

Security Policy Review: Credible Event Management

Scope and Methodology

June 2009



SYSTEM OPERATOR

Keeping the energy flowing

TRANSPower



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Version	Date	Change
1	4 May 2009	Draft scope and methodology
2	2 June 2009	Final scope and methodology

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1 Introduction

1.1 Background

The Policy Statement¹ sets out the policies and means that are considered appropriate for the System Operator to observe in attaining the Principal Performance Obligations² (PPOs), subject to the obligation of the System Operator to act as a reasonable and prudent system operator. The System Operator is responsible for initiating and plays a large part in the annual review of the Policy Statement. This responsibility recognises the specialist knowledge held by the System Operator on grid security issues. It also allows the System Operator to innovate and take advantage of new, smarter and more cost effective ways of achieving its objectives. This could occur through the use of new technologies, processes or techniques. It is also necessary for the System Operator to take account of the changing composition of the assets that make up the power system and changing costs.

To date the System Operator has taken advantage of annual reviews³ of the policy statement to make incremental changes and provide for specific changes in the power system or changes in the System Operator processes or tools, for example the quantity of instantaneous reserves dispatched when there is insufficient offers and /or reserve offers to meet anticipated demand in a trading period. This is the first review of one of the core elements of the Policy Statement. It is anticipated that reviews of other core elements will occur over time.

The Security Policy, Chapter 1 of the Policy Statement, is comprised of a number of sections. The second section, Credible Event Management⁴, identifies events that could occur within the power system that if not appropriately managed could subsequently result in wide spread, or cascade, failure within the power system. The Credible Event Management section anticipates that the System Operator will, identify credible events, assess the likely incidence of the events, the means and cost of mitigating the consequence of events, and subsequently identify how the possibility of such events is to be managed. The events, and identified means of management, contribute to the System Operator's attainment of the PPOs.

The credible events covered in system operation, and the associated control for each event, have significant implications to consumers through price and security of supply outcomes. They are also of interest to a wide range of stakeholders including the Electricity Commission as industry regulator (in respect of common quality, the wholesale market and transmission), market participants and asset owners such as generators, distributors and Transpower.

The last substantive review of the events included in Credible Event Management occurred in 2003, just prior to inclusion of the Policy Statement in the Electricity Governance Rules (EGRs). The System Operator is now undertaking a substantive review of the events that could occur and how these events are categorised for the first time since 2003. Regular review of Credible Event Management is important and the Policy Statement records the System Operator's undertaking to complete this review on a regular basis.

¹ Schedule C4 of Part C of the Electricity Governance Rules (EGRs)

² Section II of Part C of the EGRs

³ No annual review was undertaken in 2008

⁴ Formally titled Risk Management Policies

1.2 Assumptions

Assumptions upon which the credible event review is based are:

- that asset owners, ancillary service providers, other service providers and the System Operator meet and comply with all contractual and EGR obligations. This assumption is based on organisation reputational risk, commercial opportunity, the enforcement measures within the EGR compliance regime, and counterparty enforcement of contracts;
- assets perform as anticipated, asset owners have conveyed this information to the System Operator and the System Operator is using this information. This relies on asset owners having, or obtaining, the resource to comprehensively understand the performance of their assets; and
- the security standard to be met is as set out in Part C of the EGRs.

More specifically the event management review assumes:

- the Automatic Under-Frequency Load Shedding (AUFLS) scheme operating as anticipated, i.e. 2x16% demand blocks exist at all times and load is shed within the prescribed timeframe;
- the power system remaining stable after the operation of the AUFLS scheme , including the possibility that more than 32% of demand is shed;
- asset capability statements fairly reflecting asset capability and performance;
- the System Operator incorporating Asset Capability Statement (ACS) data into system models;
- system models adequately representing the actual power system;
- co-ordination between asset owner protection schemes;
- offered transmission, generation, ancillary services, and special protection schemes being physically available;
- asset owners and ancillary service providers complying with dispatch instructions;
- assets remaining connected and contributing to maintaining or restoring power quality while power quality remains within Asset Owner Performance Obligations (AOPO) limits specified in the EGRs or as exempted or dispensated;
- no change to the EGRs, other than the Event Management section of the Policy Statement.

1.3 Framework

The Policy Statement requires that the methodology used by the System Operator in reviewing the identification, assessment and assignment of potential credible events is consistent with the risk management principles of AS/NZS 4360. The figure below (from AS/NZS 4360) shows an overview of the risk management process in the standard.

