POWER NETWORKS

NETWORK TECHNICAL CODE

and

NETWORK PLANNING CRITERIA

Version 3.1

December 2013
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Introduction

Transmission and distribution networks owned by Power and Water cover the major centres of the Northern Territory. The legislated Third Party Access regime gives rights to private Generators and load customers to use the networks to enable contracted trade between Generator Users and Customer Users.

Structure of this document

This document comprises the following parts:

Part A  The legislative requirements that apply to Power and Water Networks and to customers seeking access to its regulated electrical networks.

Part B  The Network Technical Code sets out technical requirements designed to ensure that the network and the customer installations and equipment connected to the network may be operated and maintained in a secure and reliable manner.

Part C  The Network Planning Criteria are designed to ensure that new loads and Generators connected to the network do not compromise the security and reliability of supply to all network Users.

Part D  Attachments, including, amongst other things, a Glossary of terms and Schedules of the information that is required to be provided by customers seeking to connect to Power and Water’s regulated networks.


Document nomenclature

Terms defined in the Glossary of this document are italicised.

Explanatory and contextual material is included in boxed sections that do not form part of the Network Technical Code or Network Planning Criteria.

Document amendment

This document is subject to amendment in accordance with the legislative provisions and users of the document are advised to obtain the current version from the Manager Regulation, Pricing and Economic Analysis, at the following address:

Power and Water Corporation
Level 7, Mitchell Centre, Darwin NT 0800
GPO Box 1921. Darwin NT 0801
Telephone: (08) 8985 8431
Facsimile: (08) 8923 9527

The document is also available from Power and Water’s Internet site at the following address: http://www.powerwater.com.au/.
Part A  Legislative requirements

This document is prepared pursuant to the Northern Territory *Electricity Networks (Third Party Access) Act* (TPA Act), as in force at 1 August 2012.

The Northern Territory Electricity Networks (Third Party Access) Code (Network Access Code) is established in Part 2 of the TPA Act and the accompanying Schedule. The Network Access Code sets out:

(a) The terms and conditions under which access to an *electricity network* is to be granted to third party *Users* and the associated obligations both on the *network provider* and on *network Users*;

(b) The framework within which *Access Agreements* are to be negotiated and implemented; and

(c) The mechanism for resolving access disputes.

Clause 9, sub clause (2) of the Network Access Code requires the *network provider* to prepare and make publicly available a *Network Technical Code* and *Network Planning Criteria*.

Clause 30, sub clause (2) of the Network Access Code states that all *network Users* shall comply with the *Network Technical Code* regarding *connection* to and use of the *electricity network*.
**Network Technical Code**

Schedule 1, clause 1 of the Network Access Code lists the requirements of the *Network Technical Code*. This *Network Technical Code* sets out the following matters. The relevant clauses of this document are also referenced in Table 1.

**Table 1 – Requirements of the Network Technical Code**

<table>
<thead>
<tr>
<th>Code requirement</th>
<th>clause</th>
</tr>
</thead>
<tbody>
<tr>
<td>(a) performance standards in respect of service quality parameters in relation to the <em>electricity network</em>;</td>
<td>2</td>
</tr>
<tr>
<td>(b) the technical requirements that apply to the design or operation of <em>plant</em> or equipment <em>connected</em> to the <em>electricity network</em>;</td>
<td>3</td>
</tr>
<tr>
<td>(c) requirements relating to the operation of the <em>electricity network</em> (including the operation of the network in emergency situations);</td>
<td>4</td>
</tr>
<tr>
<td>(d) obligations to test <em>plant</em> or equipment in order to demonstrate compliance with the <em>Network Technical Code</em>;</td>
<td>5.1</td>
</tr>
<tr>
<td>(e) procedures that apply if the network provider believes that an item of <em>plant</em> or equipment does not comply with the requirements of the <em>Network Technical Code</em>;</td>
<td>5.6</td>
</tr>
<tr>
<td>(f) requirements relating to the inspection of <em>plant</em> or equipment <em>connected</em> to the <em>electricity network</em>;</td>
<td>5.7</td>
</tr>
<tr>
<td>(g) requirements that relate to control and protection settings for <em>plant</em> or equipment <em>connected</em> to the <em>electricity network</em>;</td>
<td>6</td>
</tr>
<tr>
<td>(h) procedures that apply in the case of commissioning and testing of new <em>plant</em> or equipment <em>connected</em> to the <em>electricity network</em>;</td>
<td>7</td>
</tr>
<tr>
<td>(i) aside from matters appropriately dealt with in the <em>System Control Technical Code</em>, procedures that apply to the disconnection and reconnection of <em>plant</em> or equipment from the <em>electricity network</em>;</td>
<td>8</td>
</tr>
<tr>
<td>(j) aside from matters appropriately dealt with in the <em>System Control Technical Code</em>, procedures relating to the operation of <em>Generating Units connected</em> to the <em>electricity network</em> (including the giving of <em>dispatch</em> instructions and compliance with those instructions);</td>
<td>9</td>
</tr>
<tr>
<td>(k) <em>metering</em> requirements in relation to <em>connections</em>; and</td>
<td>10</td>
</tr>
<tr>
<td>(l) the information required to be provided to the <em>Network Operator</em> in relation to the operation of <em>plant</em> or equipment <em>connected</em> to the <em>electricity network</em> at a <em>connection</em> and how and when that information is to be provided.</td>
<td>11</td>
</tr>
</tbody>
</table>
Network Planning Criteria

Schedule 1, clause 2 of the Network Access Code lists the matters that shall be contained in the Network Planning Criteria. The relevant clauses of this document are referenced in Table 2.

Table 2 – Requirements of the Network Planning Criteria

<table>
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<tr>
<th>Planning criterion</th>
<th>clause</th>
</tr>
</thead>
<tbody>
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<td>(a) contingency criteria;</td>
<td>14.6</td>
</tr>
<tr>
<td>(b) steady-state criteria including:</td>
<td>15</td>
</tr>
<tr>
<td>(i) voltage limits;</td>
<td>15.2</td>
</tr>
<tr>
<td>(ii) thermal rating criteria; and</td>
<td>15.3</td>
</tr>
<tr>
<td>(iii) fault rating criteria;</td>
<td>15.4</td>
</tr>
<tr>
<td>(c) stability criteria including:</td>
<td>16</td>
</tr>
<tr>
<td>(i) transient stability criteria; and</td>
<td>16.1</td>
</tr>
<tr>
<td>(ii) voltage stability criteria;</td>
<td>16.2</td>
</tr>
<tr>
<td>(d) quality of supply criteria including:</td>
<td>17</td>
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<tr>
<td>(i) voltage fluctuation criteria;</td>
<td>17.1</td>
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<tr>
<td>(ii) harmonic voltage criteria;</td>
<td>17.2</td>
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<td>(iii) harmonic current criteria;</td>
<td>17.2</td>
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<td>(iv) voltage unbalance criteria; and</td>
<td>17.3</td>
</tr>
<tr>
<td>(v) electro-magnetic interference criteria;</td>
<td>17.4</td>
</tr>
<tr>
<td>(e) construction standards criteria; and</td>
<td>18</td>
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<tr>
<td>(f) environmental criteria.</td>
<td>19</td>
</tr>
</tbody>
</table>
Part B - Network Technical Code

1 Application

In this Network Technical Code (Code), unless otherwise stated, a reference to Network Operator or Power System Controller refers to the appropriate business unit of the Power and Water Corporation.

1.1 Persons to whom the Code applies

(a) Power and Water Corporation in its role as the operator of the electricity network (Network Operator);

(b) Power and Water Corporation in its role as the Power System Controller;

(c) Every person who seeks access to spare capacity or new capacity or makes an Access Application in order to establish a connection or modify an existing connection; and

(d) Every person to whom access to the electricity network is made available (including, without limitation, the Power and Water Corporation in its role as a trader of electricity and every person with whom the Network Operator has entered into an Access Agreement).

1.2 Plant and equipment to which the Code applies

(a) Equipment installed in the Network Operator’s electricity networks; and

(b) Equipment installed by Users who are connected (either directly or indirectly) to the electricity networks.

1.3 Other documents

(a) This Code and the Network Planning Criteria at Part C shall be read in conjunction with the following Power and Water Corporation documents:

   (1) Service Rules;
   (2) Installation Rules;
   (3) Metering Manual;
   (4) Network Policies and Safe Working Procedures; and
   (5) System Control Technical Code.

1.4 Commencement

(a) Version 1 of the Code came into operation on 1 April 2000 ("Code commencement date").

(b) Amendment 2.0 of the Code was entitled the Network Connection Technical Code and was issued in April 2003.
(c) This Version 3.1 amendment of the Network Technical Code and Network Planning Criteria has been made in accordance with legislative provisions and takes effect from December 2013.

1.5 Interpretation

(a) In this Code, words and phrases are defined in Attachment 1 and have the meanings given to them in Attachment 1, unless the contrary intention appears.

(b) This Code shall be interpreted in accordance with the rules of interpretation set out in Attachment 2, unless the contrary intention appears.

1.5.1 Conflict between Technical Codes

(a) A conflict exists when there is a difference in substance or interpretation of the provisions contained in the Network Technical Code and provisions contained in the System Control Technical Code relating to power system:

(1) reliability;
(2) safety;
(3) security;
(4) operational issues; or
(5) procedures.

(b) In the event of a conflict and to the extent of any inconsistency, the provisions of the System Control Technical Code will prevail over the Network Technical Code.

(c) Where a conflict cannot be resolved under sub clause (b), consultations will take place between:

(1) the Power System Controller;
(2) the Network Operator; and
(3) any affected Users.

(d) An affected User is a User who provides evidence to the Power System Controller and in the opinion of the Power System Controller the evidence proves the User’s sufficient interest in consultations.

1.6 Dispute resolution

(a) Should a dispute arise between a User and the Network Operator concerning this Code, the Network Operator shall negotiate with the User to determine mutually acceptable agreed outcomes.

(b) If an agreement cannot be reached between these two parties, the Utilities Commissioner shall arbitrate the dispute.
1.7 Obligations

1.7.1 Obligations of the Network Operator

(a) The Network Operator shall comply with the power system performance and quality of supply standards:

(1) described in this Code; and

(2) in accordance with any Access Agreement with a User.

(b) The Network Operator shall:

(1) ensure that to the extent that a connection point relates to the electricity network, every arrangement for connection with a User complies with all relevant provisions of this Code;

(2) permit and participate in inspection and testing of facilities and equipment in accordance with clause 5.1;

(3) permit and participate in commissioning of facilities and equipment which is to be connected to its network in accordance with clause 7;

(4) advise a User with whom there is an Access Agreement of any expected interruption characteristics at a connection point on or with its network so that the User may make alternative arrangements for supply during such interruptions, including negotiating for an alternative or backup connection; and

(5) use its reasonable endeavours to ensure that modelling data used for planning, design and operational purposes is complete and accurate and order tests in accordance with clause 5.5 where there are reasonable grounds to question the validity of data.

(c) The Network Operator shall arrange for:

(1) management, maintenance and operation of the electricity network such that in the satisfactory operating state, electricity may be transferred continuously at a connection point up to the agreed capability;

(2) management, maintenance and operation of its network to minimise the number of interruptions to agreed capability at a connection point on or with that network by using good electricity industry practice; and

(3) restoration of the agreed capability as soon as reasonably practical following any interruption at a connection point on or with its network.

1.7.2 Obligations of Users

(a) All Users shall maintain and operate (or ensure their authorised representatives maintain and operate) all equipment that is part of their facilities in accordance with:

(1) relevant laws;
(2) the requirements of this Code; and
(3) good electricity industry practice and applicable Australian Standards.

(b) Each User shall:
(1) comply with the reasonable requirements of the Network Operator in respect of design requirements of equipment proposed to be connected to the network of the Network Operator in accordance with clause 3;
(2) permit and participate in inspection and testing of facilities and equipment in accordance with clause 5.1;
(3) permit and participate in commissioning of facilities and equipment which is to be connected to a network location for the first time in accordance with clause 7;
(4) operate facilities and equipment in accordance with any reasonable direction given by the Network Operator and Power System Controller; and
(5) give notice of intended voluntary disconnection in accordance with clause 8.

1.7.3 Obligations of Generator Users
(a) A Generator User shall comply at all times with applicable requirements and conditions of connection for Generation Units:
   (1) as set out in clauses 3.2 and 3.3; and
   (2) in accordance with any Access Agreement with the Network Operator.

1.7.4 Obligations of Generator Users with Small Generators
(a) A Generator User with a Small Generator shall comply at all times with applicable requirements and conditions of connection for Small Generation Units:
   (1) as set out in clauses 3.2 and 3.4; and
   (2) in accordance with any Access Agreement with the Network Operator.

1.7.5 Obligations of Users with Small Inverter Energy Systems
(a) A User with a Small Inverter Energy System shall comply at all times with applicable requirements and conditions of connection for Small Inverter Energy Systems:
   (1) as set out in clauses 3.2 and 3.5; and
   (2) in accordance with any Access Agreement with the Network Operator.
1.7.6 Obligations of Users with loads

(a) Each User with a load shall ensure that all facilities which are owned, operated or controlled by it and are associated with a connection point at all times comply with applicable requirements and conditions of connection for loads:

(1) as set out in clauses 3.2 and 3.6; and

(2) in accordance with any Access Agreement with the Network Operator.

1.8 Variations and exemptions from the Code

(a) Various clauses throughout this Code permit variations or exemptions from Code requirements to be granted to a User by reference to terms that include:

(1) the requirements may be varied, but only with the agreement of the Network Operator;

(2) unless otherwise agreed by the Network Operator;

(3) unless otherwise agreed; and

(4) except where specifically varied in an Access Agreement.

(b) In all cases the Network Operator will notify in writing any such variation or exemption to Users.

1.9 Amendments to the Code

(a) Any System Participant may propose an amendment to the Code.

(b) A proposal to amend the Code shall be made in writing by the System Participant to the Network Operator and shall be accompanied by:

(1) the reasons for the proposed amendment to the Code; and

(2) an explanation of the effect on System Participants of the proposed amendment to the Code.

(c) The Network Operator shall review the proposed amendment to the Code and within 30 days advise the System Participant or electricity entity:

(1) whether the proposed amendment to the Code is accepted or rejected; and

(2) the reasons for the acceptance or rejection of the proposed amendment to the Code.

(d) The Network Operator shall review the operation of the Code at intervals of no more than 5 years and may seek submissions from System Participants and the Utilities Commission during the course of the review.

(e) Before amending the Code or Network Planning Criteria in a material way, the Network Operator must consult the Utilities Commission and undertake consultation in accordance with the legislative provisions.
2 Network performance standards

2.1 Introduction

This clause 2 describes the technical performance parameters and standards for the power system. These standards provide the basis for the technical requirements for equipment connected to the electricity network, covered in clause 3.

2.2 Power system operating frequency

(a) The nominal operating frequency of the power system is 50 Hz.

(b) The accumulated synchronous time error shall be less than 15 seconds for 99% of the time.

2.2.1 Frequency range under normal operating conditions

(a) The frequency ranges under normal operating conditions for the Northern Territory regulated networks are set out in Table 3.

Table 3 – Frequency range under normal operating conditions

<table>
<thead>
<tr>
<th>Power and Water system</th>
<th>Frequency range</th>
</tr>
</thead>
<tbody>
<tr>
<td>Darwin – Katherine</td>
<td>50 Hz ± 0.2 Hz</td>
</tr>
<tr>
<td>Alice Springs</td>
<td>50 Hz ± 0.2 Hz</td>
</tr>
<tr>
<td>Tennant Creek and isolated, regional distribution networks</td>
<td>50 Hz ± 0.4 Hz</td>
</tr>
</tbody>
</table>

2.2.2 Frequency range under abnormal operating conditions

(a) To cover for the loss of a Generation Unit from the power system two measures will be applied to arrest the fall in frequency following the loss of Generation and to return the frequency to within normal operating levels as specified in clause 2.2.1:

(1) utilisation of available spinning reserve, under the direction of the Power System Controller; and

(2) disconnection of system load manually or by means of automatic protection.

(b) Under abnormal operating conditions, the network frequency may vary between 47 Hz and 52 Hz.

(c) In the case of operation below 47 Hz but at or above 45 Hz, all Generation Units shall remain connected to the Network Operator’s network for a period of at least 2 seconds.

(d) With sustained operation below 47 Hz, under frequency load shedding schemes may disconnect load on the network to restore frequency to the normal operating range, in accordance with clause 3.2.8.1.
(e) Frequency stability shall be satisfied under all credible power system load and generation patterns, and the most severe credible contingencies of transmission plant including the loss of interconnecting plant leading to the formation of islands within the power system.

(f) Each island in the power system that contains generation shall have sufficient load shedding facilities in accordance with clause 16 of the Network Planning Criteria to aid recovery of frequency to the range 49.5 Hz to 50.5 Hz in the network.

(g) When islanding occurs the Power System Controller will determine which power station or Generation Units in each isolated system will regulate the frequency in that system.

2.3 Power frequency voltage levels

2.3.1 Steady state voltage levels

(a) The requirements for steady-state voltage levels are set out in clause 15.2 of the Network Planning Criteria.

(b) The specifications for voltage levels in clause 15.2 shall apply in this Code.

(c) Users’ equipment shall be designed to withstand these voltage levels.

(d) The power frequency voltage may vary outside the ranges set out in this clause 2.3.1 as a result of a non-credible contingency event.

2.3.2 Temporary over-voltages

(a) As a consequence of a credible contingency event, the voltage of supply at a connection point shall not rise above its normal voltage by more than the percentage specified in clause 17.1.1 of the Network Planning Criteria.

(b) Users’ equipment shall also be designed to withstand these voltage levels.

(c) As a consequence of a contingency event, the voltage of supply at a connection point could fall to zero for any period.

2.3.3 Step changes in voltage levels

Step changes in the power system voltage levels may take place due to switching operations on the network. The step changes in voltage shall not exceed the limits set out in clause 17.1.2 of the Network Planning Criteria.

2.4 Quality of supply

2.4.1 Voltage fluctuations

A voltage disturbance is where the voltage shape is maintained but the voltage magnitude varies and may fall outside the steady state supply voltage range set out in clause 15.2 of the Network Planning Criteria. Short duration voltage disturbances of durations of up to one minute are termed voltage sags and swells.
The ENA publication Customer Guide to Electricity Supply contains information on the typical voltage sags experienced on Australian electricity networks and how customers can mitigate the risks of equipment maloperation because of sags.

Rapid voltage fluctuations cause changes to the luminance of lamps, which can create the visual phenomenon termed flicker.

(a) Under normal operating conditions, fluctuations in voltage on the network should be less than the “compatibility levels” defined in Table 1 of Australian Standard AS/NZS 61000.3.7 (2001).

(b) To facilitate the application of this standard Power and Water shall establish “planning levels” for its networks, as provided for in the Australian Standard.

2.4.2 Harmonic distortion

2.4.2.1 Harmonic voltage distortion

(a) Under normal operating conditions, the harmonic voltage in the network shall be less than the “compatibility levels” defined in Table 1 of Australian Standard AS/NZS 61000.3.6 (2001).

(b) To facilitate the application of this standard Power and Water shall establish “planning levels” of harmonic distortion for its networks as provided for in the Australian Standard.

(c) Planning levels for harmonic voltage distortion are specified in clause 17 of the Network Planning Criteria.

2.4.2.2 Non-integer harmonic distortion

Inter-harmonic or non-integer harmonic distortion may arise from large converters or power electronics equipment with Pulse Width Modulation (PWM) converters interfacing with the power system.

(a) Under normal operating conditions, the emission levels for inter-harmonic voltage in the network shall be less than the levels defined in section 9 of Australian Standard AS/NZS 61000.3.6 (2001).

(b) To facilitate the application of this standard Power and Water shall establish “planning levels” of inter-harmonic distortion for its networks as provided for in the Australian Standard AS/NZS 61000.3.6 (2001).

(c) Planning levels for inter-harmonic voltage distortion are specified in clause 17 of the Network Planning Criteria.
2.4.2.3 Voltage notching

Voltage notching may also arise from large convertors or power electronics equipment with Pulse Width Modulation (PWM) converters interfacing with the power system.

Voltage notching caused by a User’s facilities is acceptable provided that:
(a) the limiting values of harmonic voltage distortion as described in clause 2.4.2.1 are not exceeded;
(b) the average of start notch depth and end notch depth shall not exceed 20% of the nominal fundamental peak voltage; and
(c) the peak amplitude of oscillations due to commutation at the start and end of the voltage notch shall not exceed 20% of the nominal fundamental peak voltage.

2.4.2.4 Harmonic current distortion

(a) The harmonic voltage distortion limits of clause 2.4.2 apply to each phase and are not to be exceeded by a User injecting harmonic currents at any of its connection points.

(b) Any induced noise interference to telecommunications lines by a User’s load due to harmonic currents is not acceptable and the User is required to reduce the level of harmonic currents so as to contain such interference to limits considered acceptable by the telecommunication Network Operator.

