# Transmission Code

**TRANSPOWER APPROVED STANDARD**

**Implementation date: December 2009**

# PREFACE

This Transmission Code helps codify Transpower's approach to designing the grid in accordance with Good Electricity Industry Practice.

This initial issue has been prepared following discussions with and feedback from the New Zealand electricity industry. Over time it is expected to be updated to reflect:

- Additional matters Transpower considers ought to be included in the Code;
- Changes in good international practice (including in response to new technologies and methods);
- Further analytical work that may, from time to time, be undertaken; and
- The relative size, duty, age, and technological status of New Zealand's transmission network from time to time.

**Keywords**
Transmission Code

**CONTACT**

*This document is the responsibility of the Chief Engineer, Transpower New Zealand Limited, Wellington. If you have any queries please contact the Chief Engineer.*
*If you would like to make suggestions to improve this document, please use the "Controlled Document Feedback Form" located at the rear of this document or online via the Controlled Documentation homepage of the Transpower website at [www.transpower.co.nz](http://www.transpower.co.nz)*



**MINIMUM REQUIREMENTS**

*The requirements set out in Transpower's standards are minimum requirements that must be complied with by Transpower personnel, contractors and consultants as applicable. All personnel are expected to implement any practices which may not be stated but which can reasonably be regarded as good practices relevant to the purpose of this standard. Transpower expects all personnel to improve upon these minimum requirements where possible and to integrate these improvements into their procedures and quality assurance plans.*

 

## CONTENTS



## APPENDICES

# 1. PURPOSE

The Code is a statement of certain transmission design practices and judgements that Transpower considers reflect Good Electricity Industry Practice (GEIP). Its purpose is to assist Transpower (and others with an interest in transmission system planning) to assess whether such good practice is reflected in new transmission system designs.

This Code applies to interconnection asset investments, but may also be applied to planning connection asset investments, (e.g. the use of SPSs).

# 2. INTRODUCTION

## 2.1 GEIP and the Electricity Governance Rules

GEIP is a key planning criterion under the Electricity Governance Rules (EGRs). The EGRs require that Transpower's upgrade investment proposals reflect GEIP, along with the GRS and the GIT.

Furthermore, investment options considered as "alternative projects" under the EGRs must be reasonably likely to proceed if a proposed investment, or another alternative, does not proceed. This means that only options that reflect GEIP are considered as "alternative projects" in applying the GIT.

## 2.2 Objective of the Transmission Code

GEIP can be difficult to identify. But this does not detract from its importance as a planning criterion under the EGRs.

The Code captures in an open and transparent way the practices and judgements that Transpower considers reflect GEIP in relation to the matters covered by the Code. The Code has been developed to assist with the efficient and prudent assessment of projects and investment options. It strengthens the linkage between transmission planning and GEIP through a systematic and documented approach.

The Code also provides a mechanism for the controlled implementation of new technologies and methods, seeking to avoid moving unknowingly into uncharted territory with unintended risks to security of supply.

## 2.3 Content of the Code

The content of the Code takes into account the practices and judgements that Transpower considers reflect GEIP, as defined in the EGRs, and good international practice. But, as required by the EGRs, the assessment is grounded in a context relevant to New Zealand, taking into consideration conditions comparable to the relative size, duty, and technological status of the New Zealand transmission system.

That there may be discussion about the content of the Code is not only expected, it is a welcome and important part of the Code's evolution. The intention of the Code is not to close off debate about the correctness of a statement of GEIP as set out in the Code. As it expressly contemplates, the Code is a living document that will be updated and expanded from time to time.

## 2.4 Application of the Code

The Code cannot be, and is not intended to be, all embracing and to the exclusion of options not expressly reflected in the Code. Indeed, there may be circumstances in which it is appropriate to deviate from the Code, where there is a clear and justifiable reason for doing so in those circumstances, and while continuing to act in accordance with GEIP.

The Code requires that any such deviations be recorded, including the reasons for deviations from the existing provision of the Code in those circumstances. In this way, the Code becomes a framework for ensuring that planning decisions reflect GEIP in an open and transparent way, by reference to practices and judgements that are documented in a systematic manner.

# 3. DEFINITIONS

Terms used in the Transmission Code have the same meaning as given to them in the EGRs, except those terms expressly defined in this Code.

## 3.1 Definitions from the EGRs

The following definitions (shown in bold) from the EGRs are used in this Code. Defined terms used in these definitions, but not otherwise used in the Code, are given in the EGRs.

“**asset**” means equipment or plant that is connected to, or forms part of, the grid.

"**generating unit**" means a machine that generates electricity.

"**grid**" means the system of transmission lines, substations, and other words, including the HVDC link used to connect grid injection points and grid exit points to convey electricity throughout the North Island and South Island of New Zealand.

"**injection**" means the flow of electricity into a network.

"**local network**" means the lines, equipment, and plant that are used to convey electricity between, on the one hand, the grid and, on the other, one of the following:

(a) an embedded generator;
(b) an embedded network; or
(c) a consumer.

"**N-1 criterion**" means that, with all assets that are reasonably expected to be in service, the power system would be in a secure state.

"**offtake**" means the flow of electricity from the grid at a grid exit point.

"**satisfactory state**" means that none of the following occurs on the power system:

(a) insufficient supply of electricity to satisfy demand for electricity at any grid exit point;
(b) unacceptable overloading of any primary transmission equipment;
(c) unacceptable voltage conditions; and
(d) system instability.

"**secure state**" means that the power system:

(a) would be in a satisfactory state; and
(b) would remain in a satisfactory state during and following a single credible contingency event wheresoever occurring on the grid.

## 3.2 Definitions expressly defined in this Code

“**compensation factor**” (C) means the capacitive reactive compensation connected to an importing group of the grid divided by the maximum power demand of that importing group.

C = MVArInstalled / MWmax

The capacitive reactive compensation includes:

- All grid fixed shunt capacitors; the value of output used for the calculation will be the nominal voltage of capacitor connection;
- All variable capacitive reactive compensation (which includes continuously variable and blocked switched units) connected at transmission voltages; the value of output used for the calculation will be the maximum nominal capacitive reactive output;
- All capacitive compensation connected at the low voltage side of all grid supply points that is used in support of the transmission system.

The capacitive reactive compensation does NOT include the reactive compensation embedded within local networks or the reactive output of generating units.

"**dependent outage**" is an outage window that must occur in conjunction with another outage window.

"**dynamic ratio**" means the dynamic capacitive reactive compensation connected to an importing group divided by the total capacitive compensation in that importing group

"**failure**" means failure of the SPS to operate as designed, i.e. either failure to initiate the designed remedial actions following system conditions for which the scheme is designed to operate, or spurious operation in which remedial actions are triggered when system conditions do not require it. Either of these two conditions may be termed false operation.

"**high impact**" means cascade operation and/or significant loss of supplies and/or system wide collapse, and/or damage to equipment, and/or have the potential to impact on public safety.

"**importing group**" means a topologically contiguous group of grid exit points that has a net import of electricity. An importing group does not have significant generation or an HVDC link within it.

"**low impact**" means possible operation of the system outside operational limits but no cascade operation, no system wide collapse, and no significant loss of supplies.

"**maintenance outages**" are outages that have been scheduled with at least 24 hours notice to carry out maintenance work on an out-of-service asset. Such work includes inspection, repairs, replacement, and refurbishment of existing assets.

"**major project**" is non-maintenance work and is significant in nature. Such work would normally require more than a 5 days continuous outage window.

"**outage window**" means a period during which an asset could be taken out of service and work could be carried out on the asset.

"**planned maintenance**" is maintenance work that has been scheduled with at least 24 hours notice. Such work includes inspection, repairs, replacement, and refurbishment of existing assets.

"**stable**" means the system meets the criteria for transient, voltage, and dynamic stability given in the Grid Planning Guidelines.

 

# 4. SPECIAL PROTECTION SCHEMES

## 4.1 Introduction

Special protection Schemes (SPSs) provide a method of maintaining or enhancing transmission system performance without the requirement for additional reinforcement. However, their use is not without risk and they are not necessarily a substitute for reinforcement.

For the purposes of this Code, SPSs can be applied in the following three ways:

> **Application 1**: As part of robust overall system design for which transmission reinforcement is not generally a solution. Fast excitation, power system stabilisers, normal HVDC control and protection, generator dynamic braking, and tap changer blocking are included in this category.
>
> **Application 2:** As a substitute for transmission reinforcement. This includes permanent measures as an alternative to other forms of transmission reinforcement, interim measures (e.g. to enable connection of users' equipment prior to transmission reinforcement), and maintenance measures for use during planned outages.
>
> **Application 3**: Defence plans for the purpose of minimising or controlling the effects of multiple contingencies beyond planning or operational standards. Under frequency and under voltage load shedding, power swing blocking, system islanding, generator house load operation, and fast start and fast ramping generation are included in this category.

Applications 1 and 3 are widely used and represent GEIP when applied with appropriate care in specification, design, and implementation.

This Code applies only to Application 2 which provides a method of maintaining or enhancing the transmission system performance without the requirement for additional reinforcement.

## 4.2 Deployment of SPSs

Application 2 SPSs are to be implemented for the following purposes:

- If they are approved under a Grid Upgrade Plan or a Customer Agreement;
- If there are, or may be, delays on a project that has been approved under a Grid Upgrade Plan or a Customer Agreement and if, following commissioning of the project, the SPS will be disabled;
- As an interim measure when the preparation of a Grid Upgrade Plan or a Customer Agreement is planned for the near future (typically 12 months); and
- To satisfy operational requirements during planned outages.

Proper implementation of SPS schemes require very careful planning, analysis, design, liaison, development, testing and commissioning.

## 4.3 Acceptability

Any complicated system such as an SPS has a risk of failing to operate. The size of the risk is related to the probability of failure and impact on the power system if the SPS fails to operate correctly. It is preferable to have SPSs which have a low risk of failure. SPSs with a high probability of failure or with large system impacts (e.g. cascade failure) are not desirable.

A risk assessment for proposed SPSs should be carried out early in the design stages.

 

A risk analysis will be straight forward if the scheme is of minimal complexity, or failure results in minimal consequences, or the time of usage is particularly restricted, for example:

- If it is a generator run-back scheme that is not armed for more than three weeks in any one calendar year; or
- If it is a load control scheme whose failure would not cause loss of demand of more than 5 MW.

### 4.4 Risk assessment

A risk assessment is to be undertaken when acceptability is not clear, to determine the probability of failure and the consequences of failure.

The following principles apply when carrying out the risk assessment:

- All components that comprise the SPS scheme are to be identified, for example output devices and triggering devices;
- The number of redundant components for each part of the SPS system are to be identified;
- Component failure rates are to be determined;
- Other factors that include proof test interval and common cause failure likelihood are to be identified;
- The consequences of SPS failure are to be identified and assessed.

The precise method for carrying out the risk analysis is described in Transpower's Grid Planning Guidelines.

### 4.5 Design principles

An SPS is to be designed for the specific power system conditions associated with the intended function.

Due consideration is to be given to dependability and security. The relative effect on the transmission system of a failure of an SPS to operate when desired versus an unintended operation is to be weighed carefully in selecting design parameters.

The following design principles apply to SPS schemes:

- SPSs are to be designed, maintained, and operated to the same standard as other protection apparatus while recognising the complexity and consequences of inadvertent operation;
- SPSs are to have sufficient redundancy (duplicate hardware and communications with route diversity to the extent possible) to reduce the likelihood of failure to an acceptable level;
- Maximum operating time relevant to the situation to ensure appropriate power system co-ordination;
- Diagnostic and self-check features to detect and raise an alarm and disable when essential components fail or critical functions (including inputs) are not operational are to be incorporated into the design;
- The operation of each SPS:
    - Is to be totally independent of the operation of any other devices where possible or where this is not possible, the operation of such schemes shall be satisfactorily co-ordinated;
    - Is not to interrupt load unless it has been previously agreed;
    - May use SCADA to detect system conditions in order to determine post-contingency actions (but not for operation in real time), and use SCADA only for control under exceptional circumstances;

- Initiating signals (which should be duplicated) may be derived from either protection or SCADA systems; and
- Is not to require frequent (routine) manual intervention (e.g. re-configuration of the SPS) or manual arming or disarming.

# 5. PLANNED OUTAGES

## 5.1 Introduction

Planned maintenance on all assets is carried out to ensure that the assets perform reliably, safely, and without unacceptable environmental impact. Some maintenance can be carried out with assets in service but other maintenance requires assets to be deenergised to allow the work to be carried out safely.

This Code makes provision for outage windows for maintenance work and not for major projects. Planning for major projects is to be such that appropriate outages are available or alternative project implementation methods are adopted.

The Outage Protocol (Part F, section VII) describes the process by which outages occur, but does not ensure sufficient planned outage windows can be made available.

Grid planning shall take into account the need for maintenance of existing assets and new assets when determining the nature and timing of new investments in the grid.

## 5.2 Required outcome

There are sufficient outage windows during which assets can be taken out of service for planned maintenance which requires the assets to be de-energised.

## 5.3 Planned outage windows

A two day (continuous) outage window for planned maintenance is to be available for each asset at any weekend or weekend combined with a public holiday.

A five day (continuous) outage window for planned maintenance is to be available for each asset for at least 70 % of the year.

In planning a maintenance outage it may be assumed that the grid is intact apart from the asset under consideration and any single generating unit is unavailable.

Planning is to allow for multiple dependent outages.

Maintenance outage windows are not to be assumed to be sacrificed in order to execute major projects.

Planning is not to assume pre-contingent load shedding to enable the outage window.

## 5.4 System state during planned outages

During a planned outage, the grid is to remain stable and in a satisfactory state. For the avoidance of doubt, this means that there are to be no interruptions to load, except where there is only one circuit supplying an area (e.g. Kaitaia).

In addition, the principles outlined in the Grid Planning Guidelines and agreements with connected parties apply.

## 5.5 Contingencies during a planned outage

In the event of an unplanned outage coinciding with a planned outage, the grid is to remain stable and in a satisfactory state, except that loss of injection or offtake is allowed.

In addition, the principles outlined in the Grid Planning Guidelines apply.

# 6. REACTIVE COMPENSATION

## 6.1 Introduction

Reactive compensation may be required on a transmission system to provide voltage control and, more particularly, to provide voltage support in heavily loaded systems. High levels of reactive compensation tend to lead to brittle or ill-conditioned systems.

To provide adequate voltage control for steady-state and post-fault conditions a mix of static reactive compensation (e.g. switched capacitors) and, usually, dynamic reactive compensation (e.g. SVCs) is to be provided.

Extensive study is required to determine the levels of compensation required on a transmission system and the optimum mix of static and dynamic compensation.

This Code provides criteria for allowable levels of compensation and the required mix of static and dynamic reactive compensation that ensure system stability while optimising system performance.

## 6.2 Levels of compensation

A compensation factor for any importing group of 40 % or less is acceptable.

A compensation factor for any importing group of more than 40 % but less than 85 % is considered marginal. Analysis is required for marginal compensation factors to demonstrate that the grid remains stable and in a satisfactory state under all reasonable transmission system operating conditions and in compliance with static and dynamic analysis criteria.

A compensation factor for any importing group of 85 % or more is unacceptable.

## 6.3 Ratio of dynamic to static compensation

**Figure 1** represents the minimum dynamic ratio that is acceptable. Actual ratios for specific areas are to be determined through analysis.

