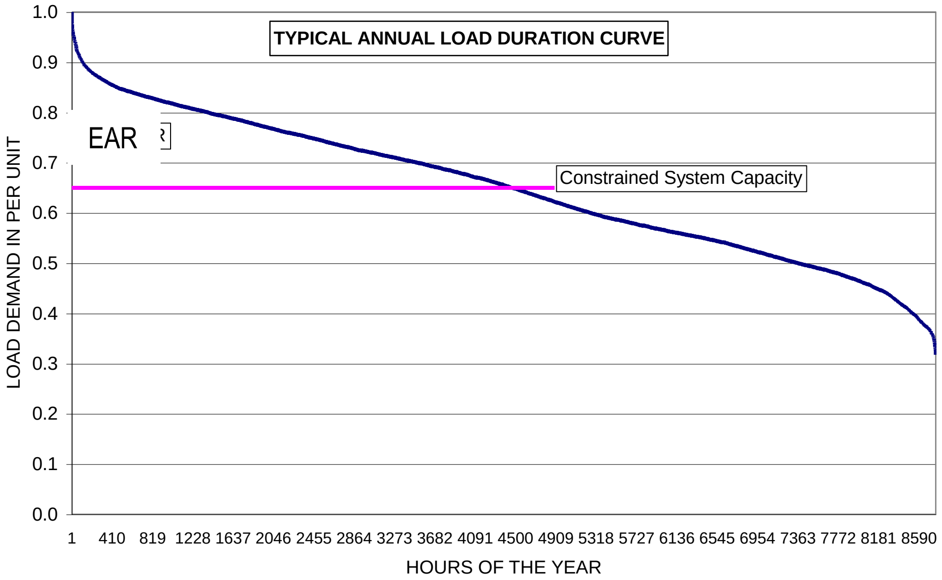


Figure 4: Illustration of the calculation of the EAR

Expected Unserved Energy

The Expected Unserved Energy (EUE) is the product of the EAR and the probability of the network being in the constrained state.

The terminal station demand forecasts obtained from AEMO's *Victorian Terminal Station Demand Forecasts* include both 50% probability exceedance (POE50) of the maximum demand and 10% probability exceedance (POE10) of the maximum demand. The following weightings are applied to determine the EUE:

10%POE weighting = 0.30

50%POE weighting = 0.70

$$EUE = EAR \times Pr(f)$$

$$= [w_{10} \times EAR_{D10} + w_{50} \times EAR_{D50}] \times Pr(f)$$

$$= [0.3 \times EAR_{D10} + 0.7 \times EAR_{D50}] \times Pr(f)$$

Where:

Pr (f)	Probability of Failure
EAR	Energy at Risk
w_{10}	Weighting apply to 10%POE
w_{50}	Weighting apply to 50%POE
EAR_{D10}	Energy at Risk using 10%POE demand forecast
EAR_{D50}	Energy at Risk using 50%POE demand forecast

Monetised Supply Security Risk

The monetised supply security risk is equivalent to the expected cost to consumers of having their electricity supply interrupted for a certain period of time and is sometimes referred to as the community cost.

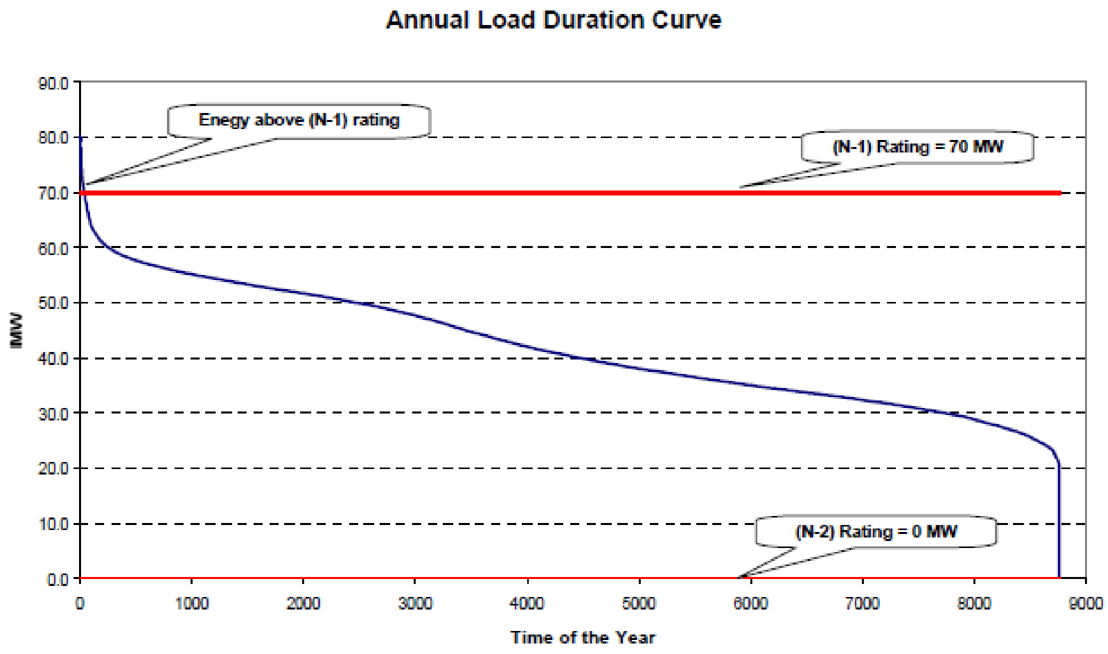
Monetised Supply Security Risk = VCR x EUE

In the economic analysis for a capital investment project (or program) that avoids or minimises the risk of supply interruptions, the community cost is treated as benefits. In other words, the benefit of an investment is the avoided community cost calculated as described above.

For asset renewal projects, the incremental benefit of an improvement in the asset failure risk usually equates to a reduction in the supply security risk and is calculated as the project supply benefits.

Example:

The following example illustrates the methodology to calculate "Expected Unserved Energy" for a terminal station with two transformers with the annual load duration curve shown below:



Where:

Energy above N-1 rating = 132 MWh

Energy above N-2 rating = 367, 877 MWh

Unavailability Pr (f) of transformer A = 0.216%

Unavailability Pr (f) of transformer B = 0.216%

VCR = $30,000 per MWh

Risk assessment calculation:

First Order Contingency (N-1):

EUE_{N-1} = EAR_{N-1} x [Pr (f) of transformer A or Pr (f) of transformer B]

= 132 MWh x [0.216% + 0.216%]

= 0.6 MWh

Second Order Contingency (N-2):

EUE_{N-1} = EAR_{N-2} x [Pr (f) of transformer A and Pr (f) of transformer B]

= 367, 877 MWh x [0.216% x 0.216%]

= 1.7 MWh

Monetised Supply Security Risk = VCR x EUE

= $30,000 per MWh x [0.6MWh + 1.7 MWh]

= $69,000

10.3.2 Market Impact Cost

There are instances where a network outage at, for example a switching station or generator connection point, would result in a generation constraint. The market dispatch modelling methodology should be used to calculate the market impact cost (generation constraint cost) and the Supply Security Risk (involuntary load shedding) for these types of network constraints.

Market Dispatch Modelling

Market dispatch modelling has to be undertaken for the Regulatory Investment Test for Transmission (RIT-T) to calculate the magnitude of market benefits, unless the transmission network service provider (TNSP) can demonstrate that generation dispatch and investments in the wholesale market are not a material factor in the ranking of options under the RIT-T.

The market dispatch modelling methodology requires calculation of the incremental market benefits by comparing the “state of the world” in the base case (the addition of no new or more restrictive constraints) with a state of the world for each of the credible options. The classes of market benefits considered in the RIT-T are defined in Paragraph 5 of the RIT-T Application Guide and include changes in generation fuel consumption, changes in voluntary and involuntary load curtailment, changes in network losses, changes in ancillary service costs, etc.

The incremental market benefits for asset replacement involves comparing the market impact cost of the base case, with a particular part of the network out of service (N-1 secure), with the market impact cost with all assets in service.

Several reasonable scenarios are considered to ensure a robust investment decision. These scenarios may be weighted in terms of their likelihood of occurrence and may include different future generation development scenarios; generator retirements; future transmission expansion plans (lines and transformers); different demand growth scenarios; changing fuel prices; technology efficiencies; and future demand management opportunities.

As guided by the RIT-T process:

> *In estimating the magnitude of market benefits, a market dispatch modelling methodology must be used and must incorporate:*
>
> *a) a realistic treatment of plant characteristics, including for example minimum generation levels and variable operation costs; and*
>
> *b) a realistic treatment of the network constraints and losses,*

The market modelling typically covers a period of ten years into the future. This is considered a period of sufficient length to cover the impact of changes in generation in Victoria (increase in wind and gas and reduction in traditional coal generators) yet short enough to minimise uncertainty around demand forecasts, new transmission augmentation projects, and new technologies such as solar photovoltaic cells, electric vehicles, and embedded storage that could otherwise skew market modelling results.

If the modelling needs to be extended beyond the ten-year window, the market benefits calculated for the final year are held constant and applied as the assumed annual market benefit that would continue under the option in the future.