(c) The User’s load shall not cause any harmonic resonance in other Users’ systems or the Network Operator’s network.

2.4.2.5 Direct current

(a) Users’ plant and equipment shall comply with the requirements on direct current components as stipulated in clause 3.12 of Australian Standard AS/NZS 3100:2009. In particular, the direct current in the neutral caused by the Users’ plant and equipment shall not exceed 120mA.h per day.

(b) Users shall ensure that all their plant and equipment is designed to withstand without damage or reduction in life expectancy the limits as specified in this clause 2.4.2.5.

(c) Responsibility of the Network Operator for direct current in the neutral outside the limits specified in this clause 2.4.2.5 shall be limited to direct current in the neutral caused by network assets.

(d) A User whose plant is identified by the Network Operator as not performing to the standards specified in this clause 2.4.2.5 shall take such measures as may be necessary to meet Australian Standard AS/NZS 3100:2009.
2.4.3 Voltage Unbalance

(a) For normal system operation and for planned system outages, the average voltage unbalance measured over a half hour at a connection point should not exceed the amount shown in Table 4.

Table 4 - Voltage unbalance limits

<table>
<thead>
<tr>
<th>Nominal supply voltage</th>
<th>Maximum negative sequence voltage (% of nominal voltage)</th>
</tr>
</thead>
<tbody>
<tr>
<td>132 kV</td>
<td>1.0</td>
</tr>
<tr>
<td>11-66 kV</td>
<td>1.5</td>
</tr>
<tr>
<td>Low voltage</td>
<td>2.0</td>
</tr>
</tbody>
</table>

An increase in the negative phase sequence voltage of up to 50% of the above is permissible for an aggregate of up to 5 minutes in any 30-minute period.

2.5 Electromagnetic interference

Electromagnetic interference caused by equipment forming part of the transmission and network shall not exceed the limits set out in Tables 1 and 2 of Australian Standard AS2344 (1997).

2.6 Stability

2.6.1 Transient rotor angle stability

All Generation Units connected to the transmission system and Generation Units within power stations that are connected to the network and that are classified as large generators shall remain in synchronism following a credible contingency event.

2.6.2 Dynamic stability

System oscillations originating from system electromechanical characteristics, electromagnetic effect or non-linearity of system components, and triggered by any small disturbance or large disturbance in the power system, shall remain within the small disturbance rotor angle stability criteria and the power system shall return to a stable operating state following the disturbance. The small disturbance rotor angle stability criteria are set out below.

(a) All electromechanical oscillations resulting from any small or large disturbance in the power system shall be well damped and the power system shall return to a stable operating state.

(b) The damping ratio of electromechanical oscillations shall be at least 0.1.

(c) For electromechanical oscillations as a result of a small disturbance, the damping ratio of the oscillation shall be at least 0.5.

(d) In addition to the requirements of clauses 2.6.2(a) and 2.6.2(b), the halving time of any electromechanical oscillations shall not exceed 5 seconds.
(e) If oscillations do not comply with clause 2.6.2(d), then appropriate measures shall be taken to change the power system configuration and/or Generation dispatch so as to eliminate such oscillations. Such measures shall be taken by automatic means.

(f) Users who may cause subsynchronous or supersynchronous resonance oscillations shall provide appropriate measures at the planning and design stage to prevent the introduction of this problem to the Network Operator’s power system or other Users’ systems.

2.6.3 Short term voltage stability

(a) Short term voltage stability is concerned with the power system surviving an initial disturbance and reaching a satisfactory new steady state.

(b) Stable voltage control shall be maintained following the most severe credible contingency event.

2.7 Contingency criteria for the network

To a great extent, the contingency criteria used for the design of the network will determine the inherent reliability of customer supply. These criteria apply to the shared network, and not to customer connections.

(a) The contingency levels to which the network and sub-clauses of the network are designed are set out in clause 14 of the Network Planning Criteria.

(b) The contingency criteria in this clause 2.7 apply only to the electricity networks and not to customer connections to the network.

(c) The contingency criteria for a sub-clause of the network may be varied by Power and Water following a risk/benefit analysis and other considerations such as capital investment priorities, social needs, the environment and land use.

(d) Connection assets will be designed in accordance with a User’s requirements and a network User may choose a design configuration having a greater or lesser level of security for its dedicated connection to the shared network, subject to the approval of Power and Water.

(e) The contingency criteria to which the network has been designed shall be taken into account when assessing the impact of a User’s installation on other Users, or the power system.

2.8 Equipment fault level ratings

(a) The Network Operator shall specify the minimum fault level ratings of equipment connected to the network.

(b) Unless otherwise agreed by the Network Operator, the equipment fault level ratings specified in clause 15.4 of the Network Planning Criteria shall apply.
2.9 **Protection arrangements**

2.9.1 **Users’ obligation to provide adequate protection**

2.9.1.1 **Safety of people**

It is the User’s responsibility to provide adequate protection (at the User’s discretion) of all User owned plant to ensure the safety of the public and personnel, and to minimise damage.

2.9.1.2 **System reliability and integrity**

(a) The Network Operator and Users shall ensure that any new equipment connected to any part of the system is protected in accordance with the requirements of clause 2.9.

(b) Where the connection of new equipment would affect critical fault clearance times, the protection of both new and existing equipment throughout the power system shall meet the new critical fault clearance times.

(c) Where existing protection would not meet the new critical fault clearance times, that protection shall be upgraded.

(d) Fault clearance time requirements may not be established until all new plant data is available and the detailed design of a User’s connection or network reinforcement has commenced.

(e) All faults of any type shall be cleared within the times specified in clause 2.9.5 unless it can be established by the Network Operator that a longer clearance time would not result in the network failing to meet the performance standards set out in clause 2.

2.9.1.3 **Minimum standard of protection equipment**

Protection systems shall be designed, installed and maintained in accordance with good electricity industry practice. In particular, the Network Operator shall ensure that all new protection apparatus including that installed on User’s equipment complies with IEC Standard 60255 and that all new current transformers and voltage transformers comply with Australian Standard AS 60044.1 (2007) and Australian Standard AS 60044.2 (2007).

2.9.1.4 **General requirements**

(a) All primary equipment on the network shall be protected so that if an equipment fault occurs, the faulted equipment item is automatically removed from service by the operation of circuit breakers or fuses.

(b) Protection systems shall be designed and their settings coordinated so that, if there is a fault, unnecessary equipment damage is avoided and any reduction in power transfer capability or in the level of service provided to Users is minimised.
(c) Consistent with the requirement of clause 2.9.1.4(b), protection systems shall remove faulted equipment from service in a timely manner and ensure that, where practical, those parts of the network not directly affected by a fault remain in service.

2.9.2 Duplication of protection

To implement a “one out of two” arrangement, complete secondary equipment redundancy is required. This includes CT and VT secondaries, auxiliary supplies, cabling and wiring, circuit breaker trip coils and batteries and intertripping arrangements.

2.9.2.1 Equipment connected at voltages of 66 kV and above

(a) Primary equipment shall be protected by a main protection system that shall remove from service only those items of primary equipment directly affected by a fault.

(b) The main protection system shall comprise two fully independent protection schemes of differing principle, connected to operate in a “one out of two” arrangement.

(c) One of the independent protection schemes shall include earth fault protection.

(d) To maintain the integrity of the two protection schemes, no electrical cross connections shall be made between them.

(e) It shall be possible to test and maintain either protection scheme independently without affecting the other.

(f) Where both protection schemes require end-to-end communications, independent teleprotection signalling equipment and communication channels shall be provided.

(g) Where failure of the teleprotection signalling would result in the failure of both protection schemes to meet the requirements of this clause 2.9.2.1 independent communication bearers shall be provided.

(h) Primary equipment shall also be protected by a back-up protection system in addition to the main protection system. The back-up protection system shall isolate the faulted primary equipment if a circuit breaker fails to operate.

(i) The design of the main protection system shall make it possible to test and maintain either protection scheme without interfering with the other.

2.9.2.2 Equipment connected at voltages of less than 66 kV

(a) Each item of primary equipment shall be protected by two independent protection systems.

(b) One of the independent protection systems shall be a main protection system that shall remove from service only the faulted item of primary equipment.
(c) At least one of the protection schemes shall include earth fault protection so as to give additional coverage for low level earth faults and to provide some remote backup.

(d) The other independent protection system may be a back-up protection system.

(e) Notwithstanding the requirements of clause 2.9.2.2(a), where a part of the distribution system may potentially form a separate island the protection system that provides protection against islanding shall comprise two fully independent protection schemes of differing principle.

(f) Where appropriate, and with the approval of the Network Operator, a single set of high rupturing capacity (HRC) fuses may be used as a protection scheme for plant at 33 kV and below, in which case a second protection scheme would not be required to satisfy the requirements of this clause 2.9.2.2.

2.9.3 Availability of protection systems

All protection schemes on the network, including any back-up or circuit breaker failure protection scheme and associated intertripping, shall be kept operational at all times except when maintenance is required.

2.9.4 Maximum total fault clearance times

(a) This clause 2.9.4 applies to short circuit faults of any type on primary equipment at nominal system voltage. Where critical fault clearance times exist, these times may be lower and take precedence over the times stated in this clause 2.9.4. Critical fault clearance time requirements are set out in clause 2.9.5.

(b) For primary equipment operating at transmission system voltages of 132 kV and 66 kV the maximum total fault clearance times in Table 5 apply to the nominal voltage of the circuit breaker that clears a particular fault for both minimum and maximum system conditions. For primary equipment operating at distribution system voltages of 33 kV and below the maximum total fault clearance times specified in Table 6 may be applied to all circuit breakers required to clear a fault for maximum system conditions, irrespective of the nominal voltage of the circuit breaker.

(c) For primary equipment operating at 132 kV and 66 kV:

(1) Both of the protection schemes of the main protection system must operate to achieve a total fault clearance time no greater than the “No CB Fail” time given in Table 5. The backup protection system must achieve a total fault clearance time no greater than the “CB Fail” time in Table 5, except that the second protection scheme that protects against small zone faults must achieve a total fault clearance time no greater than 400 msec;

(2) For a small zone fault coupled with a circuit breaker failure, maximum total fault clearance times are not defined.
(3) In Table 5, for voltages of 66 kV and above, the term “local” refers to the circuit breaker(s) of a protection system where the fault is located:

(i) within the same substation as the circuit breaker;

(ii) for a transmission line between two substations, at or within 50% of the line impedance nearest to the substation containing the circuit breaker, provided that the line is terminated at that substation; or

(iii) for a transmission line between more than two substations, on the same line section as the substation containing the circuit breaker, provided that the line is terminated at that substation.

(4) In Table 5, for voltages of 66 kV and above, the term “remote” refers to all circuit breakers required to clear a fault, apart from those specified in clause 2.9.4(c)(3).

(d) In Table 6, for primary equipment operating at nominal voltage of 33 kV and below, the term “local” refers only to faults located within the substation in which a circuit breaker is located.

Table 5 – 132 kV and 66 kV maximum total fault clearance times (msec)

<table>
<thead>
<tr>
<th></th>
<th>No CB Fail</th>
<th>CB Fail</th>
</tr>
</thead>
<tbody>
<tr>
<td>132 kV and 66 kV</td>
<td>Local 150</td>
<td>400</td>
</tr>
<tr>
<td></td>
<td>Remote 200</td>
<td>450</td>
</tr>
</tbody>
</table>

Table 6 – 33 kV and below maximum total fault clearance times (msec)

<table>
<thead>
<tr>
<th></th>
<th>No CB Fail</th>
<th>CB Fail</th>
</tr>
</thead>
<tbody>
<tr>
<td>33 kV and below</td>
<td>Local 1160</td>
<td>1500</td>
</tr>
<tr>
<td></td>
<td>Remote Not defined</td>
<td>Not defined</td>
</tr>
</tbody>
</table>

2.9.5 Critical fault clearance times

One of the major factors affecting the transient stability of the network is the fault clearance time. The critical fault clearance time is the longest time that a fault can be allowed to remain on the power system to ensure that transient instability does not occur. Critical fault clearance times are established for the various fault types at key locations. Protection then shall be set to ensure that the critical fault clearance times are achieved.

2.9.5.1 Critical fault clearance times

Where a critical fault clearance time to preserve system stability has been established by the Network Operator in a portion of the network:

(a) For plant operating at voltages of 66 kV or higher, each of the two independent protection schemes shall be capable of detecting and clearing plant faults within the critical fault clearance time.
(b) Where a critical fault clearance time exists for plant operating at 33 kV and below:

(1) one protection scheme shall be capable of detecting and clearing plant faults within the critical fault clearance time; and

(2) the second protection scheme is required to meet the maximum acceptable fault clearance times set out in clause (c).

(c) Other critical fault clearance time requirements may be imposed by the Network Operator to limit system voltage and/or frequency disturbances resulting from faults.

2.9.6 Protection sensitivity

(a) Protection schemes must be sufficiently sensitive to detect fault currents in the primary equipment taken into account the errors in protection apparatus and primary equipment parameters under the system conditions in this clause 2.9.6.

(b) For minimum and maximum system conditions, all protection schemes must detect and discriminate all primary equipment faults within their intended normal operating zones.

(c) For abnormal equipment conditions involving two primary equipment outages, all primary equipment faults must be detected by one protection scheme and cleared by a protection system. Backup protection systems may be relied on for this purpose. Fault clearance times are not defined under these conditions.

2.9.7 Trip supply supervision

Where loss of power supply to its secondary circuits would result in protection scheme performance being reduced, all protection scheme secondary circuits must have trip supply supervision.

2.9.8 Trip circuit supervision

All protection scheme secondary circuits that include a circuit breaker trip coil must have trip circuit supervision, which monitor the health of the trip coil under both circuit breaker opened and closed positions.

2.9.9 Protection flagging, indication, fault and event records

All protective devices supplied to satisfy the protection requirements must contain such indicating, flagging, fault and event recording as is sufficient to enable the determination, after the fact, of which devices caused a particular trip.

Any failure of the tripping supplies, protection apparatus and circuit breaker trip oils must be alarmed and operating procedures must be put in place to ensure that prompt action is taken to remedy such failures.
2.10 Variation of service quality parameters

(a) In particular circumstances, the requirements in clause 2 of this Code may be varied.

(b) The Network Operator may vary the Code in accordance with the derogation provisions of clause 12.

(c) Where it is intended to vary the requirements set out in this Code, it shall be demonstrated that the variation will not adversely affect Users or power system security.
3 Technical requirements for equipment connected to the network

3.1 Introduction

(a) The objective of this clause 3 is to facilitate maintenance of the power system service quality parameters specified in clause 2, so that other Users are not adversely affected and that personnel and equipment safety are not put at risk.

(b) This clause sets out details of the technical requirements which Users shall satisfy as a condition of connection of any equipment to the network including, but not limited, to the following types of equipment:

(1) Generation Units connected at all voltage levels of the network;
(2) Small Generation Units connected at voltages of 22 kV and below;
(3) Small Inverter Energy Systems connected to the low voltage network; and
(4) Loads, including those with electronic switching systems, connected at all voltage levels of the network.

(c) The Network Operator shall determine the classification of equipment to be connected to the network and may alter the technical requirements of connection in this clause 3 in respect of a particular connection only as much as is necessary to ensure the power system service quality parameters specified in clause 2 are maintained.

(d) An exemption may be granted by the Network Operator to certain provisions in clause 3 in accordance with the derogations in clause 12 of the Code.

3.2 Requirements for all network Users

3.2.1 Network performance standards

A User shall ensure that each of its facilities connected to the network is capable of operation while the power system is operating within the parameters of the performance standards set out in clause 1.7.2.

3.2.1.1 Voltage fluctuations

A User shall maintain its contributions to flicker at the connection point to below the limits allocated by the Network Operator under clause 2.4.1.

3.2.1.2 Harmonic voltage distortion

(a) A User shall comply with any harmonic emission limits allocated by the Network Operator in accordance with clause 2.4.2 of the Code.

(b) A User shall ensure that the injection of harmonics or interharmonics from its equipment or facilities into the network does not cause the maximum system harmonic voltage levels at the point of connection to exceed the levels set out in clause 17.2 of the Network Planning Criteria.
3.2.1.3 **Direct current injection**

A *User* shall ensure that any DC component of current produced by its own equipment complies with the requirements of clause 17.2.2 of the *Network Planning Criteria*.

3.2.1.4 **Voltage unbalance**

A *User* connected to all three phases shall balance the current drawn in each phase at its *connection point* so as to achieve levels of negative sequence *voltage* at all *connection points* that are equal to or less than the values specified in clause 2.4.3.

3.2.1.5 **Stability**

(a) *Users* shall cooperate with the *Network Operator* to achieve stable operation of the *networks* and shall install emergency controls as reasonably required by the *Network Operator*.

(b) The cost of installation, maintenance and operation of the emergency controls shall be borne by the *User*.

(c) The stability criteria stated in clause 2.6 shall be satisfied under the worst credible system *load* and *Generation* pattern, and the most severe credible *contingency event* arising from either a single credible contingency event at up to 100% peak *load* or a double credible contingency event at up to 80% peak *load*.

(d) *Credible contingency events* shall be considered in accordance with clause 2.7.

3.2.1.6 **Electromagnetic interference**

A *User* shall ensure that the electromagnetic interference caused by its equipment does not exceed the limits set out in clause 2.5.

3.2.1.7 **Fault levels**

(a) A *User* connected to the *network* may not install or connect equipment at the *connection point* that is rated for a *maximum fault current* lower than that specified in the *Access Agreement* in accordance with clause 3.6.6.

(b) A *User* connected to the *network* shall not install equipment at the *connection point* that is rated for a *maximum fault current* lower than that specified in clause 15.4 of the *Network Planning Criteria* unless a lower *maximum fault current* is agreed with the *Network Operator* and specified in the *Access Agreement*.

(c) Where a *User’s* equipment increases the fault levels in the *transmission* system, responsibility for the cost of any upgrades to the equipment required as a result of the *changed power system* conditions will be dealt with by commercial arrangements between the *Network Operator* and the *Users*. 
3.2.1.8 **Main switch**

Except as provided in clause 3.3.2.11, a User shall be able to de-energise its own equipment without reliance on the Network Operator.

3.2.1.9 **Users’ power quality monitoring equipment**

(a) The Network Operator may require a User to provide accommodation and connections for the Network Operator’s power quality monitoring and recording equipment within the User’s facilities or at the connection point. In such an event the User shall meet the requirements of the Network Operator in respect of the installation of the equipment and shall provide access for reading, operating and maintaining this equipment.

(b) The key inputs that the Network Operator may require a User to provide to the Network Operator’s power quality monitoring and recording equipment include:

1. three phase voltage and three phase current and, where applicable, neutral voltage and current; and
2. digital inputs for circuit breaker status and protection operate alarms hardwired directly from the appropriate devices. If direct hardwiring is not possible and if the Network Operator agrees, then the User may provide inputs measurable to 1 millisecond resolution and GPS synchronised.

3.2.1.10 **Power system simulation studies**

(a) A User shall provide to the Network Operator such of the following information relating to any of the User’s facilities connected or intended to be connected to the transmission system as is required to enable the undertaking of power system simulation studies:

1. a set of functional block diagrams, including all transfer functions between feedback signals and Generation Unit output;
2. the parameters of each functional block, including all settings, gains, time constraints, delays, dead bands and limits; and
3. the characteristics of non-linear elements.

(b) The Network Operator may provide any information it so receives to any User who intends to connect any equipment to the transmission system for the purposes of enabling that User to undertake any power system simulation studies it wishes to undertake, subject to that User entering into a confidentiality agreement with the Network Operator, to apply for the benefit of the Network Operator and any User whose information is so provided, in such form as the Network Operator may require.
3.2.1.11  **Technical matters to be coordinated**

(a) The *User* and the *Network Operator* shall use all reasonable endeavours to agree upon the following matters in respect of each new or altered *connection*:

1. *design* at *connection point*;
2. *physical layout* adjacent to *connection point*;
3. *protection* and backup;
4. *control characteristics*;
5. *communications*, metered quantities and alarms;
6. *insulation* co-ordination and lightning *protection*;
7. *fault levels* and fault clearing times;
8. *switching* and isolation facilities;
9. *interlocking* arrangements;
10. *metering* installations as described in clause 10;
11. *synchronising* facilities;
12. *under frequency load shedding* and islanding schemes;
13. *out of step/pole slip* *facility*; and
14. any special test requirements.

(b) Prior to *connection* to the *Network Operator’s power system*, the *Users* shall have provided to the *Network Operator* a signed statement to certify that the equipment to be *connected* has been designed and installed in accordance with this *Code*, all relevant standards, all statutory requirements and *good electricity industry practice*.

3.2.2  **Provision of information**

(a) A *User* shall provide all data reasonably required by the *Network Operator*.

(b) Details of the kinds of data that may be required are included in clause 11 and Attachment 3 of this *Code*.

3.2.3  **Protection requirements**

*Protection* shall be provided to detect and clear faults, without system instability and without causing equipment damage, in accordance with clauses 2.6 and 2.9.