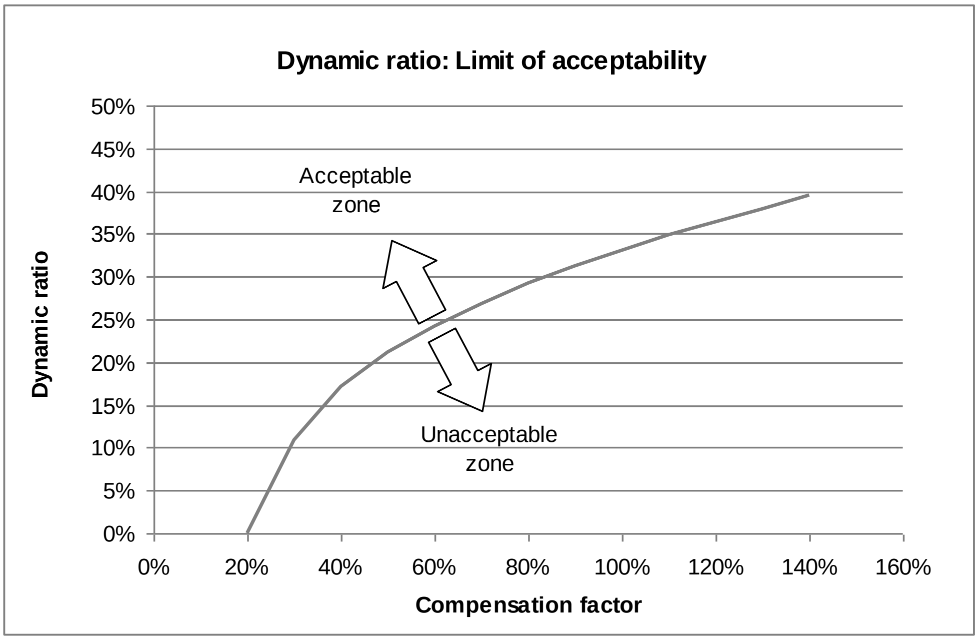


**Figure 1: Dynamic ratio**

### 6.4 Automatic control of compensation

Automatic control requires detailed engineering analysis. Automatic control between more than two physically separated substations within an importing group is unacceptable.

### 6.5 Modelling criteria

The modelling criteria defined in the Grid Planning Guidelines apply.

### 6.6 Power system analysis – static

**PV analysis**

A PV analysis should be carried out for each importing group in which the level of compensation is considered marginal.

At maximum demand, at any point within the importing group, for intact network conditions, the nose or collapse point on the PV curve should ideally be below 0.9 pu voltage; if this is not possible there are to be sufficient indicators to warn of the risk of voltage instability. Such indicators may be an observable steady state drop in voltage as load increases, but are to include real time monitoring of static and dynamic monitoring of reactive reserves.

Sufficient compensation is to be available such that the capability to deliver maximum demand to the importing group is at least 5 % back from the nose point of the PV curve for expected system states.

**VQ analysis**

A VQ analysis should be carried out for each importing group in which the level of compensation is considered marginal.

At a demand level of 5 % above maximum demand, at any point within the importing group, the VQ curve is to:

- Have a portion below the x-axis; and
- Have a positive slope (i.e. reactive power absorption reduces with increasing voltage) at 0.9 pu voltage.

If 0.9 pu voltage is not achievable, indicators must be provided to warn of the risk of voltage instability. Such indicators are to include real time static and dynamic monitoring of reactive reserves and may include an observable steady state drop in voltage as load increases but are to include real time monitoring static and dynamic monitoring of reactive reserves.

### 6.7 Power system analysis – dynamic

A dynamic analysis should be performed for each importing group in which the level of compensation factor is above 40 %.

The following criteria should be met for 105 % of summer and winter demands, a generation pattern typical of the season being considered, and an intact transmission network:

Unplanned outage without a fault:

Following an unplanned outage of any item of transmission equipment without a fault, the voltage at any point on the system is not to fall below 0.5 pu during the recovery phase and is to recover to at least 95 % of the pre-fault value at that point by the end of the recovery phase.

- Unplanned outage following a fault, fault clearance, and disconnection of faulted equipment:

 

- The voltage at any point on the system is to recover to above 0.8 pu of nominal voltage within four seconds of the fault inception time; and
- The voltage at any point on the system is to recover to at least 90 % of the pre-fault value at that point at the end of the recovery phase; and
- The voltage at any point on the system is not to rise above 1.3 pu of nominal voltage at any time during the recovery phase; and
- The voltage at any point on the system is not to rise above 1.1 pu for more than 0.5 seconds at any time during the recovery phase; and
- Motor current on any motor within the model is not to be greater than six times the steady state current for more than three seconds and is not to be greater than three times the steady state current for more than eight seconds during any period of the recovery phase.

The recovery phase is defined as the period from fault clearance to when the voltage at any point on the system has recovered to at least 0.9 pu of the nominal voltage.

# A SPECIAL PROTECTION SCHEMES COMMENTARY

## A1 Introduction

Special protection schemes (SPSs) are arrangements for protecting the security of the grid. They detect abnormal system conditions and take automatic, pre-determined, corrective actions.

The paper in IEEE Transactions on Power Systems, Vol 11, No 3, August 1996, Industry Experience with Special Protection Schemes, states that “Special Protection Schemes are those designed to detect one or more predetermined system conditions that have a high probability of causing unusual stress on the power system, and for which planned remedial action is considered necessary.” This paper lists the most common types of SPS as generator rejection, load rejection, under-frequency load shedding, system separation, turbine valve control, load and generator rejection, stabilizers, HVDC controls, out-of-step relaying, discrete excitation control, dynamic braking, generator runback and VAR compensation.

This Commentary is not intended to provide an alternative or more restrictive definition of an SPS, but to define some specific applications of SPSs to the New Zealand transmission system and how these applications are consistent with GEIP. These applications are not inconsistent with the IEEE paper and are consistent with other international practice.

SPSs differ from normal protection mechanisms in that they protect all or a section of the grid, not just an individual component, e.g. line, generator, etc.

SPSs can be a substitute for grid investment. It should be noted though, that they can take considerable time to implement, although usually less than the time required for a transmission line augmentation.

For various reasons, SPSs are not always highly reliable, and the impact of malfunction can be catastrophic. In addition, their reliability cannot easily be assigned a quantitative measure; this is particularly true of those that are complex. Therefore, any decision to deploy an SPS requires a degree of engineering judgement, and it is prudent to deploy them only if the impact of malfunction is low. The basic design principles must expressly cater for the consequences of incorrect operation.

For the purpose of the Code, SPSs have been categorised according to application:

(a) As part of robust system design for which transmission reinforcement is not a solution;

(b) As a permanent or temporary substitute for transmission reinforcement; or

(c) As a defence measure for the purpose of minimising the effects of multiple contingences for which the transmission system has not been designed.

Applications 1 and 3 are sensible and prudent measures that provide for robustness of operation and do not impact on the fundamental design and construction of a transmission system. For these reasons, applications 1 and 3 are not considered within the code.

However, application 2 impacts directly on the transmission system itself by seeking to substitute transmission reinforcement, either temporarily or permanently, by what is essentially a control scheme. This inevitably introduces risk of mal-operation and the possible consequences of damage to equipment, loss of supply, personal injury, and environmental damage. For this reason, the Code seeks to address these issues and provide criteria for the appropriate application of SPSs in these circumstances.

The inclusion of HVDC controls and protection within Application 1 is intended for normal HVDC controls. Application 2 is intended to cover generator run back schemes, but HVDC schemes could also be included. Application 2 gives examples of what is included, but does not preclude the use of run back schemes in this category.

## A2 Application of SPSs

The code has been developed in consideration of international standards and practice, with particular reference to NPCC Regional Reliability Reference Directory # 7, Special Protection Schemes, California ISO Planning Standards, and Mid Atlantic Area Council (MAAC) Special Protection System Criteria (Document A-3).

However, applications are particularly system and country specific and the applications described in the Code are those required by Transpower, in liaison with customers, to provide effective management of particular conditions and governance requirements.

## A3 Acceptability

In order to simplify the assessing of SPSs, Transpower classifies them according to acceptability. Acceptability is a function of perceived reliability and the reckoned impact of malfunction and is affected by the SPS's complexity. CAISO planning standards attempt to limit complexity in ISO G7 by stating that:

“The SPS must be simple and manageable. Generally, there should be no more than 4 local contingencies (single or credible double contingencies) that would trigger the operation of a SPS and the SPS should not be monitoring the loading on more than 4 system elements".

ISO G7 does not define a local contingency, and Transpower’s view is that a better method of determining acceptability, other than for those schemes that have a high impact on failure, is to carry out a detailed risk assessment.

Some SPSs are simple, have limited impact on malfunction, and are thus easily classified as acceptable (in the "green" zone). Others are clearly unacceptable (red zone). Those in the amber zone are subject to a risk assessment, which evaluates their complexity and impact.

The definitions of ‘high impact’ and low ‘impact’ contain the words ‘significant loss of supplies’. The categorisation of such terms inevitably requires some degree of judgement and is deliberately left so, in order not to be too prescriptive.

## A4 Risk assessment

As described in **Section A5** below, various factors give rise to a risk of malfunction.

Quantitative reliability measures can be assigned to some of these factors (e.g. hardware, software, and communications). However, others (design errors, human intervention errors) must be assessed qualitatively.

A model is being developed to assign and weight, as much as is possible, quantitative reliability measures, and this model is expected to guide SPS decisions. Nevertheless, engineering judgement will always be required.

## A5 Design principles

SPSs must operate safely. They must also operate reliably, because they are commonly critical to maintaining system integrity and security, protecting plant, and ensuring supply to customers.

### A5.1 Modes of failure

SPSs are deemed to have failed if they do not operate when they should, operate when they should not, or interact spuriously with other SPSs.

A joint IEEE / CIGRÉ survey published in 1994 and covering 49 utilities in 17 countries, reviewed the results of SPS operations, as shown in **Table A1**.

| **Table A1** | | |
|---|---|---|
| **Result** | **Number of operations** | **Percentage** |
| Successful | 1093 | 95.13 % |
| Failed * | 36 | 3.13 % |
| Unsuccessful ** | 20 | 1.74 % |
| Total | 1149 | 100.00 % |

*	failed to operate; operated spuriously; interacted spuriously with other SPSs

**	failed to react to (unforeseen) system conditions

While the performance of these schemes has not been completely as expected, individual protection mechanisms may provide a backstop should an SPS fail, although the outcome is not as favourable as correct operation.

A5.2	Causes of failure

The same survey, which included defence plans (i.e. application 3 SPSs), identified the causes of failure, as shown in **Figure A1**.

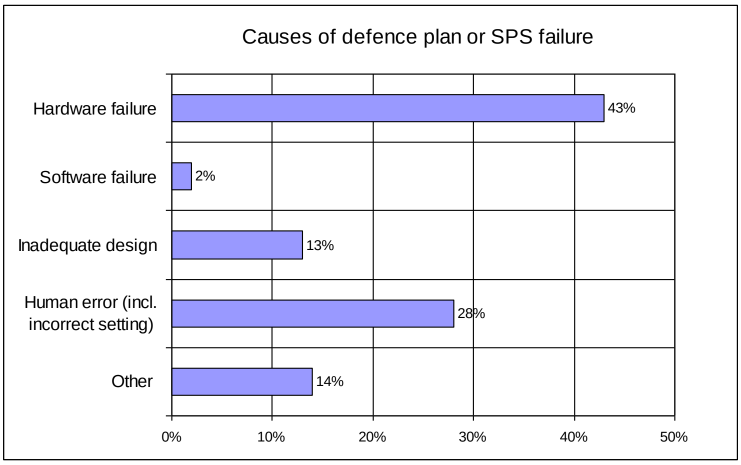


**Figure A1: Causes of defence plan or SPS failure**

These results emphasise the need to take into account:

- Hardware robustness;
- Increasing complexity;
- Paucity of design standards;
- Monitoring, testing, and maintenance.

**Hardware robustness**

SPSs should be adequately robust for the tasks they are to perform and the impact of failure. This means such measures as:

- Hardware redundancy;
- Design against spurious operation, when itself experiencing a credible failure;
- Thermal capability to withstand the conditions to which the power system is subjected; and
- Communications diversity.

 

It should be noted that the above conclusions were based on the 1994 survey and it is possible that improvements in reliability have occurred since then. Further information is expected once the results of the recent IEEE/CIGRE/EPRI 2007 survey become available.

SCADA is not generally considered sufficiently reliable within an SPS scheme. However, the Code does allow its use under certain limited circumstances in which the effects of failure, owing to insufficient reliability would be minimal.

**Complexity**

SPSs can be particularly complex. For example, the Basslink system monitors the power transfer in the link and the status of 18 circuits, it controls load shedding at up to 10 substations, and it can send trip signals to up to 18 generators.

This complexity, coupled with the continued proliferation of SPSs, increasingly degrades the robustness of the system by exposing it to design errors (inability to foresee credible system conditions) and the human factor (e.g. incorrectly setting the SPS in response to changed system conditions). Furthermore, it is a recognised hazard that this degradation can occur without the system operator being aware of the risks being incurred. Maintenance, testing, and extension of complex SPSs can be particularly difficult. Ideally, SPS should be based on regions and minimise overlaps of operation.

**Paucity of standards**

The CIGRÉ survey also revealed that some 65 % of the SPS schemes were put into service without calculating or modelling reliability. System operators applied various reliability models to the remaining 35 %, but complained of the lack of industry standards.

However, since the survey (1994), this need for standards is being increasingly recognised:

- The Western Systems Coordinating Council (WSCC) requires that system studies assess the consequence of SPS failure. However, most requirements are qualitative, rather than quantitative. There is little industry guidance as to how to develop, study, assess, and maintain SPS reliability;
- WECC has a specific Remedial Action Scheme Reliability Task Force that approves, reviews, and registers all schemes. Its standards contain numerous caveats that reflect the caution with which WECC permits SPSs to be addressed. WECC members produce their own guidelines for compliance; CAISO imposes limits on scheme complexity;
- NERC established standards in 2005, to which all new and existing schemes must comply. Fines are imposed for non-compliant schemes.

MAAC Special Protection System Criteria (Document A-3) states:

> "To enhance dependability, ……SPSs shall be designed with sufficient redundancy such that the SPS is capable of performing its intended function while itself experiencing a single component failure….."

This principle has been included in the Code's Design Principles, but enhanced to provide examples of the components that need to be considered.

NPCC Regional Reliability Reference Directory # 7 Special Protection Systems specifies a number of SPS design requirements that provide for reliability and acceptability. Section 3.3.1.1 states that:

> "To enhance dependability, a Special Protection System shall be designed with sufficient redundancy such that the Special Protection System is capable of performing its intended function while itself experiencing a single failure."

The Code therefore requires SPSs to have sufficient redundancy.

The NERC/WECC Planning Standards provide a number of standards and guidelines for SPSs. Guideline G1 states that:

> "Complete redundancy should be considered in the design of an SPS with diagnostic and self-check features to detect and alarm when essential components fail or critical functions are not operational."

This has been simplified in the Code to "Diagnostic and self-check features to detect and raise an alarm when essential components fail or critical functions are not operational must be incorporated into the design".

Other terms, such as "sufficient redundancy", have been used to ensure adequacy of design while allowing some scope on how it should be achieved.

Additional principles have been added that are specific to the New Zealand context.

**Monitoring, testing, and maintenance**

Certain SPS applications are perceived as highly reliable because they have substantial redundancy and self-diagnostic features that identify error or failure mechanisms before mal-operation of the SPS occurs. However, SPSs are inherently difficult to test, so that even with comprehensive maintenance it is difficult to confirm their overall functionality. The design should be such that routine tests can be carried out as easy as normal power system protection. SPS must also go through comprehensive acceptance testing.