Models assume load and wind behaviour from a particular year and an assumption of the Short Run Marginal Cost (SRMC) bidding behaviour of generators. In addition to generator and load behaviour, the models include a set of National Electricity Market Dispatch Engine (NEMDE) pre-dispatch system normal constraints. New constraints are developed and modelled for the impact of the asset failure (for example, thermal, transient stability, or voltage collapse constraints for the loss of a line or transformation capacity).

AusNet Services does not have the resources and data to perform this modelling and rely on AEMO to perform these modelling studies. AEMO supplies AusNet Services with the market impact cost for up to ten years for both the 'System Normal Secure' and 'N-1 Secure' scenarios, which are then used to calculate the marginal market cost.

Prophet by Intelligent Energy Systems[8] (IES) and PLEXOS® by Energy Exemplar[9] are the two models that are used for market modelling studies.

Market Impact Cost Example

The marginal market cost provided by AEMO is multiplied by the asset's unavailability prior and post replacement to calculate the incremental project benefits and to ascertain whether the project benefits outweigh the project cost in the economic cost-benefits tests. (See section 10.2).

Example:

> A market study is required to assess the market impact cost of a Hazelwood Terminal Station (HWTS) 500/220 kV transformer failure because generation rescheduling may be required following an unplanned outage of a HWTS 500/220 kV transformer. The most likely result would be a thermal constraint being invoked and for generation to be scheduled out of merit to ensure the remaining three 500/220 kV transformers are not overloaded.
>
> *Assumptions:*

8 Intelligent Energy Systems, http://www.iesys.com/ies/, accessed 23rd January, 2014.

9 Energy Exemplar, http://energyexemplar.com/, accessed 23rd January, 2014.

The Mean time to recovery (MTTR) is assumed to be 2.6 months in this example. (A 500/220 kV transformer would usually have a longer MTTR, but a spare phase for the three banks of 500/220 kV transformers is available on site at HWTS).

Risk assessment calculation

The transformer unavailability is:

$$\Pr(f) = \frac{MTTR}{MTTR + \frac{1}{\lambda}} = \frac{\frac{2.6}{12}}{\frac{2.6}{12} + \frac{1}{1\%}} = 0.216\%$$

An example of the marginal market cost (MMC) provided by AEMO is shown in Table 3.

Table 3: Marginal market cost (MMC) associated with the HWTS A4 transformer

Year	**2013-14**	**2014-15**	**2015-16**	**2016-17**	**2017-18**	**2018-19**	**2019-20**	**2020-21**	**2021-22**
Marginal Market Cost ($,000)	[C-I-C]	[C-I-C]	[C-I-C]	[C-I-C]	[C-I-C]	[C-I-C]	[C-I-C]	[C-I-C]	[C-I-C]

Monetised Market Risk Cost (2013-14) = MMC (2013-14) x Pr(f)

[C-I-C]

[C-I-C]

10.3.3 Safety, Plant Collateral Damage and Environmental Risks

The Electricity Safety Act requires AusNet Services to "*design, construct, operate, maintain and decommission its supply network to minimise, as far as practicable, the hazards and risks to the safety of any person arising from the supply network*.[10]

What is considered "practicable" is determined by having regard to:

a) *the severity of the hazard or risk in question; and*
b) *state of knowledge about the hazard or risk and any ways of removing or mitigating the hazard or risk; and*
c) *the availability and suitability of ways to remove or mitigate the hazard or risk; and*
d) *the cost of removing or mitigating the hazard or risk.*[11]

The Occupational Health and Safety Act requires AusNet Services to:

10 Electricity Safety Act 1998 (Vic), section 98(a).

11 Electricity Safety Act 1998 (Vic), section 3.

> *"so far as is reasonably practicable, provide and maintain for employees of the employer a working environment that is safe and without risks to health".*[12]

When determining what is (or what was, at a particular time), reasonably practicable in ensuring health and safety, the OHSA requires that regard be had to the following matters:

a) *the likelihood of the hazard or risk concerned eventuating;*
b) *the degree of harm that would result if the hazard or risk eventuated;*
c) *what the person concerned knows, or ought reasonably to know, about the hazard or risk and any ways of eliminating or reducing the hazard or risk;*
d) *the availability and suitability of ways to eliminate or reduce the hazard or risk;*
e) *the cost of eliminating or reducing the hazard or risk.*[13]

In practice this means safety risk should be proactively managed until the cost becomes grossly disproportionate to the benefits[14].

The failure effect cost for safety is the product of:

- Likelihood of consequence
- Value of statistical life
- Value of Lost Time Injury
- Disproportionality factor

The likelihood of consequence is sourced from the DNO Common Network Asset Indices Methodology (Table 215). The value of statistical life is sourced from the Australia Government Best Practice Regulation Guidance Note Value of statistical life, escalated to current year dollars.

The value of a lost time injury is source from Safe Work Australia's The Cost of Work-related Injury and Illness for Australian Employers, Workers and the Community (2012-13) (November 2015), Table 2.3b Electricity, Gas, Water and Waste Services.

The disproportionality factors provide guidance on the reasonableness of costs associated with safety risk mitigation measures to meet the requirements of the Electricity Safety Act 1998. They are a measure of society's expectation of how much should be spent to prevent a fatality. Higher values of disproportionality are justified when the consequences or likelihood are higher. They may also be higher when there is a low level of trust that a risk is being adequately managed.

Table 4 gives safety effect costs in 2014 dollars[15] using the following inputs:

- The reference safety probabilities given in the DNO Common Network Asset Indices Methodology
- The value of statistical life of $4.2m in 2014 dollars, as per the Best Practice Regulation Guidance Note Value of Statistical Life

12 Occupational Health and Safety Act 2004 (Vic), Section 21(1).

13 Occupational Health and Safety Act 2004 (Vic), Section 20(2).

14 Practical application of SFAIP in project specification 2012

15 The safety effect cost is then escalated with CPI to present the cost in the year of the assessment

- The value of lost time accident of $162,780 per event for Electricity, Gas, Water and Waste Services, as per Safe Work Australia's The Cost of Work-related Injury and Illness for Australian Employers, Workers and the Community (2012-13), Table 2.3b
- A disproportionality factor of 3 for a single fatality of either a member of the public or a worker

Asset Type	Lost Time Accident[16]	Death or Serious Injury to Public[17]	Death or Serious Injury to Staff[18]	Safety Effects Cost (in 2014 dollars)
Circuit Breaker (≥132 kV)	[C-I-C]	[C-I-C]	[C-I-C]	[C-I-C]
Transformer (≥132 kV)	[C-I-C]	[C-I-C]	[C-I-C]	[C-I-C]

Table 4: Safety Effects Cost

The following assumptions are used to monetise plant collateral damage and environmental hazards presented by plant in AusNet Services' cost-benefit studies to establish the scope and timing of remedial projects:

- Plant that contains large volumes of oil poses an environmental risk with an average consequence cost of $30 K
- Transformer with oil that contains poly-chlorinated biphenyls (PCB) poses an environmental risk with an average consequence cost of $100k per event
- Plant collateral damage, including consequent supply outages, is on average $1 M per event

The likelihood of the above hazards is based on the major failure rates defined in the RCM models and the CIGRE research[19] into the probability of explosion and fire associated with major plant failures, which presents the probability of a major failure with collateral plant damage or environmental consequences.

The method of calculations and the assumptions applied in monetising the risks above are further discussed in the example below.

10.3.4 Network Performance Incentive Schemes

The transmission network has a performance incentive scheme the Service Target Performance Incentive Scheme (STPIS).

[16] From Table 215 of *DNO Common Network Indices Methodology,* Health and Criticality Version 1.1, 30 January 2017

[17] From Table 215 of DNO Common Network Indices Methodology, Health and Criticality Version 1.1, 30 January 2017

[18] From Table 215 of DNO Common Network Indices Methodology, Health and Criticality Version 1.1, 30 January 2017

19 Cigre Final Report of the 2004 – 2007 International Enquiry on Reliability of High Voltage Equipment.

The STPIS[20] has been developed by the Australian Energy Regulator (AER) in accordance with clause 6A.7.4 of the National Electricity Rules (NER). This scheme presently consists of the following three components:

- Service Component – provides an incentive to reduce the occurrence of unplanned outages and to return the network to service promptly after unplanned outages that lead to a supply interruption.
- Market Impact Component – provides an incentive to reduce the impact of planned and unplanned outages on wholesale market outcomes.
- Network Capability Component – provides an incentive to deliver benefits through increased network capability, availability or reliability through minor capex or opex projects.

Outages on assets that are not providing prescribed transmission services are excluded from these two incentive schemes, but may have contracted performance standards.