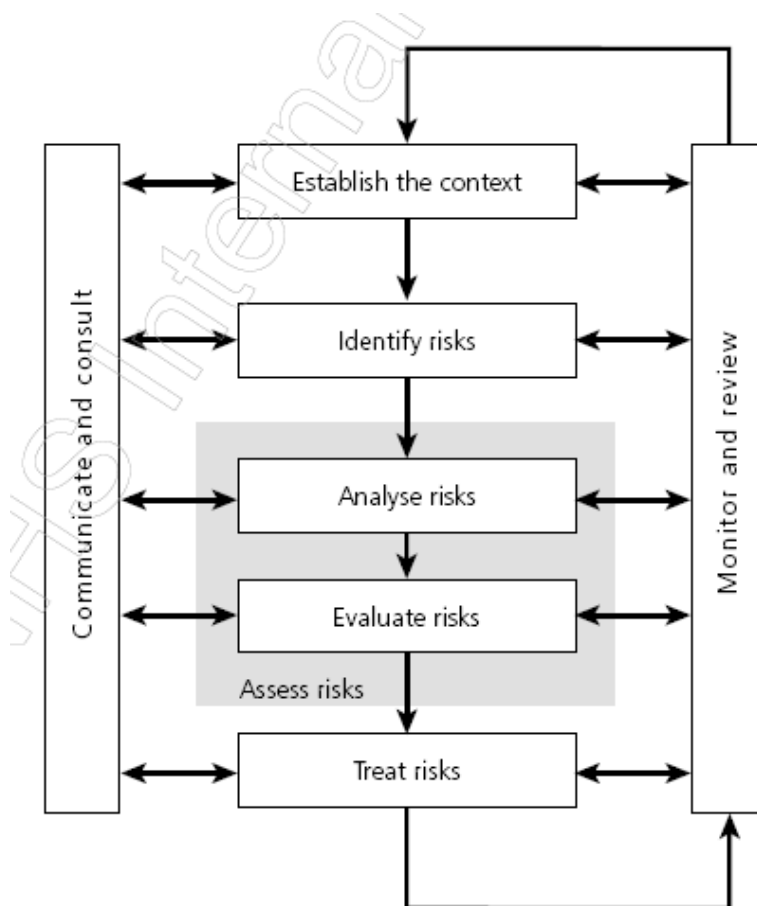


Figure 3.1 Risk management overview

The table below describes the tasks identified within the framework of AS/NZS 4360.

Table 1 Tasks identified within AS/NZS 4360

AS/NZS 4360	Description
Establish the Context	Establish the strategic, organisational and risk management context in which the rest of the process will take place. Criteria against which risk will be evaluated should be established and the structure of the analysis defined.

AS/NZS 4360	Description
Identify Risks	Identify what, why and how things can arise as the basis for further analysis.
Analyse Risks	Determine the existing controls and analyse risks in terms of consequence and likelihood in the context of those controls. The analysis should consider the range of potential consequences and how likely those consequences are to occur. Consequence and likelihood may be combined to produce an estimated level of risk.
Evaluate Risks	Compare estimated levels of risk against the pre-established criteria. This enables risks to be ranked so as to identify management priorities. If the levels of risk established are low then risks may fall into an acceptable category and treatment may not be required.
Treat Risks	Accept and monitor low-priority risks. For other risks, develop and implement a specific management plan which includes consideration of funding.
Monitor and review	Monitor and review the performance of the risk management system and changes which might affect it.
Consult and communicate	Communicate and consult with internal and external stakeholders as appropriate at each stage of the risk management process and concerning the process as a whole.
Documentation	Publish methodology. Publish explanation and summary of conclusions.

1.3.1 Establish the Context

Project Objective: *To review the credible events, their categorisation, and the operational measures to manage events, covered under Credible Event Management to ensure the System Operator continues to comply with the Principle Performance Obligations.*

Proposed changes to Credible Event Management will be included in the Policy Statement submitted to the Electricity Commission in early 2010.

This document specifies the criteria against which credible events will be identified, analysed, evaluated and treated as anticipated by the AS/NZS 4360 risk management framework. The analysis approach will be described and individual tasks identified.

1.3.2 Identify Risks

Historic events, asset owner data and assessment of the existing power system will be used to identify credible events identified in the existing Policy Statement and identify any new credible events. Historical data will be used to indicate the likelihood of an event occurring.

New Zealand planning criteria will be reviewed to ensure that credible events considered by the Grid Owner for planning purposes are considered by the System Operator. International planning and operational standards will be reviewed to ensure that the relevance of credible events defined by other countries are considered with respect to the New Zealand power system and events are suitably defined.

1.3.3 Analyse Risks

Identification of elements; generating units, transmission lines, busbars, transformers, components of HVDC transmission, protection schemes, and voltage regulating equipment, comprising the North and South Island power system and historic failures (incidence and duration) are used to identify potential events. The existing classification of events and associated risk management measures will be reviewed. The analysis will consider the cost and consequence of applying the existing management measures to manage identified events, based on historic likelihood of occurrence. The cost and consequence of alternate means of means of managing identified events will also be investigated to ascertain whether existing management measures are appropriate.

1.3.4 Evaluate Risks

Based on the cost and consequence of pre-event measures to mitigate the cost and consequence of post event outcomes, whether implemented automatically or through re-dispatch of the power system, identify optimal risk management measures to attain the Principal Performance Obligations and categorise events and the associated means of management accordingly.

Credible events identified and the means of risk management employed by transmission system operators around the world will be reviewed to ensure that Credible Event Management is in accordance with international best practice.

1.3.5 Treat Risks

Put in place systems, procedures or enter agreements to manage the risk and consequence of credible events in the manner identified. Pursue any associated rule changes to facilitate identified means with the Electricity Commission.

1.3.6 Monitor and review

The policy statement is reviewed on an annual basis, with an explicit requirement for the System Operator to focus on credible event management at least every five years. The Electricity Commission development plan for Part C includes ongoing review of the mitigations available to manage common quality and System Operation outcomes to achieve the optimum cost benefit trade off.

1.3.7 Consult and Communicate

Communication and consultation with the Electricity Commission and industry stakeholders will be ongoing throughout the review. Participants will be invited to comment on the Scope and Methodology and the Draft Credible Event Management Policy.

Opportunity for ongoing consultation will include the annual review of the policy statement and System Operator workshops.

