Transmission Code of Practice

TRANSPOWER APPROVED STANDARD

Implementation date: June 2011

PREFACE

This Transmission Code of Practice (**TCOP**) sets out Transpower's application of a set of technical planning requirements to ensure the design and development of the **grid** is in accordance with **Good Electricity Industry Practice**.

The **TCOP** is owned by Transpower's Chief Engineer. The principal audience for the **TCOP** is technical managers within Transpower and the wider Electricity Industry. It is designed as a "living" document that will be reviewed, updated and reissued as required.

Keywords
Transmission Code of Practice (**TCOP**)

References

The following documents are referred to in this Code of Practice

- Transmission Code of Practice Technical Commentary

CONTACT

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1. PURPOSE

Good Electricity Industry Practice (GEIP) is a fundamental component in Transpower operating, maintaining and planning the transmission system. This document outlines how GEIP is used to support the way the grid is planned.

The Transmission Code of Practice (**TCOP**) is a statement of certain transmission design practices and judgements that Transpower considers reflect **Good Electricity Industry Practice**. 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.

2. INTRODUCTION

2.1 GEIP and the Electricity Industry Participation Code

GEIP is a key planning criterion under the Electricity Industry Participation Code and the Commerce Commission's Capex Input Methodology. It is defined as "*in relation to transmission, means the exercise of that degree of skill, diligence, prudence, foresight and economic management, as determined by reference to good international practice, which would reasonably be expected from a skilled and experienced asset owner engaged in the management of a transmission network under conditions comparable to those applicable to the grid consistent with applicable law, safety and environmental protection. The determination is to take into account factors such as the relative size, duty, age and technological status of the relevant transmission network and the applicable law*". .

When a need is identified to replace or enhance an element of the transmission grid, an investigation process is followed to determine an investment proposal.

A long list of options is developed initially, which includes as many potential solutions as possible.

This long list is modified to a short list of options which then undergoes a cost benefit analysis to determine a preferred option. A range of criteria are used to filter the long list, including **GEIP**. Only options which conform with **GEIP** are considered for short listing.

2.2 Objective of the Transmission Code of Practice (TCOP)

While **GEIP** can be difficult to identify, this does not detract from its importance as a planning criterion under the Electricity Industry Participation Code.

The **TCOP** captures, in an open and transparent way, the practices and judgements that Transpower considers reflect **GEIP** in relation to the matters covered by the **TCOP**. This includes the degree of skill, diligence, foresight and economic management required in the effective planning and management of a transmission network. It takes into account factors such as the size, duty, age and technological status of the transmission **assets** and network, and references good international practice.

The **TCOP** has been developed to assist with the efficient and prudent assessment of projects and investment options. It reflects the requirement for an economic assessment that recognises cost efficient practices for planning solutions and it strengthens the linkage between transmission planning and **GEIP** through a systematic and documented approach.

The **TCOP** 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 TCOP

The **TCOP** is "principle focused" and outlines a set of technical planning considerations that Transpower applies when invoking GEIP arguments in the Grid Upgrade Plans to ensure that the transmission grid as a whole remains resilient and fit for purpose. The supporting information for each of the key technical areas can be found in the companion document – "Transmission Code of Practice (TCOP) Technical Commentary".

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

Transpower welcomes discussion about the content of the **TCOP** and views such discussion as an important part of the **TCOP**'s evolution. Transpower does not intend to close off debate about the correctness of a statement of **GEIP** by way of the TCOP, rather it contemplates that the **TCOP** is a living document which will be updated and expanded over time.

Further development of the TCOP will include:

- Additional matters Transpower considers ought to be included in the **TCOP**;
- 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.

2.4 Application of the TCOP

The **TCOP** is intended to provide guidance on how GEIP is applied in the design of the transmission system, through the development and application of standardised planning principles. Where circumstances arise that have a clear and justifiable reason for considering alternative options which deviate from those in the TCOP, it is intended that the TCOP provide guidance on the approach and methodology Transpower will employ to assist in assessing those options, while continuing to act in accordance with **GEIP**.

2.5 Structure of the TCOP

The **TCOP** draws together, in one location, the planning considerations for key technical areas which have been selected and developed through a collaborative and transparent engagement process with industry and end-use consumers. The technical areas currently covered by the **TCOP** are:

- Special Protection Schemes;
- Planned Outages;
- Reactive Compensation;
- Grid Connection;
- Substation Configuration; and
- Fault Levels.