3.2.3.1  **Transmission lines and other Plant operated at 66 kV and above**

(a) *Protection* shall be by two fully independent *protection schemes* as set out in clause 2.9.2.1.

(b) The *protection* arrangements shall be capable of clearing a fault within the clearance times set out in clause 2.9.5.
3.2.3.2  **Interconnectors** and ties operated at 33 kV and below

(a)  *Protection* shall be by two fully independent *protection schemes* as set out in clause 2.9.2.2.

(b)  The *protection* arrangements shall be capable of clearing a fault within the clearance times set out in clause 2.9.5.

3.2.3.3  **Feeders, reactors, capacitors and other plant** operated at 33 kV and below

(a)  The *protection* arrangements shall be capable of clearing a fault within the clearance times set out in clause 2.9.5.

(b)  Where a *critical fault clearance time* exists, *protection* of these items will be by two independent *protection schemes of differing principle*, each one discriminating with the *Network Operator power system* and capable of meeting the *critical fault clearance time*.

(c)  At least one of these *protection schemes* shall also include earth fault *protection* so as to give additional coverage for low level earth faults and to provide some remote backup.

(d)  Where there is no *critical fault clearance time*, the following shall be the minimum *protection requirement*:

   (1)  three Phase Inverse Definite Minimum *Time* Overcurrent; and

   (2)  three Phase Instantaneous Overcurrent; and

   (3)  inverse Definite Minimum Time Earth Fault; and

   (4)  instantaneous Earth Fault.

(e)  With the approval of the *Network Operator*, a single set of HRC fuses may be deemed to provide equivalent *protection* to subclause (c) of this clause 3.2.3.3.

3.2.3.4  **Transformers**

The composition of each of the two *protection schemes* should be *complementary* such that, in combination, they provide dependable clearance of *transformer* faults within a specified *time*. With any single failure to operate of the secondary *plant*, fault clearance shall still be achieved by *transformer protection*, but may be delayed until the nature of the fault changes or evolves.

*Protection of transformers* larger than 3 MVA will require at least one of the *protection schemes* to be a unit *protection* and provide high-speed fault clearance of *transformer* faults.

(a)  For *transformers* with a primary voltage of 66 kV and above, *protection* shall be by two fully independent *protection schemes* as set out in clause 2.9.2.1.
(b) For transformers with a primary voltage of 33 kV and below, protection shall be by two protection schemes which are complementary, as set out in clause 2.9.2.2.

(c) The protection arrangements shall be capable of clearing a fault within the clearance times set out in clause 2.9.5.

3.2.3.5 Protection discrimination

Where the Network Operator protection is overcurrent, the maximum operate time will be 1 second at maximum fault level. Generally, Network Operator overcurrent and earth fault protection employs devices with standard inverse characteristics to BS142 with a 3 second curve at 10 times current and time multiplier of 1.0. Note that this is the specification of the characteristic rather than the device setting. Operating times for other types of protection will generally be lower and will be dependent upon location.

The protection in clauses 3.2.3.1, 3.2.3.2, 3.2.3.3 and 3.2.3.4 is required to discriminate with the Network Operator’s protection on the power system.

3.2.3.6 Backup protection

(a) The protection in clauses 3.2.3.1, 3.2.3.2, 3.2.3.3 and 3.2.3.4 is required to be backed up by an independent protection to ensure clearance of faults with a protection failure.

(b) Backup protection shall be provided to detect and clear faults involving small zones.

(c) Protection shall be provided to detect and clear faults involving circuit breaker failure.

(d) Where critical fault clearance times do not exist, or are greater than the times given in clause 2.9.5, the clearance times are to be as specified by the Network Operator in an Access Agreement.

(e) Such protection schemes shall be capable of detecting and initiating clearance of uncleared or small zone faults under both normal and minimum system conditions.

(f) Under abnormal plant conditions, all primary system faults shall be detected and cleared by at least one protection scheme on the User’s equipment. Remote backup protection or standby protection may be used for this purpose.

3.2.3.7 Protection alarm requirements

(a) Specific requirements and the interface point to which alarms shall be provided will be mutually decided during the detailed design phase. These alarms will be brought back to the Network Operator’s control centre via the installed SCADA system supplied by the User in accordance with clause 3.2.5 or clause 3.3.3, as applicable.
(b) In addition, any failure of the User’s tripping supplies, protection apparatus and circuit breaker trip coils shall be alarmed within the User’s installation and operating procedures put in place to ensure that prompt action is taken to remedy such failures.

3.2.3.8 Islanding of a User’s facilities from the power system

(a) Unless otherwise agreed by the Network Operator, a User shall ensure that islanding of its Generation plant together with part of the Network Operator power system, cannot occur upon loss of supply from the Network Operator’s power system.

(b) Clause 3.2.3.8(a) should not preclude a design that allows a User to island its own Generation and plant load, thereby maintaining supply to that plant, upon loss of supply from the Network Operator’s power system.

(c) Islanding shall only occur in situations where Power and Water’s power system is unlikely to recover from a major disturbance.

(d) Unless otherwise agreed by the Network Operator, the User shall provide facilities to initiate islanding in the event of their system drawing more than the agreed MW/MVAr demands from the Network Operator power system for a specified time.

(e) Users shall co-operate to agree with the Network Operator the type of initiating signal and settings to ensure compatibility with other protection settings on the network and to ensure compliance with the requirements of clause 2.2.

(f) Where a User does not wish to meet the requirements of clause 2.2, appropriate commercial arrangements will be required between the User, the Network Operator and/or another User(s) to account for the higher level of access service.

3.2.3.9 Automatic reclose equipment

The installation and use of automatic reclose equipment in a User’s facility and in the power system shall only be permitted with the prior written agreement of Network Operator.

3.2.3.10 Maintenance of protection

(a) Users shall regularly maintain their protection systems at intervals of not more than 3 years. Records shall be kept of such maintenance and the Network Operator may review these. Refer also to clause 5.2.

(b) Each scheduled routine test, or any unscheduled tests that become necessary, shall include both a calibration check and an actual trip operation of the associated circuit breaker.
All maintenance and testing of User owned protection shall be carried out by personnel suitably qualified and experienced in the commissioning, testing and maintenance of primary plant and secondary plant and equipment.

### 3.2.4 Design requirements for Users’ substations

The following requirements apply to the design, station layout and choice of equipment for a substation.

(a) Safety provisions shall comply with requirements applicable and notified by the Network Operator.

(b) Where required by the Network Operator appropriate interfaces and accommodation shall be incorporated by the Users for metering, communication facilities, remote monitoring and protection of plant that is to be installed in the substation by the Network Operator.

(c) A substation shall be capable of continuous uninterrupted operation with the levels of voltage, harmonics, unbalance and voltage fluctuation from all sources as defined in clause 2 of this Code.

(d) Earthing of primary plant in the substation shall be in accordance with the Electricity Supply Association of Australia Substation Earthing Guide, and shall reduce step and touch potentials to safe levels.

(e) Synchronisation facilities or reclose blocking shall be provided if Generating Units are connected through the substation.

(f) Secure electricity supplies of adequate capacity to provide for the operation for at least eight hours of plant performing metering, communication, monitoring, and protection functions, on loss of AC supplies, shall be provided.

(g) Plant shall be tested to ensure that the substation complies with the design and specifications required by clause 3.2.3.10. Where appropriate, type test certificates provided by the manufacturer satisfy this clause.

(h) The protection equipment required would normally include protection schemes for individual items of plant, back-up arrangements, auxiliary DC supplies and instrumentation transformers.

(i) Insulation levels of plant in the substation shall co-ordinate with the insulation levels of the network to which the substation is connected without degrading the design performance of the network.

(j) Prior to connection to the Network Operator’s power system, the User shall have provided to the Network Operator a signed written statement to certify that the equipment to be connected has been designed and installed in accordance with:

1. this Code;
2. all relevant standards;
3. all statutory requirements; and
(4) good electricity industry practice.

The statement shall have been certified by a Chartered Professional Engineer with NPER-3 standing with the Institution of Engineers, Australia, unless otherwise agreed.

3.2.5 Remote monitoring and control requirements

(a) The Network Operator may require the User to:

(1) provide remote monitoring equipment (RME) to enable the Network Operator to remotely monitor status and indications of the load facilities where this is reasonably necessary in real time for control, planning or security of the power system; and

(2) upgrade, modify or replace any RME already installed in a power station provided that the existing RME is, in the reasonable opinion of the Network Operator, no longer fit for purpose and notice is given in writing to the relevant User.

(b) The RME provided, upgraded, modified or replaced (as applicable) under subclause (a) shall conform to an acceptable standard as agreed by the Network Operator and shall be compatible with the Network Operator’s SCADA system, including the requirements of clause 4.9 of this Code.

(c) Input information to RME may include, but not be limited to, the following:

(1) Status Indications
   (i) relevant circuit breakers open/closed (double pole) within the plant
   (ii) relevant isolators within the plant
   (iii) connection to the network

(2) Alarms
   (i) protection fail
   (ii) battery fail - AC and DC
   (iii) Trip circuit supervision
   (iv) Trip supply supervision

(3) Measured Values
   (i) active power load
   (ii) reactive power load
   (iii) load current
   (iv) relevant voltages throughout the plant

(4) Sequence-of-event (SOE) points
   (i) protection operation
(ii) circuit breaker status

(5) Such other input information reasonably required by the Network Operator.

3.2.6 Communications equipment

(a) A User shall provide electricity supplies for any RME installed in relation to its plant capable of keeping these facilities available for at least eight hours following total loss of supply at the connection point for the relevant plant.

(b) A User shall provide communications paths (with appropriate redundancy) between any RME installed at its plant to a communications interface at the relevant plant and in a location reasonably acceptable to the Network Operator.

(c) Communications systems between this communications interface and the relevant control centre shall be the responsibility of the Network Operator unless otherwise agreed.

(d) The cost of the communications systems shall be met by the User, unless otherwise determined by the Network Operator.

3.2.7 Secure electricity supplies

Secure electricity supplies of adequate capacity to provide for the operation for at least eight hours of plant performing metering, communication, monitoring, and protection functions, on loss of AC supplies, shall be provided by a User.

3.2.8 Load shedding facilities

If reasonably required by the Network Operator, Users are to provide automatic interruptible load to the Network Operator in accordance with clause 2.2.2.

3.2.8.1 Load to be available for disconnection

(a) It is a requirement for power system security that 75% of the power system load at any time be available for disconnection:

(1) under the automatic control of under frequency relays; and

(2) under manual or automatic control from control centres; and/or

(3) under the automatic control of under voltage relays.

(b) In some circumstances, it may be necessary to have up to 90% of the power system load, or up to 90% of the load within a specific part of the network, available for automatic disconnection. The Network Operator will advise Users if this additional requirement is necessary.

(c) Special load shedding arrangements may be required to be installed to cater for abnormal operating conditions.
(d) Subject to clauses 4.3.4(c) and 4.3.4(d), arrangements for load shedding shall be agreed between the Network Operator and User and can include the opening of circuits in a network.

(e) The Network Operator shall specify, in the Access Agreement, control and monitoring requirements to be provided by a User for load shedding facilities.

3.2.8.2 Installation and testing of load shedding facilities

Users shall, if reasonably required by the Network Operator:

(a) Provide, install, operate and maintain facilities for load shedding in respect of any connection point.

(b) Co-operate with the Network Operator in conducting periodic functional testing of the facilities, which shall not require load to be disconnected, provided facilities are available to test the scheme without shedding load.

(c) Apply under frequency settings to relays as determined by the Power System Controller.

(d) Apply under voltage settings to relays as determined by the Network Operator.

3.2.9 Impact on power system performance

(a) Prior to a User’s facilities being connected to the power system, the impact on power system performance due to the Users’ facilities is to be determined by power system simulation studies as specified by the Network Operator.

(b) These studies may be performed by the User or a third party, in which case, the Network Operator will require full details of the studies performed including, without limitation:

(1) assumptions made;
(2) results;
(3) conclusions; and
(4) recommendations.

(c) The acceptance of studies performed by a User or a third party will be entirely at the Network Operator’s discretion.

(d) Acceptance of power system studies by the Network Operator does not absolve Users of responsibility/liability for damages or losses incurred by others.

(e) The Network Operator reserves the right to perform its own studies (at the User’s cost) and will provide details of such studies to the User.

(f) The Network Operator will make the final determination on the suitability of a User’s facilities and the requirements to be fulfilled prior to and after the facilities are connected, in accordance with this Code.
3.2.10 Safety criteria

(a) As part of the planning process the safety risk should be considered for any new developments and existing facilities which may have a significant impact on safety. The safety risk is to be assessed in the planning process. Relevant bodies should be informed, consulted and steps taken to ensure safety is maintained to industry standards.

(b) The ESAA National Electricity Network Safety (NENS) Code shall be applied and reference shall be made to the NENS Reference Guidelines.

3.2.11 Environmental criteria

(a) Environmental management of the transmission and distribution networks will be in keeping with the ESAA Code of Environmental practice. This applies in planning, construction, operation and decommissioning.

(b) Users shall inform and consult with relevant public bodies, community interest groups and the general public, and shall avoid where economically possible the use of land where conflicting uses or potential conflicting uses exist.

3.2.12 Construction criteria

3.2.12.1 Overhead lines

Overhead lines and cable systems shall be designed and constructed to Australian Standard HB C(b)1, “Guidelines for Design and Maintenance of Overhead Distribution and Transmission lines”.

3.2.12.2 Underground cables

Cables shall be installed in a manner that takes into account the local environmental and service conditions, the location of other utilities’ services and the risk of damage from excavation. Installation practices shall be in accordance with ESAA Code C(b)2, “Guide to the Installation of Cables Underground”.

3.3 Requirements for connection of Generators

(a) The Network Operator will carry out detailed power system studies to determine performance requirements to be expected from a proposed new Generation Unit or modification to an existing Generation Unit.

(b) All costs associated with these studies, including studies to obtain any necessary optimal settings for the Generation Unit and its controls shall be borne by the User.

(c) The User shall be responsible for all costs associated with the installation, performance verification, parameter tuning and model validation of any additional equipment identified in the studies.

(d) Users will be responsible for ensuring that plant capabilities and ratings are monitored on an ongoing basis to ensure continued suitability as conditions
on the power system change in the future (e.g. increasing fault levels as additional plant is connected to the power system).

(e) A User will be responsible for the cost of any plant upgrades required at its facilities as a result of changing power system conditions.

(f) If, after installation of a User’s facilities, it is found that the installation is adversely affecting the security or reliability of the power system, the quality of supply, or the installation does not comply with the Code or the relevant Access Agreement, the User shall be responsible for remedying the problem at its cost.

3.3.1 Protection requirements

(a) Protection of a Generator shall generally be at the discretion of the User, but shall be sufficient to protect the Generator from faults on the Network Operator power system.

(b) Protection of a Generator will be by two fully independent protection schemes of differing principle, each one discriminating with the protection schemes used on the Network Operator power system.

(c) Where a critical fault clearance time exists, each protection shall be capable of meeting the critical fault clearance time.

(d) Generator protection schemes are to meet the fault clearance times specified in clause 2.9.5.

(e) In addition, the User shall provide protection and controls to achieve, even under circuit breaker fail conditions, the following functions:

1. Separation of the User’s Generation Plant from the Network Operator power system in the event of any of the above protection schemes operating.

2. Separation of the User’s Generation Plant from the Network Operator power system in the event of loss of supply to the User’s installation from the Network Operator’s power system.

3. Prevention of the User’s Generation Plant from energising de-energised Network Operator plant, or energising and supplying an otherwise isolated portion of the Network Operator’s power system.

4. Adequate protection of the User’s equipment and complete installation without reliance on back up from the Network Operator’s protection.

3.3.1.1 Check synchronising

(a) Check synchronising interlocks shall include a feature such that circuit breaker closure via the check synchronism interlock is not possible if the permissive closing contact is closed prior to the circuit breaker close signal being generated. Such a feature is intended to protect the check synchronism
interlock permissive contact from damage and to ensure out of synchronism closure cannot occur if the contact is welded closed.

(b) Distinction should be drawn between check synchronising interlocks and synchronising facilities (refer to clause 3.3.5).

(c) The check synchronising interlocks may be installed on circuit breakers within the Network Operator's power system where the risk of out of synchronism closure is unacceptable. This will be installed by the Network Operator at the User’s cost.

(d) In addition, the check synchronising interlocks shall be installed on all Users’ circuit breakers capable of out-of-synchronism closure, unless otherwise interlocked.

3.3.2 Technical characteristics

(a) If required by the Network Operator a User shall provide power system stabilising facilities on each synchronous Generation Unit if power system simulations indicate such a requirement.

(b) If required by the Network Operator, a User shall ensure that new synchronous Generation Units have a short circuit ratio of not less than 0.5 if necessary to limit the reduction in power transfer capabilities that are determined by transient stability considerations.

(c) A User shall ensure that its Generation Unit(s) comply with the requirements advised by the Network Operator as to the minimum subtransient reactance that the Generation Unit may have if necessary to control fault levels on the network.

(d) A User shall ensure that its Generation Unit(s) satisfy the Network Operator’s reasonable requirements to ensure stability of the electricity network and maintain power transfer capabilities. These requirements will have an impact on the Generator, governor and excitation system parameters, including the inertia constant, of the Generation Unit.

(e) The technical requirements described in this clause 3.3.2 are required to be demonstrated by the methods described in clause 5.4 of this Code.

3.3.2.1 Reactive power capability

(a) Each Generation Unit, and the power station in which the Generation Unit is located, shall be capable of continuously providing its full reactive power output within the full range of steady state voltages at the connection point permitted under clause 2 and clause 15.2 of the Network Planning Criteria.
(b) Unless otherwise agreed by the Network Operator:

(1) Each synchronous Generation Unit, while operating at any level of active power output between its registered maximum and minimum active power output level, shall be capable of:

(i) supplying at its generator machine’s terminals an amount of reactive power of at least the amount equal to the product of the rated active power output of the Generation Unit at nominal voltage and 0.750; and

(ii) absorbing at its generator machine’s terminals an amount of reactive power of at least the amount equal to the product of the rated active power output of the Generation Unit at nominal voltage and 0.484.

This clause requires a Generation Unit, when producing its registered maximum active power output, to be capable of operating at any power factor between 0.8 lagging and 0.9 leading.

These details are displayed in Figure 1. The minimum reactive power capability requirement is shown shaded.

**Figure 1 – Synchronous Generation Unit reactive power capability**

(2) Each induction Generation Unit, while operating at any level of active power output between its registered maximum and minimum output level, shall be capable of supplying or absorbing an amount of reactive power at the connection point of at least the amount equal to the product of the rated active power output of the Generation Unit at nominal voltage and 0.329.

This clause requires an induction Generation Unit, when producing its registered maximum active power output, to be capable of operating at any power factor between 0.95 lagging and 0.95 leading.
These details are displayed in Figure 2. The minimum reactive power capability requirement is shown shaded.

**Figure 2 - Induction Generation Unit reactive power capability**

Where necessary to meet the performance standards specified in clause 2, the Network Operator may require an induction Generation Unit to be capable of supplying or absorbing a greater amount of reactive power output than specified in clause 3.3.2.1(b)(2). The need for such a requirement will be determined by power system simulation studies and any such a requirement shall be included in the Access Agreement.

Each inverter coupled Generation Unit or converter coupled Generation Unit, while operating at any level of active power output between its registered maximum and minimum output level, shall be capable of supplying reactive power such that at the inverter or converter connection point the lagging power factor is less than or equal to 0.95 and shall be capable of absorbing reactive power at a leading power factor less than or equal to 0.95.
These details are displayed in Figure 3. The minimum reactive power capability requirement is shown shaded.

**Figure 3 – Invertor coupled Generation Unit reactive power capability**

(5) Where necessary to meet the requirements of the Code, the Network Operator may require an invertor Generation Unit to be capable of supplying a reactive power output coincident with rated active power output over a larger power factor range. The need for such a requirement will be determined by power system simulation studies and any such a requirement shall be included in the Access Agreement.

(c) For Generation Units not described by clause 3.3.2.1(b), the power factor requirements shall be as advised by the Network Operator and included in the Access Agreement. In determining the appropriate power factor requirement, the Network Operator shall consider the intrinsic capabilities of such a new technology and the potential for its penetration.

(d) If the power factor capabilities specified in clause 3.3.2.1(b) cannot be provided, the Generator shall reach an arrangement under the Access Agreement with the Network Operator for the supply of the deficit in reactive power at the connection point. The basis for negotiation will be the responsibility of the proponent to provide an equivalent reactive performance (MVAR output) over a range of voltages at the connection point.

Clause 3.3.2.1(d) is intended to facilitate flexibility in design by assisting proponents to connect Generation Units that, of themselves, are not capable of meeting the reactive power generation requirements specified in clause 3.3.2.1(b) through providing for the shortfall to be made up through some other means.