1.3.8 Documentation

Documentation to be published will include:

- the Scope and Methodology;
- a draft Credible Event Management Policy with proposed clauses for incorporation within the Policy Statement; and
- the final Credible Event Management Policy with proposed clauses for incorporation within the Policy Statement

1.4 Project Schedule

The Credible Event Management review is to be completed by December 2009. To allow for review and stakeholder comment a draft report for consultation should be issued during October 2009.

Defining tasks and the associated project milestones will enable project progress to be monitored and indicate resource requirements during different phases of the project. Project tasks are indicated in *Figure 1*, milestone dates are given in *Table 2*.

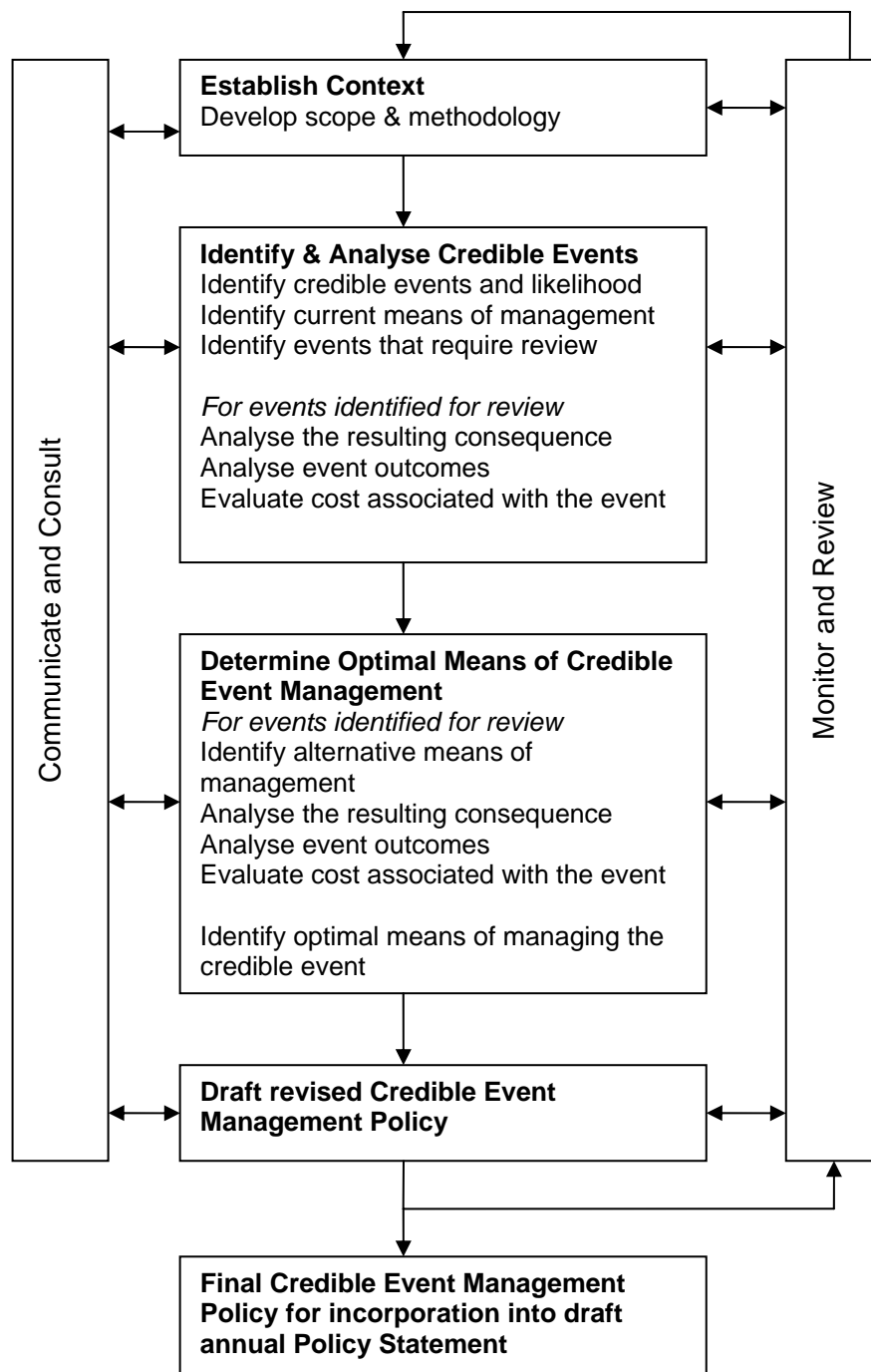


Figure 1:- Overview of project tasks

Table 2 Project Milestones

<i>Date *</i>	<i>Milestone Description</i>
4 May 2009	Draft scope and methodology released for consultation
	<i>Consultation</i>
31 May 2009	Context established, scope and methodology completed
31 July 2009	Identification and analysis of credible events completed
30 Sept 2009	Optimal means of credible event management completed
31 Oct 2009	Draft event management policy released for consultation
	<i>Consultation</i>
31 Dec 2009	Event Management Policy Review completed
	Incorporation of Event Management Policy into draft annual Policy Statement Review
31 Mar 2010	Event Management Policy submitted to the Electricity Commission as part of the draft Policy Statement

**Milestone dates will be the last working day of the calendar month*

2 New Zealand Operating Standard

2.1 Credible Event Management

The Credible Event Management Policy sets out the policies and means that are considered appropriate for the System Operator to observe in order to meet the Principle Performance Obligations (PPOs).