Each technical area contains the following information:

- Introduction – General description of the topic;
- Planning Principles – What are the principles that are required to be considered in planning, and
- Outcomes – What are the expected outcomes (if any?).

2.6 Planning Principles

Each section in the **TCOP** outlines the planning principles including any applicable planning assumptions that need to be considered. The planning principles are guided by the following:

- Legal and Statutory requirements – including the Electricity Industry Act 2010, Electricity Industry Participation Code 2010 and the Health and Safety Act 1992;
- New Zealand and International Electricity Industry Standards;
- Good International Practice, such as that adopted or recognised by international agencies such as CIGRE and/or IEEE, and
- Engagement with the industry and customers.

Planning principles take into account safety, capacity, availability, operation, reliability, cost and power quality requirements.

Transpower develops and maintains the skills and competencies of its workforce as appropriate to plan and develop the grid.

Transpower adopts standard approaches when possible to ensure the **grid** is built and maintained in a consistent manner.

Transpower utilises technical and economic modelling as appropriate to plan and develop the **grid**.

Transpower makes available a range of acceptable standard solutions.

Where a solution is not typical or considered “standard”, Transpower will assess the proposed alternative against the same design principles that were used in the development of the standard solutions including the required performance criteria.

3. DEFINITIONS

Terms used in the Transmission Code of Practice (**TCOP**) have the same meaning as given to them in the Electricity Industry Participation Code, except those terms expressly defined in this **TCOP**.

Terms not defined in the Electricity Industry Participation Code (shown in bold) have the following meanings, unless the context requires otherwise.

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

CF = 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 unit**s (unless these are the subject of long term service contracts).

“**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 equipment to operate as designed. When used in context of SPS it means 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 has 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.

“**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**.

"**TCOP**" means the Transmission Code of Practice.

4. SPECIAL PROTECTION SCHEMES

4.1 Introduction

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

SPS' have been used in the New Zealand power system for many years, such as, Automatic Under Frequency Load Shedding (AUFLS), and generation runback schemes.

SPS' 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 **TCOP**, SPS' 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 to manage security during transmission upgrade projects 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 **TCOP** 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 Planning principles

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

The operation of an SPS is to follow the principles of managing the transmission system in real time, and is to automate power system operation actions where specific conditions require a faster response than a manual response is capable of providing.

In a similar manner to any other significant investment or change in transmission assets, 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 principles apply to SPS schemes:

- SPS' are to be designed, maintained, and operated to the same standard as other protection apparatus while recognising the complexity and consequences of inadvertent operation;
- SPS' are to have sufficient redundancy to reduce the likelihood of failure to an acceptable level (this may require duplicate hardware and communication with route diversity to the extent possible);
- 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;
- Detection and control should be at the local site where possible, rather than relying on complicated signalling across multiple sites;
- The SPS:
    - Must operate in a manner consistent with the real time actions the System Operator would take, had the operation been undertaken manually;
    - 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 is to be satisfactorily co-ordinated;
    - Is understood and predictable beyond normal planning or operating standards;
    - Is not to impact on normal governor action at generation sites, unless agreed and coordinated with the generator(s);
    - action is to be in one direction, resulting in either a decrease in generation or a reduction in the loading of the transmission system, even if the SPS is inadvertently operated;
    - 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 only use SCADA for control under very exceptional circumstances;
    - Initiating signals (which should be duplicated) may be derived from protection systems, and
    - Is not to require frequent (routine) manual intervention (e.g. re-configuration of the SPS, arming/disarming).
- For schemes involving complex generation interaction, alternative schemes such as Automatic Generation Control (AGC) or system reconfiguration schemes (e.g. bus splitting) are to be considered in preference to using SPS'.
- Interaction with governor action at a single station may be considered, provided governor action (in particular governor response to frequency changes due to the SPS) at the station and within the transmission network is taken into consideration.

4.2.1 Risk assessment

A risk assessment is to be undertaken when acceptability is not clear, to determine the probability of failure and the consequence of failure. Where the application and implementation of an SPS is similar to a traditional protection scheme (circuit or transformer protection), a separate risk assessment is not required.

SPS that involve complex system interaction, or operate over a wide area, have 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.

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.