STPIS – Service Component

The Service Component of the STPIS consists of four parameters, which measure different aspects of service performance. These parameters measure network reliability by focusing on unplanned outages (ability to minimise the number of events and to quickly rectify them when they occur) and by providing an incentive for TNSPs to improve their performance. The parameters are:

- Average Circuit Outage Rate – measures the frequency of unplanned (forced and fault) outages on lines, transformers and reactive plant
- Loss of Supply Event Frequency – measures the frequency of outages which cause a loss of supply to customers
- Average Outage Duration – measures the duration of unplanned outages with a loss of supply
- Proper Operation of Equipment – requires TNSPs to report on near miss events such as failures of protection systems, material failure of the Supervisory Control and Data Acquisition (SCADA) system and incorrect operational isolation of primary and secondary equipment. No financial incentive is associated with this parameter.

The weightings applied to each parameter and sub-parameter of the Service Component are specified in Table 5, where MAR is the maximum allowed revenue for the relevant calendar year[21].

20 Australian Energy Regulator, Final: Electricity transmission network service providers: Service target performance incentive scheme, Version 04, 20 December 2012, AER reference 45236-D12/137417.

21 AusNet Services' regulatory year runs from 1 April to 31 March in the following year. To account for this, there is a three-month lag between when AusNet Services' performance is measured, and when the financial incentive adjustment is made to AusNet Services' MAR.

Table 5: Weightings for each parameter/sub-parameter

Parameter	Weighting (MAR %)
Unplanned outage circuit event rate:	**0.75**
Lines event rate – fault	0.20
Transformer event rate – fault	0.20
Reactive plant event rate – fault	0.10
Lines event rate – forced	0.10
Transformer event rate – forced	0.10
Reactive plant event rate – forced	0.05
Loss of supply event frequency:	**0.30**
> (x) system minutes	0.15
> (y) system minutes	0.15
Average outage duration	**0.20**
Proper operation of equipment	**0.00**

(Source: Australian Energy Regulator, Final: Electricity transmission network service providers: Service target performance incentive scheme, Version 05, 30 September 2015

Table 6 shows the caps, collars and targets which are defined as:

- **Cap** – the level of performance that results in a TNSP receiving the maximum financial reward attributed to a parameter.
- **Floor** – the level of performance that results in a TNSP receiving the maximum financial penalty attributed to a parameter.
- **Target** – the historical average performance attributed to a parameter for which a TNSP would not receive a reward or penalty.

Table 6: Caps, Floors and Targets for service component (2017 to 2022)

Parameter	Distribution	Cap	Target	Floor
Lines outage rate - fault	Weibull	16.0%	25.4%	33.8%
Transformers outage rate - fault	Weibull	9.2%	20.3%	31.8%
Reactive plant outage rate - fault	Pearson5	18.4%	34.3%	61.2%
Lines outage rate - forced	Weibull	12.3%	15.0%	17.1%
Transformer outage rate - forced	Weibull	6.1%	10.4%	14.4%
Reactive plant outage rate - forced	Weibull	19.9%	30.9%	40.7%
Average outage duration	Lognormal	3.4	75.1	334.2
No. of events > 0.05 system minutes	Poisson	0	2	5
No. of events > 0.30 system minutes	Poisson	0	1	2
Failure of protection system	Poisson	23	32	42
Material failure of SCADA	Poisson	0.0	1.8	4.0
Incorrect operational isolation of primary or secondary equipment	Poisson	2.0	5.6	10.0

STPIS – Market Impact Component

The Market Impact Component (MIC) of the STPIS incentivises TNSPs to minimise transmission outages that can affect the economic dispatch of generation in the NEM. This is measured by the number of five-minute Dispatch Intervals (DIs) where an outage on the transmission network results in a network outage constraint[22] with a marginal value greater than $10/MWh. This measure is known as the market impact parameter (MIP).

Where there is more than one network outage constraint with a marginal value greater than $10/MWh in one dispatch interval, the MIP counts the dispatch interval for each network outage constraint (that is, the same dispatch interval may be counted more than once).

Clause 4.2(a) of the current STPIS requires TNSPs to submit MIC performance data in accordance with Appendix C of the STPIS Guidelines for the preceding two calendar years. The target for the forthcoming regulatory control period will be determined by a rolling average of the previous three years performance.

The maximum revenue increment that a TNSP may earn against its parameter and values under this market impact component is 1 per cent of the TNSP's maximum allowed revenue for the relevant calendar year. Assuming an approximate MAR of $500M, the maximum incentive is $5M. Assuming the three-year rolling average provides a market impact parameter of 2,000 dispatch intervals, each market impact constraint dispatch interval is

22 Details can be found at AEMO's website www.aemo.com.au. Useful documents include:

AEMO, Constraint Naming Guidelines, Ref: SC_CM_04, Version 8, 3 May 2013

AEMO, Constraint Formulation Guidelines, Ref: 170-0040, Version 10, 6 July 2010

AEMO, Operating Procedure: Generic Constraints due to Network Limitations, Ref: SO_OP3709, Version 30, 9 November 2010 worth $2.5k. Outages on the network have been studied and the typical expected revenue reduction has been estimated[23]. These are done by asset and include three failure event types: during optimum outage conditions (M1); over a typical 24-hour period (M2); and during peak periods, overnight during independencies or other non-optimum periods (M3).

Example:

One example of an outage is the loss of an ‘A’ transformer at HWTS. In the example the following definitions are made:

- Failure Rate (λ(t)) is defined as the anticipated number of times an item will fail in a specified time period, t.
- The Mean time to recovery (MTTR) is the time it takes to return the failed asset to service.

Assumptions:

Failure will result in a defined asset being out of service. Failure Rate (λ(t)) in a particular year is 1%. Typical MIP $k/hr is over a typical 24hr period (M2). For an ‘A’ transformer at HWTS, M2 is $60/hr. MTTR is equivalent to the transformer average of 2.6 months or 1,898 hours (an ‘A’ transformer would usually have a longer MTTR).

Parameter 1 incentive calculation:

Incentive Reduction in Revenue Cost	= λ(t) x MTTR x M2
	= 1% x 1,898hrs x $60k/hr
	= $1,138.8k

Note: the maximum incentive ($10 million) should not be exceeded.

STPIS – Network Capability Component

The Network Capability Component has been introduced to encourage improvements in the capability of transmission assets, particularly those that are most important to determining spot prices and at times when network users place greatest value on the reliability of the transmission system.

Participation in this component requires TNSPs to submit a Network Capability Incentive Parameter Action Plan (NCIPAP) which contains:

- A list of every transmission circuit and injection point on the network, and the reason for the limit for each.
- A list of priority projects to be undertaken during the forthcoming regulatory control period to improve the limit of the transmission circuits and injection points listed above.

AEMO plans the transmission network in Victoria. Therefore, the NCIPAP has been prepared jointly with AEMO. The incentive of this component is not for asset renewal projects, but constraint removal projects identified by AEMO.

23 AusNet Services, Market Impact Parameter (MIP) Incentive Scheme Guide, 29 November 2012.

10.4 Option and Project Selection Methodology

By aggregating all the risk costs of the assets, the baseline risk for the terminal station is valued. The baseline risk increases over time due to both the deterioration in condition of the assets and demand growth. It presents the risk cost for the “Business as Usual” option, which is used to justify further investigation when the monetised risk is material.

The process chart in Figure 6 below shows how individual asset replacement projects are being selected by quantifying the asset failure risk (where expected cost is a function of consequence and probability) and by undertaking an economic evaluation of credible options. The objective of the economic evaluation is to identify the option with the lowest present value (PV) cost.

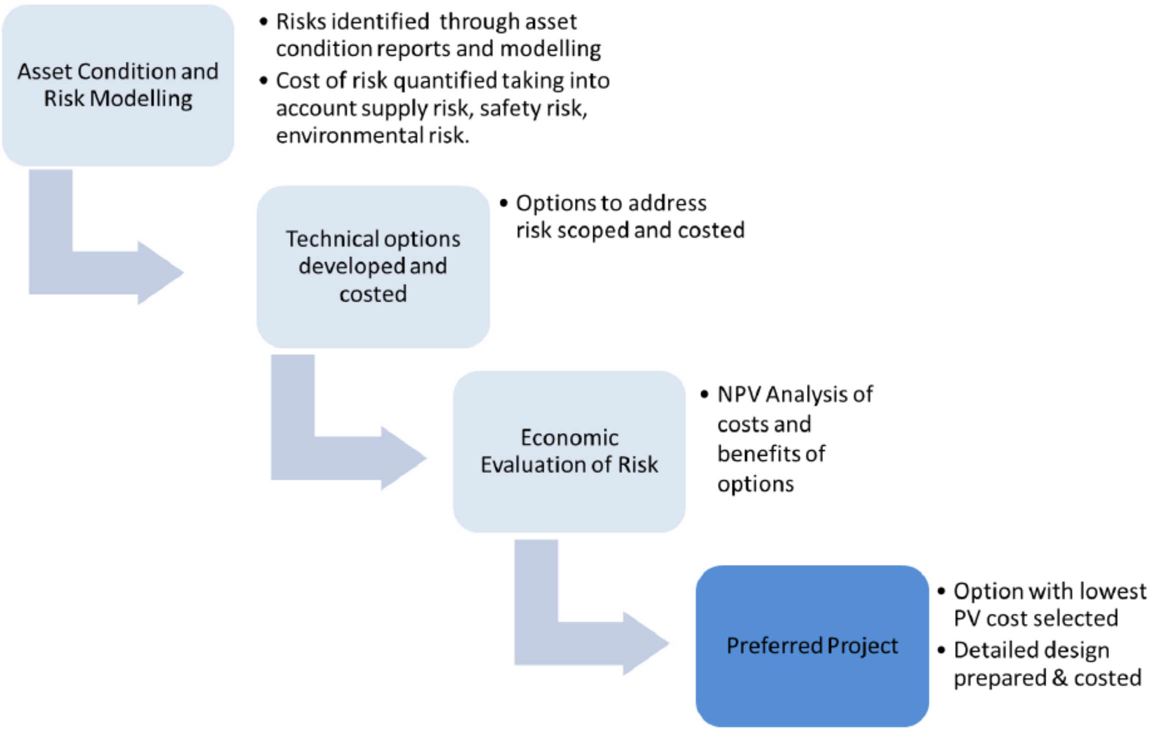


Figure 5: Project Selection Method

Different technically credible and feasible options to address the identified risk, ranging from refurbishment to asset replacement, are identified and scoped in the option and project selection stage of the asset renewal planning process.