The current approach employed by the System Operator to manage credible events, as set out in Credible Event Management section of the Policy Statement is to:

- identify potential credible events;
- assess each event to estimate the likely risks based on potential impact on the power system taking into account the effects of mitigating factors;
- assign the event to one of the following categories:
 - contingent events (which are managed pre-event to avoid post event load shedding);
 - extended contingent events (which are managed pre-event but allow some post event load shedding);
 - stability events (for which power system stability is maintained pre and post event); or
 - other events (which are not managed pre-event but rely on post event emergency and restoration procedures.

This categorisation in turn determines the mitigation measures be used to manage events.

2.2 Credible Events

The 2003 Risk Management Policies identified the following credible events:

- Loss of a generating unit;
- Loss of multiple generating units;
- HVDC link valve group and single pole interruptions;
- HVDC link bipole interruptions;
- Single transmission circuit interruptions;
- Simultaneous interruptions of both circuits on a double circuit transmission line;
- Multiple simultaneous transmission line interruptions;
- Busbar interruptions;
- Interconnecting transformer interruptions;
- Connection or disconnection of large load or loads; and
- Interruption of reactive injections, both when provided as ancillary services or when available from transmission assets.

Events are then assigned to distinct categories that determine the measures that can be applied to manage the impact of the event.

2.3 Event Management

There are many types of measures that can be used to mitigate or control event outcomes to maintain the power system in a secure state. A simple measure is to limit load or constrain generation such that the assets will not be overloaded, cascade failure does not occur and voltages remain within quality targets. This type of measure is in effect at all times.

Other types of measure include those that only come into effect once the event has occurred. An example is an automated scheme that will manage load (e.g. AUFLS) or control generation (e.g. a generation runback scheme) ensuring that transmission assets remain within safe limits following the occurrence of the event. These types of measures can be automated schemes or manual processes (e.g. the use of off-load time ratings to allow higher pre-contingency loading but requiring re-dispatch of generation within a fixed time following an event to ensure that asset loading is below steady state rating). It should be noted that such schemes must be made operational prior to the event but have no effect until the event occurs.

Another measure for managing event outcomes is to voluntarily change the quality targets that apply for a particular event. For example, Transpower can enter into an agreement with a distributor to manage voltages at a particular grid exit point to different targets than set out in Part C of the EGRs. Such an agreement (known as a Wider Voltage Agreement) allows greater operational flexibility during situation such as during planned outages.

Many of the measures available for managing event outcomes are those facilitated through the EGRs, including the provision of ancillary services, minimum asset performance standards, and mandatory obligations to provide load management capabilities. An instantaneous reserves market, procurement of over frequency reserves, and compulsory provision of AUFLS are examples.

The management of event outcomes can be placed into two broad categories:

- events which are managed without involuntary load shedding through the use of pre-contingency measures (e.g. dispatch of generation and ancillary services), post contingency involuntary measures (e.g. AUFLS), quality variation measures and industry arrangements
- events which are managed with pre-event, voluntary or involuntary, load shedding or involuntary (AUFLS or dispatched) uncontrolled post event load shedding as available pre-contingency measures, post contingency measures, quality variation measures and industry arrangements (other than AUFLS) are insufficient. Emergency response and restoration measures are also relied on for managing these types of event.

Figure 2 shows a framework for how events are managed operationally. Contingent and extended contingent events are special subsets of the framework. The framework accommodates the increased reliance since 2003 on Special Protection Schemes and changed quality targets. In the case where quality targets can not be met for a

contingency, agreed measures would first be implemented. These measures effectively allow the power system to be run harder before the contingency knowing the post contingency measures are available (either automated or manual) that can be relied upon to return the power system to a secure state following a contingency.

When considering contingencies, the System Operator needs to consider whether the event can be managed through agreed measures without resorting to SO pre-contingency measures prior to or following the contingency. If so, the agreed measures should be applied; if not, the trade off between shedding load prior to or the impact of the post contingency outcomes.