4.3 Outcomes

Application 2 SPS' are only to be implemented for the following purposes:

- If they are approved under a Grid Upgrade Plan or a Customer Agreement;
- Temporarily as part of an approved Grid Upgrade Project to manage security of supply
- 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.

Application 2 SPS' must satisfy the principles specified in this **TCOP** and operate correctly thereby minimising risk.

Proper implementation of modifications to the power system require very careful planning, analysis, design, liaison, development, testing and commissioning.

Power System assets with a high probability of **failure** or with large system impacts (e.g. cascade **failure**) are not desirable and therefore operation must be such that these are not implemented.

5. PLANNED OUTAGES

5.1 Introduction

Planned outages are the removal of assets from service for **planned maintenance** activities.

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 de-energised to allow the work to be carried out safely. Some outages require dependent outages of other **assets** to allow the first outage to proceed.

Planned outages can reduce security and reliability on the **grid**. Some outages may require load management or certain generation being available to maintain security of supply during the outage. Some outages are subject to agreements with connected parties for different levels of security and quality during outages.

This **TCOP** makes provision for **outage window**s for maintenance work and not for **major project**s. Planning for **major project**s is to be such that appropriate outages are available or alternative project implementation methods are adopted.

The **Outage Protocol** describes the process by which outages occur, but does not ensure sufficient planned **outage window**s can be made available.

5.2 Planning Principles

Grid planning is to 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**.

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.

Outage planning is to allow for multiple **dependent outages**

Maintenance outage windows are not to be assumed to be sacrificed in order to execute **major project**s.

Outage planning is not to assume pre-contingent load shedding to enable the **maintenance outage**.

5.2.1 System state during maintenance outages

During a **maintenance 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).

Load management (e.g. ripple control of water heating) or requiring generation to be available is acceptable.

5.2.2 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.

5.3 Outcomes

In planning the grid Transpower should seek to ensure that, if possible, sufficient transmission investment is proposed to allow for:

- 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 50 % of the year.

If these criteria are unable to be satisfied in a timely manner, then transmission investment may be brought forward subject to economic considerations.

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.

This **TCOP** provides guidance on the analysis and issues to be considered when considering investment options with high levels of reactive compensation.

6.2 Planning Principles

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

Any automatic control requires detailed engineering analysis. Automatic control between more than two physically separated substations is to be subject to detailed engineering and economic analysis.

The requirement for reactive support is dependent on the evolving nature of the load. Increasing proportions of motor loads and heat pumps influence how the power system responds to major faults.

6.2.1 Power system analysis – static

PV analysis

PV analysis can be carried out for each **importing group** in which the level of compensation is considered marginal. Transpower limits the use of PV analysis to operations. In the longer term, Transpower considers VQ analysis a more appropriate methodology for static power system analysis.

At maximum demand and for intact network conditions, the nose or collapse point on the PV curve at any point within the **importing group** 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 allows the capability to deliver maximum demand to the **importing group** a 5 % increase in demand to be supplied without crossing the nose point of the PV curve for expected system states.

VQ analysis

VQ analysis can 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 should:

- 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.

6.2.2 Power system analysis – dynamic

Dynamic analysis is to be performed if during loadflow analysis non-convergence is suspected due to voltage stability issues. Load flow analysis should consider operation to at least 0.9 pu voltage under first contingency situations. Dynamic analysis should also be undertaken whenever transient and dynamic stability issues are likely due to the proximity of electrical machines, generators and fast acting control systems.

The following criteria are to 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.

and,

- 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.

6.3 Outcomes

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 factor**s 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.