Nevertheless, continuing testing and maintenance of an SPS must be part of the specification of the scheme, because the continuing verification of the scheme may well alter the design or even the whole viability of the scheme.

# B PLANNED OUTAGES COMMENTARY

## B1 Introduction

Assets making up the transmission grid require regular maintenance. Some maintenance can be carried out while the asset is in service (e.g. live line work), but other maintenance requires the asset, along with certain adjacent assets, to be removed from service, i.e. an outage.

Planning of the transmission grid needs to take into account this need for maintenance outages. There must be sufficient time when the system has sufficient redundancy that the outages can be taken without materially reducing power system's security or quality during the outages.

The Code provides the criteria to ensure that planned maintenance outages can take place while ensuring appropriate power system conditions are maintained.

The Code does not make provision for outage windows for major projects.

The Outage Protocol (Part F, section VII) describes the process by which outages are scheduled. The Protocol does not ensure that there are sufficient planned outage windows available.

## B2 Outage types

There are two sorts of planned outages:

- Planned Maintenance Outages are outages that have been scheduled with at least 24 hours notice to carry out maintenance work on an out-of-service asset. Such work includes inspection, repairs, replacement and refurbishment of existing assets and would normally require an outage duration of 5 days or less.
- Major Project Outages are for non-maintenance work and for work of a significant nature. Such work normally requires an outage of more than 5 continuous days and tends to involve procedures that cannot be terminated quickly in an emergency.

Maintenance outage windows must not be assumed to be sacrificed for major projects outages.

## B3 Maintenance requirements

The ability to carry out maintenance outages at appropriate times and under satisfactory system and environmental conditions (e.g. weather, ground conditions) is a key factor in maintaining grid security and reliability. Assets that are not maintained are more prone to faults and are less likely to operate correctly. Assets that fail from lack of proper maintenance are likely to take longer to be repaired and restored to service. They may also present a safety or environmental hazard.

Generally, planned outages are taken without interrupting supply, so the transmission system must have the capacity to supply the demand occurring during the course of the outages. The threat to loss of supply during an outage is reduced if planned outages are taken during periods of low demand.

During planned outages, there is, of course, risk of a fault causing a second (unplanned) outage. The risk and impact of this need to be recognised and measures taken to limit the impact to an acceptable level.

Some loads are supplied by a single circuit, e.g. Kaitaia. In these situations, an outage results in loss of supply unless there is local generation within the islanded area.

When an asset must be taken out of service for maintenance, three factors apply:

- The time required to complete the maintenance. Assets cannot necessarily be taken out of service and returned to service at the beginning and end of each day. A single activity may require a lengthy period to complete and the taking out and returning to service may involve major switching (with attendant risks), significant safety issues, and significantly increased time and cost;
- The grid must be capable of accommodating the outage without contravening any security criteria. This is best achieved during lighter load conditions when assets are less stressed. Hence, in temperate climates, summer has been the traditional season for maintenance activities; and
- Emergency return-to-service time and contingency arrangements.

## B4 Outage planning

### B4.1 Demand

Ensuring adequate grid capacity to meet demand is an important factor when scheduling outages. The impact of an outage on the system is minimised if outages are scheduled during periods of low (off-peak) demand.

### B4.2 Coordination with generators

Outages may need to be coordinated with generators.

An outage may constrain transmission from a generating export area. This means:

- Transmission maintenance and generation maintenance should coincide − when the generator is out of service the demand for transmission is reduced; and
- A hydro generator may be prevented from selling surplus energy (rather than spilling water) during the periods of peak flow (spring and early summer in the South Island).

An outage may constrain transmission into a demand import area and, if the area has some local generation, it may be crucial to have that generation fully available during the outage.

### B4.3 Other parties

Customers and other parties may be affected by planned outages, e.g:

- Planned outages may exacerbate the impact of a fault; some customers are sensitive to increased risk to supply during certain seasons, e.g. milk processing plants, whose production peak occurs during the summer;
- Outages may require land-owner consent. Farmers do not want crops damaged or stock disturbed at critical times by maintenance teams;
- Customers are particularly concerned about any requirement for pre-contingent event load shedding by the system operator in order that an outage is able to proceed. There are transformer feeders for which load reductions are requested prior to an actual tripping to avoid an asset being unacceptability overloaded should a contingency occur. Planning needs to ensure that grid capacity is sufficient, appropriate HV buses are installed, or alternative schemes (e.g. SPS) are provided to avoid these situations.

Co-ordination is becoming increasingly onerous for all parties. In the Christchurch area, for example, 18 parties must agree to a load reduction before a planned outage can proceed, even during the summer demand period. If any one of these parties subsequently withdraws, the outage must be postponed or cancelled.

### B4.4 Inter-related outages

Sometimes multiple outages are necessary − more than one planned outage at the same time − e.g. 66 kV circuits to West Coast have two circuits on the same pi-pole construction, so one circuit cannot be worked on while the other is live.

Interaction between maintenance and project outages must be carefully managed to ensure that both are accorded appropriate priority. Project work should not cause maintenance work to be cancelled. Issues arising when generation outages change close to a planned maintenance date need to be managed similarly.

SPSs can be used to enable maintenance outside the summer minimum, but they are not a panacea, as extensive use leads to interaction between SPSs, and can result in added complexity.

B4.5 System security considerations

The System Operator determines in real time whether a planned outage may proceed or not. The system operator's prime concerns are that:

- Primary transmission assets are not unacceptably overloaded;
- Voltage is within limits;
- The system is stable (no risk to synchronisation); and
- Security of supply is maintained whenever possible.

The system operator cancels a planned outage if concerned about being able to secure the system in the event of an outage.

B4.6 Transpower outage co-ordination procedure

Transpower's coordination procedure is set out in the “Outage Protocol”, the key points of which are that:

- Transpower produces a draft outage plan by 31 January of each year, covering the outages for the next “outage year”, which begins on 1 July;
- Transpower then has two months to consult with interested parties; and
- Transpower publishes its final outage plan on 19 May. This is six weeks before the outage year begins, but at least five months before most outages occur, as most are scheduled during the summer.

The System Operator reviews the acceptability of outages 10 weeks prior to the outage. This may involve further connected party discussions.

This 10-week period is relatively short. While it is undoubtedly workable if outages are easy to obtain, resource planning problems for contractors (and higher contractor prices) are likely if a significant number of outage requests are turned down or changed.

By comparison, outage planning and coordination in Britain spans a five-year period.

**Case study: Maintenance planning in Britain**

In Britain, maintenance planning follows a complex and detailed procedure, which includes:

- 3 – 5 years ahead: generators advise the transmission company of planned outages so that it can check that the system will always have sufficient generation;
- 2 years ahead: the transmission company co-ordinates long-duration transmission and generation outages and produces a draft transmission outage plan;
- 1 year ahead: the transmission company updates the outage plan as necessary and adds routine maintenance outages;
- The transmission company shares the plan continually with other stakeholders to enable consultation and negotiation;
- The plan is continually updated with minor changes and modifications as the outage time is approached.

The duration of this procedure allows several iterations of the outage plan, thus optimising the plan and maximising system security (or minimising constraints). As well, the planning is sufficiently far in advance to avoid imposing significant additional costs on any party.

Britain's planning timescale may not be appropriate to New Zealand, as the Britain's generation is largely thermal and has large generating units (up to 660 MW). These require significant outages for periodic maintenance, which must be planned fully in order to avoid constraints (in the grid, internal power station resources, or external contractors' resources).

New Zealand's generation technologies may be more flexible with respect to altering maintenance outages, but as the system is operated increasingly close to its limits (and as the proportion of large thermal units increases), detailed maintenance planning and coordination will become increasingly important. All outages, whether generation or transmission, must be assessed and given due priority.

## B5 International industry practice

This section discusses factors that affect outages, how they are generally handled within the international context, and the comparable situation in New Zealand. The factors include:

- Design for maintenance;
- System capacity;
- System topology;
- System planning technique;
- Outage planning and coordination.

### B5.1 Design for maintenance

The impact of maintenance requirements on a transmission system depends on the system's design, especially the configuration of substations. For example, substations can be designed so that the circuit breakers can be maintained without taking associated overhead line or cable circuits out of service. However, this facility needs to be incorporated into the design from the outset and it usually difficult to incorporate retrospectively.

**Case study: Design of London substations**

Many substations in London were built in the 1960s and had limited switching facilities because of the high cost of land and circuit breakers − generally a mesh design was used. This is now considered to have been false economy; a large amount of switching is required daily to manage the voltage profile (the system in London is mostly cabled), but the limited facilities make this difficult.

In January 1987, in freezing weather, the system came close to voltage collapse; the voltage fell to 0.92 pu because two 200 MVAr shunt reactors could not practicably be taken out of service. Over 50 breaker and isolator operations were needed to take the reactors out of service. Then, some two hours later, when the load was falling, a similar set of switching operations was required to restore them to service in order to control the rising voltage.

This case study suggests that Transpower adopt a standard substation design that minimises operations and maintenance costs. Another benefit is reduced System Operator error. Transpower's preference for "breaker and a half design" at new key sites, which enables circuit breakers can be taken out of service for maintenance without interrupting overhead line circuits, is consistent with this.

### B5.2 System capacity: the "N-1" criterion

International practice is that the N-1 criterion applies during planned outages. This means that the system has the capacity to withstand a planned outage plus a single coincident fault without becoming insecure (that is, N-1-1 or N-2). If N-1-1 cannot be met, the maintenance may be postponed or curtailed.

**Note:** There is some confusion between planning and operating timescales. Systems are planned for N-1 under peak demand conditions. When operated, N-2 is required, but only during lower-demand periods when planned outages might reasonably be scheduled.

Two examples of applying this international practice are the administrations in Britain and peninsula Malaysia, which specifically allow for planned outages in the design of their transmission systems, together with expected background conditions and typical generator operating regimes.

New Zealand does not adhere to this international N-1 practice. Some parts of the system are never secure (even before an outage of any sort), e.g. in the Far North, where Kaitaia is supplied by a single circuit, security there would be prohibitively expensive. Elsewhere, planned outages may render the system insecure, which makes taking outages difficult. In these situations pre-cautionary load-shedding is implemented before the outage is started.

B5.3 System topology

The impact of outages (and therefore the system capacity needed to maintain security) is influenced by the system topology.

Compared with (say) Britain, the topology of New Zealand's transmission system is sparse. New Zealand's population centres are served by small numbers of circuits. For some small centres, as noted above, N-1 security cannot be justified economically, and even larger centres, where N-1 is justified, are served by relatively few circuits. This following simple model illustrates this for three areas: (a) Auckland and Northland, (b) Christchurch (i.e. USI as an importing group), and (c) London and the south of England.

It is appreciated that London's demand group size is significantly larger than those of Auckland and Christchurch, but the comparison is not intended to demonstrate the performance of similar demands. Instead, it demonstrates the performance of a number of infeeding circuits and the capacities that they provide during fault and maintenance outages. As such, it is quite reasonable to show how these capacities compare with summer and winter demands.

Auckland and Northland are supplied by six 220 kV circuits. The design criterion is N-1, so the peak (winter) demand can be supplied using only five circuits. During a planned outage, when (summer) demand is down to 78 % of peak, five circuits would be operating, but it should be possible to supply this demand using only four circuits (in the event of a coincident fault). At the same time, it may be necessary to de-rate (by say 15 %) the capacity of the remaining system assets, e.g. overhead lines and cables, because of summer ambient temperatures.

Similarly, Christchurch (USI) is supplied by only four circuits and its summer demand is 86 % of peak.

London and the south of England, on the other hand, are supplied by 10 circuits, but are designed to N-2 (two simultaneous faults) and their summer demand is 80 % of peak. **Table C1**, below, compares the circuits, capacities, and demands of these three areas.

| Table B1: Comparison of capacities and demands | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| **Area** | **Circuits** | | | **Capacity** | | | | **Demand** | | |
| | Intact sys. | With fault | Mtce. + fault | Intact sys. | With fault * | Mtce. + fault | Mtce. + fault - 15% | Winter | Summer |
| Auckland | 6 | 5 | 4 | 120 % | 100 % | 80 % | 68 % | 100 % | 78 % |
| USI | 4 | 3 | 2 | 100 % | 75 % | 50 % | 43 % | 100 % | 86 % |
| London | 10 | 8 | 7 | 125 % | 100 % | 88 % | 74 % | 100 % | 80 % |
| USI with 6 circuits | 5 | 4 | 3 | 125 % | 100 % | 75 % | 64 % | 100 % | 86 % |

* These figures are 100 % because the system is designed to N-1.

**Table B1** shows that in each case the summer demand is greater than the capacity to supply when there is a planned outage, a fault (two faults in London's case), and a 15 % de-rating of remaining assets. USI is the worst case, as its demand is 86 % compared with its capacity of 43 % (of peak demand), a 100 % (= 86 / 43) overload. In London's case, the overload is only 8 % (= 80 / 74), and this occurs only in the event of a double fault during a planned outage.

**Table B1** also shows the situation if USI were supplied by five circuits instead of the existing four. In this case, system capacity in the event of a fault during a planned outage is still not adequate.

This model is subject to numerous assumptions and simplifications, including:

- Local generation is ignored; it can contribute substantially, but the generator itself needs to be maintained;
- Summer and winter demands are assumed to have the same characteristics, although in practice the power factor in summer is likely to be worse (more inductive loads, e.g. air conditioning) than in winter (more resistive loads, e.g. heating), which exacerbates the voltage performance;
- The load is shared equally between all circuits; and
- Multiple planned outages are not required.

However, despite these assumptions and simplifications, the model demonstrates the key points that:

- The sparseness of New Zealand's system demands a larger than otherwise margin of capacity in order to handle planned outages (USI would need 50 % overcapacity (six circuits); for London, 25 % is almost sufficient.);
- Currently, even in a major centre such as USI, the system is not secure during a planned outage (unless "pre-contingency arrangements" are made before the outage, e.g. a special protection scheme, system splitting, load shedding, etc.); and
- Summer asset ratings can sometimes make outages more difficult to achieve in summer.

B5.4 Planning technique

Broadly speaking, internationally, system planning is deterministic. That is, the planner assumes a peak demand and appropriate generation and ensures that the system can meet specified security criteria following defined contingencies.

This technique can be extended to cover planned outages, for which typical test conditions (assuming summer maintenance) would be:

- Summer demand and power factor;
- Overhead lines and cables de-rated for summer conditions;
- Summer generation pattern (e.g. reflecting seasonal availability of water for hydro generation) and typical generation maintenance; and
- Realistic, but not excessively onerous, outages; e.g. with parallel arrangements of system assets, only one asset is taken out of service.

These test conditions are only typical; in practice a precise, system-specific analysis is required.

In contrast, New Zealand uses a cost-benefit technique for system planning. Each possible investment is tested on an incremental basis, and its capital cost is compared with the benefit, expressed in economic terms, of the improved system. For a complex system, some form of (probabilistic) Monte Carlo modelling is normal, because the range of possible system conditions cannot realistically be enumerated and analysed.

This technique can be applied to fault outages, because faults can be modelled as random events. However, planned outages sit less easily with a probabilistic model because they are planned (deterministic) events and subject to specified constraints, e.g. parallel circuits must not be taken out-of-service simultaneously, generation and transmission maintenance must be performed simultaneously, or not performed simultaneously, etc.

A cost-benefit calculation is thus a complex exercise, as it requires describing a full-year maintenance schedule before adding in probabilistic (fault) outages.

## B6 Outage issues

### B6.1 System loading

Historically, it has been possible to take outages without reducing power system security or quality. However, outages are becoming increasingly difficult to accommodate because demand is increasing, but associated system capacity is not.