(e) Each Generation Unit's connection shall be designed to permit the dispatch of the full active power and reactive power capability of the facility as specified in the Access Agreement under all power system conditions contained in clause 2.
3.3.2.2 **Quality of electricity generated**

(a) When operating unsynchronised, a synchronous Generation Unit shall generate a constant voltage level with balanced phase voltages and harmonic voltage distortion equal to or less than permitted in accordance with either Australian Standard AS/NZS 1359.102.3:2000 “Rotating Electrical Machines - General Requirements” or a recognised equivalent international standard, as agreed between the Network Operator and the User.

(b) For non-synchronous Generators the contributions to quality of supply shall be not less than that required to be provided by Users as defined in clause 2.4.

3.3.2.3 **Generation Unit response to disturbances in the power system**

The following are design requirements for Generation Units. Network performance requirements are detailed in clause 2 of this Code.

(a) A Generation Unit, and the power station in which the Generation Unit is located, shall be capable of continuous uninterrupted operation within the frequency limits specified in clause 2.2.

(b) Subject to clause 3.3.2.3(b) a Generation Unit, and the power station in which the Generation Unit is located, shall be capable of continuous uninterrupted operation during the occurrence of the range of voltage variation conditions permitted by clause 2.3, including the voltage dip caused by a network fault which causes voltage at the connection point to drop to zero for up to 500 milliseconds in any one phase or combination of phases, followed by a period of ten seconds where voltage may vary in the range 80-110% of the nominal voltage, and a subsequent period of three minutes in which the voltage may vary within the range 90-110% of the nominal voltage.

(c) The Network Operator may agree to vary the requirements of clause 3.3.2.3(b) provided that it is satisfied that the Network performance standards of clause 2 of the Code and the system stability requirements of clause 16 of the Network Planning Criteria would be met.

3.3.2.4 **Partial load rejection**

A Generation Unit shall be capable of continuous uninterrupted operation, during and following a load reduction which occurs in less than 0.5 seconds, from a fully or partially loaded condition provided that the load reduction is less than 50% of the Generation Unit’s nameplate rating and the load remains above minimum load or as otherwise agreed between the Network Operator and the relevant User and stated in the Access Agreement between them.

3.3.2.5 **Loading rates**

A scheduled Generation Unit shall be capable of increasing or decreasing load in response to a manually or remotely initiated loading order at a rate not less than 5% of nameplate rating per minute or as otherwise agreed between the Network Operator and the relevant User, stated in their Access Agreement.
3.3.2.6 Safe shutdown without external electricity supply

A Generation Unit shall be capable of being safely shut down without electricity supply available from the network at the relevant connection point.

3.3.2.7 Restart following restoration of external electricity supply

(a) If reasonably required by the Network Operator, a Generation Unit shall be capable of being restarted and synchronised to the power system without unreasonable delay following restoration of external supply from the network power system at the relevant connection point, after being without external supply for two hours or less, provided that the Generation Unit was disconnected for any reason other than a fault within the Generation Unit.

(b) Examples of unreasonable delay in the restart of a Generation Unit are:

(1) delays not inherent in the design of the relevant start-up facilities and which could reasonably have been eliminated by the relevant User; and

(2) the start-up facilities for a new Generation Unit not being designed to minimise start up time delays for the Generation Unit following loss of external supplies for two hours or less.

3.3.2.8 Protection of Generation Units from power system disturbances

(a) A Generation Unit shall be automatically disconnected from the power system in response to conditions at the relevant connection point that are not within the agreed engineering limits for operating the Generation Unit or where the conditions may impact on other Users. If reasonably required by the Network Operator, these abnormal conditions will include and are not necessarily limited to:

(1) loss of synchronism (out-of-step protection/pole-slip protection may need to be located on the network; this should be determined by performing power system simulation studies);

(2) sustained high or low frequency outside the power system frequency range 47 Hz to 52 Hz (in the case of operation below 47 Hz but at or above 45 Hz, all Generators shall remain connected to the Network Operator’s network for a period of at least two seconds - refer to clause 2.2.2);

(3) sustained excessive Generation Unit stator current that cannot be automatically controlled;

(4) excessive high or low stator voltage;

(5) excessive voltage to frequency ratio;

(6) excessive negative phase sequence current;

(7) loss of excitation; and

(8) reverse power.
(b) The actual settings of the protection equipment installed on a Generation Unit determined by the User to satisfy requirement (a) of this clause shall be consistent with power system performance requirements specified in clause 2 and shall be approved by the Network Operator in respect of their potential to reduce power system security. They shall be such as to maximise plant availability, to assist the control of the power system under emergency conditions and to minimise the risk of inadvertent disconnection consistent with the requirements of plant safety and durability.

(c) The Network Operator shall bear no responsibility for any loss or damage incurred by the User as a result of a fault on either the power system, the User’s facility or within the Generation Unit itself.

3.3.2.9 Users’ protection systems that impact on power system security

Refer to clause 3.2.3 for the requirements of protection systems for Users’ plant. The requirements of clause 3.2.3 apply only to protection that is necessary to maintain power system security. Protection solely for User risks is at the User’s discretion.

3.3.2.10 Generator transformer tapping

Unless otherwise agreed between the Network Operator and the User, the Generator transformer of a Generation Unit shall be capable of off-load tapping within the range specified in the relevant Access Agreement.

3.3.2.11 Tripping of Generation Units and associated loads

Unless otherwise agreed by the Network Operator, the tripping of a User’s Generation Unit which is connected to the network will require the intertripping of associated loads within 0.2 seconds unless the loads are the subject of an Access Agreement with the Network Operator and the User has contracted for the provision of standby power and that standby power is available at the time of the tripping of the Generation Unit.

3.3.3 Monitoring and control requirements

3.3.3.1 Remote monitoring

The Network Operator will require the Users to:

(a) Provide remote monitoring equipment (“RME”) to enable the Network Operator and the Power System Controller to remotely monitor performance of a Generation Unit (including its dynamic performance) where this is reasonably necessary in real time for control, planning or security of the power system; and

(b) Upgrade, modify or replace any RME already installed in a power station provided that the existing RME is, in the reasonable opinion of the Network Operator, no longer fit for purpose and notice is given in writing to the relevant Users.
(c) In clause 3.3.3.1(a) and 3.3.3.1(b), the RME provided, upgraded, modified or replaced (as applicable) shall conform to an acceptable standard as agreed by the Network Operator and shall be compatible with the Network Operator’s SCADA system, including the requirements of clause 4.9 of this Code.

(d) Input information to RME may include, but not be limited to, the following:

1. Status Indications
   (i) Generation Unit circuit breaker open/closed (double pole)
   (ii) remote Generation load control on/off
   (iii) Generation Unit operating mode
   (iv) governor limiting operation
   (v) connection to the network

2. Alarms
   (i) Generation Unit circuit breaker tripped by protection
   (ii) prepare to off load

3. Protection Defective Alarms

4. Measured Values
   (i) Gross active power output of each Generation Unit
   (ii) Net station active power import or export at each connection point
   (iii) Gross reactive power output of each Generation Unit
   (iv) Net station reactive power import or export at each connection point
   (v) Generation Unit stator voltage
   (vi) Generation Unit transformer tap position
   (vii) Net station output of active energy (impulse)
   (viii) Generation Unit remote Generation control high limit value
   (ix) Generation Unit remote Generation control low limit value
   (x) Generation Unit remote Generation control rate limit value

5. Such other input information reasonably required by the Network Operator.

3.3.3.2 Remote control

(a) A User may install remote control equipment (“RCE”) that is adequate to enable the Power System Controller to remotely control:

1. the active power output of any Generation Unit; and
2. the reactive power output of any Generation Unit;

in a system emergency.
Where a User does not provide RCE, the User shall satisfy the Network Operator and the Power System Controller that adequate arrangements are in place to allow the Power System Controller to give directions to the User for the control of the Users’ Generation Units in a system emergency, and to allow the User to respond appropriately to those directions. These arrangements shall include the control of active power and reactive power.

(c) Unless agreed otherwise, the relevant User will be responsible for the following actions at the request of the Network Operator:

1. activating and de-activating RCE installed in relation to any Generation Unit; and

2. setting the minimum and maximum levels to which, and a maximum rate at which, the Power System Controller will be able to adjust the performance of any Generation Unit using RCE.

3.3.3.3 Communications equipment

(a) A User shall provide electricity supplies for the RME and RCE installed in relation to its Generation Units capable of keeping these facilities available for at least eight hours following total loss of supply at the connection point for the relevant Generation Unit.

(b) A User shall provide communications paths (with appropriate redundancy) between the RME or RCE installed at any of its Generation Units to a communications interface at the relevant power station and in a location reasonably acceptable to the Network Operator.

(c) Communications systems between this communications interface and the relevant control centre shall be the responsibility of the Network Operator unless otherwise agreed.

(d) The User shall meet the cost of the communications systems, unless otherwise determined by the Network Operator.

(e) Telecommunications between the Power System Controller and Generators shall be established in accordance with the requirements set down below for operational communications.

(1) Primary Speech Facility

(i) Each User shall provide and maintain equipment by means of which routine and emergency control telephone calls may be established between the User’s responsible Engineer/Operator and the Power System Controller.

(ii) The facilities to be provided, including the interface requirement between the Power System Controller’s equipment and the User’s equipment shall be specified by the Network Operator.
(2) Back-up Speech Facility

(i) Where the Network Operator advises a User that a back-up speech facility to the primary facility is required, the Network Operator will provide and maintain a separate telephone link or radio installation. The costs of the equipment shall be recovered through the charge for connection.

(ii) The Network Operator shall be responsible for radio system planning and for obtaining radio licenses for equipment used in relation to the Network Operator networks.

3.3.3.4 Governor system

(a) All Generation Units shall have an automatic governing system capable of droop governing. These governor systems shall include facilities for both speed and load control.

(b) The droop setting of the governor shall be adjustable and capable of operating in the range 1% to 6% droop.

(c) The Power System Controller will determine the governor mode of a Generation Unit in the system.

(d) Unless otherwise agreed between the Network Operator and the relevant User and stated in the Access Agreement between them, Generation Units shall normally operate in ‘droop’ mode.

(e) If in the Access Agreement, the Network Operator and the relevant User agree to operate the Generation Unit in ‘block load’ mode (constant active power output of the Generation Unit) or ‘import/export’ mode (constant active power delivery into the system at the connection point), the Generation Unit shall automatically change to regulating mode if the Generation Unit is islanded from the system.

(f) The User shall notify the Power System Controller prior to a Generation Unit being operated in a mode where the Generation Unit will be unable to respond as specified in the Access Agreement.

(g) The steady state deadband of a Generation Unit (sum of increase and decrease in power system frequency before a measurable change in the Generation Unit’s active power output occurs) shall be less than 0.05 Hz.

(h) For a load increase of 20% of the Generation Unit’s nameplate rating, the Generation Unit shall re-enter the steady state deadband within 3 seconds of the load change, provided that the load on the Generation Unit after the load increase does not exceed the Generation Unit’s nameplate rating.

(i) The governor system of a Generation Unit shall be adjusted for stable performance under all operating conditions.

(j) The structure and parameter settings of all components of the governor control equipment, including the speed/load controller, actuators (for
example hydraulic valve positioning systems), valve flow characteristics, limiters, valve operating sequences and steam tables for steam turbine (as appropriate) shall be provided to the Network Operator in sufficient detail to enable the dynamics of these components to be characterised for short and long term simulation studies. This shall include a control block diagram and all model parameters in suitable form to perform dynamic simulations and compatible with the power system analysis software used by the Network Operator (currently PSS/E from Siemens PTI). The proposed settings for the governor system for all expected modes of governor operation shall also be provided.

(k) These parameters shall not be varied without prior approval of the Network Operator.

| The overriding objective of a Generation Unit’s voltage control system is to maintain the specified voltage range at the connection point. |
| Each Generator must therefore provide sufficient reactive power injection into, or absorption from, the transmission system or distribution system to meet the reactive power requirements of its loads, plus all reactive power losses required to deliver its real power output at system voltages within the ranges specified in the relevant Access Agreement for normal operation and contingency conditions. |

3.3.3.5 Excitation control system

The excitation control system of a synchronous Generation Unit shall be capable of:

(a) limiting Generation Unit operation at all load levels to within Generation Unit capabilities for continuous operation;

(b) controlling the Generation Unit output to maintain the short-time average Generation Unit output voltage at highest rated level (which shall be at least 5% above the nominal output voltage and is usually 10% above the nominal output voltage);

(c) maintaining adequate Generation Unit stability under all operating conditions including providing power system stabilising action if fitted with a power system stabiliser;

(d) in the case of a rotating synchronous generator, the five second ceiling excitation voltage shall be at least twice the excitation voltage required to achieve maximum continuous rating at nominal voltage; and

(e) providing reactive current compensation settable for boost or droop unless otherwise agreed by the Network Operator.

3.3.3.6 Excitation control system performance

(a) New synchronous Generation Units shall be fitted with fast acting excitation control systems utilising modern technology. AC exciter, rotating rectifier or static excitation systems shall be provided for any new Generation Units with
a rating greater than 10 MW or for new smaller Generation Units within a power station totalling in excess of 10 MW. Excitation control systems shall provide voltage regulation to within 0.5% of the selected set point value.

(b) New non-synchronous Generation Units must be fitted with fast acting voltage and/or reactive power control systems, which must utilise modern technology and be approved by the Network Operator. Control systems must provide regulation to within 0.5% of the selected set point value.

(c) Unless agreed by the Network Operator, new synchronous Generation Units shall incorporate power system stabiliser circuits that modulate Generation Unit field voltage in response to changes in power output and/or shaft speed and/or any other equivalent input signal approved by the Network Operator. The stabilising circuits shall be responsive and adjustable over a frequency range that shall include frequencies from 0.1 Hz to 2.5 Hz.

(d) The Network Operator may require power system stabiliser circuits on synchronous Generation Units with ratings less than or equal to 10 MW or smaller synchronous Generation Units within a power station with a total active power output capability less than or equal to 10 MW (if power system simulations indicate a need for such a requirement). Before commissioning of any power system stabiliser, the Generator must propose preliminary settings for the power system stabiliser, which must be approved by the Network Operator.

(e) Power system stabilisers may also be required for non-synchronous Generation Units. The performance characteristics of these Generation Units with respect to power system stability must be similar to those required for synchronous Generation Units. The requirement for a power system stabiliser and its structure and settings will be determined by the Network Operator from power system simulations.

(f) Before commissioning of any power system stabiliser, its preliminary settings shall be agreed by the Network Operator. The User shall propose these preliminary settings that should be derived from system simulation studies and the study results reviewed by the Network Operator.
(g) The performance characteristics set out in Table 7 are required for AC exciter, rotating rectifier and static excitation systems.

**Table 7 – Synchronous Generator excitation system performance requirements**

<table>
<thead>
<tr>
<th>Performance Item</th>
<th>Units</th>
<th>Static Excitation</th>
<th>A.C. Exciter or Rotating Rectifier</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Sensitivity:</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>A sustained 0.5% error between the voltage reference and the sensed voltage will produce an excitation change of not less than 1.0 per unit.</td>
<td>Open loop gain (ratio)</td>
<td>200 minimum</td>
<td>200 minimum</td>
<td>1</td>
</tr>
<tr>
<td><strong>Field voltage rise time:</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Time for field voltage to rise from rated voltage to excitation ceiling voltage following the application of a short duration impulse to the voltage reference.</td>
<td>second</td>
<td>0.05 maximum</td>
<td>0.5 maximum</td>
<td>2</td>
</tr>
<tr>
<td><strong>Settling time with the Generator synchronised following a disturbance equivalent to a 5% step change in the sensed Generator terminal voltage.</strong></td>
<td>second</td>
<td>2.5 maximum</td>
<td>5 maximum</td>
<td>3</td>
</tr>
<tr>
<td><strong>Settling time with the Generator unsynchronised following a disturbance equivalent to a 5% step change in the sensed Generator terminal voltage.</strong> Shall be met at all operating points within the Generator capability.</td>
<td>second</td>
<td>1.5 maximum</td>
<td>2.5 maximum</td>
<td>3</td>
</tr>
<tr>
<td><strong>Settling time following any disturbance that causes an excitation limiter to operate.</strong></td>
<td>second</td>
<td>5 maximum</td>
<td>5 maximum</td>
<td>3</td>
</tr>
</tbody>
</table>

**Notes:**

1. One per unit is that field voltage required to produce nominal voltage on the air gap line of the Generator open circuit characteristic (Refer IEEE Standard 115-1983 – Test Procedures for Synchronous Machines).
2. Rated field voltage is that voltage required to give nominal Generator terminal voltage when the Generator is operating at its maximum continuous rating. Rise time is defined as the time taken for the field voltage to rise from 10% to 90% of the increment value.
3. Settling time is defined as the time taken for the Generator terminal voltage to settle and stay within an error band of ±10% of its increment value.
(h) The performance characteristics required for the voltage or reactive power control systems of all non-synchronous Generation Units are specified in Table 8.

Table 8 – Non-synchronous Generator voltage or reactive power control system performance requirements

<table>
<thead>
<tr>
<th>Performance Item</th>
<th>Units</th>
<th>Limiting Value</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>Sensitivity:</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>A sustained 0.5% error between the reference voltage and the sensed voltage must produce an output change of not less than 100% of the reactive power generation capability of the Generation Unit, measured at the point of control.</td>
<td>Open loop gain (ratio)</td>
<td>200 minimum</td>
<td>1</td>
</tr>
<tr>
<td>Rise time: Time for the controlled parameter (voltage or reactive power output) to rise from the initial value to 90% of the change between the initial value and the final value following the application of a 5% step change to the control system reference.</td>
<td>second</td>
<td>1.5 maximum</td>
<td>2</td>
</tr>
<tr>
<td>Small disturbance settling time</td>
<td>second</td>
<td>2.5 maximum</td>
<td>3</td>
</tr>
<tr>
<td>Settling time of the controlled parameter with the Generation Unit connected to the transmission or distribution network following a step change in the control system reference that is not large enough to cause saturation of the controlled output parameter. Must be met at all operating points within the Generation Unit’s capability.</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Large disturbance settling time</td>
<td>second</td>
<td>5 maximum</td>
<td>3</td>
</tr>
<tr>
<td>Settling time of the controlled parameter following a large disturbance, including a transmission or distribution network fault, which would cause the maximum value of the controlled output parameter to be just exceeded.</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Notes:

1. A control system with both proportional and integral actions must be capable of achieving a minimum equivalent gain of 200.
2. The controlled parameter and the point where the parameter is to be measured must be agreed and included in the relevant Access Agreement.
3. Settling time is defined as the time taken for the controlled parameter to settle and stay within an error band of ±10% of its increment value.

(i) The Network Operator shall approve the structure and parameter settings of all components of the excitation control system, including the voltage regulator, power system stabiliser, power amplifiers and all excitation limiters.

(j) The structure and settings of the excitation control system shall not be changed, corrected or adjusted in any manner without prior written
notification to the Network Operator. The Network Operator may require Generation Unit tests to demonstrate compliance with the requirements of Table 7 or Table 8. The Network Operator may witness such tests.

(k) Settings may require alteration from time to time as advised by the Network Operator. The cost of altering the settings and verifying subsequent performance shall be borne by the User, provided alterations are not made more than once in each 18 months for each Generation Unit. If more frequent changes are requested the person making that request shall pay all costs on that occasion.

(l) Excitation limiters shall be provided for under excitation and over excitation and may be provided for voltage to frequency ratio. The Generation Unit shall be capable of stable operation for indefinite periods while under the control of any excitation limiter. Excitation limiters shall not detract from the performance of any stabilising circuits and shall have settings applied which are co-ordinated with all protection systems.

3.3.4 Power station auxiliary transformers

In cases where a power station takes its auxiliary supplies through a transformer via a separate connection point, the User shall comply with the conditions for connection of loads (clause 3.6) in respect of that connection point.

3.3.5 Synchronising

(a) The User shall provide and install manual or automatic synchronising at the Generator circuit breakers.

(b) Check synchronising shall be provided on all Generator circuit breakers and any other circuit breakers, unless interlocked (as outlined in clause 3.3.1.1), that are capable of connecting the User’s Generation Facilities to the network.

(c) Prior to the initial synchronisation of the Generation Unit(s) to the network, the User and the Power System Controller shall agree on the operational procedures necessary for synchronisation.

3.3.6 Secure electricity supplies

Secure electricity supplies of adequate capacity to provide for the operation for at least eight hours of plant performing metering, communication, monitoring, and protection functions, on the loss of AC supplies, shall be provided by a User.

3.4 Requirements for connection of Small Generators

3.4.1 Scope

(a) This clause 3.4.1 addresses the requirements for the connection of Small Generation Units and groups of Small Generation Units.

(b) This clause 3.4.1 does not apply to the connection of Small Inverter Energy Systems, in respect of which clause 3.5 applies.
3.4.2 Objectives

(a) The issues addressed by this clause 3.4.2 are:

(1) the possibility that Small Generation Units embedded in networks may affect the quality of supply to other Users, cause reverse power transfer, use up network capacity, create a network switching hazard and increase risks for operational personnel;

(2) the possibility that a Small Generation Unit connected to a network could become islanded on to a de-energised part of the network resulting in safety and quality of supply concerns; and

(3) a simplified connection process for Small Generators.