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

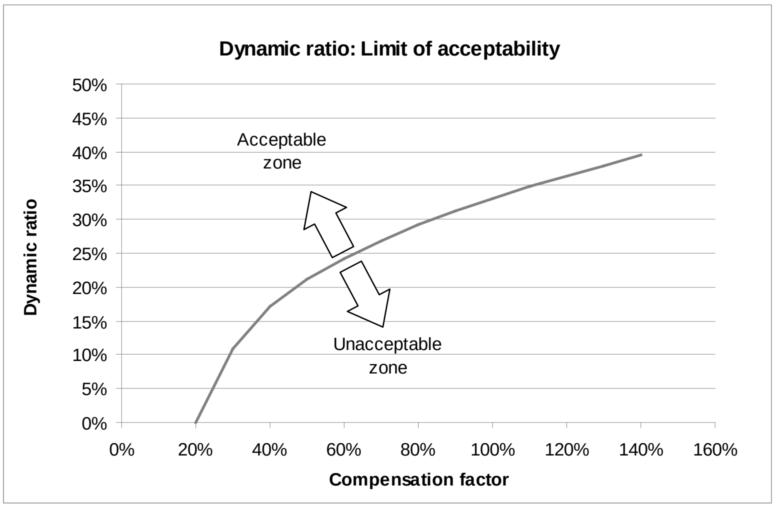

Figure 1: Dynamic ratio

7. GRID CONNECTION

7.1 Introduction

A **grid** point of connection is the manner in which physical **assets** are arranged for a customer to inject power into (Grid Injection Point – GIP) or to **offtake** power from (Grid Exit Point – GXP) the power system.

At various times generators and network companies wish to make new connections to existing Transpower **assets** or create new ones. These connections can be of various capacities, voltages and configurations.

This section provides general guidance on the preferred forms of connecting to the **Grid.**

The configuration of new connections is based on an assessment of technical, operational, commercial, legal and economic requirements.

7.2 Planning Principles

A new **grid** connection needs to account for a number of many interrelated, performance, operational and technical matters. These include:

- Proposed protection schemes complexity and reliability;
- Communications infrastructure;
- Comparative size and importance of through transmission;
- Impacts of faults on the network and other customers;
- Type and magnitude of the load at each of the connections and the through transmission, their compatibility and differing performance expectations;
- Market implications of the proposed connection and possible constraints it may impose;
- Ability to gain outages for maintenance;
- Capital and operational costs, and
- Fleet management.

Transpower assesses the impact any proposed connection has on the power system and the system's ability to accommodate it.

Connections are designed in a manner to enable the deployment of a protection system which:

- Utilise Transpower's existing standard protection designs;
- Utilise relay types acceptable to Transpower;
- Take into account the existing protection systems for that part of the transmission network which will be impacted by the proposed connection;
- Can be operated in a manner that provides agreed levels of performance for the connection and for the power system as a whole, and
- Can provide a level of performance, security, and maintainability which is consistent with **Good Electricity Industry Practice**.

Connections, including any augmentation or extension to the existing transmission network are to be designed in a manner which:

- Is compatible with the existing transmission system;
- Does not hinder the foreseeable future development of the transmission system, and
- Considers access to the transmission system by other users.

Connections are to be designed in a manner which:

- Allows the associated primary plant to be operated with minimal impact on other transmission circuits and customers;
- Allows the associated primary plant to be maintained and outages obtained with minimal impact on other transmission circuits and customers;
- Takes account of the electrical and physical location of the connection in relation to the rest of the transmission system around it; and
- Allows Transpower to use reasonable endeavours to accommodate the wishes of third parties with regards to the impact of the proposed connection while not indirectly and unduly hindering present or probable future access to the transmission system by other transmission network users.

7.3 Outcomes

New connections, including any augmentation or extension to the transmission network should:

- Not materially affect the power system security or reliability;
- Not materially degrade the quality of network service to other network users;
- Consider future access by other network users;
- Plan for reasonable and foreseeable eventualities, and
- Be consistent with **Good Electricity Industry Practice**.

Transpower's Grid Connection Standard (TP.XX.AA.01)[1] contains standard grid connection configurations which are considered to be in accordance with Good Electricity Industry Practice (GEIP), meet the Grid Reliability Standard (GRS) and are the initial substation offerings that Transpower would offer to any Generator, Network Company or any other party wishing to connect to the grid.

Examples of typical "standard" grid connections using common situations are detailed in the Transmission Code of Practice Technical Commentary document.

[1] Being developed

8. SUBSTATION CONFIGURATION

8.1 Introduction

A substation configuration is the manner in which physical **assets** are arranged to enable the required system performance and customer performance expectations to be met.

A substation's configuration can include some or all of the following components:

- Circuits, overhead lines or cables;
- Busbars;
- Transformers;
- Circuit Breakers;
- Instrument Transformers, and
- Disconnectors and Earthing Switches.

8.2 Planning Principles

New substation configurations, depending on the magnitude and importance of the connection generation and/or load, are to take into consideration:

- Operational flexibility;
- System safety;
- Reliability;
- Availability;
- Impact on power system frequency when a contingent event occurs
- Operational costs
- System control, and
- Capital and lifetime costs.