In outage planning, the critical issues are (a) how much outage time is required (over the course of a year) to complete the needed maintenance and (b) how much load reduction is required to enable the needed outages.

Traditionally, maintenance is scheduled for the summer, when demand is low compared with the winter peak. However, the difference between summer and winter demand is becoming less marked, because of increasing use of air conditioning and irrigation. This is limiting the opportunities for outages and raising the needed system capacity

**Comparison of summer loading periods**

The system loading in New Zealand appears more onerous than in Britain. As shown **Figures B1** and **B2**, demand in Britain is 78 % of peak for 18 weeks during the summer, whereas in New Zealand the equivalent period is only 8 weeks.

Similarly, average demand in Britain falls below 70 % of peak during the summer, but in New Zealand the equivalent figures are 78 % (North Island) and 86 % (South Island).

Thus, Britain has a deeper trough of low demand and a correspondingly longer period of outage opportunity.

Demand in Britain falls below 86 % of peak (the South Island trough) for about 31 weeks (60 % of the year) and below 90 % of peak for 36 weeks (70 % of the year). These figures suggest that an outage window of 60-70 % of the year is not unreasonable.

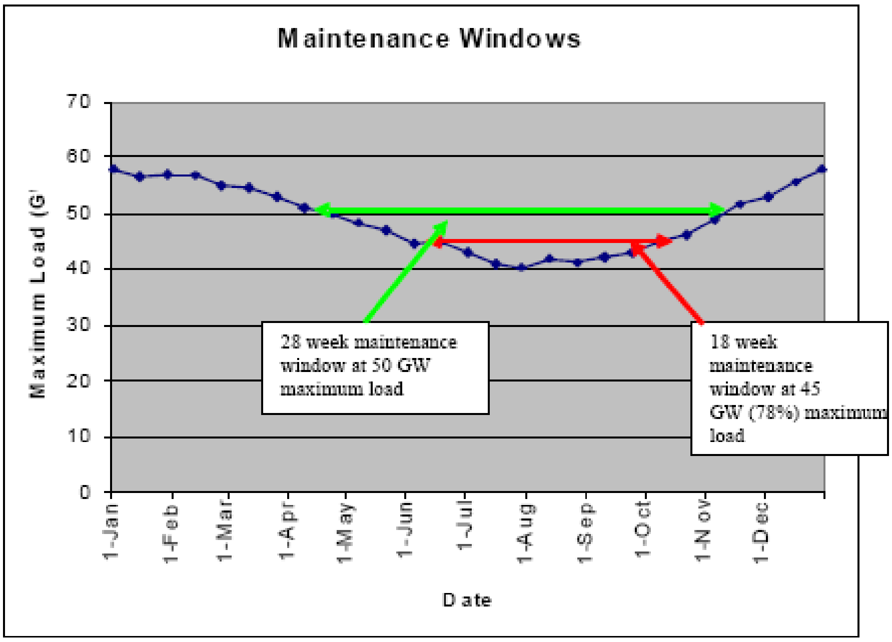


**Figure B1: National Grid (Britain) maintenance outage window**

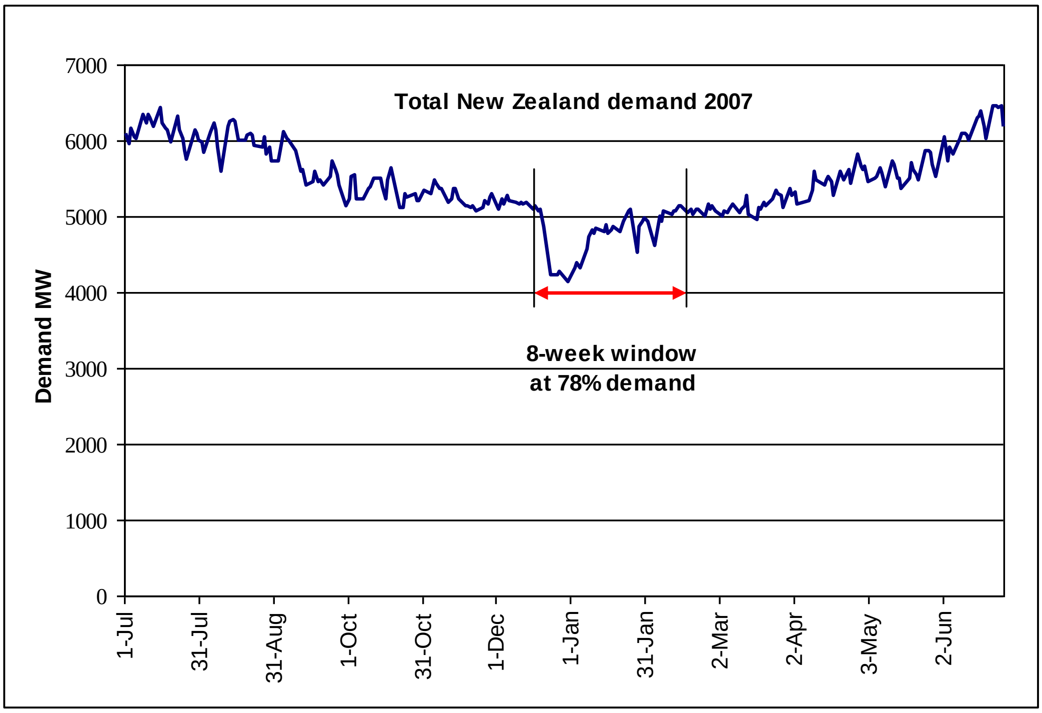


**Figure B2: Transpower maintenance outage window**

### Scheduling difficulties

The shortness of New Zealand's low summer demand period (eight weeks) makes scheduling substantial outages particularly difficult. This was highlighted recently during the commissioning of Ohinewai and the bussing of the Islington-Timaru-Twizel circuit at Ashburton. The Ashburton outages required significant load management in the Upper South Island over three weekends in May and June. The Ohinewai outages caused significant constraints on North Island thermal generation (during dry year conditions in the South Island) and reduced power system security to large amounts of demand.

**Concurrent outages**

Some outages cannot proceed without grid reconfigurations and these are affecting the ability to take concurrent outages of nearby assets. For example, the Otahuhu substation diversity project required an outage that could be achieved only by shifting load from Penrose to Roskill grid exit points. However, a concurrently-planned, maintenance outage required just the opposite.

**Reduced security**

An outage may reduce the security of supply to a large number of grid exit points. For example, the outage of the Hamilton-Huntly circuit can require Hamilton, Karapiro, Te Awamutu, Hinuera, Cambridge, Valley spur, Huntly, Bombay, and Wiri grid exit points (up to 400 MW) to be placed on N security.

Radially-fed parts of the grid have reduced security during maintenance outages. Queenstown, for example, is fed by one double-circuit transmission line and has reduced security when one or the other of the circuits is taken out of service for maintenance.

B6.2 Upper South Island

The Upper South Island (USI) load is supplied by four 220 kV parallel circuits. Power transfer through these circuits is typically limited by voltage stability constraints and is about 1100 MW when all plant is in service and about 900 MW when one 220 kV circuit is out of service. **Figure B3** shows the USI demand over the last year and the typical voltage stability limits.

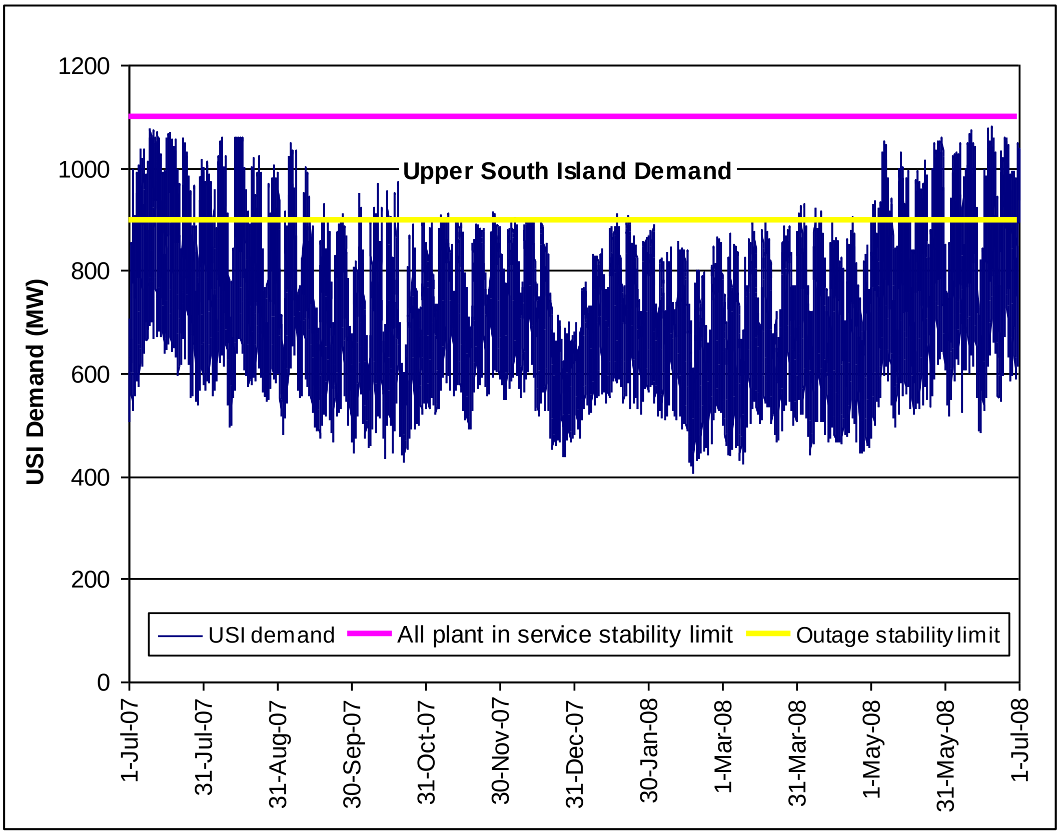


**Figure B3: Upper South Island demand**

From **Figure B3**, it is apparent that USI demand can be met when all plant are in service (purple line), but cannot be met if one of the 220 kV circuits is out of service and summer ratings (yellow line) apply.

**Figure B4** shows the summer ratings period (20 October to 10 May) with expanded vertical and horizontal scales. The yellow line is the voltage stability limit when one 220 kV circuit is out of service, and it can be seen that this limit is exceeded, mid-week, on numerous occasions. Load management is needed on these occasions, which implies that a five-day outage of a 220 kV USI circuit cannot be carried out without the prospect of load management (except during the Christmas-New Year period).

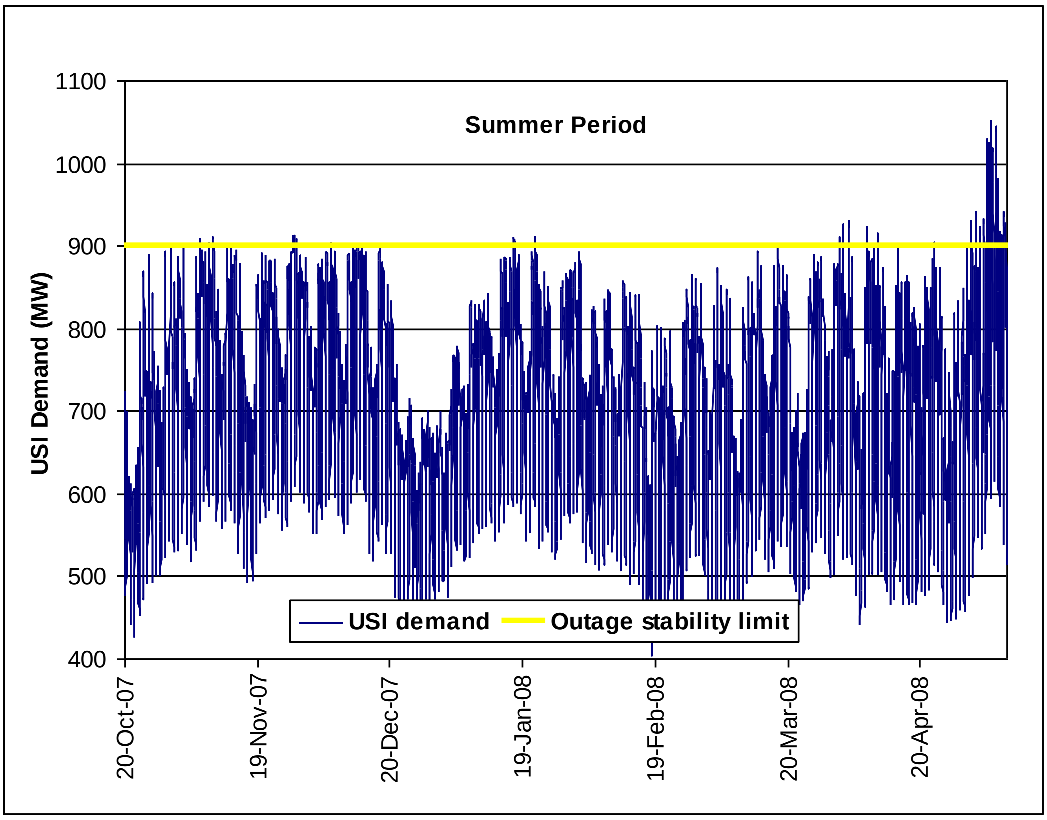


**Figure B4: Upper South Island demand, summer ratings period**

**Figure B5** shows the winter ratings period (1 July to 20 October) with expanded vertical and horizontal scales. Again, the yellow line is the voltage stability limit when one 220 kV circuit is out of service, and it can be seen that the weekend peak demand exceeds this limit on occasion. Load management would be needed on these occasions if an outage were in effect.

In summary, although the grid (in this example) is capable of meeting USI peak demand when all plant are in service, it is incapable of allowing either a five-day maintenance outage in summer or an urgent weekend outage in winter without the prospect of load management being required.