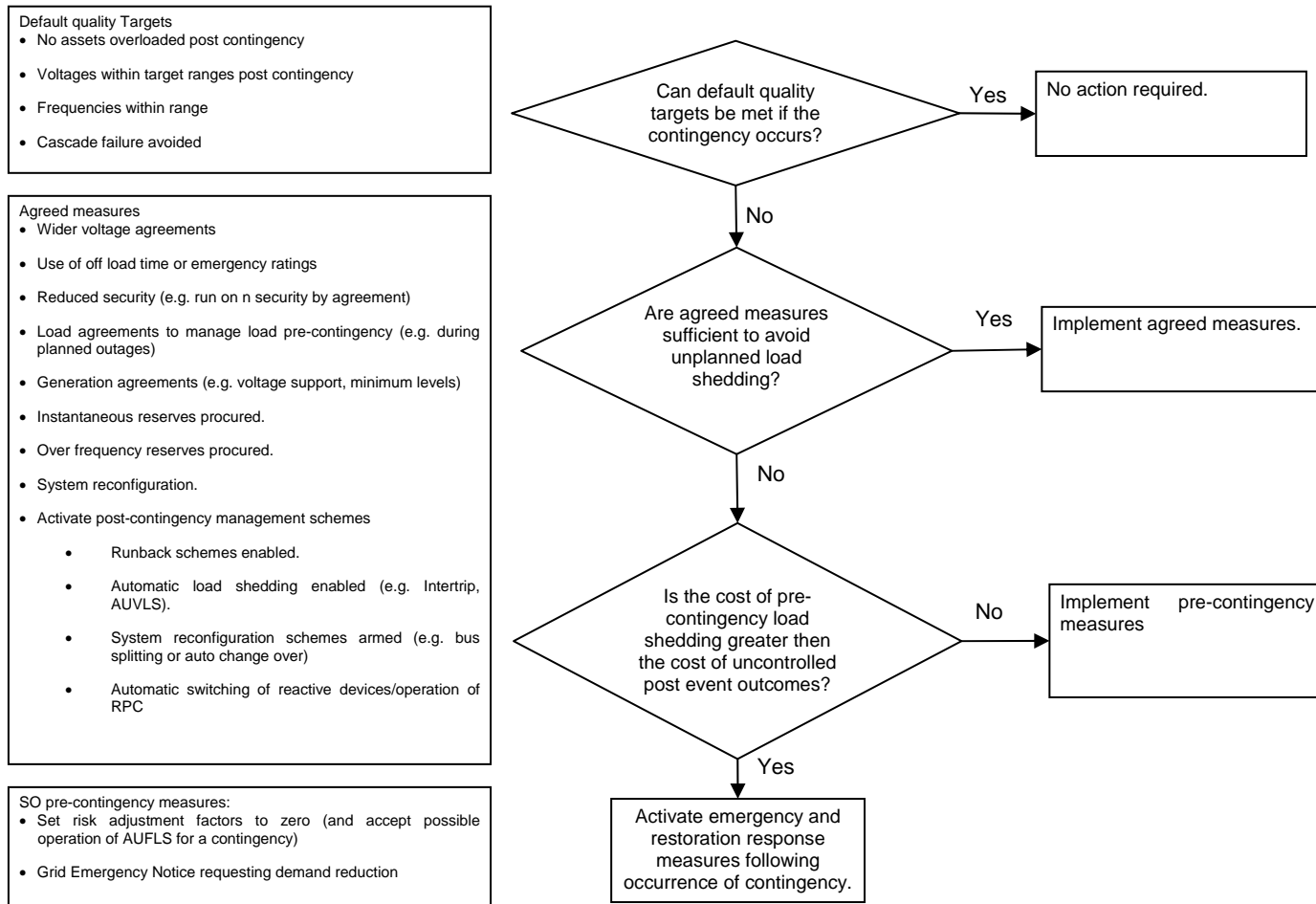


Figure 2:- Event Management Framework

2.4 The Grid Reliability Standard (GRS)

Transpower uses the Grid Reliability Standard to justify the requirement for a new transmission investment from a planning perspective. The Grid Reliability Standard defines which contingent events and how planned outages are to be taken into account in the planning process. The review will consider whether the Standard provides any insights or has a bearing on the credible event management policy.

2.5 Distribution Planning and Operating Standards

Due to the differences in the planning and operation of distribution and transmission networks, consideration of distribution planning and operating standards has not been included in the scope of this review. Distribution networks have increased probability of a contingent event occurring on the network, they are therefore designed to a higher level of security that allows increased operational flexibility. Furthermore, contingent events observed on a distribution network may not be relevant to a transmission network and similarly, operational measures available to a distribution system operator may not be feasible on a transmission network.

Comment is invited with regard to the importance of considering distribution codes when developing transmission operating standards.

2.6 International Transmission Planning and Operating Standards

The review will consider operating and planning standards published by international transmission system owners and operators. The purpose of reviewing international standards is to ensure that the development of the credible event management policy is in accordance with Good Electricity Industry Practice (GEIP).

The review will compare international definitions of credible events and the methods used to classify and manage the events. Where information is available, the rationale behind how management measures are chosen for the different classes/types of event will be discussed. The frequency and the mechanism by which international system operators review their event management standards will also be considered.

3 Identification & Analysis of Credible Events

To meet its PPOs the System Operator is required to consider possible events and the means of managing the event in order to maintain network stability and security. It is the objective of the System Operator to identify operationally effective and cost efficient measures for managing an event.

The first stage will involve the identification of an exhaustive list of credible events that may occur on the New Zealand network, identify possible means of management and evaluate the level of risk associated with each event. A level of “risk” can be attributed to the credible events based on the likelihood of the event, the outcome of the event and the consequence of the event.

The following tasks will be undertaken:

- Identify credible events and likelihood. A set of credible events will be derived from historical data, national and international experience and network analysis. The likelihood of the event occurring and the likely duration of an event will be extrapolated from historical data.
- Review the existing means of managing the event(s)
- Identify events where the likelihood of the event occurring indicates that the existing management measures require further investigation.

For events that are identified for further investigation:

- Determine the consequence of the event following the application of automatic measures and determine the cost of the consequence. Studies will be undertaken to assess the impact on quality, the potential customers affected and the duration of the event.
- Determine the outcome of the event following the application of manual measures and determine the cost associated with the outcome. Studies will be undertaken to assess the ability to preserve system stability and restore demand. The availability of adequate assets, ancillary services, and generation to restore security will be considered.
- Estimate level of risk in terms of likelihood, consequence, outcome and cost.

Costs will be assessed based on the costing methodology described in Appendices 1 to 4.

4 Optimal Means of Credible Event Management

In applying the Security Policy, the System Operator is required to consider the costs and benefits of applying various control and mitigation measures to manage the occurrence and consequence of a credible event. The costs of applying existing management strategies to address credible events are evaluated in the first stage of the review process. The second stage will identify and evaluate alternative means of managing the events. The consequences, outcomes and costs of the event in addition to the cost of securing and applying alternative management measures will be assessed in order to determine optimal means of managing the set of credible events.