3.4.3 Categorisation of facilities

(a) This clause 3.4.3 covers Small Generation Units of all types, whether using renewable or non-renewable energy sources.

(b) Unless otherwise specified, technical requirements for Small Generation Units will apply at the connection point, rather than at the Generator machine terminals, except that the reactive power requirements for synchronous Small Generation Units will apply at the Generator machine terminals.

(c) Connection points for small power stations are characterised as:

(1) high voltage connected: 3 phase, 11 kV or 22 kV; or

(2) low voltage connected: 1, 2 or 3 phase plus neutral, 230 V or 400 V.

(3) Where a Small Generation Unit is the only facility connected to a low voltage network the Generator may choose to have the power station assessed for compliance as if the power station was high voltage connected. Prior to another User subsequently connecting to the same low voltage network the Network Operator shall reassess the power station for compliance with the requirements for low voltage connected power stations and the Small Generator shall rectify any noncompliance identified in the reassessment.

(d) The mode of operation of a Small Generation Unit in a small power station is characterised as being in:

(1) continuous parallel operation with the network, and either exporting electricity to the network or not exporting electricity to it;

(2) occasional parallel operation with the network, and either exporting electricity to the network or not exporting electricity to it, including Generation Units participating in peak lopping and system peak load management for up to 200 hours per year;

(3) short term test parallel operation with the network, and either exporting electricity to the network or not exporting electricity to it, and having a maximum duration of parallel operation 2 hours per event and 24 hours per year; or
(4) bumpless (make before break) transfer operation, being:

(i) operation in rapid transfer mode where, when load is transferred between the Generation Unit and the network or vice versa, the Generation Unit is synchronised for a maximum of one second per event; or

(ii) operation in gradual transfer mode where, when load is transferred between the Generation Unit and the network or vice versa, the Generation Unit is synchronised for a maximum of 60 seconds per event.

3.4.4 Information to be provided by a Small Generator

(a) A Small Generator shall provide all information in relation to the design, construction, operation and configuration of that small power station as is required by the Network Operator to ensure that the operation and performance standards of the network, or other Users, are not adversely affected by the operation of the power station.

(b) Details of the kinds of information that may be required for Small Generators are included in clause 11.

3.4.5 Safety and reliability

The requirements imposed on a Small Generator by this clause 3.4.5 are intended to provide minimum safety and reliability standards for the network and other Users.

(a) A Small Generator shall design its facilities in accordance with applicable standards and regulations, good electricity industry practice and the manufacturers’ recommendations.

(b) The safety and reliability of the network and the equipment of other Users are paramount and connection applications shall be evaluated accordingly.

(c) A Small Generator shall not connect or reconnect to the network if the safety and reliability of the network or Users would be placed at risk.

(d) Where it is apparent that the operation of equipment installed in accordance with the requirements of this clause may have an adverse impact on the operation, safety or performance of the network, or on the quality of supply to other Users, the Network Operator shall consult with the Users to reach an agreement on an acceptable solution.

(e) Pursuant to clause 3.4.5(d), the Network Operator may require the Small Generator to test or modify its relevant equipment.

(f) Unless otherwise agreed in the relevant Access Agreement, the Network Operator may require a Small Generator not to operate equipment in abnormal network operating conditions.
(g) Equipment directly connected to the *connection point* of a small *power station* shall be rated for the *maximum fault current* at the *connection point* specified in clause 2.8.

(h) A *Small Generator* shall ensure that the *maximum fault current* contribution from a *Generation Unit* or small *power station* is not of a magnitude that will allow the total fault current at the *connection point* to exceed the levels specified in clause 2.8 for all normal operating conditions.

### 3.4.6 Small Generation Unit characteristics

(a) To assist in controlling *network* fault levels, *Small Generators* shall ensure that *Generation Units* comply with the *Network Operator’s* requirements relating to *minimum fault current* and *maximum fault current* contribution through a *connection point*.

(b) If the *connection or disconnection* of a *User’s small power station* causes or is likely to cause excessively high or low fault levels, this shall be addressed by other technical measures specified in the relevant *Access Agreement*.

### 3.4.7 Connection and operation

#### 3.4.7.1 Main switch

(a) Each *facility* at which a *Small Generation Unit* in a small *power station* is *connected* to the *network* shall contain one main switch provided by the *User* for each *connection point* and one main switch for each *Generation Unit*, where a *Small Generation Unit* shares a *connection point* with other *Small Generation Units* or *loads*. For larger installations, additional *connection points* and main switches or a dedicated feeder may be required.

(b) Switches shall be automatically operated, fault current breaking and making, ganged switches or circuit breakers. The relevant *facility* may also contain similarly rated interposed paralleling switches for the purpose of providing alternative *synchronised* switching operations.

(c) At each relevant *connection point* there shall be a means of visible and lockable isolation and test points accessible to the *Network Operator’s* operational personnel. This may be a withdrawable switch, a switch with visible contacts, a set of removable links or other approved means. It shall be possible for the *Network Operator’s* operational personnel to fit safety locks on the isolation point. *Low voltage Small Generation Units* with moulded case circuit breakers and fault limiting fuses with removable links are acceptable for isolation points in accordance with this sub clause.

#### 3.4.7.2 Synchronising

(a) For a synchronous *Small Generation Unit* in a small *power station*, a *Small Generator* shall provide automatic *synchronising* equipment at each *Small Generation Unit* circuit breaker.
(b) Check *synchronising* shall be provided on all Small Generation Unit circuit breakers and any other switching devices that are capable of *connecting* the User’s generating equipment to the *network* unless otherwise interlocked to the satisfaction of the Network Operator.

(c) Prior to the initial *synchronisation* of the Generation Unit(s) to the *network*, the Small Generator and the Network Operator shall agree on written operational procedures for *synchronisation*.

### 3.4.7.3 Safe shutdown without external supply

A Small Generation Unit shall be capable of being safely shut down without electricity *supply* being available from the *network*.

### 3.4.8 Power quality and voltage change

(a) A Small Generator shall ensure that the *network* performance standards of clause 2 are met when a small *power station* is *connected* by it to the *network*.

(b) The step *voltage change* at the *connection point* for *connection* and *disconnection* shall comply with the requirements of clause 2.3.3. These requirements may be achieved by *synchronising* individual Generation Units sequentially. On low voltage feeders, *voltage changes* up to 5% may be allowed in some circumstances with the approval of the Network Operator.

(c) The steady state *voltage* rise at the *connection point* resulting from export of power to the *network* shall not exceed 2% and shall not cause the *voltage* limits specified in clause 2.3.1 to be exceeded.

(d) When operating *unsynchronised*, a synchronous Small Generation Unit in a small *power station* shall generate a constant *voltage* level with balanced phase *voltages* and harmonic *voltage* distortion equal to or less than permitted in accordance with either Australian Standard AS 1359 (1997) “General Requirements for Rotating Electrical Machines” or a recognised relevant international standard, as agreed between the Network Operator and the User.

### 3.4.9 Remote control, monitoring and communications

(a) For Small Generation Units exporting 1 MW or more to the *network* the *Generator* shall provide for:

(1) tripping of the Small Generation Unit remotely from the Network Operator’s control centre;

(2) a close-enable interlock operated from the Small Network Operator’s control centre; and

(3) remote monitoring at the control centre of (signed) MW, MVAr and *voltage*.

(b) For Small Generation Units exporting less than 1 MW monitoring may not be required.
(c) Where concerns for safety and reliability arise that are not adequately addressed by automatic protection systems and interlocks, the Network Operator may require the Small Generator to provide remote monitoring and remote control of some functions in accordance with this clause 3.4.9.

(d) A Small Generator shall provide a continuous communication link with the Network Operator’s control centre for monitoring and control for Small Generation Units exporting 1 MW and above to the network. For Small Generation Units exporting below 1 MW, non-continuous monitoring and control may be required eg. a bi-directional dial up arrangement.

(e) A Small Generator shall have available at all times a telephone link or other communication channel to enable voice communications between a small power station and the Network Operator’s control centre.

(f) For Small Generation Units exporting above 1 MW, a dedicated telephone link or other dedicated communication channel may be required.

3.4.10 Protection

3.4.10.1 General

(a) A Small Generator shall provide, as a minimum, the protection functions specified in this clause in accordance with the aggregate rated capacity of Small Generation Units in a small power station at the connection point.

(b) A Small Generator’s proposed protection system and settings shall be approved by the Network Operator, who shall assess their likely effect on the network and may specify modified or additional requirements to ensure that:

1. the network performance standards specified in clause 2 are met;
2. the power transfer capability of the network is not reduced; and
3. the quality of supply to other Users is maintained. Information that may be required by the Network Operator prior to giving approval is specified in clause 11.

(c) A Small Generator’s protection system shall clear internal plant faults and coordinate with the Network Operator’s protection system.

(d) The design of a Small Generator’s protection system shall ensure that failure of any protection device cannot result in the network being placed in an unsafe operating mode or lead to a disturbance or safety risk to the Network Operator or to other Users. This may be achieved by providing back-up protection schemes or designing the protection system to be fail-safe, eg. to trip on failure.

(e) All protection apparatus shall comply with the IEC 60255 series of standards. Integrated control and protection apparatus may be used provided that it can be demonstrated that the protection functions are functionally independent of the control functions, ie. failure or maloperation of the control features will not impair operation of the protection system.
(f) All Small Generators shall provide under and over voltage, under and over frequency and overcurrent protection schemes in accordance with the equipment rating.

(g) All Small Generators shall provide earth fault protection for earth faults on the network. All small power stations connected at high voltage shall have a sensitive earth fault protection scheme.

(h) The earth fault protection scheme may be:
   (1) earth fault; or
   (2) neutral voltage displacement depending on the connection type).

(i) No Small Generator may supply a de-energised network and all small power stations shall provide protection against abnormal network conditions, as specified in clause 3.2.3, on one or more phases. This protection against loss of external supply may be:
   (1) loss of mains;
   (2) rate of change of frequency (ROCOF);
   (3) vector surge;
   (4) reverse power; or
   (5) directional over current.

(j) All Small Generators that have an export limit shall have reverse power or directional current limits set appropriate to the export limit.

(k) All Small Generators shall have loss of AC and DC auxiliary supply protection, which shall immediately trip all switches that depend on that supply for operation of their protection.

(l) Where synchronisation is time limited, the Small Generator shall be disconnected by an independent timer.

(m) Small Generation Units that are only operated in parallel with the network during rapid bumpless transfer shall be protected by an independent timer that will disconnect the Generation Unit from the network if the bumpless transfer successfully completed. Automatic transfer switches shall comply with Australian Standard AS 60947.6.2 (2004). For the avoidance of doubt Small Generation Units covered by sub-clause 3.4.10.1(m) need not comply with sub sub-clauses (f) to (l) of clause 3.4.10.1. This exemption recognises that the rapid bumpless transfer will be completed or the Generation Unit will be disconnected by the disconnection timer before other protection schemes operate. Protection of the Small Generation Unit when it is not operating in parallel with the network is at the discretion of the Small Generator.
3.4.10.2 Pole slipping

Where it is determined that the disturbance resulting from loss of synchronism is likely to exceed that permitted in clause 2.6, the Small Generator shall install a pole slipping protection scheme.

3.4.10.3 Islanding protection and intertripping

(a) For sustained parallel operation (which excludes rapid or gradual bumpless transfer), islanding protection schemes of two different functional types shall be provided to prevent a Small Generation Unit energising a part of the network that has become isolated from the remainder of the transmission or network under all operating modes. The Small Generator shall demonstrate that two different functional types of islanding protection schemes have been provided.

(b) Small Generation Units designed for gradual bumpless transfer shall be protected with at least one functional type of islanding protection scheme.

(c) Islanding protection shall operate within 2 seconds to ensure disconnection before the first network reclosing attempt (typically 5 seconds). Relay settings are to be agreed with the Network Operator. It should be assumed that the Network Operator will always attempt to auto-reclose to restore supply following transient faults.

(d) In cases where, in the opinion of the Network Operator, the risk of undetected islanding of part of the network and the Small Generator’s facility remains significant, the Network Operator may also require the installation of an intertripping link between the Small Generator’s main switch(es) and the feeder circuit breaker(s) in the zone substation or other upstream protection device nominated by the Network Operator.

3.4.10.4 Protection of Small Generator’s equipment

(a) This clause 3.4.10.4 applies only to protection necessary to maintain power system security. A Small Generator shall design and specify any additional protection required to guard against risks within the Small Generator’s facility.

(b) Any failure of the Small Generator’s tripping supplies, protection apparatus or circuit breaker trip coils required under clause 3.4.10 shall be alarmed within the Small Generator’s facility and operating procedures put in place to ensure that prompt action is taken to remedy such failures. As an alternative to alarming, Small Generation Unit main switches may be tripped automatically.

3.4.11 Commissioning and testing

The Small Generator shall comply with the testing and commissioning requirements for Small Generation Units connected to the network specified in clause 7.
3.4.12 Technical matters to be coordinated

As an alternative to network augmentation, the Network Operator may require a Generator to provide additional protection schemes to ensure that operating limits and agreed import and export limits are not exceeded.

3.5 Requirements for connection of Small Inverter Energy Systems

The Network Operator is not able to enter an energy buyback agreement directly. A User wishing to enter into such an agreement shall apply to a participating retailer. It should also be noted that whereas this clause 3.5 covers connection issues for Small Inverter Energy Systems of up to 30 kVA, the maximum capacity that a retailer may be prepared to enter into an energy buyback agreement may be less than this amount.

3.5.1 Scope

(a) Clause 3.5 addresses the particular requirements for the connection of Small Inverter Energy Systems to the Network Operator’s low voltage network.

(b) For similarly rated non-Inverter Energy systems, the requirements of clause 3.4 for Small Generators apply.

(c) The scope of clause 3.5 is limited to technical conditions of connection.

3.5.2 Relevant standards

(a) The installation of primary energy systems shall comply with the relevant Australian Standards and international standards.

(b) Inverter systems shall satisfy the requirements of Australian Standard AS 4777 “Grid connection of energy systems via inverters” as published and revised. The following parts of this standard apply:

(1) AS 4777.1 – 2005 Part 1 Installation requirements.

(2) AS 4777.2 – 2005 Part 2 Inverter requirements.

(3) AS 4777.3 – 2005 Part 3 Grid protection requirements.

(c) The term ‘Inverter Energy system’ in these Rules has the same meaning as in Australian Standard AS 4777.

(d) A type-test report or type-test certificate from an independent and recognised certification body showing compliance of inverter plant with Australian Standard AS 4777.2 (2005) shall be supplied to the Network Operator.

(e) Should it be necessary to change any parameter of the equipment as installed and contracted, approval shall be sought from the Network Operator. Subsequently, the Network Operator shall determine whether a revised application is required.
### 3.5.3 Metering installation

The *User* shall make provision for import and export *metering* in accordance with the requirements of clause 10.4.

### 3.5.4 Safety

(a) Installations shall comply with the relevant *Australian Standards* and all statutory requirements including Australian Standards AS/NZS 3000, AS/NZS 5033 and *Power and Water*’s Power Networks Service Rules and Power Networks Installation Rules.

(b) All electrical installation, commissioning and maintenance work wherever required shall be carried out by an electrical contractor licensed under the *Northern Territory Electrical Workers and Contractors Act*, as in force at 25 November 2011.

### 3.5.5 Security of operational settings

Where operational settings are applied via a keypad or switches, adequate security shall be employed to prevent tampering or inadvertent/unauthorised changes to these settings. A suitable lock or password system shall be used. The *Network Operator* shall approve changes to settings prior to implementation.

### 3.5.6 Circuit arrangements

3.5.6.1 Schematic diagram

A durable single sided schematic-wiring diagram of the installation showing all equipment and switches shall be affixed on the site adjacent the inverter system.

### 3.5.7 Protection

(a) A *Small Inverter Energy System* connected to the *network* shall be approved by the *Network Operator* and meet the requirements of relevant standards in accordance with clause 3.5.2 and the following requirements below.

(b) The *User* shall provide the information required by the *Network Operator* prior to approval being given.

3.5.7.1 Islanding protection

The islanding function shall be automatic and shall physically remove the *Small Inverter Energy System* from the *network*. The Islanding protection shall be capable of detecting loss of *supply* from the *network* and *disconnect* the *Small Inverter Energy System* from the *network* within 2 seconds.

3.5.7.2 Synchronising

Connection to the *network* shall be automated. The protective apparatus shall be capable of confirming that the *supply voltage* and *frequency* is within limits for no less than one minute prior to *synchronisation*.
3.5.7.3 **Reconnection to network**

Reconnection to the network shall be automated. The protective apparatus shall be capable of confirming that the supply voltage and frequency are within limits for no less than one minute prior to synchronisation.

3.5.7.4 **Overcurrent protection**

Overcurrent protection shall be provided at the isolating switch of a Small Inverter Energy System in accordance with the equipment rating, unless otherwise agreed with the Network Operator.

3.5.7.5 **Voltage limits**

(a) The Inverter voltage limits shall be set according to equipment capability and Australian Standard AS 4777.

(b) The Small Inverter Energy System shall remain connected for voltage variations within the limits of Table 9 unless otherwise agreed with the Network Operator. The network voltage range is based on 5-minute averages of the RMS value.

**Table 9 - Low voltage limits for Small Inverter Energy Systems**

<table>
<thead>
<tr>
<th>Nominal voltage</th>
<th>Lower limit</th>
<th>Upper limit</th>
</tr>
</thead>
<tbody>
<tr>
<td>230 V</td>
<td>226 V</td>
<td>254 V</td>
</tr>
<tr>
<td>400 V</td>
<td>390 V</td>
<td>440 V</td>
</tr>
</tbody>
</table>

(c) The Network Operator is not responsible for failure of the Small Inverter Energy System to remain connected for the full range of voltage on the network set out in Table 9.

3.5.7.6 **Frequency limits**

(a) The Inverter frequency limits shall be set according to the equipment capability and Australian Standard AS 4777.

(b) The Small Inverter Energy System shall remain connected for frequency variations between 47.5 Hz and 52 Hz unless otherwise agreed with Network Operator.

3.5.8 **Commissioning and testing**

3.5.8.1 **Commissioning**

(a) Commissioning may occur only after the installation of the metering equipment.

(b) In commissioning equipment installed under clause 3.5.8, a User shall verify that:

(1) The approved schematic has been checked and accurately reflects the installed electrical system.
(2) All required switches present and operate correctly as per the approved schematic.

(3) Signage and labelling comply with that specified in Power and Water’s Service Rules.

(4) The installation is correct and fit for purpose.

(5) Operational settings are secure as specified.

(6) The islanding protection operates correctly and disconnects the Inverter Energy system from the network within 2 seconds.

(7) The delay in reconnection following restoration of normal supply is greater than 1 minute.

(c) Subsequent modifications to the inverter installation shall be submitted to the Network Operator for approval.

3.5.8.2 Re-confirmation of correct operation

(a) The Network Operator may elect to inspect the proposed Small Inverter Energy System from time to time to ensure continued compliance with these requirements. In the event that the Network Operator considers that the installation poses a threat to safety, to quality of supply or to the integrity of the network it may disconnect the generating equipment.

(c) Small Inverter Energy System protection systems shall also be tested for correct functioning at regular intervals not exceeding 5 years. The User shall arrange for a suitably qualified person to conduct the tests. Results of tests shall be certified by a competent person and supplied to the Network Operator.

3.6 Requirements for connection of loads

The following requirements apply to the connection of loads to networks.

(a) These requirements and particular provisions may be waived for smaller Users and Users that have no potential to affect other Users, at the discretion of the Network Operator.

(b) Nothing in this clause 3.6 waives the requirements for all installations to comply with the Network Operator’s Service and Installation Rules, Metering Manual, Contractor’s Bulletins, and any requirement included in an Access Agreement.

3.6.1 Connection point for a User

Connection points between a User’s facility and a network will be defined in the Access Agreement.

3.6.2 Information

Before any new or additional equipment is connected, the User may be required to submit information to the Network Operator in accordance with clause 11.
3.6.3 Design standards

Changes to the power system may result in the requirements for connected equipment changing. For example, as additional plant is connected to the power system fault levels will increase and the User’s plant may no longer be suitable for connection to the system.

(a) A User’s installation shall comply with the relevant Australian Standards as applicable at the time, good electricity industry practice and this Code, including, but not limited to, the quality of supply standards as specified in clause 2.4.

(b) All plant ratings shall co-ordinate with the equipment installed on the Network Operator power system.

(c) Users will be responsible for ensuring that plant capabilities and ratings are monitored on an ongoing basis to ensure continued suitability as conditions on the power system change.

(d) A User will be responsible for the cost of any plant upgrades required at its facilities as a result of changing power system conditions.

(e) If, after installation of a User’s facilities, it is found that the installation is adversely affecting:

(1) the security or reliability of the power system;

(2) the quality of supply; or

(3) the installation does not comply with the Code or the relevant Access Agreement;

the User shall be responsible for remedying the problem at the User’s cost, and within a time frame reasonably required by the Network Operator.