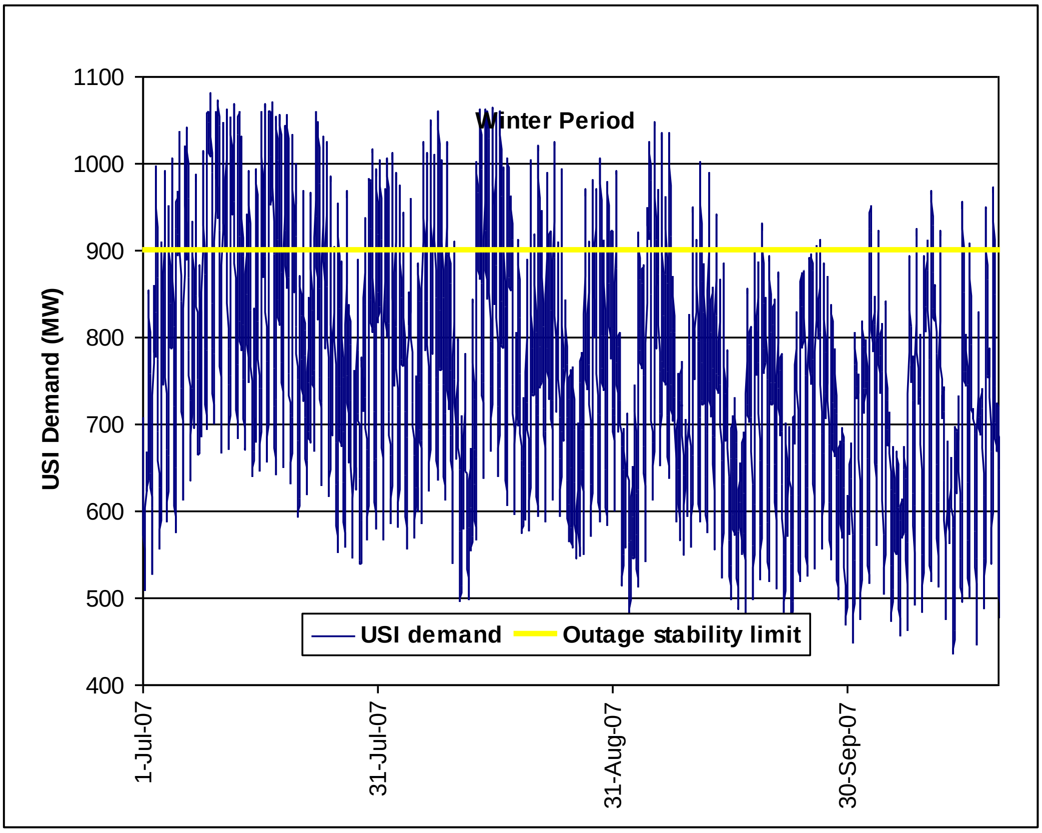


**Figure B5: Upper South Island demand, winter ratings period**

## B7 Managing power system security during planned outages

A number of measures are available to manage power system security and quality during outages:

- Grid reconfiguration. This includes implementing system splits, potentially reducing security, to manage pre and post contingency power flows and voltages during the outage;
- Wider voltage agreements. These are agreements with affected parties which allow local voltages to be operated outside the EGR range during outages;
- Market constraints. Market constraints can be applied during the outage. These constraints will restrict power flows on certain circuits which will result in generation in the constrained area being dispatched;
- Load agreement. These are agreements with distributors to manage load at grid exit points during the outage;
- Generation agreements. These are agreements with generators to make plant available for dispatch during the outage;
- Special protection schemes. These are schemes that could be used during planned outages to manage system security. Various system states and conditions are monitored and actions taken (e.g. demand shedding, generator runback etc.) in the event of unsatisfactory situation; and
- Emergency return to service. The maximum recall time to achieve this should be specified. This must be considered in project planning, work practices, and contingency planning.

Most of the above measures affect market outcomes, and their costs need to be considered when considering long-term investment decisions.

## B8 Code planned outage criteria

From the above, the following is apparent:

- Maintenance generally requires outages that must be continuous over a number of days;
- Maintenance of grid assets is essential. The number and extent of maintenance outages means that all required outages cannot be taken during the summer trough;
- The period for opportunities for maintenance is becoming shorter because the summer demand trough is becoming closer to the winter peak demand;
- In some instances, customer requirements prevent maintenance activities during the summer trough;
- Some utilities specifically design their transmission system to accommodate maintenance outages; and
- The net result of this is that there is a requirement for maintenance to be undertaken for a substantial part of the year outside the summer trough and for outages to be taken for a continuous period of up to five days.

The Code therefore includes the following requirements:

> “A two day (continuous) **outage window** for **planned maintenance** must be available for each **asset** at any weekend or weekend combined with a public holiday.
>
> A five day (continuous) **outage window** for **planned maintenance** must be available for each **asset** for at least 70 % of the year.
>
> In planning a **maintenance outage** it may be assumed that the grid is intact apart from the asset under consideration and any single **generating unit** is unavailable.
>
> Planning must allow for multiple **dependent outages**.
>
> Maintenance **outage windows** must not be assumed to be sacrificed in order to execute **major projects**.
>
> Planning must not assume pre-contingent load shedding to enable the **outage window**.”

A two day (continuous) outage window for planned maintenance at any weekend or weekend combined with a public holiday ensures that there are opportunities for critical or short notice maintenance to be carried out throughout the year.

Five days continuous per year per circuit for 70 % of the year is proposed in the Code to recognise the cyclical nature of maintenance work and the increasing maintenance replacement demands. The adoption of 70 % ensures that the planning process does not have to ensure that maintenance outages must occur at times of peak demand and ensures that there is sufficient capability to allow co-ordination of all outages, while recognising access, resource, demand and generation considerations. The level also needs to be such that an annual outage plan can be produced in order to achieve all the work required. There are not enough days in the year to have only one outage at a time so the 70 % provides this flexibility.

The 70 % figure will be reviewed from time to time to confirm its appropriateness. As noted previously, this just provides a trigger for investment decision making and there will be alternative methods such as use of SPS and demand management to enable the outage to occur without major investments.

The Code specifically requires that the planning should not assume precontingent load shedding (other than water heating). Customers, understandably, object to being turned off “just in case” an asset might overload.

The 70 % criterion also reflects the need to ensure that there is sufficient overall grid capacity. New Zealand is being increasing outage constrained when the period of time the demand is below a set level is considered. New Zealand has only 8 weeks when the demand is below, 78 % whereas Britain has 18 weeks.

Transpower considers that 100% is unreasonable but likewise, 50 % does not provide sufficient opportunities for maintenance work as planning considers for example, access issues, resource capability and ability to develop an overall network outage plan which will not just result in only one outage at any one time as there are insufficient days in the year.

Distribution planners adopt a capacity factor approach by ensuring that no asset is loaded to more than a certain level which results in sufficient network redundancy for maintenance work. This is not considered appropriate at a transmission level.

The grid is assumed to be intact (all assets in or available for service) apart from the asset under consideration and that any single generating unit is unavailable. This aligns with the approach taken by the System Operator when operating the grid. Further consideration is required to align with System Operator practice of also wanting to ensure that system security is maintained in the N-1-G situation.

Planning must also allow for multiple dependent outage windows. Dependent outages are when one or more additional outages must occur in conjunction with the primary outage. For example, when work is carried out on one of the Coleridge-Otira circuits, the other must be taken out at the same time. This is because one circuit cannot be worked on when the other is in service owing electrical safety clearances on the pi-pole construction.

The Code also specifies the following in relation to system state:

> "System state during planned outages.
>
> During a planned outage, the **grid** must remain in a stable and **satisfactory state**. For the avoidance of doubt, this means that there must be no interruptions to load, except where there is only one circuit supplying an area (e.g. Kaitaia).
>
> In addition, the principles outlined in the Planning Guidelines and agreements with connected parties must apply.
>
> Contingencies during a planned outage.
>
> In the event of an unplanned outage coinciding with a planned outage the **grid** must remain **stable** and in a **satisfactory state**, except that loss of **injection** or **offtake** is allowed.
>
> In addition, the principles outlined in the Planning Guidelines must apply."

These criteria, supported by the Grid Planning Guidelines, which contain detailed planning principles, describe the outcomes required during planned outages or when unplanned outages occur during planned outages. "**Satisfactory state**" is as specified in EGR.

# C REACTIVE COMPENSATION COMMENTARY

## C1 Introduction

Transpower is applying increasing quantities of reactive compensation to the grid in order to maximise the utilisation of assets and is currently at the forefront of internationally accepted levels. Moving into the future it is becoming apparent that these levels may be exceeded:

- Operation is starting to be beyond international experience and is likely to be increasingly so in the future;
- There are real-time operational management issues and system risks; and
- Traditional key operational parameters are being eroded in that busbar voltage is no longer a reliable indicator of system health and voltage instability is becoming an increasing risk, even at voltages within operational limits.

Operating in this way requires that the risks be fully recognised, are measurable, and managed; it is essential that reactive control facilities be suitably developed and validated, potentially requiring an area control capability (which must be on a system specific basis).

To alleviate these concerns, Transpower is seeking to formalise the application of reactive compensation to the grid.

Studies have confirmed that absolute technical limits for either static or dynamic reactive compensation levels are difficult to define, as, in practice, there are no rigid boundaries or prescriptive limits. Therefore, the approach adopted combines good industry practice and findings from generic studies.

This approach combines:

- Assessing system performance at different levels of compensation, based on a comparison with other utilities and generic (two-port-model) analysis;
- Assessing the acceptable ratio of dynamic and static compensation, based on WECC standards and a comparison with other utilities;
- Avoiding unacceptable risks resulting from over complex automatic control systems;
- Static modelling, using PV and VQ curves, based on the need to operate at the lower voltage limit and with stability margins defined in WECC standards;
- Dynamic modelling as currently performed by Transpower; and
- Use of real-time reactive tools such as VSAT in the control room.

## C2 Acceptable levels of compensation

Transpower's approach to assessing performance at different levels of compensation has been to conduct generic (two-port) modelling and to reconcile the results with international norms.

### C2.1 Generic modelling

Clear technical limits to compensation are hard to quantify, as evidenced by lack of clear-cut standards internationally in this respect, but generic modelling indicates operating conditions that must be avoided if system stability is to be maintained.

In particular, compensation should not prevent the system reaching its lower operating voltage limit, i.e. there should be a smooth, progressive decline in voltage as load increases. Being unable to reach the lower operating voltage limit implies a brittle and ill-conditioned system that could suffer voltage instability very quickly should reactive compensation reserves be depleted. Monitoring of reactive reserves is essential if the decline in voltage reaches a sudden limit at which voltage instability takes place without warning.

 

A brittle system is one that can move from being well-conditioned, linear, and operating normally to one that is unstable, non-linear, and uncontrolled, with little or no transition phase. Such a shift can arise from (say) a line trip that creates a step change in the loading of other lines. In this condition, reactive compensation runs out of its control range, which leads to a sudden decrease in output, immediate voltage instability, relay mal-operation, break up of the system, generation disconnection, and black-out conditions. This occurs in a matter of seconds, so operators are unable to take manual corrective action. System black out events internationally have confirmed the rapid failure that can be experienced under voltage instability conditions.

Highly compensated demand importing groups are particularly susceptible to this phenomenon.

Utilities have generally adopted a lower operating voltage limit of 10 % below nominal value (0.9 pu), in order to keep the system within its stable operating range and to ensure correct co-ordination of automatically-controlled equipment, e.g. transformer tap changers and generator AVRs. Most utilities have voltage limits of ±10 % of nominal specified within their governance documents (e.g. Grid Code, Planning and Operational Standards), as shown in Table C.1 below.

Keeping equipment within its control ranges ensures that the transmission system is not required to operate outside its design parameters. In many cases utilities set planning voltage limits within operating limits (e.g. a lowest planned voltage of 0.95 pu) to allow for system conditions that are not exactly as planned (e.g. higher load levels, different generation patterns, alternative maintenance outages).

**Table C1: Voltage limits**

| **Country** | **Voltage** | |
|---|---|---|
| | Normal<br>i.e. steady state | Abnormal<br>i.e. post-contingency |
| Abu Dhabi | ±5 % | ±10 % |
| Britain | ±5 % | ±10 % |
| Ireland | 370-410 kV<br>210-240 kV<br>105-120 kV | 350-420 kV<br>200-245 kV<br>99-123 kV |
| Malaysia | ±5 % | ±10 % |
| Pakistan | ±5 % | ±10 % |
| Philippines | ±5 % | Not defined |
| NZ (Rules & Regs) | ±10 % | ±10 % |

C2.2 Acceptable compensation levels

Acceptable compensation levels have been designated by three zones:

- Acceptable zone – Generic models indicate a robust system in which it is possible to operate at the lower end of the operating voltage range (10 % below nominal) and there is operational visibility provided by real time voltage measurements of system performance even below this voltage level;

  Operating in this zone is consistent with international norms. See below.
- Marginal zone – The generic model shows a small inherent stability margin allowing operation down to 10 % below nominal, but further, albeit minimal, voltage deterioration would move the system into instability; or

- Unacceptable zone – The system operates in a stable manner until critical reactive reserves are depleted causing the system to collapse without warning. The system, under stable conditions, cannot be operated down to a voltage of 10 % below nominal.

Unacceptable conditions are at or beyond the limits of international GEIP. Adoption of such conditions would present significantly elevated risk. They may become acceptable with advance control and automation facilities in the longer term.

Systems in the marginal zone must be analysed in more detail.

C2.3 Compensation factor

Compensation factor is a generalised parameter for the purposes of broad comparisons between different transmission systems and assumes (at this stage) a representative power factor of 0.9. It provides a measure of the degree of compensation in an importing system against the peak demand of that system, and hence can give indications of:

- Whether the system is being planned in a manner that creates an ill-conditioned system and, therefore, one that is likely to lead to voltage instability without warning; or
- Design beyond international norms and therefore inconsistent with GEIP.

It should be appreciated that it provides a measure of system robustness in comparison with what other utilities do and is not an absolute figure based on particular demand characteristics.

For the purpose of being able to carry out a comparison on an international basis, compensation is measured in terms of installed capacity.

Compensation factor is the capacitive reactive compensation connected to a transmission system divided by the maximum power demand of that system. This factor is calculated for a basically importing demand group within that system.

Capacitive reactive compensation includes:

- All shunt fixed capacitors connected at transmission voltages;
- All variable capacitive reactive compensation (including continuously-variable and block-switched units) connected at transmission voltages. The value of output used for the calculation is the maximum nominal capacitive reactive output; and
- All capacitive compensation connected at the low voltage side of all grid supply points that is used in support of the transmission system.

The capacitive reactive compensation does NOT include the reactive compensation embedded within local networks or the reactive output of generating units.

It might be argued that tap changer action on distribution networks keeps approximately constant voltage on the demand. Therefore, in the steady state, the demand along with its capacitors remains at a constant PQ. However, any large aggregation of distribution capacitors that do not have constant voltage applied should not be ignored in the calculation of the compensation factor.

However, Transpower considers that while including all shunt capacitive compensation might have some merits in the development of an absolute measure, the compensation factor is a relative measure enabling a comparison between utilities (i.e. assessment of GEIP). As such, transmission systems are dealt with rather than distribution systems, and it would be difficult, if not impossible, to obtain the appropriate data on distribution systems from other transmission utilities.

Compensation directly affects system stability, and it is convenient to define the boundaries between the three zones of the three zone model, for a demand importing group, in terms of compensation factor in the first instance.

 

C2.4 International norms

In the absence of clear technical limits, international norms provide a guide to the generally accepted limits of compensation. Going beyond such norms demands a controlled and monitored progression, e.g. confirming automatic reactive control behaviour; confirming post-disturbance dynamic responses of automatically-controlled equipment; monitoring operational control; reviewing demand forecasting; and real-time assessment and management of a highly brittle network.

Transpower distributed a questionnaire to other major Transmission System Operators (TSO) worldwide seeking information on maximum levels of compensation and the mix of static and dynamic compensation. The aim was to further refine the boundaries between these three zones in terms of compensation factor.

From the survey results, **Table C2** below gives an indication of the level of compensation in terms of the Compensation Factor and the ratio of total compensation to maximum demand.

**Table C2: TSO compensation factors**

| | Max demand (GW) | Compensation (GVAr) | Ratio of Total Compensation of Maximum Demand |
|---|---|---|---|
| Belgium | 13.7 | 1.89 | 14 % |
| England & Wales | 61.2 | 19.59 | 32 % |
| Ireland | 4.88 | 0.77 | 17 % |
| Italy | 56.8 | 3.944 | 7 % |
| Portugal | 8.95 | 2.04 | 23 % |
| Queensland[1] | 8.71 | 7.938 | 91 % |
| Queensland (10 % POE)[2] | 9.54 | 7.938 | 83 % |
| Victoria | 9.82 | 4.31 | 44 % |
| *New Zealand (North Island)* | *4.46* | *1.989* | *44 %* |
| *New Zealand (South Island)* | *2.23* | *1.122* | *50 %* |

The demand figures for New Zealand, in the above table, are taken from Part C of the System Security Forecast 2008. The compensation figures for New Zealand, in the above table, are taken from Part G of the System Security Forecast 2008.

It will be noted that the level of compensation in Australia, based on the two states considered, is significantly higher than in Europe. This is due to the long lines and consequent distance over which power needs to be transferred. Compensation in New Zealand is generally higher than Europe but low compared to Queensland. The New Zealand transmission system is less interconnected than Europe, but does not cover such long distances as the transmission system in Queensland. Hence the level of compensation lies between the two.