The following tasks will be undertaken:

- Identify alternative means of managing events and determine the cost associated with the alternative management measures.
- Determine the consequence of the event following the application of **alternative** measures and determine the cost of the consequence. Studies will be undertaken to assess the impact on quality, the potential customers affected and the duration of the event.
- Determine the outcome of the event following the application of **alternative** measures and determine the cost associated with the outcome. Studies will be undertaken to assess the ability to preserve system stability and restore demand. The availability of adequate assets, ancillary services, and generation to restore security will be considered.
- Identify optimal means of managing the credible events. Optimal categorisation and event management measures for events based on consequence, outcome and cost will be derived.

Costs will be assessed based on the costing methodology described in Appendices 1 to 4.

5 Draft New Event Management Policy

The review of credible event management will deliver a document that proposes updates to the event management clause(s) within the Credible Event Management Policy. The updates will then be incorporated within the draft annual Policy Statement review and submitted to the Electricity Commission as indicated in Table 2, Section 1.4.

In addition to documenting proposed updates to clauses the document will include the findings the following tasks associated with the review.

- Review of historical event data
- Literature review of Grid Reliability Standard (GRS) and planning criteria
- Literature review of International requirements
- Identification and analysis of credible events
- Optimal means of credible event management

Appendix 1 – Costing Methodology

A costing methodology will be developed to calculate an indicative cost of the immediate consequence of the event and of the pre- and post-event measures applied to manage or mitigate the immediate consequence of the event. The purpose of the cost value is to allow an assessment of the **relative costs** of an event for each available means of management rather than necessarily determining an actual event cost. Assessing the relative cost of managing an event by different means will identify potential cost-benefits associated with an alternative measure.

The cost associated with the consequence of the event will be evaluate using the amount of load affected, the duration of the event and the value of lost load (VoLL).

The cost of managing an event will include the cost of arranging measures pre-event and the application of post event measures where such costs exist.

The expected cost of an event will be calculated by factoring in the likelihood of event occurrence.

It will therefore be possible to determine the relative cost of an event for alternate means of management from the following:

- the number of times an event is expected to occur in a year;
- the expected duration of the event;
- the quantum and cost of pre-event measures;
- the quantum and cost of post-event measures; and
- the quantum and cost of the event consequences.

The cost will be re-calculated when using alternative management measure(s) including:

- the quantum and cost of pre-arranged post-event load shedding.

Appendix 2 – Event Management Costs

To establish the relative costs of alternate means of managing credible events the following indicative costs will be used.

Value of Lost Load

Costs associated with involuntary load shedding will be based on the Value of Lost Load (VoLL). In December 2004 the Electricity Commission set VoLL at \$20,000/MWh dollars for the Grid Investment Test. It should be recognised that internationally VoLL is given a much higher value. The Electricity Commission currently uses a load weighted average of \$22,000/MWh for transmission planning studies however this figure is under review. The cost for involuntary load shedding increases rapidly (step jump) as the amount of load shed increases. Consideration will be given to the sensitivity of results and the validity of conclusions to adopting an involuntary load shedding value of \$22,000/MWh.

Cost of pre-arranged measures

Costs associated with pre-arranged load shedding associated with special protection schemes (or similar) will be based on three scenarios using average values of \$2000/MWh, \$5000/MWh and \$10,000/MWh.

Initial assumptions with regard to the cost of the management measures are listed below.

- Wider Voltage Agreements
 - Application of measure: free of charge
- Pre-arranged pre-event load /generation agreements
 - Application of measure: three scenarios using average values of \$2000/MWh, \$5000/MWh and \$10,000/MWh.
- Manual system re-configuration pre-event and/or post event
 - Application of measure: No cost
 - Consequence of measure: potential reduced security
 - Time to close a permanent split: It is assumed to take approximately 2 hours to close a permanent split
 - Time to restore a transformer following overload: It is assumed to take approximately 2 hours to restore a transformer that has tripped on overload
- Reduced security by agreement
 - Application of measure: No cost
 - Consequence of measure: loss of supply
- Off-load time or 24 hour emergency ratings
 - Application of measure: No cost
- Instantaneous reserves (Fast Instantaneous Reserves FIR and Sustained Instantaneous Reserves SIR)

- Application of measure:
 - North Island FIR & SIR – \$5/MW
 - South Island FIR & SIR – \$1/MW
- North Island 260 MW of FIR and 415 MW of SIR.
- South Island 90 MW of FIR and 150 MW of SIR
- Overfrequency reserves (armed pre-event)
 - Overfrequency reserve is procured for the South Island
 - Application of measure: \$54,000 per month
- Special Protection Schemes (armed pre-event)
 - Application of system re-configuration: No cost
 - Application of generation runback: No cost
 - Application of load shedding (intertrip, AUVLS): three scenarios using average values of \$2000/MWh, \$5000/MWh and \$10,000/MWh
- Automatic load shedding AUFLS
 - Application of measure: \$20,000/MWh for interrupted load.
- Post-event re-dispatch of generation
 - Application of measure: generation re-dispatch is determined by SPD the cost of which is based on market prices at the time of dispatch. The costs associated with re-dispatch will not be included in the costing of event management.
- Dispatched post-event emergency load shedding
 - Application of measure: a cost of \$20,000/MWh

New or alternative management measures:

- Pre-arranged post-event load and/or generation agreements
 - Application of measure: three scenarios using average values of \$2000/MWh, \$5000/MWh and \$10,000/MWh

Appendix 3 – Event Consequence Costs

A methodology will be developed to calculate the total cost of post event consequences. The approach will consider the risk associated with reduced security, loss of supply, un-restored load after two trading periods and un-controlled load shedding or voltage collapse following the application of measures.