Substation configurations are to be designed to provide operational flexibility by:

- Having duplicate circuits and components where appropriate;
- Endeavouring to minimise the disconnection of customers and generators due to faults within the system or system components;
- Having more bus sections installed in comparison to the number of circuits where there is a requirement to limit the fault level, and
- Ensuring the configuration is designed in a manner which clears faults (occurring on circuits connected to a substation or within the substation itself) quickly by as small a number of circuit breakers as possible, to limit disturbances in the network and maintain non-faulted circuit circuits in service.
- Substation configurations are also to be designed in a manner which takes into consideration:
- The reliability and availability of the type of equipment to be used;
- The manner in which the equipment is installed;
- The environment;
- The substation configuration and any secondary systems, and
- Particular care is taken in the design, installation and testing of secondary systems where there are multiple interfaces and interconnections in a given system of substation and substation components.

The substation control scheme is to be designed to allow the safe, obvious, effective and efficient performance of normal and abnormal operational switching, including but not limited to busbar selection, isolation, and earthing for all operation and maintenance

8.3 Outcomes

Transpower's Substation Standard (TP.XX.BB.01)[2] contains standard substation configurations which are considered to be in accordance with Good Electricity Industry Practice (GEIP), meets the Grid Reliability Standard (GRS) and are the initial substation offerings that Transpower would offer to any Generator, Network Company or any other party wishing a substation connection.

Examples of typical "standard" substation configurations using common situations are detailed in the Transmission Code of Practice Technical Commentary. These examples, where possible, depict the following:

- Single solid bus substations for HV/MV installations, where the design criteria includes little security against busbar faults, minimal switching flexibility and fairly extensive outages for busbar and bus side disconnector maintenance is possible;
- Single sectionalised bus arrangements, where the design criteria is similar to the single solid bus except for the inclusion of a bus section breaker that provides some protection against bus faults and some flexibility for switching and maintenance;
- Double bus arrangements for substations where a higher level of supply security is required. Particularly useful for interconnected power networks where switching flexibility is important and multiple supply points are available;
- Double circuit breaker arrangements for substations handling larger amounts of power, such as large power stations, and/or major urban or switching stations, where the design criteria may also include predominantly radial circuits; and
- Circuit breaker and a half for substations handling larger amounts of power and where the importance of through transmission is significant.

[2] Being developed

9. FAULT LEVELS

9.1 Introduction

The monitoring and management of fault levels on the transmission system is important for all parties connected to the grid, including lines companies, generators, direct connect customers and Transpower, as any of these can be impacted by changes to fault levels.

Therefore adequate information is required to ensure assets are appropriately designed to withstand faults on the power system.

9.2 Planning Principles

Transpower adopts the IEC 60909 calculation methodology for 10 year fault level forecasts, which makes provision for the fault voltage at the faulted bus to be specified.

As the 220 kV and 110 kV network voltages can be operated at 1.1p.u, this is the maximum voltage chosen in the first instance.

For more accurate analysis forecast fault levels are determined from credible load flow solutions that reflect operational realities. If forecast fault levels begin to approach 10 % of the design limits of installed equipment, then a more in depth analysis will be carried out.

As there will be mixture of 3-cycle and 5-cycle interrupt circuit breakers installed in the power system presently, consideration is also given to fault duration and installed equipment capability.

Management of fault levels is to be carried out in accordance with the Benchmark Agreements and the Connection Code.

9.3 Outcomes

In addition to fault level design studies for new transmission assets, Transpower monitors fault levels on the transmission system on an ongoing basis and publishes a 10 year fault level forecast in accordance with the Electricity Industry Participation Code 2010.

Transpower also publishes the following information in the Annual Planning Report, the

- Existing and 10 year forecast fault levels per Grid Exit Point; and
- Transpower nominated design capability rating per Grid Exit Point for existing sites;

Transpower will specify the new equipment ratings required for existing and new sites[3]. Where fault levels have the potential to adversely affect connected parties, Transpower will engage with that connected party to develop the most appropriate solution (including both technical and economic factors).

A change to Transpower's specified capability ratings are to be discussed with affected connected parties prior to implementation.

[3] Transpower's 10 year forecast of maximum fault levels includes an assessment of committed transmission and generation projects known at the time of publication. The forecast fault levels may change for any number of reasons outside Transpower's control, such as new generation or additional supply transformers. Transpower encourages asset owners to discuss with us for detailed information on maximum fault levels at specific sites relating to new equipment.