[1] Includes substations demand and supply to Terranora in New South Wales.
[2] Includes substations demand, transmission losses and supply to Terranora in New South Wales, based on 10% probability of exceedance.

C2.5 Code boundaries

The boundaries of acceptability for incorporation in the Code are:

| Compensation factor | | |
|---|---|---|
| Acceptable | Marginal | Unacceptable |
| C < 40 % | 40 % ≤ C ≤ 85 % | C > 85 % |

The figures of 40 % and 85 % are based on the generic model, in which up to 40 % compensation results in a reasonable nose point. A compensation factor of 40 % to 85 % enables 0.9 pu voltage to be attained, but with a sharp nose point. If the compensation factor is above 85 %, it is not possible to attain 0.9 pu voltage before voltage collapse occurs.

Transpower acknowledges that in the analysis of compensation requirements there can be some doubt on the representation of load characteristics. For this reason, Transpower recommends both static and dynamic analyses (see **Section C6**, below), particularly the latter at high levels of compensation. This approach is cautious and limits the amount of compensation being implemented.

Transpower accepts that utilities, in general, do not set limits on the levels of reactive compensation. However, an examination of the compensation used by several utilities shows that the level installed rarely approaches that seen and being contemplated in New Zealand. Hence, there has been little practical requirement for other utilities to consider setting such limits. Further, a number of generic studies, described below, demonstrate the difficulties of operating a transmission system with high levels of compensation. Such levels could result in transmission systems in which the transition to instability can be rapid and unpredictable. The Code provides a practical set of limits to safeguard the New Zealand system against such an outcome.

C2.6 Independent review

Transpower commissioned a review of its Auckland 400 kV plans. This review stated that a compensation factor is "a matter of concern once it exceeds 25 %" and that "a 50 % level is generally considered unacceptable" (p. 28). These figures are considerably lower than the proposed acceptable zone boundaries (40 %, 85 %). However, the report goes on to say "there are no studies to prove this rule". Nor is there any information on the power systems from which these concerns originated.

Analysis indicates that line length is a critical determinant of real power transfer capability. Substantial reactive compensation is required to achieve a real power transfer over a long line (say 250 km) that would require relatively little compensation on a short line (< 100 km). Thus, dense, heavily meshed systems, as encountered in many countries, particularly in Europe, require substantially lower compensation factors than sparse, largely linear systems, as is New Zealand's. The 25 % and 50 % figures given in the review need to be considered in this light.

## C3 Balance of dynamic and static compensation

Having established that a given level of compensation is acceptable (or marginal and requires further analysis), the next step is to assess the necessary mix of dynamic and static compensation.

The mix is expressed as a percentage of dynamic to total compensation.

C3.1 WECC recommendations

The WECC report, Voltage Stability Criteria and Reactive Power Reserve Monitoring Methodology, states:

> "Sufficient reactive resources must be located throughout the electric systems, with a balance between static and dynamic characteristics. Both static and dynamic reactive power resources are needed to supply the reactive power requirements of customer demands and the reactive power losses in the transmission and distribution systems, and provide adequate system voltage support and control."

Further, it provides a principle:

> "Reactive power resources, with a balance between static and dynamic characteristics, shall be planned and distributed throughout the interconnected transmission systems..."

Thus WECC acknowledges that both static and dynamic compensation are needed for satisfactory transmission performance.

The WECC report recommends that:

> "The best method for determining the proper mixture of static and dynamic reactive power is to conduct dynamic simulations using the current ...... programs. Member systems which already have the capability to conduct long-term dynamic /simulations should use dynamic simulations to determine the required mixture of static and dynamic reactive power support."

Transpower is able to perform such studies, and the use of authenticated programs, other than those suggested by WECC, is acceptable. WECC notes that the simulation time depends on the system studied and could vary from a few minutes up to about 15 minutes following a contingency. The WECC report does not recommend an absolute mix of static and dynamic reactive compensation.

C3.2 Model

Transpower distributed a questionnaire to major TSOs worldwide seeking information on maximum levels of compensation and the mix of static and dynamic compensation. This survey would assist in further refining the percentage of dynamic compensation planned for Transpower's system.

**Figure C1** below shows some available data, plotted against compensation factor. The curve is fitted to New Zealand data for Upper South Island and derived from planning study work on the development of the associated grid for the years 2010-25; three data points from Britain have been added for comparison.

Plotting percentage against compensation factor incorporates demand into the model, and indeed provides a better fit to the data than when plotted against just compensation (MVAr).

The proposed code, therefore, is that the percentage of dynamic compensation should always lie above the illustrated curve.

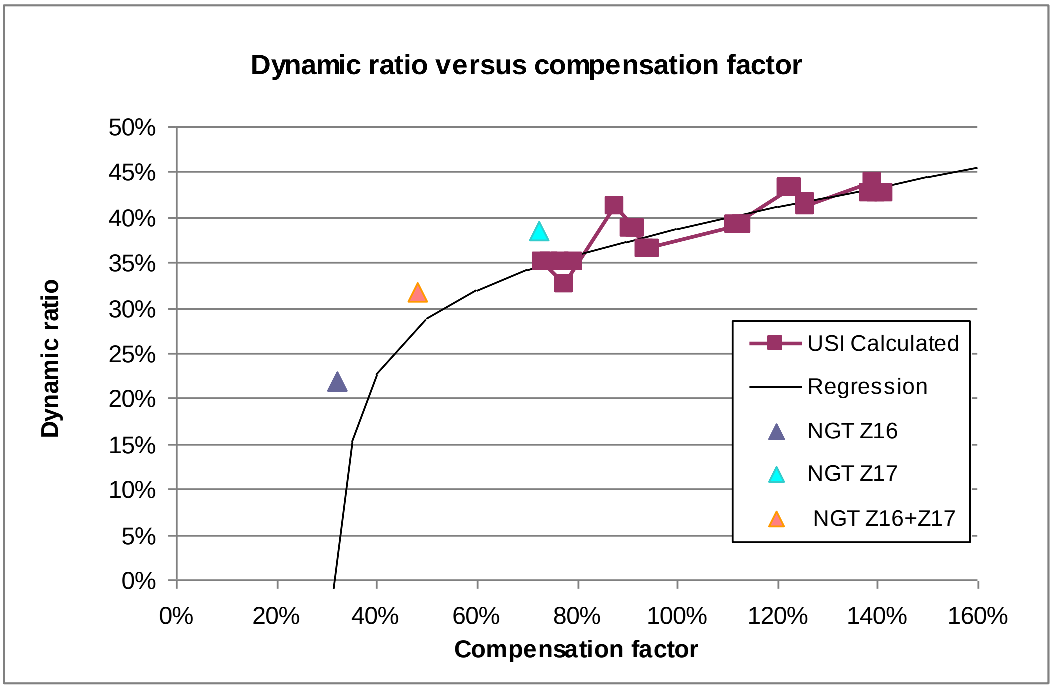


**Figure C1: Dynamic ratio versus compensation factor**

From the international survey results, there is limited information on importing groups from the respondents, because either demand data is unavailable or there do not appear to be significant importing groups in some areas. For those where information is available, information has been summarised on the following table which shows the proportion of dynamic compensation plotted against Compensation Factor. This enables the absolute level Compensation Factor levels to be seen as well as the proportion of dynamic compensation at various levels of compensation factor.

| Zone | Peak Demand MW | Shunt Capacitors MVAr | SVC MVAr | Total MVAr | Compensation Factor % | Dynamic ratio % |
|---|---|---|---|---|---|---|
| **England and Wales, Z16** | 4275 | 1071 | 300 | 1371 | 32.0 | 21.8 |
| **England and Wales, Z17** | 2802 | 1247 | 780 | 2027 | 72.3 | 38.5 |
| **England and Wales, Z16 + Z17** | 7077 | 2318 | 1080 | 3398 | 48.0 | 31.8 |
| **Ireland, NW** | 358 | 90 | 45 | 135 | 37.7 | 33.3 |
| **Ireland, SW** | 144 | 30 | 0 | 30 | 20.9 | 0 |
| **Australia, Queensland, Far North**[3] | 367 | 285 | 150 | 435 | 118.5 | 34.5 |
| **Australia, Queensland Moreton + Gold Coast**[4] | 5669 | 3650 | 950 | 4600 | 81.1 | 20.7 |

[3] 10% Probability of Exceedance (POE) demand
[4] Includes supply to demand at Terranora in New South Wales, 10% probability of exceedance (POE) demand

 

| Zone | Peak Demand MW | Shunt Capacitors MVAr | SVC MVAr | Total MVAr | Compensation Factor % | Dynamic ratio % |
|---|---|---|---|---|---|---|
| New Zealand UNI | 2070 | 1045 | 371 | 1416 | 68.4 | 26.2 |
| New Zealand USI | 1079 | 616 | 310 | 926 | 85.8 | 33.5 |

The last two columns in the table above are plotted in **Figure C2** below and demonstrate the high magnitude of compensation factor for both New Zealand Upper North Island (UNI) and Upper South Island (USI) when compared with importing groups in other utilities. Although the Far North of Queensland does have a higher compensation factor, this is due to the extreme distance over which the power must be transmitted.

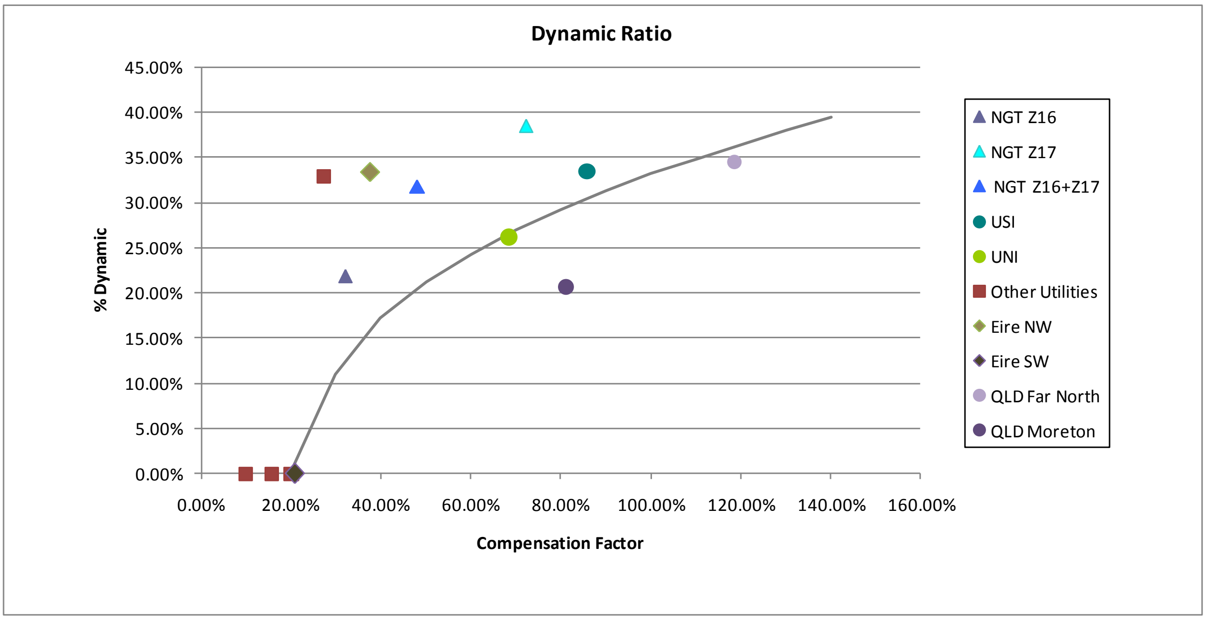


**Figure C2: Ratio of dynamic compensation to Compensation Factor for various importing groups**

From the overseas utilities data, it may be noted that the compensation factors are generally 80 % or below with only one instance, Queensland, above. It can also be seen that most ratios fall above the dynamic ratio line rather than below. This indicates that Transpower is already in the upper range of compensation deployment compared with other utilities and that extreme caution should be exercised where compensation factors higher than 80 % considered. It is also considered good practice internationally, concurring with Transpower practice, that the dynamic ratio for any particular area should be above the line unless it can be proved that less dynamic compensation will be satisfactory for all operating conditions.

On the basis of the data points in **Figure C2**, it is difficult to assess a universal level for the balance of static and dynamic compensation, but the curve in **Figure C2** illustrates the principle.

The curve in **Figure C3** shows that even at the lowest levels of compensation some dynamic compensation is required, i.e. even if the compensation factor is acceptable. As the compensation factor increases, higher levels of dynamic compensation are required.

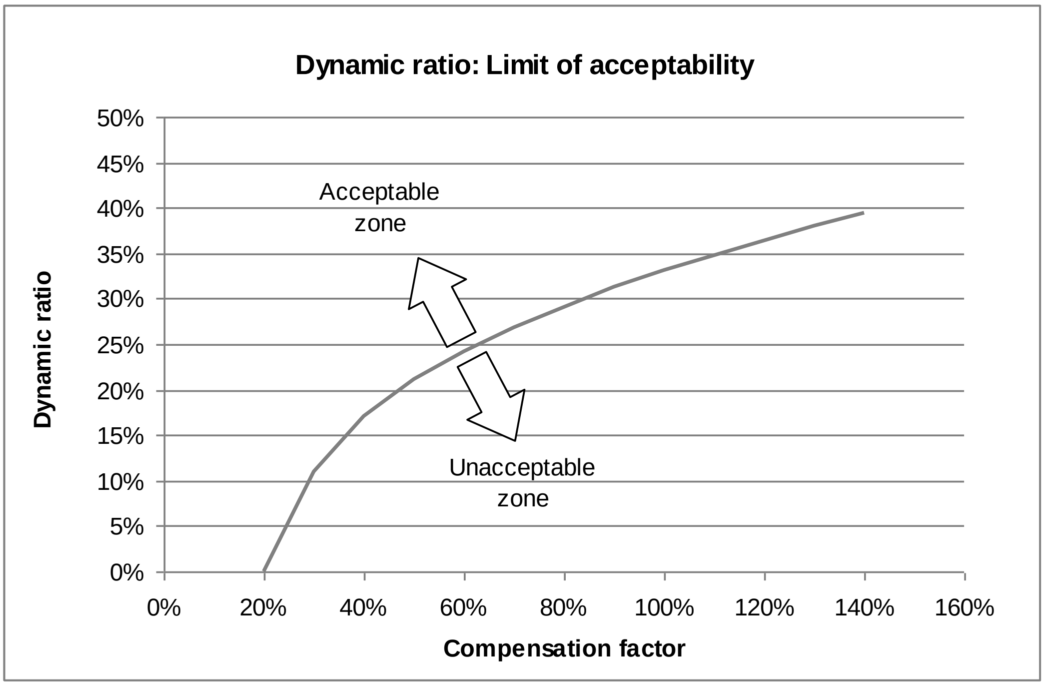


**Figure C3: Acceptable levels of compensation**

For the purpose of assessing capacitive dynamic reactive compensation, synchronous condensers, SVCs, STATCOMs, and TSCs should be included.

It should be noted that the above diagram applies to important groups and not individual grid exit points. Thus, there is no requirement to provide dynamic compensation to small load points on the transmission system where levels of compensation are below 20 %.