3.6.4 Users’ protection systems that impact on power system security

(a) Where a User connection to the network may affect power system security, the protection systems of the User’s connection shall comply with the requirements of clause 3.2.3.

(b) Protection of the connection equipment solely for the User’s risks is at the User’s discretion.

3.6.5 Thermal limits

The thermal ratings of the network components shall comply with the specifications set out in clause 15.3 of the Network Planning Criteria.

3.6.6 Fault limits

The calculated fault levels in the networks shall not exceed 95% of the equipment fault ratings set out in clause 15.4 of the Network Planning Criteria.
The power factor of a load connection affects the required capacity of the network to supply the load and the management of voltage conditions on the network.

Power factor improvement may be achieved by installing additional reactive plant or reaching a commercial agreement with the Network Operator to install, operate and maintain equivalent reactive plant as part of connection assets.

(a) Power factor ranges to be met by Users for their loads are shown in the Table 10.

Table 10 - Power factor requirements (Loads)

<table>
<thead>
<tr>
<th>Supply Voltage (nominal)</th>
<th>Permissible Power factor Range (half-hour average, unless otherwise specified by the Network Operator)</th>
</tr>
</thead>
<tbody>
<tr>
<td>132 kV / 66 kV &lt;66 kV</td>
<td>0.95 lagging to unity 0.9 lagging to 0.9 leading</td>
</tr>
</tbody>
</table>

(b) The Network Operator may permit a lower lagging or leading power factor where this will not reduce system security and/or quality of supply, or require a higher lagging or leading power factor to achieve required power transfers.

(c) If the power factor falls outside the range in the table over any critical loading period nominated by the Network Operator, the User shall, where required by the Network Operator in order to economically achieve required power transfer levels, take action to ensure that the power factor falls within range as soon as reasonably practical.

(d) A User who installs static var compensator systems for either power factor or quality of supply requirements shall ensure its control system does not interfere with other normal control functions on the electricity network. Adequate filtering facilities shall be provided if reasonably required by the Network Operator to absorb any excessive harmonic currents.
4 Power system security

This section 4 of the Network Technical Code establishes requirements relating to the operation of the electricity network (including the operation of the network in emergency situations). It applies to the Network Operator, the Power System Controller and all network Users.

The Power System Controller has responsibility for control of the day-to-day dispatch of generators and associated ancillary services and for maintaining power system security.

The following related operational matters are set out in the System Control Technical Code:

(a) operating protocols;
(b) arrangements for system security and dispatch;
(c) arrangements for disconnection; and
(d) any other matters necessary to the efficient operation, monitoring and control of the power system.

4.1 Introduction

4.1.1 Purpose and application of clause 4

(a) Clause 4 of the Code applies to, and defines obligations for all Users, including:

(1) the framework for achieving and maintaining a secure power system;
(2) the conditions under which the Power System Controller can issue directions to Users so as to maintain or re-establish a secure power system.

(b) By virtue of this clause 4, the Power System Controller has the responsibility to maintain power system security within the design and operating limits determined by the Network Operator.

4.2 Power system security principles

This clause 4.2 sets out certain definitions and concepts that are relevant to power system security.

4.2.1 Power system operating state

(a) The Power System Controller shall define the operating states of the power system in the System Control Technical Code:

(1) satisfactory operating state; and
(2) secure operating state.

(b) The definition of operating states in section 4.2.1(a) shall be in accordance with:

(1) operating frequency requirements set out in clause 2.2 of this Code;
(2) voltage requirements set out in clause 2.3 of this Code;
(3) current flows for lines and equipment within the ratings defined by the Network Operator;
(4) the power system stability requirements set out in clause 2.6; and
(5) the technical envelope of power system performance set out in clause 4.2.2.

4.2.2 Technical envelope

(a) The technical envelope means the technical boundary limits of the power system for achieving and maintaining the secure operating state of the power system for a given demand and power system scenario.

(b) The Network Operator shall determine and revise the technical envelope (as may be necessary from time to time) by taking into account the prevailing power system and plant conditions as described in clause 4.2.2(c).

(c) The technical envelope determination shall take into account matters including but not limited to:
   (1) the Network Operator forecast total power system load;
   (2) the provision of the applicable contingency capacity reserves;
   (3) operation within all plant capabilities and constraints on the power system;
   (4) contingency capacity reserves available to handle credible contingency events in accordance with clauses 2.6 and 2.7 of this Code;
   (5) agreed Generation load constraints;
   (6) constraints on the network, including short term limitations;
   (7) frequency control requirements;
   (8) reactive power support and ancillary services requirements; and
   (9) the existence of proposals for any major equipment or plant testing, including the checking of or possible changes in plant availability.

4.2.3 General principles for maintaining power system security

The power system security principles are as follows:

(a) To the extent practical, the Power System Controller shall operate the power system such that it is and will remain in a secure operating state.

(b) Following a credible contingency event or a non-credible contingency event, the power system may no longer be in a secure condition on the occurrence of a further contingency event. In that case, the Power System Controller shall take all reasonable actions to return the power system to its satisfactory operating state as soon as practical, in accordance with the System Control Technical Code.
(c) The Network Operator shall ensure the provision of adequate load shedding facilities initiated automatically by frequency or voltage conditions outside the normal operating frequency or voltage excursion band to restore the power system to a satisfactory operating state following a significant contingency event.

(d) The Power System Controller shall ensure adequate load shedding facilities are in service to restore the power system to a satisfactory operating state following a significant contingency event.

(e) A User shall be required, either under their Access Agreement or ancillary services agreement, to provide and maintain all required facilities consistent with both their Access Agreement and good electricity industry practice and operate their equipment in a manner:

1. to assist in preventing or controlling instability within the power system;
2. to assist in the maintenance of, or restoration to a satisfactory operating state of the power system;
3. to prevent uncontrolled separation of the transmission network into isolated regions or partly combined regions, intra-regional transmission break-up, or cascading outages, following any power system incident; and
4. in accordance with the technical requirements of their Access Agreement.

(f) Users shall arrange sufficient black start-up provisions so as to allow the restoration and any necessary restarting of their Generation Units following a black system condition.

4.3 Power system security obligations and responsibilities

4.3.1 Time for undertaking action

An event which is required under this clause 4 of the Code to occur on or by a stipulated day shall occur on or by that day whether or not a business day.

4.3.2 Network Operator

(a) The Network Operator shall use its reasonable endeavours, including through the provision of appropriate information to Users to the extent permitted by law and under this Code, to ensure that:

1. the power system;
2. network equipment;
3. network connections; and
4. User equipment;

are specified, planned and developed in accordance with power system security principles and good electricity industry practice.

(b) Where an obligation is imposed on the Network Operator under this clause of the Code to arrange or control any act, matter or thing or to ensure that any other person undertakes or refrains from any act, that obligation is limited to
a requirement for the Network Operator to use reasonable endeavours, including to give such directions as are within its powers, to comply with that obligation.

(c) If the Network Operator fails to arrange or control any act, matter or thing or the acts of any other person notwithstanding the use of the Network Operator’s reasonable endeavours, the Network Operator will not be taken to have breached such obligation.

(d) The Network Operator shall make accessible to Users such information as:

(1) the Network Operator considers appropriate;

(2) the Network Operator is permitted to disclose in order to assist Users to make appropriate market decisions related to open access to the Network Operator’s networks; and

(3) the Network Operator is able to disclose to enable Users to consider initiating procedures to manage the potential risk of any necessary action by the Network Operator to restore or maintain power system security.

(e) In making information available in accordance with clause 4.3.2(d), the Network Operator shall use reasonable endeavours to ensure that such information is available to those Users who request the information on an equivalent basis.

(f) In the event that the Network Operator, in its reasonable opinion for reasons of safety to the public, the Network Operator personnel, Users’ equipment or the Network Operator equipment or for power system security, needs to interrupt supply to any User, the Network Operator will (time permitting) consult with the relevant User prior to executing that interruption.

(g) The Network Operator shall arrange controls, monitoring and secure communication systems which are appropriate in the circumstances to facilitate a manually initiated, rotational load shedding and restoration process which may be necessary if there is, in the Network Operator’s opinion, a prolonged major power system disruption.

4.3.3 Power System Controller

The Power System Controller shall:

(a) Take reasonable steps to ensure that high voltage switching procedures and arrangements are utilised by Users to provide adequate protection of the power system.

(b) Assess potential infringement of the technical envelope or power system operating procedures that could affect the security of the power system.

(c) Operate the power system within the limits of the technical envelope.
(d) Operate all *plant* and equipment under its control or co-ordination within the appropriate operational or emergency limits that are either established by the *Network Operator* or advised by the respective *User*.

(e) Assess the impacts of any technical and operational *constraints* on the operation of the *power system*.

(f) Monitor the *dispatch* of *Generation Units* and *associated loads* to ensure they stay within both their allowable limits and the dynamic limits of the *technical envelope*.

(g) Determine any potential *constraint* on the operation of *Generation Units* and *loads* and to assess the effect of this *constraint* on the maintenance of *power system security*.

(h) Assess the availability and adequacy, including the dynamic response, of *contingency capacity reserves* and *reactive power reserves* in accordance with clause 2 of this Code and to take reasonable steps to ensure that appropriate levels of *contingency capacity reserves* and *reactive power reserves* are available:

   (1) to ensure the *power system* is, and is maintained, in a *satisfactory operating state*; and

   (2) to arrest the impacts of a range of significant multiple *contingency events* (affecting up to 90% of the total *power system load*) to allow a prompt restoration or recovery of *power system security*, taking into account *under frequency* or *under voltage* initiated *load shedding* capability provided under *Access Agreements* or as otherwise.

(i) Make available to *Users* as appropriate, information about the potential for, or the occurrence of, a situation that could significantly impact, or is significantly impacting on *power system security*.

(j) Refer to other *Users*, as the *Power System Controller* deems appropriate, information of which the *Power System Controller* becomes aware in relation to significant risks to the *power system* where actions to achieve a resolution of those risks are outside the responsibility or control of the *Network Operator*.

(k) Determine the extent to which the levels of *contingency capacity reserves* and *reactive power reserves* are or were appropriate through appropriate testing, auditing and simulation studies.

(l) Utilise resources and services provided or procured as *ancillary services* or otherwise to maintain or restore the *satisfactory operating state* of the *power system*.

(m) Co-ordinate the operation of *black start-up facilities* in response to a partial or total *black system* condition sufficient to re-establish a *satisfactory operating state* of the *power system*. 
(n) Interrupt, subject to this clause 4.3.3, Users’ connections as necessary during emergency situations to facilitate the re-establishment of the satisfactory operating state of the power system.

(o) Direct (as necessary) any Users to take action necessary to ensure, maintain or restore the power system to a satisfactory operating state.

(p) Co-ordinate and direct any rotation of widespread interruption of demand in the event of a major supply shortfall or disruption.

(q) Investigate and review all major power system operational incidents and to initiate action plans to manage any abnormal situations or significant deficiencies that could reasonably threaten power system security. All Users shall co-operate with such action plans at their own cost. Such situations or deficiencies include without limitation:

1. power system frequencies outside those specified in the definition of satisfactory operating state;
2. power system voltages outside those specified in the definition of satisfactory operating state;
3. actual or potential power system instability; and
4. unplanned/unexpected operation of major power system equipment.

4.3.4 Network Users

(a) All Users shall co-operate with and assist the Power System Controller in the proper discharge of the Power System Controller’s power system security responsibilities.

(b) All Users shall operate their facilities and equipment in accordance with any reasonable direction given by the Power System Controller.

(c) All Users shall provide automatic interruptible load of the type described in clause 3.2.8. The level of this automatic interruptible load will be a minimum of 75% of their expected demand, or such other minimum interruptible load level as may be periodically determined by the Network Operator in accordance with clause 3.2.8.

(d) Users shall provide their interruptible load in manageable blocks spread over a number of steps within under frequency bands from 49.25 Hz down to 48.50 Hz as nominated by the Network Operator.

4.4 Power system frequency control

4.4.1 Power system frequency control responsibilities

The Power System Controller shall use its reasonable endeavours to:

(a) Control the power system frequency and associated time error in accordance with clause 2.2; and
(b) Ensure that the power system frequency operating standards set out in clause 2.2.1 of this Code are achieved.

4.4.2 Operational frequency control requirements

To assist in the effective monitoring of power system frequency by the Power System Controller the following provisions apply:

(a) The authority to control and direct the output of all Generation Units and supply to loads is given to the Power System Controller pursuant to clause 9.1.

(b) Each User shall ensure that all of its Generation Units have automatic and responsive speed governor systems and automatic load control schemes in accordance with the requirements of clause 3.3, so as to automatically adjust for changes in associated power demand or loss of Generation as it occurs through response to the resulting excursion in power system frequency and associated load.

(c) The Power System Controller shall use its reasonable endeavours to arrange to be available and specifically allocated to regulating duty such Generation Facilities as the Power System Controller considers appropriate which can be automatically controlled or directed by the Power System Controller to ensure that normal load variations do not result in frequency deviations outside the limitations specified in clause 2.2.1.

(d) The Power System Controller shall use its reasonable endeavours to arrange ancillary services and contractual arrangements associated with the availability, responsiveness and control of necessary contingency capacity reserve and the rapid unloading of Generation as may be reasonably necessary to cater for the impact on the power system frequency of potential power system disruptions ranging from the critical single credible contingency event to the most serious contingency events.

(e) The Power System Controller shall use its reasonable endeavours to ensure that adequate facilities are available and are under the direction of the Power System Controller to allow the managed recovery of the satisfactory operating state of the power system.

4.5 Control of network voltages

4.5.1 Network voltage control

(a) The Network Operator shall determine the adequacy of the capacity to produce or absorb reactive power in the control of the network voltages.

(b) The Network Operator shall assess and determine the limits of the operation of the network associated with the avoidance of voltage failure or collapse under credible contingency event scenarios.

(c) The limits of operation of the network shall be translated by the Network Operator, into key location operational voltage settings or limits, power line capacity limits, reactive power production (or absorption) capacity or other
appropriate limits to enable their use by the Power System Controller in the maintenance of power system security.

(d) The determination referred to in clause 4.5.1(b) shall include a review of the dynamic stability of the voltage of the transmission network.

(e) The Power System Controller shall use its reasonable endeavours to maintain voltage conditions throughout the network in accordance with the technical requirements specified in clause 2.

(f) The Network Operator shall use its reasonable endeavours to arrange the provision of reactive power facilities and power system voltage stabilising facilities through:

1. contractual arrangements for ancillary services with appropriate Users;
2. obligations on the part of Users; or under their Access Agreements;
3. provision of such facilities by the Network Operator.

(g) Without limitation, such reactive power facilities may include:

1. synchronous Generator voltage controls usually associated with tap-changing transformers; or Generator AVR set point control (rotor current adjustment);
2. synchronous condensers (compensators);
3. static var compensators (SVC);
4. shunt capacitors;
5. shunt reactors;
6. series capacitors.

4.5.2 Reactive power reserve requirements

(a) The Power System Controller shall use its reasonable endeavours to ensure that sufficient reactive power reserve is available at all times to maintain or restore the power system to a satisfactory operating state after the most critical contingency event as determined by previous analysis or by periodic contingency analysis by the Power System Controller.

(b) If voltages fall outside acceptable limits, and the means of voltage control set out in this clause 4.5.2 are exhausted, the Power System Controller shall take all reasonable actions, including to direct changes to demand (through selective load shedding from the power system), additional Generation operation or reduction in the transmission line flows but only to the extent necessary to restore the voltages to within the relevant limits.

(c) A User shall comply with any direction made by the Power System Controller under this clause 4.5.2.
4.6 Power system operating procedures

(a) The Power System Controller shall be responsible for developing and maintaining power system operating procedures including, but not limited to:

(1) basic electrical safety requirements;
(2) electrical safety instructions;
(3) general operating/field procedures; and
(4) station-specific procedures related to the operation of the power system in that station.

(b) The nature and effect of the power system operating procedures shall be set out in the System Control Technical Code.

4.6.1 Network operations

(a) The Power System Controller shall conduct or direct operations on the network in accordance with the appropriate power system operating procedures, the System Control Technical Code and good electricity industry practice.

(b) Users shall operate their equipment interfacing with the network in accordance with the requirements of:

(1) this Code;
(2) any applicable Access Agreement or ancillary services agreement;
(3) the requirements of the System Control Technical Code and the Network Operator's Electrical Safety Manual; and
(4) the relevant power system operating procedures.

(c) Users shall ensure that network operations performed on their behalf are undertaken by competent persons.

4.6.2 Switching of reactive power facilities

(a) The Power System Controller may instruct a User to place reactive facilities belonging to or controlled by that User into or out of service for the purposes of maintaining power system security where prior arrangements concerning these matters have been made between the Network Operator and a User.

(b) Without limitation to its obligations under such prior arrangements, a User shall use reasonable endeavours to comply with such an instruction given by the Network Operator or its authorised agent.

4.6.3 Generation limits

Limits to the VAr Generation and absorption capability of Generation Facilities and reactive compensation plant such as static var compensators are not to be exceeded.
4.7  **Power system security operations**

4.7.1  **Users’ advice**

A *User* shall promptly advise the *Power System Controller* at the *time* that the *User* becomes aware of any circumstance that could be expected to adversely affect the secure operation of the *power system* or any equipment owned or under the control of the *User*.

4.7.2  **Protection or control system abnormality**

(a) If a *User* becomes aware that any relevant *protection or control system* is defective or unavailable for service, that *User* shall advise the *Power System Controller* in accordance with the requirements of the *System Control Technical Code*.

(b) If the *Power System Controller* considers the unavailability of the *protection system* in 4.7.2(a) to be a threat to *power system security*, the *Power System Controller* may direct that the equipment protected or operated by the relevant *protection or control system* be taken out of operation or operated as the *Power System Controller* directs.

(c) A *User* shall comply with a *direction* given by the *Power System Controller* under clause 4.7.2(b) at no cost to the *Power System Controller*.

4.7.3  **Power System Controller advice on power system emergency conditions**

(a) The *Power System Controller* shall advise affected or potentially affected *Users* of all relevant details promptly after the *Power System Controller* becomes aware of any circumstance with respect to the *power system* which, in the reasonable opinion of the *Power System Controller* could be expected to materially adversely affect *supply* to or from *Users*.

(b) Without limitation, such circumstances may include:

   (1) electricity capacity shortfall, being a condition where there are insufficient *network* or *supply* options available to enable the secure *supply* of the total *load* in a *region*;

   (2) unexpected disruption of *power system security*, which may occur when:

      (iv) an unanticipated major *power system contingency event* occurs; or

      (v) significant environmental or similar conditions, including weather, storms or fires, are likely to, or are affecting the *power system*; or

   (3) a *black system* condition.
4.7.4 Managing a power system contingency event

(a) During the period when the power system is affected by a contingency event the Power System Controller shall carry out actions, in accordance with the guidelines set out in this Code and the System Control Technical Code to:

(1) identify the impact of the contingency event on power system security in terms of the capability of the network;

(2) identify and implement the actions required in each affected region to restore the power system to its satisfactory operating state.

(b) When contingency events lead to potential or actual electricity supply shortfall events, the Power System Controller shall follow the procedures outlined in clause 4.7.

4.7.5 Managing electricity supply shortfall events

(a) If, at any time, there are insufficient supply options available to securely supply total load in a region, then, the Power System Controller may undertake all or any of the following:

(1) recall of equipment outages;

(2) disconnect one or more points of load connection as the Power System Controller considers necessary;

(3) direct a User to take such steps as are reasonable to immediately reduce its load.

(b) A User shall use all reasonable endeavours to comply with a notice given under clause 4.7.5(a)(3).

(c) If there is a major supply shortfall, the Power System Controller shall implement, to the extent practical, a sharing of load shedding across interconnected regions up to the power transfer capability of the network.

4.7.6 Directions by the Power System Controller affecting power system security

Subject to the Power System Controller giving a User a reasonable period of time to take appropriate action:

(a) The Power System Controller may give reasonable directions to any User in accordance with the provisions of the System Control Technical Code requiring the User to do any act or thing which the Network Operator considers reasonably necessary to ensure the security of the power system.

(b) A User shall use all reasonable endeavours to comply within a reasonable period of time with any such directions given to it by the Network Operator. If a User does not comply with a direction within a reasonable period of time and as such a satisfactory operating state cannot be re-established, the Network Operator may disconnect the User without further recourse.
4.7.7 Disconnection of Generation Units and/or associated loads

(a) Where, under this Code or the relevant Access Agreement the Power System Controller has the authority or responsibility to disconnect either a Generation Unit or its associated load, then it may do so (either directly or through any agent) as described in clause 8.

(b) The relevant User and associated load shall provide all reasonable assistance to the Network Operator for the purpose of such disconnection.

4.7.8 Emergency black start-up facilities

Generator Users shall ensure they have sufficient facilities available and operable for their own black start-up requirements.