Analysis is also undertaken across projects to identify potential efficiencies of coordination of project scope and timing. For example, some minor replacement work may be included in a major replacement or augmentation project to attain synergies in project design, project management and project establishment costs. This reduces the cost of minor replacement work and ensures that new assets are configured to function reliably with other assets, as an integrated system. The shared network augmentation needs of AEMO and the connection asset augmentation needs of the distribution businesses are taken into account in the scoping and scheduling of all asset replacement work.

Initial project cost estimates are used in the economic evaluation to ascertain which option maximises the net present benefits. The Net Present Value (NPV) study analyses the costs and benefits of each option, with the aim of identifying the most economical option (the preferred option) for a range of planning scenarios and input assumption sensitivities.

10.5 Scenario Planning and Sensitivity Studies

Scenario planning and sensitivity studies around demand growth, discount rate, VCR rate and asset failure rate are conducted for new investments to test the robustness of the economic evaluation and option selection. This is a crucial step in ensuring replacement investment is economic under a range of reasonable scenarios[24].

Figure 6 shows how the following two credible options have been evaluated to ascertain which option delivers the highest net present value (NPV) benefits for a range of planning scenarios and input assumptions (demand growth, discount rate, VCR rate and asset failure rate):

- Option 4 – In Situ Replacement
- Option 6 – Replace in new location

The most economical option is the option that maximises the NPV benefits for most of the planning scenarios or input assumptions. In this example it is Option 4 - In situ replacement by a small margin.

24 The Transmission Planning Assumptions are detailed in Appendix A

[C-I-C]

Figure 6: Economic option selection methodology

Option 4: In Situ Replacement is considered a robust solution[25] as it delivers NPV benefits for all twelve scenarios, i.e. the expected outcome has been tested taking into account its variability and the NPV benefits ranges from $10.7 M to $30.6 M compared with the "Business as Usual" option. It also delivers the highest NPV benefits of the two options (Option 4 and 6) for all scenarios except the "High demand growth" scenario.

Scenario analysis, with the scenarios used by AEMO in their most recent Integrated System Plan (ISP), is also used to ensure the investment option that maximises the net present benefit for the chosen scenarios is selected as the preferred option. The following three scenarios are used Slow Change (weighting of 25%), Central Scenario (50% weighting) and Fast Change (25% weighting). This is consistent with the RIT-T requirements and practice notes on risk-cost assessment methodology.[26]

[25] A robust solution is a solution for which the objective value for any realised scenario remains within the expected objective value for all possible scenarios.

[26] Australian Energy Regulator, *"Industry practice application note for asset replacement planning,"* available at https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/industry-practice-application-note-for-asset-replacement-planning, viewed on 7 November 2019.

Table 7: Scenario Analysis

Parameter	Slow Change Scenario	Central Scenario	Fast Change Scenario
Description	a slow-down of the energy transition, characterised by slower changes in technology costs, and low political, commercial, and consumer motivation	the pace of transition is determined by market forces under current federal and state government policies	a more rapid technology-led transition, its costs reduced by advancements in grid-scale technology and targeted policy support
Weighting	25%	50%	25%
Demand forecast	AEMO 2019 Connection Point Forecasts - 15%	AEMO 2019 Connection Point Forecasts	AEMO 2019 Connection Point Forecasts + 15%
Value of customer reliability[27]	Latest AER VCR figures – 30%	Latest AER VCR figures	Latest AER VCR figures + 30%
Network option capital cost	AusNet Services assessment - 15%	AusNet Services assessment	AusNet Services assessment + 15%
Discount rate	2.58% - the WACC rate of a network business	4.68% - the latest commercial discount rate	6.78% - a symmetrical adjustment upwards

It is also important to consider irreversibility and uncertainty in investment decisions, where asset renewal investments are normally undertaken for asset with very long asset lives (45 years on average). Breakeven analysis provides an indication of how long (number of years) it will take before the present value benefits will exceed the present value cost for the particular investment.

The proposed investment in the example below (

[27] The range of values used for the Value of Customer Reliability (VCR) is 'consistent with the confidence interval ranges applied to VCR estimates.' Australian Energy Regulator, *"Values of Customer Reliability, Final report on VCR values,"* page 84, available at https://www.aer.gov.au/system/files/AER%20-%20Values%20of%20Customer%20Reliability%20Review%20-%20Final%20Report%20-%20December%202019.pdf, viewed on 12 February 2020.

Figure 7) delivers NPV benefits after year 8. Due consideration of uncertainty in all planning assumptions must be taken into account in the planning decision; particularly for investments that have a breakeven point after more than ten years, has considerable uncertainty in planning assumptions such as future demand growth and where the economic investment decision is sensitive to changes in the assumptions.

[C-I-C]

Figure 7: Investment Breakeven Analysis

A Regret function can be used to assess, which option minimises the maximum loss which could result from selecting a particular option. This methodology compares the NPV for each option in each scenario with the NPV which could have been achieved for the scenario if the outcome had been known in advance and the most appropriate option chosen. The investment decision can also be based on the expected net present value (ENPV) where probabilities can be ascribed to particular outcomes.

Selective asset replacement options often result in residual risk, which need to be quantified and tested to ascertain whether it is within the corporate accepted risk profile, particularly where residual safety risk results from selective or staged asset renewal options.

Investment decisions are not only characterised by irreversibility and uncertainty but also by flexibility with regard to the timing of the investment. The methodology to calculate the economic timing of a new investment is discussed in the next section.

10.6 Economic Project Timing

Efficient network investments proceed once the annual service quality improvement exceeds the annual cost of the investment. The economic timing of an asset replacement is thus determined based on a comparison of the annual cost and benefits provided by the replacement. Under this evaluation approach, the economic timing is identified as the point in time at which the annual incremental benefits exceed the annualised cost.

The economic benefits considered in the evaluation include savings achieved by lowering network losses and operating and maintenance cost, reduction in safety, plant collateral damage and environmental risk costs, and reducing customer load at risk. The reduction in customer load at risk, expressed as the Energy at Risk (EAR), is valued at the VCR.

The annualised capital cost of the asset replacement is used in the economic cost-benefit evaluation, representing the cost of the asset replacement. The methodology used to assess the economic time for the preferred option to proceed is described next.

10.6.1 Annual Levelised Capital Cost

The incremental capital cost or annual levelised capital cost (ALCC) of the capital investment (P) is calculated by applying the capital recovery factor (CRF) and the present value factor (PVF) to the initial capital amount as illustrated in the figure and formulas below.

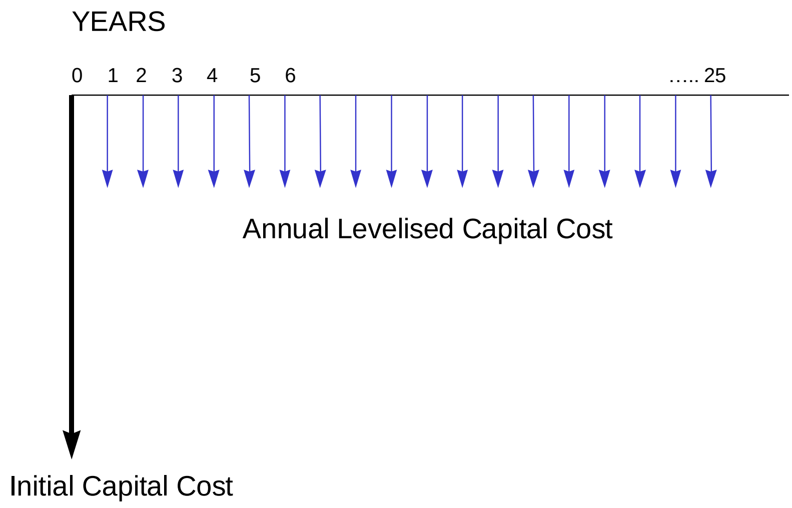


Figure 8: Illustration of the calculation of the ALCC

The annual levelised capital cost series starts in year 1. To obtain the annual levelised capital cost (annuity), which is equivalent to the investment made in year 0, the PVF is calculated with n = 1 (Equation 2) and multiplied with the CRF (Equation 1) to obtain Equation 3.

$$CRF = \frac{i(1+i)^n}{(1+i)^n - 1}$$ Equation 1

$$PVF = \frac{1}{(1+i)^n}$$ Equation 2

$$ALCC_{Year\,0} = P\,\frac{i(1+i)^{(n-1)}}{(1+i)^n - 1}$$ Equation 3

The regulatory investment test specifies that present value calculations must use a commercial discount rate appropriate for the analysis of a private enterprise investment in the electricity sector. The weighted-average cost of capital for regulated electricity infrastructure ought to provide the lower bounds of the discount rate used in any sensitivity analysis.