- Un-restored load
 - Consequential cost: a cost of \$20,000/MWh applied to the MW of un-restored load.
- Loss of supply
 - Consequential cost: a cost of \$20,000/MWh applied to the MW of lost load.

Appendix 4 – Costing Examples

The following examples aim to illustrate the costing approach to assess the **relative** costs of existing and alternative management measures for a typical N-1 and N-2 credible event. The values given in the tables are not actual values, they have been **invented** for the purpose of illustrating the costing methodology.

Example 1: N-1

Event: Loss of a 220/110 kV Transformer

Region: Hawkes bay

Average Total No. of Tx events in a year: 30

Average duration: 8 hours

Existing Approach:

Pre-event measures: None

Post event:

Maximum load in Hawkes Bay area is 162 MW

One transformer can supply 115 MW of Load

Average load affected obtained from load duration curve

Average load of 129 MW for 27% of the time

Consequence:

Unable to restore on average 14 MW of load

Reduced security for remaining 115 MW

Costs	Average Load (MW)	Duration (h)	Unit Cost (\$/MWh)	Event Cost (\$m)	Average No. Events per year	Average load risk factor	Annual Cost (\$m)
Post-event load shedding	129	2	20,000	5.16	0.61	0.27	0.85
Consequence (un-restored load)	14	6	20,000	1.68	0.61	0.27	0.28
TOTAL							1.13

Alternative Approach 1: Pre-arranged post-event load shedding (\$10,000/MWh)

Pre-event measures: Arrange 14 MW of available post-event load shedding

Post event:

Pre-arranged load is shed

Consequence:

No consequence

Costs	Average Load (MW)	Duration (h)	Unit Cost (\$/MWh)	Event Cost (\$m)	Average No. Events per year	Average load risk factor	Annual Cost (\$m)
Pre-arranged post event load shedding	14	8	10,000	1.12	0.61	0.27	0.18
Post-event load shedding	0	0	20,000	0	0.61	0.27	0
Consequence (un-restored load)	0	0	20,000	0	0.61	0.27	0
TOTAL							0.18

Alternative Approach 1: Pre-arranged post-event load shedding (\$5,000/MWh)

Pre-event measures: Arrange 14 MW of available post-event load shedding

Post event: Pre-arranged load is shed

Consequence: No consequence

Costs	Average Load (MW)	Duration (h)	Unit Cost (\$/MWh)	Event Cost (\$m)	Average No. Events per year	Average load risk factor	Annual Cost (\$m)
Pre-arranged post event load shedding	14	8	5,000	0.56	0.61	0.27	0.092
Post-event load shedding	0	0	20,000	0	0.61	0.27	0
Consequence (un-restored load)	0	0	20,000	0	0.61	0.27	0
TOTAL							0.092

Alternative Approach 1: Pre-arranged post-event load shedding (\$2,000/MWh)

Pre-event measures: Arrange 14 MW of available post-event load shedding

Post event: Pre-arranged load is shed

Consequence: No consequence

Costs	Average Load (MW)	Duration (h)	Unit Cost (\$/MWh)	Event Cost (\$m)	Average No. Events per year	Average load risk factor	Annual Cost (\$m)
Pre-arranged post event load shedding	14	8	2,000	0.224	0.61	0.27	0.037
Post-event load shedding	0	0	20,000	0	0.61	0.27	0
Consequence (un-restored load)	0	0	20,000	0	0.61	0.27	0
TOTAL							0.037

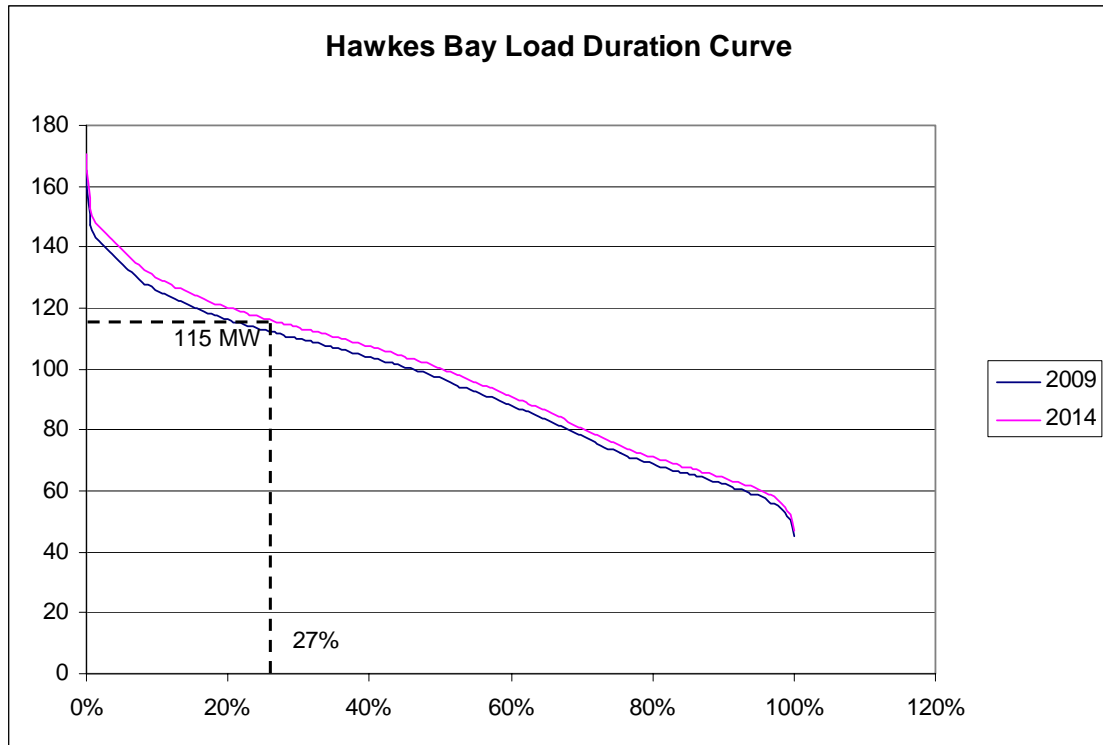
Average No. Events per year associated with an element (Interconnecting Transformers)