4.7.9 Black system procedures

(a) The Power System Controller shall develop system black procedures and set these procedures out in the System Control Technical Code.

(b) A Generator User shall develop the draft black system procedures for each of its power stations in accordance with the requirements of the System Control Technical Code.

(c) The Power System Controller may request amendments to a User’s draft black system procedures or any proposed changes as the Power System Controller reasonably considers necessary by notice in writing to the User, where use is to be made of the network.

(d) If the Power System Controller and a User are unable to agree on the amendments, the matter may be dealt with under the dispute resolution process described in clause 1.6.

4.7.10 Black system start-up

(a) The Power System Controller shall advise a User if, in the Power System Controller’s reasonable opinion, there is a black system condition which is affecting, or which may affect, that User.

(b) If a User is providing black start-up facilities under an ancillary services agreement with another User, then the local black system procedures for that User shall be consistent with this Code and their Access Agreement.

(c) The Power System Controller may by notice in writing to the relevant User require such amendments to the local black system procedures for a User which, in its reasonable opinion, are needed for consistency with:

(1) actual power system requirements; or

(2) if the User is providing black start-up facilities to another User under an ancillary services agreement, the relevant Access Agreement.

(d) If the Power System Controller advises a User of a black system condition, and/or if the terms of the relevant local black system procedures require the
User to take action, then the User shall comply with the agreed requirements of the local black system procedures.

(e) If there is a black system condition, then a User/Customer shall comply with the Power System Controller’s instructions with respect to the timing and magnitude of load restoration, as well as subsequent load movements or disconnections.

4.7.11 Review of operating incidents

(a) The Power System Controller shall conduct reviews of significant operating incidents or deviations from normal operating conditions in order to assess the adequacy of the provision and response of facilities or services, and the appropriateness of actions taken to restore or maintain power system security.

(b) For all cases where the Power System Controller has been responsible for the disconnection of a User, the Power System Controller shall provide a report of the review carried out to the User advising of the circumstances requiring that action.

(c) A User shall co-operate in any such review conducted by the Power System Controller (including making available relevant records and information).

(d) A User shall provide to the Power System Controller such information relating to the performance of its equipment during and after particular power system incidents or operating condition deviations as the Power System Controller reasonably requires for the purposes of analysing or reporting on those power system incidents or operating condition deviations.

(e) The Power System Controller shall provide to a User such information or reports relating to the performance of that User’s equipment during power system incidents or operating condition deviations as that User reasonably requests and in relation to which the Power System Controller is required to conduct a review under this clause.

4.8 Power system security support

4.8.1 Remote control and monitoring devices

(a) All remote control, operational metering and monitoring devices and local circuits as described in clause 3, shall be installed and maintained by a User in accordance with the standards and protocols determined and advised by the Power System Controller (for use in the Power System Controller’s control centre) for each:

1. Generation Unit and associated load connected to the network;
2. zone substation connected to the network; and
3. ancillary service provided by that User.

(b) The provider of any ancillary services shall arrange the installation and maintenance of all remote control equipment and remote monitoring
equipment in accordance with the standards and protocols determined by the Power System Controller for use in the Power System Controller’s control centre.

(c) The controls and monitoring devices shall include the provision for indication of active power and reactive power output, and to signal the status and any associated alarm condition relevant to achieving adequate protection control and indication of the network, and the User’s plant active and reactive output consumption.

4.8.2 Operational control and indication communication facilities

In accordance with clauses 3.3.3.1, 3.3.3.2 and 3.3.3.3, as applicable, Each User shall provide and maintain the necessary primary and, where nominated by the Network Operator, back-up communications facilities for control, operational metering and indication from the relevant local sites to the appropriate interfacing termination as nominated by the Network Operator.

4.8.3 Power system voice/data operational communication facilities

(a) The Power System Controller shall establish:

1) procedures for written and oral communications on operational matters; and

2) minimum telecommunications facilities to be provided by Users; in the System Control Technical Code.

(b) Each User shall advise the Power System Controller of each nominated position for the purposes of giving or receiving operational communications in relation to each of its facilities in accordance with the requirements of the System Control Technical Code.

(c) Each User shall provide, for each nominated position, communication systems in accordance with the requirements of the System Control Technical Code.

(d) Each User shall maintain communication systems in good repair and shall investigate faults within 4 hours, or as otherwise agreed with the Power System Controller, of a fault being identified and shall repair or procure the repair of faults promptly.

(e) The Power System Controller shall advise all Users of nominated persons for the purposes of giving or receiving operational communications in accordance with the requirements of the System Control Technical Code.

4.8.4 Records of power system operational communication

The Power System Controller shall establish the procedures for recording power system operational communications in the System Control Technical Code.
4.8.5 Agent communications

(a) A User may appoint an agent (called a “User Agent”) to coordinate operations of one or more of its facilities on its behalf, but only with the prior written consent of the Power System Controller.

(b) A User who has appointed a User Agent may replace that User Agent but only with the prior written advice to and consent of the Power System Controller.

(c) The Power System Controller may only withhold its consent to the appointment of a User Agent under clause 4.8.5(a), if it reasonably believes that the relevant person is not suitably qualified or experienced to operate the relevant facility at the interface with a network.

(d) For the purposes of this Code and any applicable Access Agreement acts or omissions of a User Agent are deemed to be acts or omissions of the relevant User.

(e) The Power System Controller and its representatives (including authorised agents) may:

1. rely upon any communications given by a User Agent as being given by the relevant User; and

2. rely upon any communications given to a User Agent as having been given to the relevant User.

(f) The Power System Controller is not required to consider whether any instruction has been given to a User Agent by the relevant User or the terms of those instructions.

4.9 Nomenclature standards

(a) The Network Operator shall establish nomenclature standards for network equipment;

(b) A User shall use the nomenclature standards for network equipment and apparatus as agreed with the Network Operator or failing agreement, as determined by the Network Operator.

(c) A User shall use reasonable endeavours to ensure that its representatives comply with the nomenclature standards in any operational communications with the Power System Controller.

(d) A User shall ensure that name plates on its equipment relevant to operations at any point within the power system conform to the requirements set out in the nomenclature standards.

(e) A User shall use reasonable endeavours to ensure that nameplates on its equipment relevant to operations within the power system are maintained to ensure easy and accurate identification of equipment.
(f) A User shall ensure that technical drawings and documentation provided to the Network Operator comply with the nomenclature standards.

(g) The Network Operator may, by notice in writing, request a User to change the existing numbering or nomenclature of network equipment and apparatus of the User for purposes of uniformity, and the User shall comply with such request provided that if the existing numbering or nomenclature conforms with the nomenclature standards, the Network Operator shall pay all reasonable costs incurred in complying with the request.

(h) All nomenclature shall be unique and unambiguous.
5 Testing of plant and equipment

The testing of plant and equipment is required before connection to the network and periodically thereafter to ensure that the network and connections can continue to operate within the parameters of the network performance standards set out in clause 2 and that equipment meets the requirements to be connected to the network set out in clause 3.

5.1 Obligations to test plant or equipment

5.1.1 Network Operator obligations

(a) The Network Operator shall arrange, co-ordinate and supervise the conduct of such appropriate tests as may be necessary to ensure that:

(1) the equipment at new connections to the network meets the requirements set out in clause 3.

(2) the protection of the network is adequate to protect against damage to power system plant and equipment. Such tests shall be performed according to the requirements of clause 5.2.

(3) the power system capability and performance is adequate to meet forecast operating conditions and power flows, as set out in clause 5.5.

(4) adequate reactive power devices are provided and available to control and maintain power system voltages under both satisfactory operating state and contingency event conditions;

(5) adequate devices are installed and available to maintain power system stability.

(6) Users continue to comply with the conditions set out in Access Agreements and that all Users’ connection equipment meets the requirements to set out in clause 3 and 5.4.

(7) the testing of metering installations is carried out in accordance with clause 10.6

5.1.2 Network Users’ obligations

(a) All network Users shall cooperate to permit the testing of their connection equipment as required under clause 5.1.1.

(b) A Generator shall provide evidence that each Generation Unit complies with the technical requirements of clause 3.3 and the relevant Access Agreement as required by clause 5.4
5.2 Routine testing of protection equipment

(a) Subject to clause 3.2.3.10, a User shall cooperate with the Network Operator to test the operation of equipment forming part of a protection scheme relating to a connection point at which that User is connected to a network and the User shall conduct these tests:

(1) prior to the plant at the relevant connection point being placed in service; and

(2) at intervals specified in the Access Agreement or in accordance with an asset management plan agreed between the Network Operator and the User.

(b) A User shall, on request from the Network Operator, demonstrate to the Network Operator’s satisfaction the correct calibration and operation of the User’s protective devices.

(c) Each User shall pay the Network Operator’s reasonable costs and shall bear its own costs of conducting tests under this clause 5.2.

5.3 Testing by Users of their own plant requiring changes to agreed operation

(a) A User proposing to conduct a test on equipment related to a connection point, which requires a change to the operation of that equipment as specified in the Access Agreement, shall give notice in writing to the Network Operator of at least 15 business days except in an emergency.

(b) The notice to be provided under clause 5.3(a) is to include:

(1) the nature of the proposed test;

(2) the estimated, start and finish time for the proposed test;

(3) the identity of the equipment to be tested;

(4) the power system conditions required for the conduct of the proposed test;

(5) details of any potential adverse consequences of the proposed test on the equipment to be tested;

(6) details of any potential adverse consequences of the proposed test on the power system; and

(7) the name of the person responsible for the coordination of the proposed test on behalf of the Users.

(c) The Network Operator shall review the proposed test to determine whether the test:

(1) could adversely affect the normal operation of the power system;

(2) could cause a threat to power system security;

(3) requires the power system to be operated in a particular way which differs from the way in which the power system is normally operated; or
(4) could affect the normal metering of energy at a connection point;

(d) If, in the Network Operator's reasonable opinion, a test could threaten public safety, damage or threaten to damage equipment or adversely affect the operation of the power system, the Network Operator may direct that the proposed test procedure be modified or that the test not be conducted at the time proposed.

(e) The Network Operator shall advise any other User who will be adversely affected by a proposed test and consider any reasonable requirements of those Users when approving the proposed test.

(f) The User who conducts a test under this clause 5.3 shall ensure that the person responsible for the coordination of a test promptly advises Network Operator when the test is complete.

(g) If the Network Operator approves a proposed test, the Network Operator shall use its reasonable endeavours to ensure that power system conditions reasonably required for that test are provided as close as is reasonably practical to the proposed start time of the test and continue for the proposed duration of the test.

(h) Within a reasonable period after any such test has been conducted, the User who has conducted a test under this clause 5.3 shall provide the Network Operator with a report in relation to that test including test results where appropriate.

5.4 Tests to demonstrate Generator compliance

(a) Each User shall provide evidence to the Network Operator that each of its Generation Units complies with the technical requirements of clause 3.3.2 and the relevant Access Agreement.

(b) Each User shall provide facilities to carry out power system tests prior to commercial operation in order to verify acceptable performance of each Generation Unit, and provide information and data necessary for computer model validation. These test requirements are detailed in Attachment 5.

(c) Other tests, if reasonably necessary, may be specified by the Network Operator, and Users will be advised accordingly.

(d) Each User shall negotiate in good faith with the Network Operator to agree on a compliance monitoring program, including an agreed method, for each of its Generation Units to confirm ongoing compliance with the applicable technical requirements of clause 3.3.2 and the relevant Access Agreement.

(e) If a performance test or monitoring of in-service performance demonstrates that a Generation Unit is not complying with one or more technical requirements of clause 3.3.2 and the relevant Access Agreement then the User shall:

1. promptly notify the Network Operator of that fact; and
(2) promptly advise the Network Operator of the remedial steps it proposes to take and the timetable for such remedial work; and

(3) diligently undertake such remedial work and report at monthly intervals to the Network Operator on progress in implementing the remedial action; and

(4) conduct further tests or monitoring on completion of the remedial work to confirm compliance with the relevant technical requirement.

(f) From the Code commencement date or from the date of access, whichever is the later, Each User shall maintain records and retain them for a minimum of 7 years (from the date of creation of each record) for each of its Generation Units and power stations setting out details of the results of all technical performance and monitoring conducted under this clause 5.4 and make these records available to Network Operator on request.

5.4.1 Tests of Generation Units requiring changes to agreed operation

(a) The Network Operator may, at intervals of not less than 12 months per Generation Unit, require the testing by a User of any Generation Unit connected to the network of the Network Operator in order to determine analytic parameters for modelling purposes or to assess the performance of the relevant Generation Unit. The Network Operator is entitled to witness such tests and the Network Operator shall have reasonable grounds for requiring such tests.

(b) Adequate notice of not less than 15 business days shall be given by the Network Operator to the User before the proposed date of a test under clause 5.4.1(a).

(c) The Network Operator shall use its reasonable endeavours to ensure that tests permitted under this clause 5.4.1 are to be conducted at a time which will minimise the departure from the commitment that is due to take place at that time.

(d) If not possible beforehand, a User shall conduct a test under this clause 5.4.1 at the next scheduled outage of the relevant Generation Unit and in any event within 9 months of the request.

(e) A User shall provide any reasonable assistance requested by the Network Operator in relation to the conduct of tests.

(f) Tests conducted under this clause 5.4.1 shall be conducted in accordance with test procedures agreed between the Network Operator and the relevant User, who shall not unreasonably withhold agreement to the test procedures proposed for this purpose by the Network Operator.

(g) The Network Operator shall provide to a User such details of the analytic parameters of the model derived from the tests referred to in this clause 5.4.1 for any of that User’s Generation Units as may reasonably be requested by the User.
(h) Each User shall bear its own costs associated with tests conducted under this clause 5.4.1 and no compensation is to be payable for financial losses incurred as a result of these tests or associated activities.

5.5 **Power system tests**

(a) Tests conducted for the purpose of either verifying the magnitude of the power transfer capability of networks or investigating power system performance shall be coordinated and approved by the Network Operator. The Network Operator or a User requesting such tests shall have reasonable grounds for requiring such tests.

(b) The tests described in clause 5.5(a) may be conducted whenever:

1. a new Generation Unit or facility of a Customer, User or a network development is commissioned that is calculated or anticipated to substantially alter power transfer capability through the network;

2. setting changes are made to any governor system and excitation control system, including power system stabilisers; or

3. a test is required to verify the performance of the power system or to validate computer models.

(c) The Network Operator shall notify all Users who could reasonably be expected to be affected by the proposed test at least 15 business days before any test under this clause 5.5 may proceed and to consider any reasonable requirements of those Users when approving the proposed test.

(d) Operational conditions for each test shall be arranged by the Network Operator and the test procedures shall be coordinated by an officer nominated by the Network Operator who has authority to stop the test or any part of it or vary the procedure within pre-approved guidelines if it considers any of these actions to be reasonably necessary.

(e) Each User shall cooperate with the Network Operator when required in planning, preparing for and conducting network tests to assess the technical performance of the networks and if necessary conduct co-ordinated activities to prepare for power system wide testing or individual, on-site tests of the User’s facilities or plant, including disconnection of a Generation Unit.

(f) The Network Operator may direct operation of Generation Units by Users during power system tests if this is necessary to achieve operational conditions on the networks that are reasonably required to achieve valid test results.

(g) The Network Operator shall plan the timing of tests so that the variation from dispatch that would otherwise occur is minimised and the duration of the tests is as short as possible consistent with test requirements and power system security.
(h) Each User is to bear its own costs of conducting tests under this clause 5.5 and no compensation is to be payable for financial losses incurred as a result of these tests or associated activities.

(i) If the Network Operator has initiated the tests as part of a series of periodic power system performance assessment studies, then the costs of the studies will be borne by the Network Operator. If the tests demonstrate the need for a User to install additional equipment in order to maintain or enhance power system performance in accordance with this Code, then the User will be responsible for the cost of installing the additional equipment.

5.6 Compliance with the Network Technical Code

5.6.1 Right of inspection and testing

(a) If the Network Operator has reasonable grounds to believe that equipment owned or operated by a User may not comply with this Code or the Access Agreement, the Network Operator may require testing of the relevant equipment by giving notice in writing to the User.

(b) If a notice is given under clause 5.6.1(a) the relevant test is to be conducted at a time agreed by the Network Operator.

(c) The User who receives a notice under clause 5.6.1(a) shall co-operate in relation to conducting tests requested under clause 5.6.1(a).

(d) The cost of tests requested under clause 5.6.1(a) shall be borne by the Network Operator, unless the equipment is determined by the tests not to comply with the relevant Access Agreement, and/or this Code in which case all reasonable costs of such tests shall be borne by the owner of that equipment.

(e) Tests conducted in respect of a connection point under this clause 5.6.1 shall be conducted using test procedures agreed between the relevant User, which agreement is not to be unreasonably withheld or delayed.

(f) Tests under this clause 5.6.1 shall be conducted only by persons with the relevant skills and experience.

(g) If the Network Operator requests a test under this clause 5.6.1, the Network Operator may appoint a representative to witness a test and the relevant User shall permit a representative appointed under this clause 5.6.1(g) to be present while the test is being conducted.

(h) Subject to clause 5.6.1(i), a User who conducts a test shall submit a report to the Network Operator within a reasonable period after the completion of the test and the report is to outline relevant details of the tests conducted, including but not limited to the results of those tests.
(i) If a performance test or monitoring of in-service performance demonstrates that equipment owned or operated by a User does not comply with this Code or the relevant Access Agreement then the User shall:

1. promptly notify the Network Operator of that fact; and
2. promptly advise the Network Operator of the remedial steps it proposes to take and the timetable for such remedial work; and
3. diligently undertake such remedial work and report at monthly intervals to the Network Operator on progress in implementing the remedial action; and
4. conduct further tests or monitoring on completion of the remedial work to confirm compliance with the relevant technical requirement.

(j) The Network Operator may attach test equipment or monitoring equipment to plant owned by a User or require a User to attach such test equipment or monitoring equipment, subject to the provisions of clause 5.7.1 regarding entry and inspection.

(k) In carrying out monitoring under clause 5.6.1(j), the Network Operator shall not cause the performance of the monitored plant to be constrained in any way.

5.6.2 Generator compliance with the Code

(a) If the Network Operator reasonably believes that a Generator is not complying with one or more technical requirements of clause 3.3.2 and the relevant Access Agreement, the Network Operator may instruct the User to conduct tests within 25 business days to demonstrate that the relevant Generation Unit complies with those technical requirements.

(b) If the tests provide evidence that the relevant Generation Unit continues to comply with the technical requirement(s) Network Operator shall reimburse the User for the reasonable expenses incurred as a direct result of conducting the tests.

(c) If the Network Operator:

1. is satisfied that a Generation Unit does not comply with one or more technical requirements; and
2. does not have evidence demonstrating that a Generation Unit complies with the technical requirements set out in clause 3.3; or
3. holds the reasonable opinion that there is or could be a threat to power system security,
then the Network Operator may direct the relevant User to operate the relevant Generation Unit at a particular generated output or in a particular mode until the relevant User submits evidence reasonably satisfactory to the Network Operator that the Generation Unit is complying with the relevant technical requirement.
(d) A direction under clause 5.6.2(c) shall be recorded by the Network Operator.

5.7 Inspection of plant and equipment

5.7.1 Right of entry and inspection

(a) The Network Operator or any of its representatives (including authorised agents) may, in accordance with this clause 5.7.1, inspect a facility of a User and the operation and maintenance of that facility in order to:

(1) assess compliance by the relevant User with its operational obligations under this Code, or an Access Agreement, or an ancillary services agreement; or

(2) investigate any possible past or potential threat to power system security; or

(3) conduct any periodic familiarisation or training associated with the operational requirements of the facility.

(b) If the Network Operator wishes to inspect the facilities of a User under clause 5.7.1(a), the Network Operator shall give that User at least 2 business days’ notice in writing of its intention to carry out an inspection. In the case of an emergency condition affecting the power system which the Network Operator reasonably considers requires access to the User’s facility, prior notice is not required, however, the Network Operator shall notify the User as soon as practical after deciding to enter the User’s facility of the nature and extent of the Network Operator’s activities at the User’s facility.

(c) A notice given under clause 5.7.1 (b) shall include the following information:

(1) the name of the representative who will be conducting the inspection on behalf of the Network Operator;

(2) subject to clause 5.7.1(h), the time when the inspection will commence and the expected time when the inspection will conclude; and

(3) if associated with clause 5.7.1(a)(1) then the nature of the suspected non-compliance with the Code or Access Agreement or ancillary services agreement, or if associated with clauses 5.7.1(a)(2) or 5.7.1(a)(3) then the relevant reasons for the inspection.

(d) The Network Operator may not carry out an inspection under clause 5.7.1 within 6 months of any previous inspection except for the purpose of verifying the performance of corrective action claimed to have been carried out in respect of a non-conformance observed and documented on the previous inspection or for the purpose of investigating an operating incident in accordance with clause 4.7.11.