10.6.2 Economic Cost-Benefit Evaluation

Once the economic costs and benefits of the replacement have been calculated a decision is made regarding the timing of the replacement. A replacement is justified economically in the year that the benefits exceed the cost of the replacement.

This test relies on the assumption that an adequate level of service quality and network reliability would be provided to network users, when using the VCR in the calculation of the incremental worth of service quality improvement, once it exceeds the incremental cost to provide that improvement.

10.6.3 Economic Investment Year Sensitivity Studies

Sensitivity studies around the discount rate, VCR rate, asset failure rate and demand growth scenarios are conducted to test the robustness of the proposed economical investment year of the selected option.

Figure 9 shows how sensitive the project economical investment year is to changes in asset failure rate.

[C-I-C]

Figure 9: Project Economical Timing Sensitivity Study

10.7 Preferred Option

A detailed project scope and cost estimate is prepared for the most economic option. AusNet Services does this using a detailed technical scope of works and current unit costs for installing assets. This resulting cost estimate is the most likely cost of the project. The estimate does not capture possible changes in unit costs but does account for the expected cost of various project contingencies (estimated using Monte Carlo analysis).

AusNet Services also explores the potential for efficiencies to be derived by staging the timing of large complex projects. Under this approach, AusNet Services identifies the highest asset failure risks so that these can be addressed in a timely fashion, while lower-risk project components may be deferred.

Overall, AusNet Services' approach is consistent with the annual Victorian transmission plans published by AEMO (Victorian Annual Planning Report) and the Distribution Businesses (Transmission Connection Planning Report). It is also consistent with the principles underpinning the regulatory investment test for transmission (RIT-T).

11 TECHNICAL PLANNING CRITERIA AND PLANNING STANDARDS

AusNet Services' Stations Design Manual describes AusNet Services' standards, policies and processes required for the design of all stations including terminal stations, power station switchyards and transmission lines.

11.1 Ratings

Plant and network elements are designed for a maximum operating temperature and this limits their capability to a maximum load. Plant and equipment ratings depend on ambient temperature and both summer and winter ratings are defined, but it is the summer limitation that usually is the most critical.

All items of plant in a terminal station will have defined maximum current carrying capacities. Transformers, circuit breakers, droppers, inter plant connections, isolators etc. will all have maximum capabilities defined in various ways. The plant data sheets for each station will define most of these ratings and in many cases it will simply be the continuous current rating.

Ratings for overhead lines are based on maximum operating temperatures and minimum clearances as specified in the Electricity Safety (Network Assets) Regulations 1999, ENA C(b)1 – 2006 “Guidelines for design and maintenance of overhead distribution and transmission lines” and the Overhead Line Design manuals.

Ratings for underground cables are based on maximum operating temperatures and are specified in the Underground Cable Design Manual.

Ratings for transformers are based on maximum operating temperature and the manufacturer’s continuous rating. Cyclic ratings, which recognise varying load and ambient temperature cycles are calculated for cables and transformers.

Ratings for other equipment are defined by manufacturers’ specifications.

11.1.1 Power Transformers

For more complex items of plant such as transformers a range of ratings are defined that may include the following:

- Continuous rating. This is the load that can be carried on a continuous basis as the name suggests. This will result in the transformer having a winding temperature of typically 130 degrees Celsius.
- Summer and winter cyclic ratings. This is the highest point of a cyclic load curve for the relevant season that the transformer can carry and is typically around 130% of the continuous rating. The transformer can carry this cyclic load for any number of consecutive days.
- The summer and winter limited cyclic rating allows a single day of higher loading than the cyclic rating. It is typically 5% to 10% higher than the cyclic rating.
- It allows for a higher transformer loading on this day and would be used to provide operators time to transfer load away from the station.
- The limited cyclic rating is only available where a station operates with more than one transformer in parallel, sharing the load between the transformers. An outage that results in increased loading through the remaining transformer/s will be preceded by lower loading on each transformer. It is important to note that the full limited cyclic rating is only available where a station has operated at or below the N – 1 rating.
- Emergency rating. In some cases an emergency 2 hour rating will be noted and this will often bring the transformer to a higher winding temperature of typically 140 degrees Celsius.
- N – 1 station rating. The N – 1 rating refers to the rating of the station with one transformer out of service. The N – 1 rating is also often referred to as the “firm rating”. In cases where a station has only a single transformer there is strictly speaking no firm rating but usually the load transfer capability will be quoted. Shunt capacitor banks are included in the station rating calculation.

11.2 Fault Levels

Fault levels in the network must be maintained within the ratings of switchgear, plant and lines and within requirements of the Distribution Code, Station Design Manual and AEMO’s Victorian Transmission System Overview – Technical Standard.

Most augmentations including new transformers and upgraded or new lines will result in an increase in fault levels and requirements to address this issue must be included in augmentation plans.

12 ASSET RENEWAL PLANNING REPORT

A detailed planning report is required for each major asset renewal project. The report provides an analysis of all viable options and selects the best economic option to address the identified risks and to maintain the efficient delivery of electrical energy consistent with the National Electricity Rules (NER), stakeholder's requirements and AusNet Services' asset management strategies. The planning report covers the following areas:

- Asset condition – Provides a summary description of the condition of key primary and secondary equipment, asset condition rankings and references to condition assessment reports and/or asset management strategies (where applicable).
- Future Planning Requirements – Any significant asset replacement works must consider the long term shared network and connection network development plans of AEMO and the distribution businesses respectively to ensure individual decisions will not impede efficient future augmentation or compromise security of supply. Consultations with AEMO and distribution businesses in relation to their future plans are recorded.
- Emerging Constraints – Identify the risks presented by the deteriorated assets, which are typically security of supply risks, health and safety risks, environmental hazards and plant collateral damage risk. Transmission planning assumptions (refer Appendix A) are used to quantify the risks, establish the baseline risk and define the residual risk after the implementation of the remedial actions.
- Technical Analysis of Options – Identify a range of possible solutions; describe the works involved, project advantages/limitations (if any) and the estimated cost for delivering each individual solution.
- Economic Analysis – The present value (PV) cost (taking into account the total project capital cost, operating and maintenance cost and expected risk costs) for all credible options is calculated. The discount rate used is a commercial discount rate appropriate for the analysis of a private enterprise investment in the electricity sector. The approach is outlined in the Energy Networks Australia RIT-T Economic Assessment Handbook[28], applying contemporary parameter values. Sensitivity testing on the discount rate is also undertaken.. This allows for all the viable options to be ranked based on their economic merits. The option with the lowest PV cost is the most economic option. Sensitivity and scenario planning studies are conducted to assess project risk and uncertainty.
- Scenario analysis is used to select the investment option that maximises the net present economic benefit for the selected scenarios.
- Recommended Option and Timing – Specify the preferred option to address the emerging network constraints and its economical timing.
- Sensitivity Analysis – Sensitivity analysis is applied to test the robustness of the preferred solution. Typically, sensitivity testing is conducted on changes in input costs,

[28] Energy Networks Australia, RIT-T Economic Assessment Handbook, March 2019, page 46

forecast plant failure rates, demand growth scenarios, discount rates, and value of customer reliability.

- Scope of Work - Provide a summary of the high level scope of work for the preferred solution.

13 PROGRAM/PROJECT LIFE CYCLE

The Business Case Development Guide (AMS 02-02) provides a detailed description of the process that needs to be followed to seek approval for a new project or to revise an existing business case. It steps through the key stages of the project life cycle, including Idea, Plan, Build and Close.

To formally raise a project, access to SAP – PPM module is required. This can be secured by raising a request (Service Portal on Intranet).

To activate a project, it must be selected into the pipeline of active projects at Gate 2. Once a project is selected into the pipeline, the business case development process automatically starts. The Business Case Development Guide[29] provides more detailed Asset Management requirements for each step of the business case development process.

Once a project business case is approved (at Gate 3), the project is formally released to Service Delivery for design, construction and close-out.

As Asset Owner, project Initiators are required to endorse project close-out in the business transition process.

The Program/Project life cycle is illustrated in Figure 10 below.