## C4 Automatic control of compensation

Compensation is controlled at three levels:

- Primary control is automatic control of individual reactive power resources; control is based upon local measurements; the timescale is up to one minute;
- Secondary control is automatic or manual control of reactive power resources in a specific area of the system; its aim is to minimise interaction between primary controllers; the timescale is between one and a few minutes;
- Secondary controllers mainly fix or alter the reference point of the primary voltage controller, adjust the slope of the reactive power resource output characteristic, or trip or limit the output of the reactive power resource so that system security is maintained; or
- Tertiary control is secondary control actions to optimise the voltage performance in a post contingency period; the timescale is around ten minutes.

C4.1 Interaction

Having three levels of control can result in adverse interactions, and decoupling mechanisms are needed. Decoupling, in most cases, is achieved using partially-automatic or totally-automatic, secondary voltage control, in a timescale of not less than one minute, and computer-assisted, manual, tertiary voltage control.

Automating secondary voltage control reduces the operational burden considerably and facilitates the coordination of voltage controller actions. However, automation requires an appreciable investment in control facilities, as reactive power resources are usually geographically dispersed, causing increased risk, reducing reliability and requiring implementation of bespoke systems and networks. International experience shows that secondary and tertiary control systems can take years to develop, and that staged developments are needed to minimise risks both in terms of successful operation and successful implementation.

C4.2 Approach

Because of the risks and impacts associated with automatic control, Transpower proposes that initially no more than two-site control is considered and that all automatic control is subject to analysis and operational proving. RPC schemes are complex, bespoke, and not to be undertaken lightly without experience of planning and operating smaller schemes on a particular transmission system. Following successful implementation of a number of two-site schemes within the Transpower network, there is nothing to prevent the Code being revised to allow larger than two-site schemes.

In addition, other utilities have taken a number of years to develop secondary and tertiary control schemes – therefore Transpower could consider this approach for the future, but it is not considered appropriate at the current time.

## C5 Modelling criteria

Systems deemed marginal must be analysed in detail, and the criteria contained in Transpower's Grid Planning Guidelines apply.

## C6 Power system analysis − static

Systems deemed marginal i.e. between 40 % and 85 % compensation factor) require static (both PV and VQ) analysis. If this indicates an ill-conditioned system further dynamic analysis will be required.

The analysis assumes the modelling criteria given in Transpower's Grid Planning Guidelines and generally follows the procedure described in the WECC report.

C6.1 PV analysis

The voltage characteristic (PV curve) of a typical, uncompensated transmission line is shown in **Figure C4**. This characteristic is calculated from a two-port, single-transmission-line model. In this case, the maximum real power that can be transferred is 100 MW before the voltage falls below 0.9 pu.

The 'nose point' of the curve is the limit of system stability. For the curve shown, the nose is safely below the voltage limit (the voltage limit is encountered first). For lines longer than 100 km, these voltage and instability limits are usually reached before the line's thermal limit.

As compensation is added, the PV curve rises and the real power transfer increases. The curves in **Figure C5** show a system with different amounts of variable compensation (e.g. supplied by a SVC). The compensation output increases as the load increases, so the voltage declines only slightly over the range of the compensation. The rate at which the voltage declines depends upon the setting of the SVC, which typically has a 3-5 % negative slope.

At the limit of variable compensation (when the SVC runs out of its range), a 'knee point' forms in the voltage curve, as shown. The system can be operated beyond the knee point, but at high levels of compensation the margin between the flat, normal-operating portion of the voltage curve and the nose point (instability) is small (i.e. the system is brittle). See the discussion on WECC standards, below.

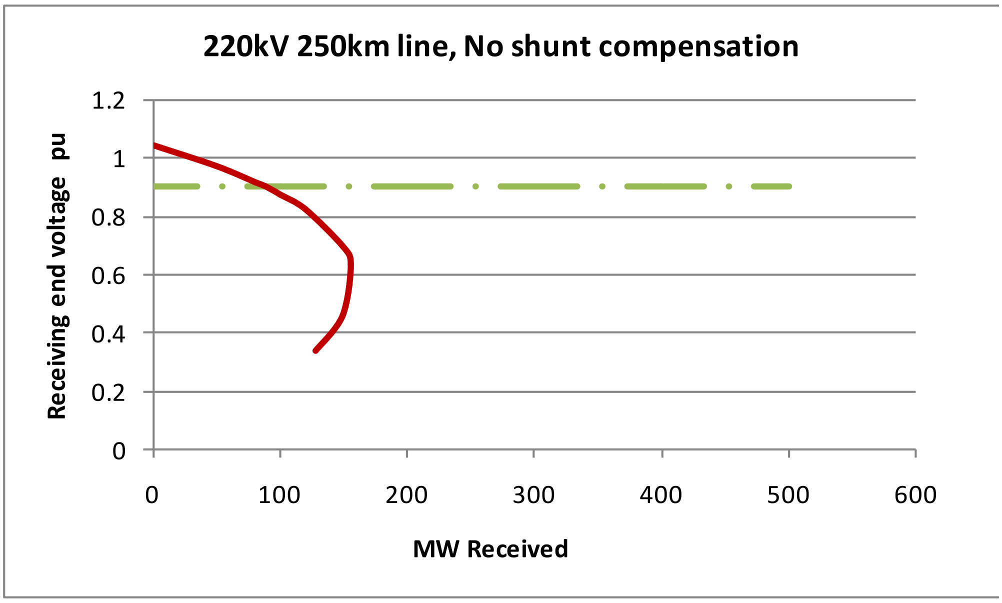


**Figure C4: 220 kV 250 km line without compensation**

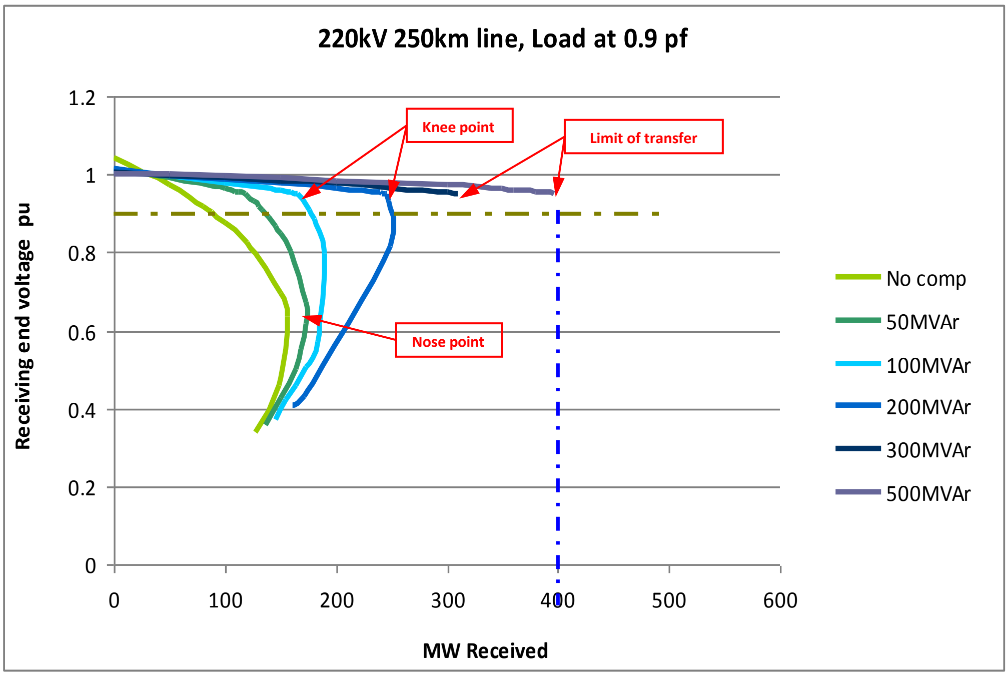


**Figure C5: 220 kV 250 km line with compensation**

At still higher levels of compensation, the stable operating range ends abruptly before the voltage falls to 0.9 pu, and the model can calculate no stable operating point for higher loads or lower voltages. Such operating characteristics are specifically excluded from the code.

**WECC stability criteria**

WECC uses the above principles to define stability criteria, as shown in **Figure C6**. Note that this diagram is stylised to illustrate the stability margin concepts and differs in detail from the curves above, which are calculated from actual models.

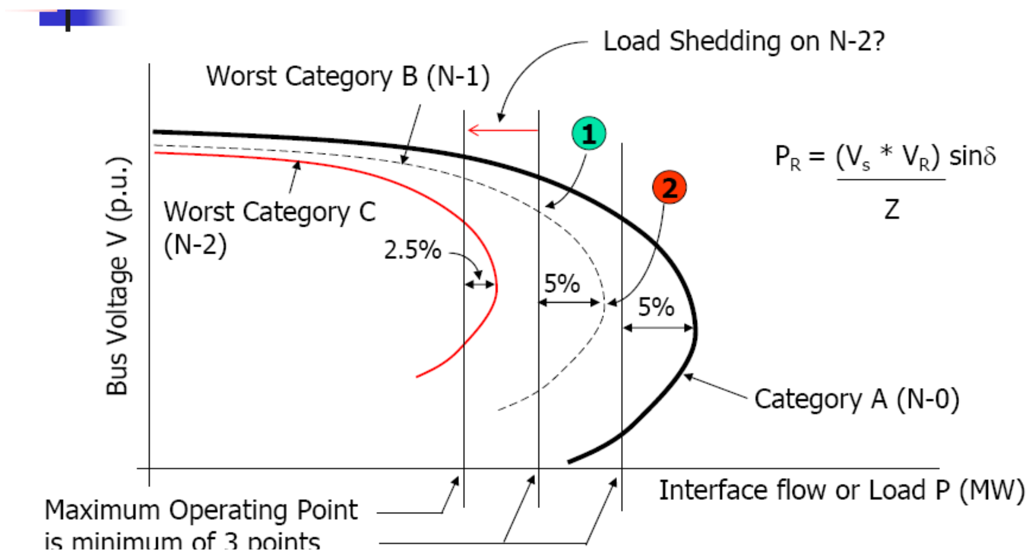


**Figure C6: WECC stability criteria**

WECC defines three stability margins:

(a) Under normal operating conditions (category A), there is a minimum 5 % margin between the operating point and the nose point.

(b) Under the worst-case, single-outage conditions (category B), there is a minimum 5 % margin between the operating point and the nose point.

(c) Under the worst-case, double-outage conditions (category C), there is a minimum 2.5 % margin between the operating point and the nose point.

(d) The operating point is the maximum established planned load limit for the area under study. The WECC criteria are illustrated by smooth curves that are typical of a well conditioned and, in their case, a highly meshed system. In an ill conditioned system, where voltage instability can take place suddenly, single and double contingency criteria are much more difficult to define.

In order to provide a succinct Code, and because the standard contingency criterion in N-1, the 5 % margin has been described in terms expected system states; this covers both the intact network and N-1 conditions.

C6.2 VQ analysis

The WECC report establishes a procedure for voltage-collapse analysis based using VQ curves. The procedure uses a normal load-flow program, and the VQ curves are produced by running a series of load flow cases.

Both PV curves and VQ curves illustrate the effect of adding compensation. They differ in that PV curves are drawn for constant load power factor and variable demand, while VQ curves are drawn for constant power demand and variable power factor. VQ curves are considered as a more effective method of determining reactive reserve requirements.

**Voltage instability point**

**Figure C7** shows a typical VQ characteristic. It is the quadrature equivalent of the PV curves in **Section C6.1**.

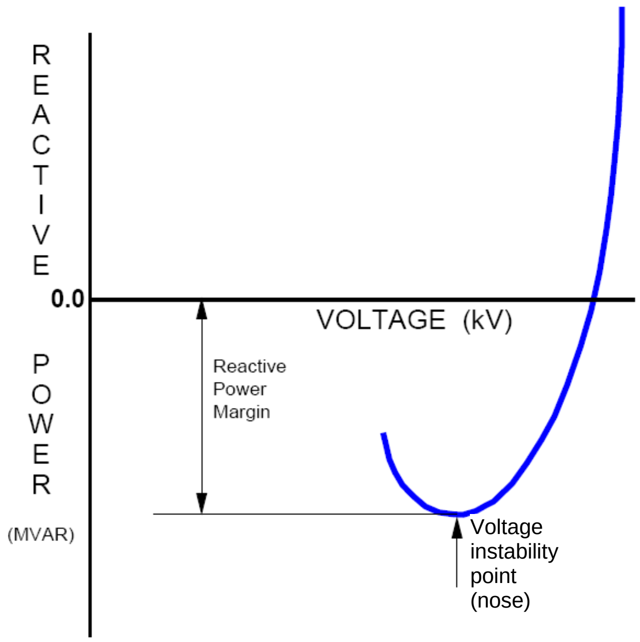


**Figure C7: Typical VQ characteristic**

The minimum point of the VQ curve (where dQ/dV = 0) is the critical "nose" point. To the right of this point, an increase in MVAr requirements causes a drop in voltage, and a decrease in MVAr requirements causes a rise in voltage, so it is therefore a stable system. Conversely, points to the left of the critical point minimum are unstable.

If the nose point of the VQ curve is above the horizontal axis, the system is reactive power deficient, and additional reactive power is required to prevent a voltage collapse.

**Reactive power margin**

**Figure C8** shows VQ curves for three different conditions:

(a) N-0, base load conditions

(b) Worst-case N-1 contingency

(c) Worst-case N-1 contingency and a 5 % increase in load.

Curve 2 (N-1 worst-case contingency) is near the lower operating voltage limit of (in this example) 0.95 pu. Thus the system has sufficient reactive compensation to just handle an N-1 contingency.

Curve 3 shows that for the worst-case N-1 contingency and a 5 % increase in load, the reactive power is 300 MVAr short of that needed to maintain the voltage at 0.95 pu. Thus, if the security criterion is the ability to maintain stability at 5 % above the expected load, then an additional 300 MVAr is required.

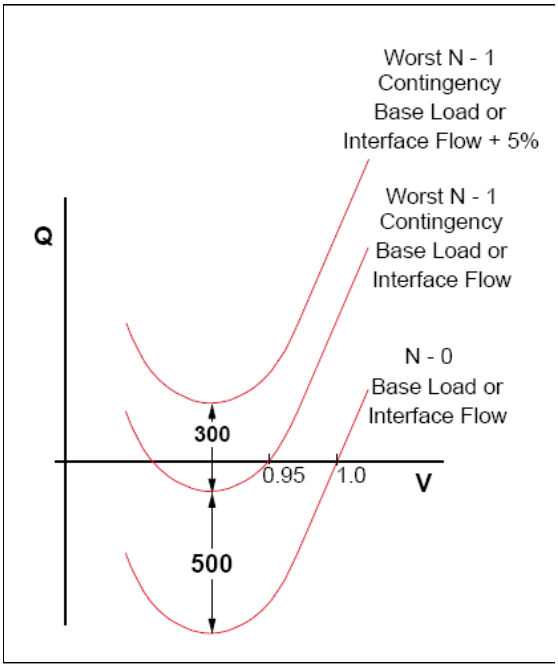


**Figure C8: VQ curves for different system conditions**

**VQ procedure**

As with the PV curves in **Section C6.1**, the above curves simply demonstrate the concept of stability and can be constructed from a simple two-port model. In practice, the procedure for similar analysis of a real power system is more complicated.

The following procedure is recommended in the WECC report.

A power flow is set up for a post-disturbance condition (N-1, N-1-1, etc, depending on the security criteria) and the critical busbar is identified (usually the most reactive deficient). A reactive power source or sink is applied to that busbar (the WECC report describes this as a "fictitious synchronous condenser"), the voltage at that busbar (V) is altered by a small amount, and the output or absorption of the reactive source or sink (Q) to achieve this is calculated. This is repeated for different excursions in voltage until a VQ curve can be drawn.

**VQ curve interpretation**

The VQ curve for a single, uncompensated transmission line is shown in **Figure C9**. This is for the same model as used in **Section C6.1**.