$$= \frac{\text{Total number of events per year associated with the set of elements}}{\text{Number of elements in risk set (No. of Interconnecting Transformers)}} = \frac{30}{49} = 0.61$$

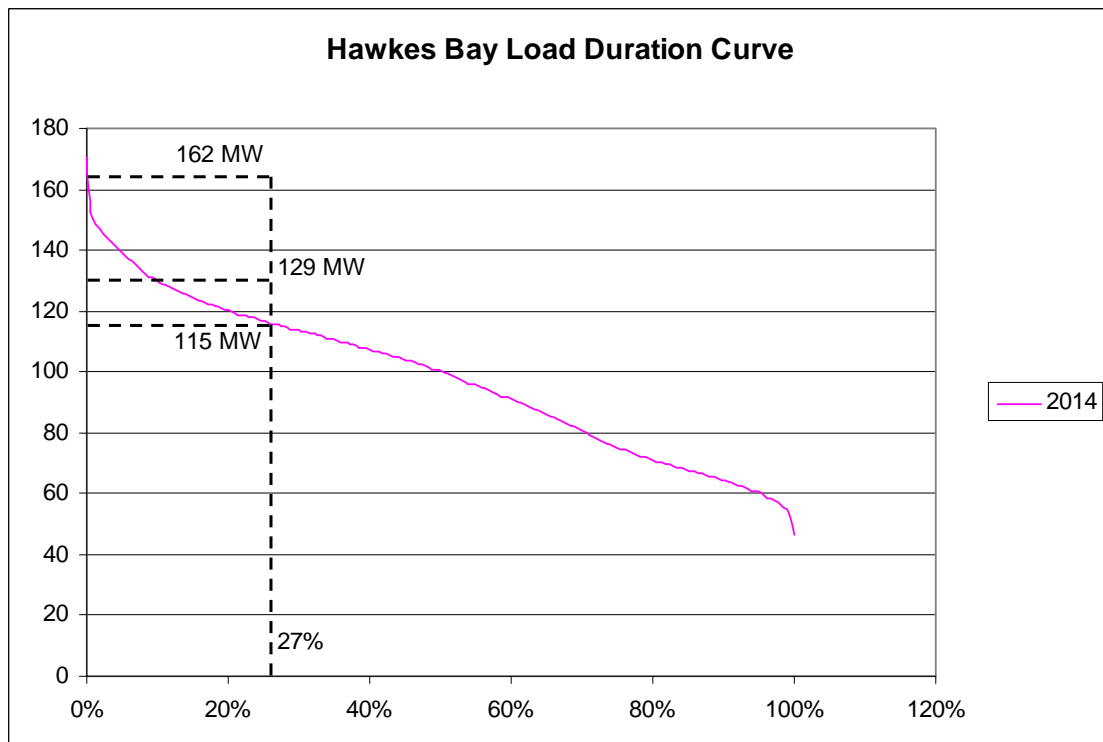
“Average load risk factor” = 0.27

Load is expected to be greater than 115 MW 27% of time during 2014

Load is expected to be greater than 115 MW 21% of time during 2009



Average load when above 115 MW is found to be 129 MW based on load duration curve shown below:



Example 2: N-2

Event: Loss of two transformers

Region: Hawkes bay

Average Total No. of events in a year: 5

Average duration: 8 hours

Existing Approach:

Pre-event measures: None

Post event: Loss of supply to Hawkes Bay, 100 MW of load shed
(Average load in Hawkes Bay 100 MW)

Assume 2 hours to close split and restore 90 MW load

Consequence: Following closure of split unable to restore 10 MW of load

Cost:	Average Load (MW)	Duration (h)	Cost (\$/MWh)	Event Cost (\$m)	Average No. Events per year	Average load risk factor	Annual Cost (\$m)
Post-event load shedding	100	2	20,000	4.0	0.21	-	0.84
SPS Action grid re-configuration	-	-	-	-	-	-	-
Post-event load shedding	10	6	20,000	1.2	0.21	-	0.25
TOTAL							1.09

Alternative Approach 1: New Investment

Pre-event measures: New investment: two new transformers

Post event: No load shed

Consequence: No consequence

Average load served by both transformers calculated as 100 MW

$$\text{Average No. Events per year associated with an element} = \frac{\text{Total number of events per year associated with the set of elements}}{\text{Number of elements in risk set (No. of parallel transformers)}} = \frac{5}{24} = 0.21$$