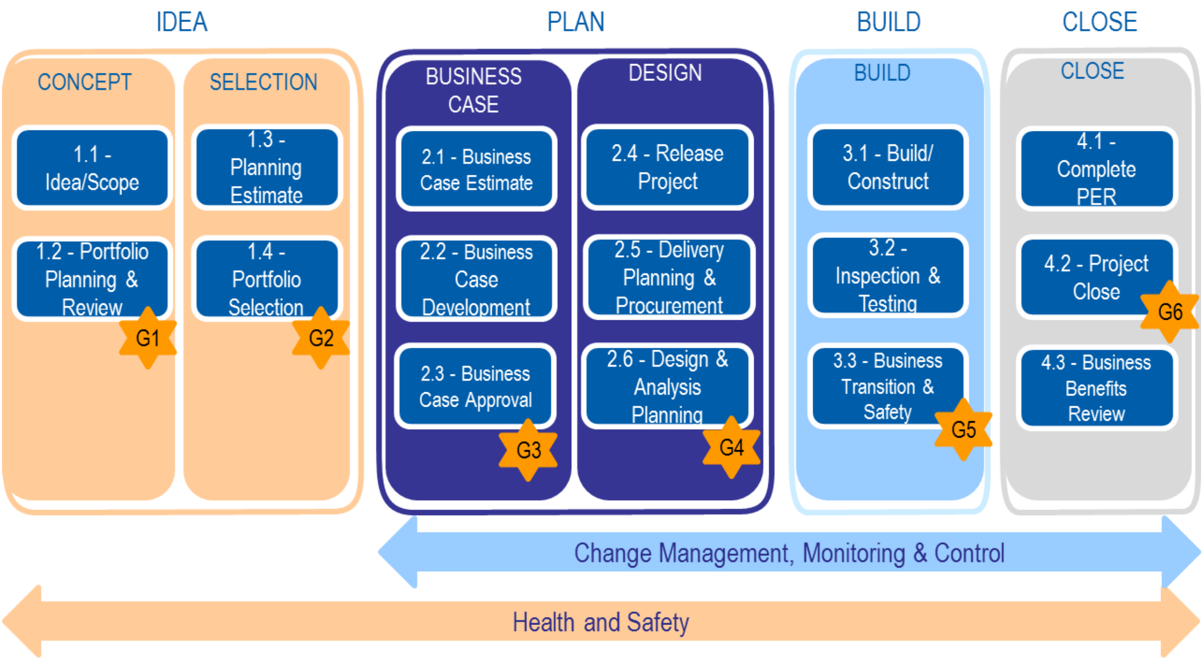


Figure 10: Program/Project Life Cycle

29 AMS 02-02 Business Case Development Guide

APPENDIX A REGULATED INVESTMENT TEST FOR TRANSMISSION

Introduction

On 18 July 2017, the AEMC made the National Electricity Amendment (Replacement expenditure planning arrangements) Rule 2017 No 5 (Repex Rule). The Repex Rule made a number of amendments to the existing planning and investment framework with the aim of creating a set of requirements that will apply to both replacement and augmentation investments.

In Victoria, AEMO is responsible for the augmentation of the transmission network. AusNet Services and other transmission asset owners are responsible for the replacement of transmission assets they own. The RIT-T for transmission network augmentation has been in effect for many years. This new rule change extended the RIT-T to include transmission asset replacements.

The process to be followed in undertaking the RIT-T is prescribed in the NER, RIT-T, AER RIT-T Guidelines and Draft Industry practice application note (Asset replacement planning).

RIT-T Requirement

The purpose of the regulatory investment test for transmission is to identify the credible option that maximises the present value of net economic benefit to all those who produce, consume and transport electricity in the market (the preferred option)[30]. AusNet Services must apply the RIT-T for all transmission asset replacement projects except in the circumstances where;

- The asset replacement is required to address an urgent and unforeseen network issue[31]
- The estimated capital cost of the most expensive technically and economically feasible option is less than $6 million[32]
- The proposed expenditure relates to maintenance and is not intended to augment the transmission network or replace network assets

Need Identification

The starting point is a clearly identified need for action to be taken. An identified need is to be expressed as the achievement of a desired objective or end, and not simply the means to achieve a desired objective or end. A description of an identified need does not mention or explain a particular method, mechanism or approach to achieving a desired outcome. In describing an identified need it is useful to explain what may happen if AusNet Services fails to take any action.

Credible Options

The options that may be available to respond to the identified need must be assessed, and compared to determine which achieves the test criterion.

[30] NER - Clause 5.16.1 (b)

[31] NER – Clause 5.16.3 (b)

[32] Cost thresholds are to review by the AER every 3 years – Clause 5.15.3 (a) of the NER

Clause 5.15.2 (a) of the NER defines a credible option as an option (or group of options) that;

- addresses the identified need;
- is (or are) commercially and technically feasible; and
- can be implemented in sufficient time to meet the identified need

Clause 5.15.2 (b) of the NER requires AusNet Services to consider all options that could reasonably be classified as credible options. Clause 5.15.2 (d) states that the absence of a proponent does not exclude an option from being considered a credible option.

The AER RIT-T application guidelines states that “The AER is of the view that a TNSP has to consider a sufficient number and range of credible options where the number of credible options being assessed regarding a particular identified need is proportionate to the magnitude of the likely costs of any credible option”.

Project Specification Consultation Report (PSCR)

Consultation with stakeholders is a key focus of the RIT-T, in particular so that proponents of nonnetwork solutions have the opportunity to contribute to the options and their assessment.

If a transmission asset replacement project is subjected to a RIT-T, AusNet Services must consult all Registered Participants, AEMO and interested parties on the RIT-T project[33]. AusNet Services must prepare a Project Specification Consultation Report (PSCR) containing all the information required under clause 5.16.4 (b) of the NER.

The PSCR must be made available to all registered Participants, AEMO and other interested parties. AusNet Services must also provide a summary of the PSCR to AEMO within 5 business days of making the PSCR and AEMO must publish the summary on its website within 3 working days. Upon request by an interested party, AusNet Services must provide a copy of the PSCR to that person within 3 business days of the request.

The consultation period on the PSCR must be not less than 12 weeks from the date AEMO publishes the summary of the PSCR on its website[34].

Project Assessment Draft Report (PADR)

AusNet Services assessments on how the consultation has effected its initial assessment of the options is then reported back to stakeholders in a Project Assessment Draft Report (PADR).

Within 12 months of the end date of the PSCR consultation period, AusNet Services must prepare and publish a PADR having regard to the submissions received and meeting the information requirements specified in the clause 5.16.4 (k) of the NER. The PADR must be made available to all Registered Participants, AEMO and interested parties.

AusNet Services must also provide a summary of the PADR to AEMO within 5 business days of making the PADR and AEMO must publish the summary on its website within 3 working days. Upon request by an interested party, AusNet Services must provide a copy of the PADR to that person within 3 business days of the request.

[33] NER – Clause 5.16.4

[34] NER – Clause 5.16.4 (g)

The consultation period on the PADR must not be less than 6 weeks from the date AEMO publishes the summary of the PADR on its website[35].

Within 4 weeks after the end of the consultation period, at the request of an interested party, a Registered Participant or AEMO, AusNet Services must meet with the relevant party if a meeting is requested by two or more relevant parties and may meet with a relevant party if after having considered all submissions, AusNet Services, acting reasonably, considers that the meeting is necessary9.

Exception from PADR

AusNet Services does not have to prepare a PADR if;

1. The estimated capital cost of the preferred option is less than $43 million; and

2. The preferred option and any other credible option has no material market benefit; and

3. AusNet Services has identified its preferred option in the PSCR and is still the preferred

option; and

4. Submissions on the PSCR did not identify any additional credible options which could deliver a material market benefit.

Under these circumstances AusNet Services could skip the preparation of the PADR and could prepare the PACR directly.

Project Assessment Conclusion report (PACR)

After the end of the consultation on the PADR and as soon as practical, AusNet Services must prepare and publish a Project Assessment Consultation Report (PACR), having regard to the submissions received and the matters discussed at any meetings held, and make this available to all Registered Participants, AEMO and interested parties.

AusNet Services must provide a summary of the PACR to AEMO within 5 business days of making the PACR and AEMO must publish the summary on its website within 3 working days of receipt. Upon request by an interested party, AusNet Services must provide a copy of the PACR to that person within 3 business days of the request.

After 30 days of the date of publication of the PSCR, AusNet Services may request, in writing to the AER, that the AER make a determination as to whether the preferred option satisfies the RIT-T. The AER must, publish a determination within 120 business days of receipt of the request. (The relevant period of time in which the AER must make a determination is automatically extended by the period of time taken by AusNet Services to provide any additional information requested by the AER).

Reapplication of the RIT-T

Subsequent to completing the test, circumstances may arise which affect the ‘preferred’ status of the preferred option.

The NER requires that AusNet Services must reapply the RIT-T for a project if there has been a material change in circumstances resulting in the preferred option identified in the PACR being no longer the preferred option, unless otherwise determined by the AER.

[35] NER – Clause 5.16.4 (r)

Dispute Process

The RIT-T process ensures accountability of AusNet Services by providing for stakeholders to dispute its conclusions on the preferred option.