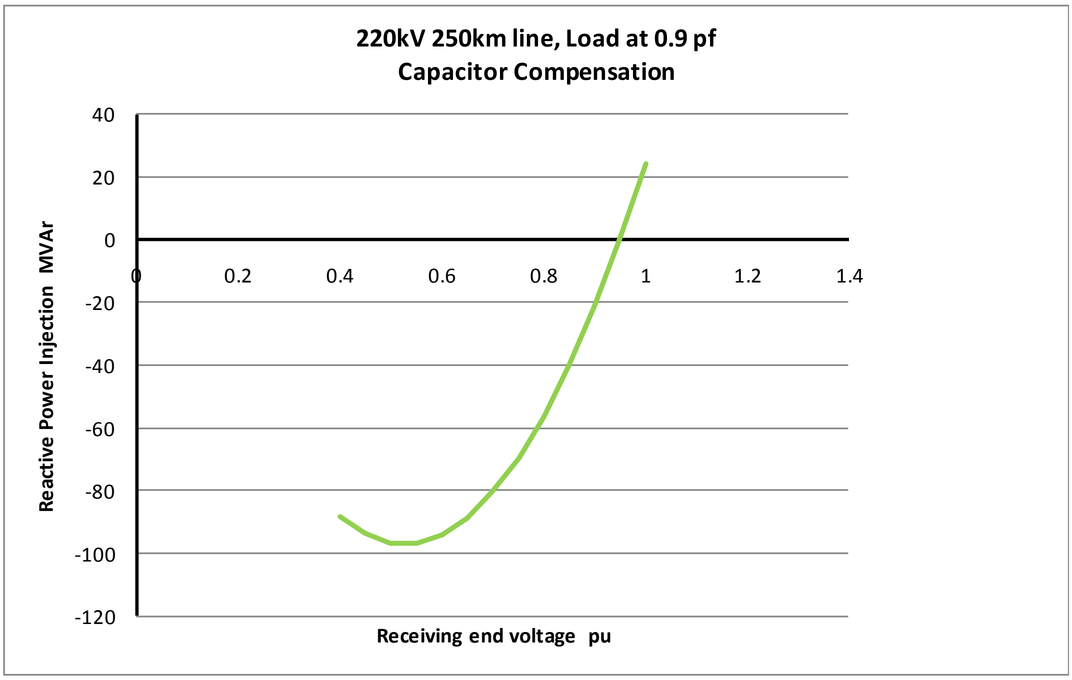


**Figure C9: VQ curve for single uncompensated line**

**Figure C9** represents a "base case" (zero-compensation). VQ curves for different levels of non-dynamic compensation are shown in **Table C4** and **Figure C10**.

**Table C4: Non-dynamic compensation levels**

| Case | Compensation MVAr | Load MW | Load MVAr | Compensation factor |
|---|---|---|---|---|
| Base case | 0 | 63.5 | 31.75 | 0 % |
| Case 1 | 50 | 118 | 59 | 42 % |
| Case 2 | 100 | 166 | 83 | 60 % |
| Case 3 | 200 | 247 | 123.5 | 81 % |
| Case 4 | 300 | 310 | 155 | 97 % |
| Case 5 | 500 | 397 | 198.5 | 126 % |

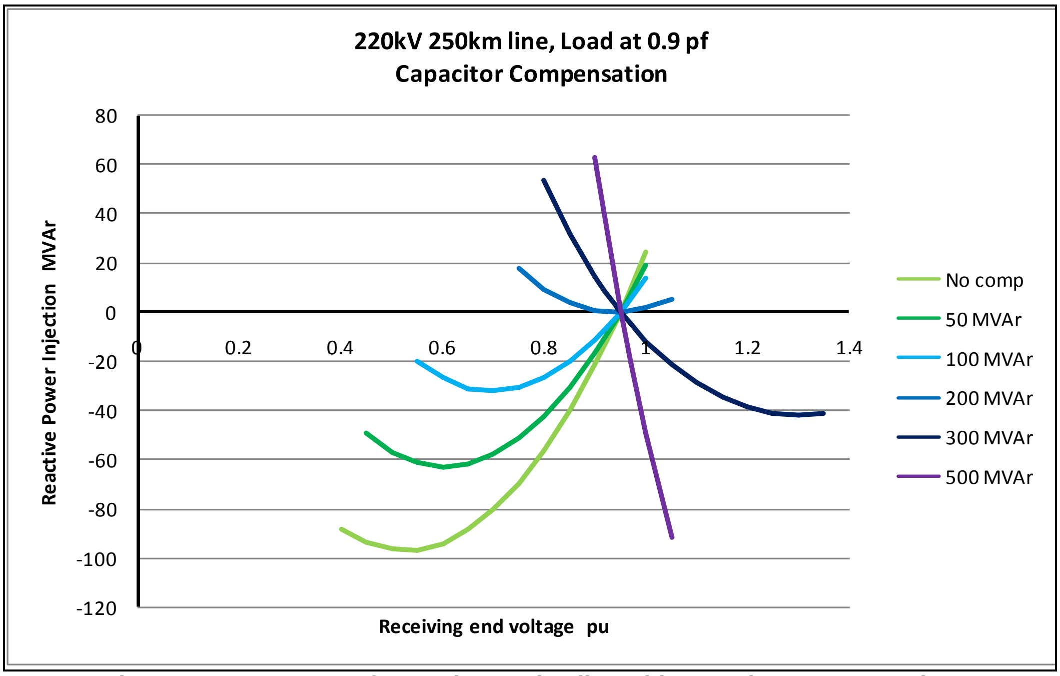


**Figure C10: VQ curves for 220 kV 250 km line with capacitor compensation**

The nose point of the 0, 50 MVAr, and 100 MVAr curves are significantly below 0.95 pu voltage, so for these levels of compensation, the system is stable.

The nose point for 200 MVAr is actually at 0.95 pu, which means the system is stable at that voltage, but unstable for lower voltages (the limiting case).

For 300 MVAr or 500 MVAr of compensation, the system operating point (0.95 pu) is well into the unstable region; the nose points for these curves (not shown for 500 MVAr) are well to the right of the operating point.

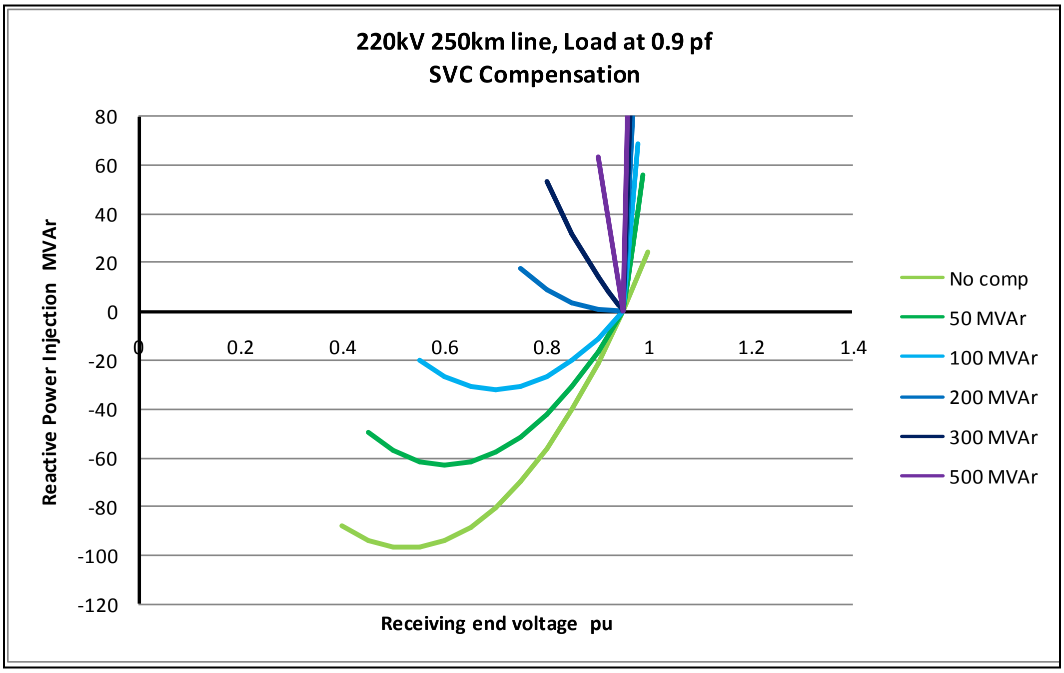


**Figure C11: VQ curves for 220 kV 250 km line with SVC compensation**

 

If the compensation in the model is provided by an SVC rather than a capacitor, voltages above 0.95 pu reflect the SVC's characteristic (and are near straight lines at slopes corresponding to the control slope of the SVC); below 0.95 pu the SVC acts as a capacitor, and the curves are identical to those shown in **Figure C10**. Curves passing through operating point thus have a non-linearity at that point, equivalent to the "knee point" in the PV curves. This is shown in **Figure C11**.

Of particular note is that, unlike as in **Figure C10**, the curves for more than 200 MVAr compensation are now stable for voltages above 0.95 pu (but below this voltage have a steeply negative slope, so are highly unstable).

C6.3 Reactive reserve

**Figure C12** illustrates the concept of reactive reserve.

**Figure C12** is the same as **Figure C11**, except that acceptable (green), marginal (yellow), and undesirable (red) zones have been highlighted. The x-axis scale has been expanded for clarity.

The green zone is bounded by the locus of nose points. The yellow zone is somewhat arbitrary, but necessary to separate the green and red zones.

Points below the x-axis are not within the normal operating region (they are below 0.95 pu), but they are points to which the system would move in the event that the reactive load increases (and no action is taken). For example, consider the system with 50 MVAr of compensation. If the system is operating at 0.95 pu and the reactive load is increased by about 60 MVArs, the system voltage falls to about 0.68 pu, but remains stable (this point is in the green zone).

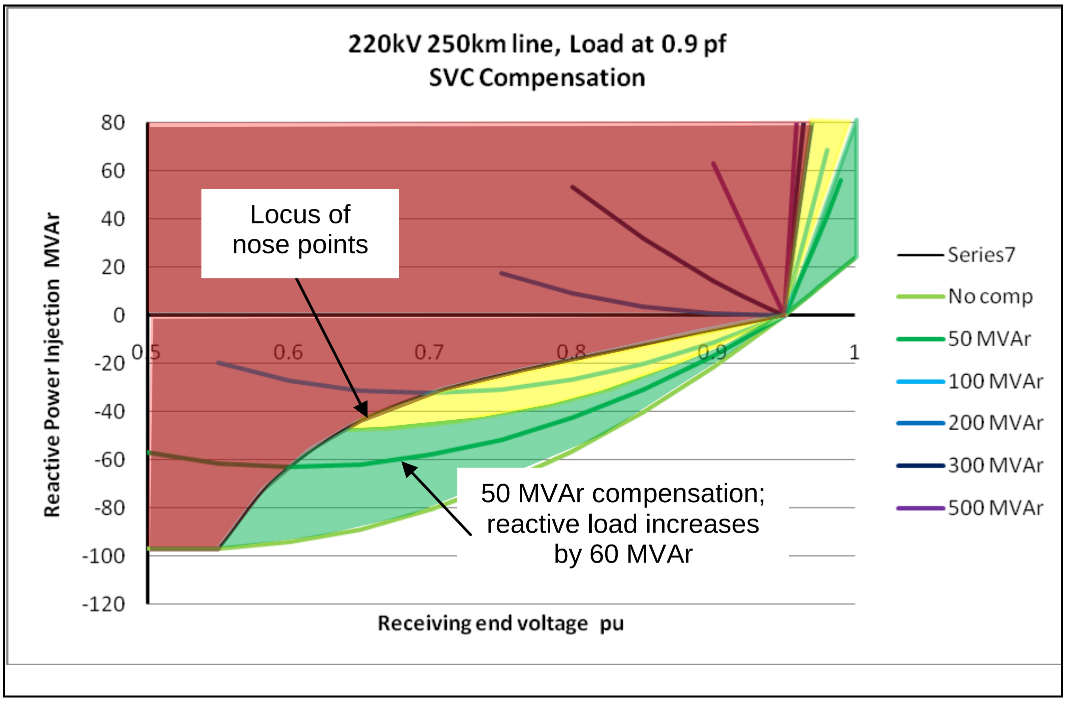


**Figure C12: VQ curves showing acceptable, marginal, and undesirable zones**

C6.4 Code requirements

The above analysis leads to the code requirements that a system's VQ curve must have a portion below the x-axis and that at 0.9 pu the curve must have a positive slope.

To be consistent with the criteria for the PQ analysis, a 5 % demand increase is applied.

There will be parts of the grid that are inconsistent with these criteria for historical and other reasons. These will be examined as part of grid planning, taking into account the requirements of this Transmission Code.

C6.5 Independent reviews

Internationally, debate continues over the best method of determining reactive compensation limits. Utility standards, in describing PV and VQ analysis, invariable show smooth curves (often stylised) for well-conditioned systems, and the means of analysing ill-conditioned systems is unresolved, apart from recommending dynamic studies that are inherently limited by the inaccuracies of demand modelling, load forecasting, generation locations, etc.

Standards often propose resolving these difficulties in terms of reactive margin, but this does not address the planning and operating of ill-conditioned systems in which voltage instability can occur rapidly and without warning.

In contrast, Transpower has based its analysis on real models, rather than just generic principles and has sought critical independent assessment of its analysis procedures.

To verify its PV and VQ analysis procedure, Transpower commissioned two separate, independent reviews of its modelling of the Upper South Island. These reviews were conducted by Pterra and EPRI.

The reviews confirmed Transpower's analysis and largely agreed with each other in terms of how much the transmission capacity into Christchurch could be augmented using reactive compensation. Pterra described Transpower's analysis as "thorough and technically correct and consistent with international planning practice" (p.32).

Pterra noted that (in the USI analysis) the PV/VQ and dynamic analyses produced similar maximum possible power transfer results (the PV/VQ analysis being more conservative), but that the dynamic analysis better differentiated between compensation options.
Both reviews commented on the system operator's ability to monitor and control the system, particularly at high levels of compensation, when the system stability becomes increasingly sensitive to small changes in demand. Pterra warned that a high nose point on the PV curve limits the "observability" of the system; it noted that reactive reserve is the most commonly used indicator of system status, and recommended that this be determined not from VQ curves but from dynamic simulation.

In addition, KEMA Limited has assisted with further modelling and has overseen the development of this Code.

C6.6 Further analysis

Following satisfactory assessments of the static analysis, additional specific evidence must be considered to guard against:

- Overloading of equipment
- Damage to equipment
- Cascade failures
- Blackouts or brownouts over a wide area
- Protection co-ordination and stability
- Defence measures and SPS interaction

C6.7 Power system analysis − dynamic

In addition to static analysis, marginal cases are subjected to dynamic (transient) analysis.

Transpower has a dynamic analysis procedure. The procedure assumes an initially intact network operating under certain conditions, including a load with a specified inductive component. Then, an outage is assumed of a single item of transmission equipment (with and without a fault), followed by a recovery phase. During the outage and the recover phase the system voltage must adhere to recovery criteria specified in the Grid Planning Guidelines.

The Code contains the criteria, contained within the Grid Planning Guidelines, for recovery of the system following the loss of an element without it being faulty. This gives an indication of the robustness of the system and increases confidence in the PV and VQ analyses.

## C7 Conclusions

The criteria developed by Transpower and set out in this document have drawn on international experience and generic modelling set in the context of the New Zealand power system. They have been developed in conjunction with key New Zealand stakeholders and have been endorsed by independent reviewers. Transpower believes they provide a sound framework for developing the New Zealand power system.