Within 30 days of the date of publication of the PSCR, Registered Participants, the AEMC, Connection Applicants, Intending Participants, AEMO and interested parties may, by notice to the AER, dispute conclusions made in the PACR[36].

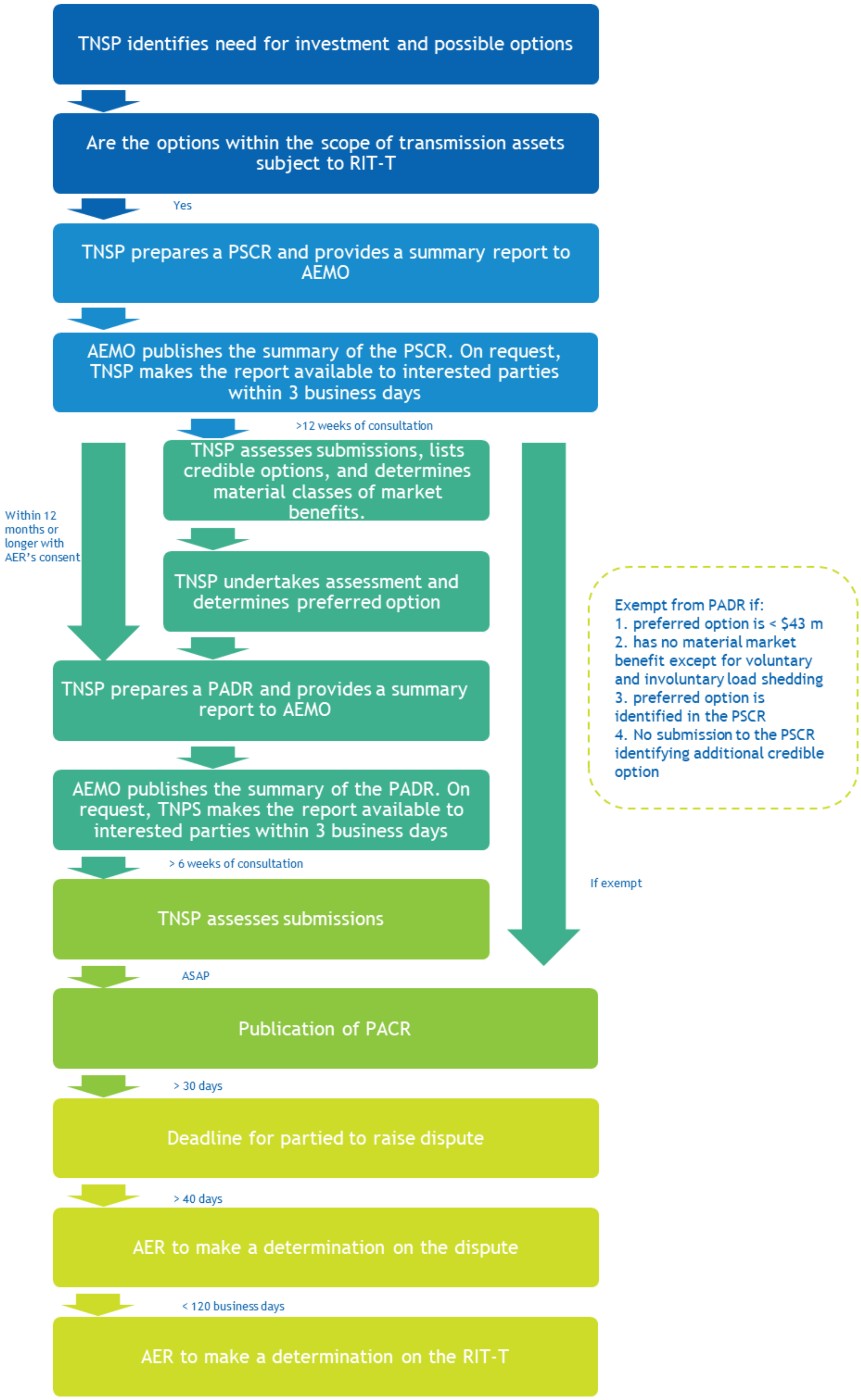
Within 40 days of receipt of the dispute notice or within an additional period of up to 60 days where the AER notifies interested parties that the additional time is required to make a determination because of the complexity or difficulty of the issues involved, the AER must either; reject any dispute and notify the person initiated dispute and AusNet Services or make and publish a determination directing AusNet Services to amend the matters set out in the PCSR.

AusNet Services must comply with an AER determination within a timeframe specified by the AER in its determination.

RIT-T Process

The following figure demonstrates the RIT-T assessment and consultation process that applies to transmission asset replacements.

[36] NER – Clause 5.16.5 (a)


TNSP identifies need for investment and possible options
Are the options within the scope of transmission assets subject to RIT-T
Yes
TNSP prepares a PSCR and provides a summary report to AEMO
AEMO publishes the summary of the PSCR. On request, TNSP makes the report available to interested parties within 3 business days
>12 weeks of consultation
Within 12 months or longer with AER's consent
TNSP assesses submissions, lists credible options, and determines material classes of market benefits.
TNSP undertakes assessment and determines preferred option
Exempt from PADR if:
1. preferred option is < $43 m
2. has no material market benefit except for voluntary and involuntary load shedding
3. preferred option is identified in the PSCR
4. No submission to the PSCR identifying additional credible option
TNSP prepares a PADR and provides a summary report to AEMO
AEMO publishes the summary of the PADR. On request, TNPS makes the report available to interested parties within 3 business days
> 6 weeks of consultation
If exempt
TNSP assesses submissions
ASAP
Publication of PACR
> 30 days
Deadline for partied to raise dispute
> 40 days
AER to make a determination on the dispute
< 120 business days
AER to make a determination on the RIT-T

APPENDIX B ABBREVIATIONS

AEMO	Australian Energy Market Operator
AIS	Availability Incentive Scheme
ALCC	Annual Levelised Capital Cost
CRF	Capital Recovery Factor
EAR	Energy at Risk
ENPV	Expected Net Present Value
EUE	Expected Unserved Energy
MTTF	Mean Time To Failure
MTTR	Mean Time To Recovery
NPV	Net Present Value
POE	Probability of Exceedance
PVF	Present Value Factor
STPIS	Service Target Performance Incentive Scheme
TNSP	Transmission Network Service Provider
VCR	Value of Customer Reliability

APPENDIX C TRANSMISSION NETWORK PLANNING ASSUMPTIONS

Parameter	Value
VCR	Use latest rates for each terminal station.
Expected Unserved Energy (EUE) and Energy at Risk (EAR) and Market impact cost	EUE = EAR x P(down state) Market impact cost to include impact on wholesale market, i.e. incremental fuel cost when generation is constraint off and the cost of ancillary services such as voltage control, system strength, inertia, etc.
Summer and Winter periods and Load Profiles	Summer Period is defined from 1 October to 31 March and Winter Period from 1 April to 30 September. Summer profile of 2016/17 for Summer POE50 Summer profile of 2015/16 for Summer POE10 Winter Profile of 2018 (Winter POE50 and POE10)
POE10 and POE50 Weighting	30% of POE10 EUE and 70% of POE50 EUE
Transformer failure rates and MTTR P(Transformer down)	Failure rates as per the Transformer Risk Model <u>B Transformers</u> : MTTR as per Transformer MTTR_Final Spreadsheet. <u>A, H and M Transformers:</u> MTTR when a spare is available = 3 months MTTR when no spare is available = 18 to 24 months (KTS A transformer took 12 months and we had a spare winding available; replacement with spare single phase on site at KTS took one month) P(down) = R/(T+R) = λ/(r+λ)
Circuit Breaker failure rates and MTTR P(CB down)	Failure rates as per the CB Risk Model 220kV CB Major Outage: 168 hrs 66kV CB Major Outage: 96 hrs (SPIE example) Minor Outage (isolate CB): 2 hrs P(down) = R/(T+R) = λ/(r+λ) Consider multiplying the CB failure rate with a 1.3 factor to reflect that a circuit outage can be caused by other systems (protection, CT, isolators, etc.).

Parameter	Value
Switching Supply Risk (Community Impact for 66 kV CB outages)	Bustie CB major failure will result in a 2 hour outage of two busses until supply can be restored. The 66 kV network is usually configured such that this will only result in 1/3 of total load being shed (rings supplied from different busbars). Calculation: 1/3 x MD x LF.
Environmental Risk	LG4C CBs or plant that contains large volumes of oil and which could pose an environmental risk. Environmental risk cost of \$30 K for non PCB and smaller oil spills and \$500K for major oil spills and oil containing PCB. Major failure rate as per Asset Risk Model x Probability of environmental impact. Assume all explosive failures will result in an average environmental impact of between \$30K and \$100 K. Failure rate x \$30 K to \$100 K.
Health and Safety Risk	The reference safety probabilities given in the DNO Common Network Asset Indices Methodology The value of statistical life of \$4.2m in 2014 dollars, as per the Best Practice Regulation Guidance Note Value of Statistical Life The value of lost time accident of \$162,780 per event for Electricity, Gas, Water and Waste Services, as per Safe Work Australia's The Cost of Work-related Injury and Illness for Australian Employers, Workers and the Community (2012-13), Table 2.3b A disproportionality factor of 3 for a single fatality of either a member of the public or a worker Power Transformer Bushings: 5%; Instrument Transformers: 10% for 220 kV ITs and 5% for 66 kV Its; Circuit Breakers[37]: 5% 220 kV CBs and 5% for 66 kV CBs

[37]Bulk oil and minimum oil CBs could pose safety, environmental and plant collateral damage risks; SF6 type CBs could pose environmental risk (safety and collateral damage risks are negligible), all safety, environmental and plant collateral damage risks are negligible for vacuum type CBs.

Parameter	Value
Plant Collateral Damage Risk and Financial Risk (clean up, media liaison, litigation, operational action (RTS), etc.)	Average of [C-I-C] per event Major failure rate as per Risk Model x Probability of an explosive failure as per following explosive failure probabilities Explosive failure probabilities for plant where failure could involve fire and explosion (porcelain bushings and oil): Power Transformer Bushings: 5%; Instrument Transformers: 5% for 220 kV ITs and 5% for 66 kV Its; Circuit Breakers[38]: 5% 220 kV CBs and 5% for 66 kV CBs
Reactive Asset Replacement Financial Risk	Major asset failure rate x Emergency Replacement cost of asset
Post Replacement / New Plant Failure Rates	Use C1 asset health score failure rates New technology switchgear does not exhibit explosive failure characteristic.
Operation and Maintenance Cost	220 kV CB: Old = [C-I-C]; New = [C-I-C] 66 kV CB: Old = [C-I-C]; New = [C-I-C] 22 kV CB: Old = [C-I-C]; New = [C-I-C] 220/66 kV Transformer: Old = [C-I-C]; New = [C-I-C] Use the incremental benefits in the economic evaluation, i.e. old O&M cost – new O&M cost.
Sensitivity Studies	Test sensitivity of economic timing for input assumptions such as plant failure rates (0.75 and 1.25 times base case), VCR (0.75 and 1.25 times base case), Demand Growth, Discount Rate, etc.
Real Discount Rate	Calculated using the ENA Handbook methodology. At the time of preparation of this document, 4.68% for the Base Case – commercial rate. Sensitivity studies at 6.78% and 2.58%.
Converting PV to annualized cost	PMT (payment for a loan based on constant payments and a constant interest rate). Assume 45 Years for the asset life
Converting PMT to PV cost	PV function. Assume 45 Years for the asset life

[38]Bulk oil and minimum oil CBs could pose safety, environmental and plant collateral damage risks; SF6 type CBs could pose environmental risk (safety and collateral damage risks are negligible), all safety, environmental and plant collateral damage risks are negligible for vacuum type CBs.

Parameter	Value
Emergency circuit breaker and Transformer replacements for the "Run to Failure" Option	Unplanned and emergency replacement will have a higher cost than planned replacements as resources need to be mobilised and work need to be reprioritised to deal with the emergency. It is prudent to allow for an increase in cost in the order of 20% to 30%. Also the country and metro spare transformers are "special" transformers to allow for their deployment at any site. This can be accounted for by allowing an additional [C-I-C] in the economic evaluation, because it has been proven that it is more economical to retain them at the terminal station after the emergency replacement.

APPENDIX D CONNECTION NETWORK ECONOMIC EVALUATION

This appendix provides details of the calculation of expected unserved energy benefits associated with replacement of 66kV circuit breakers at terminal stations.

D.1 Circuit Breakers

The net benefits (calculated both before and after replacement) associated with replacement of transformer circuit breakers can be calculated as follows (it is assumed that a circuit breaker can be replaced in 96 hours following a major failure):

Annual EUE = Circuit breaker failure rate x 96 hours/8760 hours X N – 1 energy at risk.

Example:

A circuit breaker with a 5% probability of a major failure in a station where the N – 1 energy at risk is 1000 MWh has an expected un-served energy of 0.55 MWh (0.05 x 96/8760 x 1000 = 0.55)

Once the circuit breaker is replaced the major failure probability drops to 0.1% so the residual EUE is 0.01 MWh (0.001 x 96/8760 x 1000 = 0.01).

The net benefit is 0.54 MWh. This can be valued at VCR for that station.

D.2 Feeder Circuit Breakers

Significant benefits are only evident for loops with only two 66kV circuit breakers. Generally loops with three or more 66 kV circuit breakers will be able to supply most if not all load under N – 2 for most of the time so the expected unserved energy will be small and not worth including.

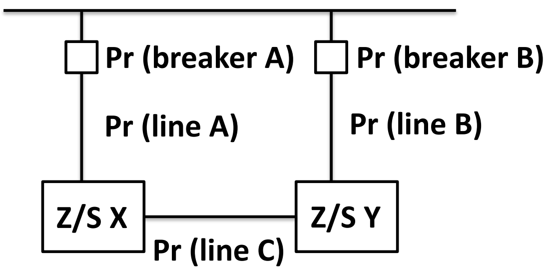
The net benefits (calculated both before and after replacement) associated with replacement of feeder circuit breakers for two line loops can be calculated as follows (It is assumed that a circuit breaker can be replaced in 96 hours following a major failure):

Annual EUE =

[Pr (circuit breaker A) + Pr (line A)] x [Pr (circuit breaker B) + Pr (line B)] x annual loop energy

+ [Pr (circuit breaker A) + Pr (line A)] x Pr (line C) x annual Z/S X energy

+ [Pr (circuit breaker B) + Pr (line B)] x Pr (line C) x annual Z/S Y energy



Where:

Pr(circuit breaker A) = unavailability of circuit breaker A = Failure rate x 96/8760,

Pr (line A) = unavailability for line A = Urban 66kV lines are on average un-available for 2 hours per annum and rural 66kV lines are unavailable for 4 hours per annum (source 2012-2016 Distribution System Planning Report (DSPR) page 25). i.e. 2/8760 for urban lines and 4/8760 for rural lines.

Example:

Two circuit breakers (A and B) are being replaced which supply an urban loop where A has a probability of a major failure of 3% and B at 6%. The total loop load is on average 60 MW for this loop with average load of 20 MW at Z/S X and 40 MW at Z/S Y. Average loop/zone sub load can be calculated as 60% of maximum demand forecast. Maximum demand forecasts are available for all 66kV loops from the DAPR for the relevant Distributor and is available on the internet.

Annual EUE =

(0.03 x 96/8760 + 2/8760) x (0.06 x 96/8760 + 2/8760) x 60 x 8760 = 0.000557 x 0.000886 x 60 x 8760= **0.259 MWh**

+ (0.03 x 96/8760 + 2/8760) x (2/8760) x 20 x 8760 = 0.000557 x 0.000228 x 20 x 8760 = **0.022 MWh**

+ (0.06 x 96/8760 + 2/8760) x (2/8760) x 40 x 8760 = 0.000886 x 0.000228 x 40 x 8760 = **0.071 MWh**

Total Expected Unserved Energy = 0.259 + 0.022 + 0.071 = **0.352 MWh**

After replacement with circuit breakers with a 0.1% probability of failure this drops to 0.059 MWh so the net benefit is 0.293 MWh which can be valued at VCR.

D.3 Bus tie Circuit Breakers

The calculation of benefits for bus tie circuit breakers depends on whether the bus tie is in a two or three tied buses arrangement. For normally open bus tie circuit breakers no expected un-served energy benefit is available as no load would normally be lost for failure of that circuit breaker.

For bus tie circuit breakers that tie two buses arranged as a group of just two buses a major failure of that circuit breaker is expected to result in all load being lost for both buses. It is expected that the load can be recovered in 2 hours by cutting away connections to the failed circuit breaker to allow buses to be restored to supply.

Annual EUE = Circuit breaker failure rate x 2hours/8760hours x annual bus energy.

Example:

For a normally closed bus tie circuit breaker connecting two buses that has a failure probability of 3% and average load of 150 MW the EUE is:-

Annual EUE = 0.03 x 2/8760 x 150 MW x 8760 = 9 MWh.

After the bus tie is replaced with a circuit breaker with a 0.1% probability of failure this drops to 0.3 MWh so the net benefit is 8.7 MWh which can be valued at VCR.

For a normally closed bus tie circuit breaker that connects buses arranged with three tied buses the load connected only to those two buses would be lost. 66kV loops connecting to the remaining bus would remain on load although lines connecting to the two lost buses would be disconnected.

The calculation is similar except only the lost load is considered rather than the whole bus load. (If the individual bus bar loads are not known, it can be assumed that 1/3 of the total station load will be lost for a three busbar station).

Example:

For a normally closed bus tie circuit breaker connecting two buses that has a failure probability of 3% and average load of 60 MW in only those loops connecting to the two lost buses the EUE is:

Annual EUE = 0.03 x 2/8760 x 60 MW x 8760 = 3.6 MWh.

After the bus tie is replaced with a circuit breaker with a 0.1% probability of failure this drops to 0.12 MWh so the net benefit is 3.48 MWh which can be valued at VCR.