(e) At any time when the representative of the Network Operator is in a User’s facility, that representative shall:

(1) cause no damage to the facility;
(2) only interfere with the operation of the facility to the extent reasonably necessary and approved by the relevant User (such approval not to be unreasonably withheld or delayed);

(3) observe “permit to test” access to sites and clearance protocols of the operator of the facility, provided that these are not used by the facility solely to delay the granting of access to site and inspection;

(4) observe the requirements of the operator of the facility in relation to occupational health and safety and industrial relations matters, which requirements are of general application to all invitees entering on or into the facility, provided that these are not used by the facility solely to delay the granting of access to site and inspection; and

(5) not ask any question other than as reasonably necessary for the purpose of such inspection or give any direction, instruction or advice to any person involved in the operation or maintenance of the facility other than the operator of the facility or unless approved by the operator of the facility.

(f) Any representative of the Network Operator conducting an inspection under this clause 5.7.1 shall be appropriately qualified and experienced to perform the relevant inspection. If so requested by the User, the Network Operator shall procure that a representative of Network Operator (other than an employee) gaining access under this Code or an Access Agreement enters into a confidentiality undertaking in favour of the User in a form reasonably acceptable to the User prior to gaining such access.

(g) The costs of inspections under this clause 5.7.1 shall be borne by the User if the suspected non-compliance is later proved by tests.

(h) Any inspection under clause 5.7.1(a) shall not take longer than one day unless the Network Operator seeks approval from the User for an extension of time (such approval not to be unreasonably withheld or delayed).

(i) Any equipment or goods installed or left on land or in premises of a User after an inspection conducted under this clause 5.7.1 do not become the property of the relevant User (notwithstanding that they may be annexed or affixed to the relevant land or premises).

(j) In respect of any equipment or goods left on land or premises of a User during or after an inspection, a User:

(1) shall not use any such equipment or goods for a purpose other than as contemplated in this Code without the prior written approval of the owner of the equipment or goods;

(2) shall allow the owner of any such equipment or goods to remove any such equipment or goods in whole or in part at a time agreed with the relevant User with such agreement not to be unreasonably withheld or delayed;
(3) shall not create or cause to be created any mortgage, charge or lien over any such equipment or goods; and

(4) shall reimburse the owner of any such equipment or goods for reasonable costs and expenses suffered or incurred by the owner due to loss or damage to any such equipment or goods caused by the User.
6 Control and protection settings

6.1 Protection of power system equipment

It is important to note that the requirements of this clause 6 are designed to adequately protect the Network Operator’s power system. The requirements are not necessarily adequate to protect Users’ plant and equipment.

6.1.1 Scope

(a) The requirements of clause 6.1 apply only to a User’s protection, which is necessary to maintain power system security.

(b) Users’ protection schemes shall be located on Users’ equipment.

(c) Protection installed solely to cover risks associated with a User’s plant and equipment is at the User’s discretion.

(d) The extent of a User’s plant and equipment that will need to conform to the requirements of clause 6.1 will vary from installation to installation.

(e) The Network Operator will assess each User’s installation individually. Users will be advised accordingly.

6.1.2 Power system fault levels

(a) The Network Operator shall determine the fault levels at all busbars of the Network Operator’s network as described in clause 6.1.2(b);

(b) The Network Operator shall ensure that there is information available about the network that will allow the determination of fault levels for normal operation of the power system. The Network Operator will make available on request the credible contingency events which the Network Operator considers may affect the configuration of the power system so that the Network Operator and Users can identify their busbars which could potentially be exposed to a fault level which exceeds the fault current ratings of the circuit breakers and other equipment associated with that busbar.

6.1.3 Power system protection co-ordination

The Network Operator shall use its reasonable endeavours to co-ordinate the protection settings for equipment connected to the network. Users with protection systems that impact power system security and reliability shall ensure their settings co-ordinate with the Network Operator’s protection. Such Users may not adjust settings without the Network Operator’s approval. Specific requirements are described in clauses 6.1.6.4 and 11.2.2.

6.1.4 Short-term thermal ratings of the power system

(a) The Network Operator may act so as to use, or require or recommend actions which use the full extent of the thermal ratings of network elements to maintain power system security, including the short-term ratings (being time dependent ratings), as defined by the Network Operator from time to time.
(b) The Power System Controller shall use its reasonable endeavours not to exceed the network element ratings and not to require or recommend action that causes those ratings to be exceeded.

6.1.5 Availability of protection

(a) All elements of protection schemes, including backup protection and associated intertripping, shall be maintained so as to be available for service at all times.

(b) For maintenance or repair purposes, one protection scheme forming part of a protection system can be taken out of service for period of up to 24 hours every 6 months.

(c) At the discretion of the Network Controller, longer periods of unavailability may require the associated primary plant to be taken out of service in accordance with clause 6.1.6.

(d) Except in an emergency, a User shall notify the Network Operator at least 5 business days prior to taking a protection scheme out of service.

6.1.6 Partial outage of power protection systems

(a) Where there is an outage of one protection of a network element, the Power System Controller shall determine, the most appropriate action. Depending on the circumstances the determination may be:

(1) to leave the network element in service for a limited duration;
(2) to take the network element out of service immediately;
(3) to install or direct installation of a temporary protection;
(4) to accept a degraded performance from the protection, with or without additional operational measures or temporary protection measures to minimise power system impact; or
(5) to operate the network element at a lower capacity.

(b) If there is an outage of both protection schemes on a network element and the Power System Controller determines this to be an unacceptable risk to power system security, the Power System Controller shall take the network element out of service as soon as possible and advise any affected User immediately this action is undertaken.

(c) Any affected User shall accept a determination made by the Network Operator under this clause 6.1.6.

6.1.6.1 Sensitivity of protection

(a) All protection schemes shall have sufficient sensitivity to detect and correctly clear all primary plant faults within their intended normal operating zones, under both normal and minimum system conditions.

(b) Protection schemes shall discriminate with the Network Operator’s protection.
Under abnormal plant conditions, all primary system faults shall be detected and cleared by at least one protection scheme on the User’s equipment. Remote backup protection or standby protection may be used for this purpose.

The protection will be considered to have sufficient sensitivity if it will detect and correctly clear a fault when there is half the fault current that will flow for the above conditions.

In rural areas where the earth return impedance is high, sensitive earth fault protection may also be required, in addition to the above backup and primary protection.

6.1.6.2 Clearance of small zone faults

Small zone faults shall be detected and cleared by backup protection as specified in clause 3.2.3.6.

6.1.6.3 Clearance of faults under circuit breaker fail conditions

Failure of a circuit breaker, due to either a mechanical or electrical fault, to clear a fault shall, when reasonably required by the Network Operator, be detected and the primary fault current shall be cleared by backup protection as specified in the clause 3.2.3.6.

6.1.6.4 Details of proposed Users’ protection settings

Unless agreed otherwise, Users shall provide the Network Operator with full details of proposed protection settings and setting calculations on all plant that may impact on the Network Operator’s power system a minimum of 65 business days prior to energisation of the protected primary plant. Refer to clause 7.1.3.

6.1.6.5 Coordination of protection settings

(a) The User shall ensure that all their protection settings coordinate with existing Network Operator protection settings. Where this is not possible, the User will be responsible for the cost of revising Network Operator settings and upgrading Network Operator or other Users’ equipment, where required.

(b) Generally, Network Operator protection which discriminates on the basis of time employs devices with standard inverse characteristics to BS EN 60255-6:1995 with a 3 second curve at 10 times current and time multiplier of 1.0. Note that this is the specification of the characteristic rather than the device setting. Distance relay Zone 2 time is generally set to 400 msec and Zone 3 time to 1000 msec.

(c) Specific details of Network Operator protection are available on request.

6.2 Power system stability co-ordination

(a) The Network Operator shall use its reasonable endeavours to ensure that all necessary calculations associated with the stable operation of the power system as described in clause 2.6 and for the determination of settings of
equipment used to maintain that stability are carried out and to co-ordinate these calculations and determinations.

(b) The Network Operator shall facilitate establishment of the parameters and endorse the installation of power system devices that are approved by the Network Operator to be necessary to assist the stable operation of the power system.
7 Commissioning and testing procedures

7.1 Commissioning

7.1.1 Requirement to inspect and test equipment

(a) A User shall ensure that any of its new or replacement equipment is inspected and tested to demonstrate that it complies with relevant Australian Standards, relevant international standards, this Code and any relevant Access Agreement prior to or within an agreed time after being connected to a network, and the Network Operator is entitled to witness such inspections and tests.

(b) The User shall produce test certificates on request by the Network Operator showing that the equipment has passed the tests and complies with the standards set out in clause 7.1.1(a) before connection to the power system, or within an agreed time thereafter.

7.1.2 Co-ordination during commissioning

A User seeking to connect to a network shall cooperate with the Network Operator to develop procedures to ensure that the commissioning of the connection and connected facility is carried out in a manner that:

(a) Does not adversely affect other Users or affect power system security or quality of supply of the power system; and

(b) Minimises the threat of damage to any other Users’ equipment.

7.1.3 Control and protection settings for equipment

(a) Not less than 65 business days prior to the proposed commencement of commissioning of any new or replacement equipment that could reasonably be expected to alter performance of the power system, the User shall submit to the Network Operator sufficient design information including proposed parameter settings to allow critical assessment including analytical modelling of the effect of the new or replacement equipment on the performance of the power system.

(b) The Network Operator shall:

(1) consult with other Users as appropriate; and

(2) within 20 business days of receipt of the design information under clause 7.1.3(a), notify the User of any comments on the proposed parameter settings for the new or replacement equipment.

(c) If the Network Operator’s comments include alternative parameter settings for the new or replacement equipment, then the User shall notify the Network Operator within 20 business days that it either accepts or disagrees with the alternative parameter settings suggested by the Network Operator.
(d) The Network Operator and the User shall negotiate parameter settings that are acceptable to them both.

(e) The User and the Network Operator shall co-operate with each other to ensure that adequate grading of protection is achieved so that faults within the User’s facility are cleared without adverse effects on the power system.

(f) The User shall pay the Network Operator’s reasonable costs associated with the assessment of the parameter settings under this clause 7.1.3.

7.1.4 Commissioning program

(a) Not less than 65 business days prior to the proposed commencement of commissioning by a User of any new or replacement equipment that could reasonably be expected to alter performance of the power system, the User shall advise the Network Operator in writing of the commissioning program including test procedures and proposed test equipment to be used in the commissioning.

(b) The Network Operator shall, within 20 business days of receipt of such advice under clause 7.1.4(a), notify the User either that it:

(1) agrees with the proposed commissioning program and test procedures; or

(2) requires changes in the interest of maintaining power system security, safety or quality of supply.

(c) If the Network Operator requires changes, then the parties shall co-operate to reach agreement and finalise the commissioning program within a reasonable period.

(d) A User shall not commence the commissioning until the commissioning program has been finalised and the Network Operator shall not unreasonably delay finalising a commissioning program.

(e) The User shall pay the Network Operator’s reasonable costs associated with the assessment of the commissioning program under this clause 7.1.4.

7.1.5 Commissioning tests

(a) The Network Operator has the right to witness commissioning tests relating to new or replacement equipment that could reasonably be expected to alter performance of the power system or the accurate metering of energy, including SCADA equipment.

(b) Prior to connection to the Network Operator’s power system, the User shall have provided to the Network Operator a signed written statement to certify that the equipment to be connected has been installed in accordance with:

(1) this Code;

(2) the relevant Access Agreement;
(3) all relevant standards;
(4) all statutory requirements; and
(5) good electricity industry practice.

(c) The statement shall have been certified by a professional engineer, as approved by the Network Operator.

(d) The Network Operator shall, within a reasonable period of receiving advice of commissioning tests, notify the User whose new or replacement equipment is to be tested under this clause 7.1.5 whether or not it:
(1) wishes to witness the commissioning tests; and
(2) agrees with the proposed commissioning times.

(e) A User whose new or replacement equipment is tested under this clause 7.1.5 shall submit to the Network Operator the commissioning test results demonstrating that a new or replacement item of equipment complies with this Code or the relevant Access Agreement or both to the satisfaction of the Network Operator.

(f) If the commissioning tests conducted in relation to a new or replacement item of equipment demonstrates non-compliance with one or more requirements of this Code or the relevant Access Agreement then the User whose new or replacement equipment was tested under this clause 7.1.5 shall promptly meet with the Network Operator to agree on a process aimed at achievement of compliance of the relevant item with this Code.

(g) The Network Operator may direct that the commissioning and subsequent connection of the User’s equipment should not proceed if the relevant equipment does not meet the technical requirements specified in clause 7.1.1.

(h) All commissioning and testing of User owned equipment shall be carried out by personnel experienced in the commissioning of power system primary plant and secondary plant.

(i) The User shall pay the Network Operator’s reasonable costs associated with the witnessing of commissioning tests under this clause 7.1.5.

7.1.5.1 Commissioning of protection

(a) The Network Operator reserves the right to witness the commissioning tests on any of the User’s protection that it deems to be important or critical for the reliable operation and integrity of the Network Operator power system.

(b) The User shall pay Network Operator’s reasonable costs associated with the witnessing of the commissioning tests.

(c) All commissioning and testing of User owned protection shall be carried out by personnel suitably qualified and experienced in the commissioning, testing and maintenance of primary plant and secondary plant and equipment.
8 Disconnection and reconnection of plant and equipment

8.1.1 Voluntary disconnection

(a) Unless agreed otherwise and specified in an Access Agreement, a User shall give to the Network Operator notice in writing of its intention to permanently disconnect a facility from a connection point.

(b) A User is entitled, subject to the terms of the relevant Access Agreement, to require voluntary permanent disconnection of its equipment from the power system in which case appropriate operating procedures necessary to ensure that the disconnection will not threaten power system security shall be implemented in accordance with clause 8.1.2.

(c) The User shall pay all costs directly attributable to the voluntary disconnection and decommissioning.

8.1.2 Decommissioning procedures

(a) In the event that a User’s facility is to be permanently disconnected from the power system, whether in accordance with clause 8.1.1 or otherwise, the Network Operator and the User shall, prior to such disconnection occurring, follow agreed procedures for disconnection.

(b) The Network Operator shall notify other Users if it believes, in its reasonable opinion, the terms and conditions of such an Access Agreement will be affected by procedures for disconnection or proposed procedures agreed with any other Users. The parties shall negotiate any amendments to the procedures for disconnection or the Access Agreement that may be required.

(c) Any disconnection procedures agreed to or determined under clause 8.1.2(a) shall be followed by the Network Operator and all Users.

8.1.3 Involuntary disconnection (refer also to clause 4.7)

(a) The Network Operator may disconnect a User’s facilities from a network:

(1) during an emergency in accordance with clause 8.1.5;

(2) in accordance with relevant laws; or

(3) in accordance with the provisions of the User’s Access Agreement.

(b) In all cases of disconnection by the Network Operator during an emergency in accordance with clause 8.1.5, the Network Operator is required to undertake a review under clause 4.7.11 and the Network Operator shall then provide a report to the User advising of the circumstances requiring such action.

8.1.4 Disconnection due to breach of an Access Agreement

(a) Subject to the relevant provisions the Network Operator may disconnect a User’s facilities from a network if in the Network Operator’s reasonable opinion, the User has breached a term of the Access Agreement and such breach poses a threat to power system security. In such circumstances the
Network Operator will not be liable in any way for any loss or damage suffered or incurred by the User by reason of the disconnection and the Network Operator will not be obliged for the duration of the disconnection to fulfil any agreement to convey electricity to or from the User’s facility.

(b) A User shall not bring proceedings against the Network Operator to seek to recover any amount for any loss or damage described in clause 8.1.4(a).

(c) A User whose facilities have been disconnected under this clause 8.1.4 shall pay charges in accordance with the Network Pricing and Charges Schedule as if any disconnection had not occurred.

8.1.5 Disconnection during an emergency

Where the Network Operator may disconnect a User’s facilities during an emergency under this Code or otherwise, then the Network Operator may:

(a) Request the relevant User to reduce the power transfer at the proposed point of disconnection to zero in an orderly manner and then disconnect the User’s facility by automatic or manual means; or

(b) Immediately disconnect the User’s facilities by automatic or manual means where, in the Network Operator’s reasonable opinion, it is not appropriate to follow the procedure set out in clause 8.1.5(a) because action is urgently required as a result of a threat to safety of persons, hazard to equipment or a threat to power system security.

8.1.6 Obligation to reconnect

The Network Operator shall reconnect a User’s facilities to a network at a reasonable cost to the User as soon as practical if:

(a) Disconnection of the User during an emergency has taken place in accordance with clause 8.1.5.

(b) A breach of this Code or Access Agreement giving rise to disconnection has been remedied; or

(c) Where the breach is not capable of remedy, compensation has been agreed and paid by the User to the affected parties or, failing agreement, the amount of compensation payable has been determined in accordance with the dispute resolution process described in clause 1.6 and that amount has been paid; or

(d) Where the breach is not capable of remedy and the amount of compensation has not been agreed or determined, assurances for the payment of reasonable compensation have been given to the satisfaction of the Network Operator and the parties affected; or

(e) The User has taken all necessary steps to prevent the re-occurrence of the breach and has delivered binding undertakings to the Network Operator that the breach will not reoccur.
9 Operation of Generators connected to the network

9.1 Power system security related market operations

9.1.1 Dispatch related limitations

A User shall not, unless in the User’s reasonable opinion public safety would otherwise be threatened or there would be a material risk of damaging equipment or the environment:

(a) Dispatch any energy from a Generation Unit, except:

   (1) in accordance with the procedures specified in this Code and its Technical Requirements for connection; or
   (2) in accordance with an instruction from the Power System Controller; or
   (3) as a consequence of operation of the Generation Unit’s automatic load following scheme approved by the Network Operator; or
   (4) in accordance with a procedure agreed with the Network Operator; or
   (5) in connection with a test conducted in accordance with the requirements of this Code or a procedure agreed with by the Network Operator.

(b) Adjust the transformer tap position or excitation control system voltage set-point of a scheduled Generation Unit except:

   (1) in accordance with an instruction from or by agreement with the Network Operator; or
   (2) in response to remote control signals given by the Network Operator or its agent; or
   (3) if, in the scheduled User’s reasonable opinion, the adjustment is urgently required to prevent material damage to the User’s plant or associated equipment, or in the interests of safety; or
   (4) in connection with a test agreed with the Network Operator and conducted in accordance with this Code or procedures agreed with the Network Operator.

(c) Energise a connection point in relation to a User’s Generator unit without prior approval from the Network Operator. This approval shall be obtained immediately prior to energisation;

(d) Synchronise a scheduled Generation Unit to, or de-synchronise a scheduled Generation Unit from, the power system without prior approval from the Power System Controller except de-synchronisation as a consequence of the operation of automatic protection equipment or where such action is urgently required to prevent material damage to plant or equipment or in the interests of safety;

(e) Change the frequency response mode of a scheduled Generation Unit without the prior approval of the Network Operator; or
(f) Remove from service or interfere with the operation of any power system stabilising equipment installed on that Generation Unit.

See also clauses 3.3 and 4.2 of Version 4.0 of the System Control Technical Code.

9.1.2 Commitment of Generation Units

In relation to any User’s Generation Unit, the User shall confirm with the Power System Controller, the expected synchronism time at least one hour before the expected actual synchronising time, and update this advice 5 minutes before synchronising unless otherwise agreed with the Power System Controller. The Power System Controller may require further notification immediately before synchronisation.

9.1.3 De-commitment, or output reduction, by Users requiring standby power

(a) Any User requiring standby power from a Generator or the Network Operator shall notify the Power System Controller well in advance. To do this a User will have to both apply for it and include it in the outage and production plans they submit to the Power System Controller.

(b) A User shall confirm with the Power System Controller the expected desynchronising time at least one hour before the expected actual desynchronising time, and update this advice 5 minutes before desynchronising unless otherwise agreed with the Power System Controller. The Power System Controller may require further notification immediately before desynchronisation.

(c) Information to be confirmed with the Power System Controller to de-commit a User’s Generation Unit if there is to be no automatic and coincident reduction in the User’s associated load shall include:

1. the time to commence decreasing the output of the Generation Unit;
2. the ramp rate to decrease the output of the Generation Unit;
3. the time to de-synchronise the Generation Unit; and
4. the output from which the Generation Unit is to be de-synchronised.

(d) Any User not requiring standby power that wishes to take a Generator out-of-service shall first reduce the associated load demand by an amount equal to the Generator output to be reduced. Once the demand has been reduced, the Generator’s load may be reduced. Clearance shall be obtained from the Power System Controller before commencing this exercise.

9.2 Users’ plant changes

A User shall, without delay, notify the Power System Controller of any event which has changed or is likely to change the operational availability or load following capability of any of its Generation Units, whether the relevant Generation Unit is synchronised or not, as soon as the User becomes aware of the event.
9.3 Operation, maintenance and extension planning

Operation, maintenance and extension planning and co-ordination shall be performed in accordance with this Code and any applicable Access Agreement.

9.4 Generating limits

Limits to the VAr Generation and absorption capability of Generation Facilities and reactive compensation plant such as static var compensators shall not be exceeded.
10 **Metering requirements**

This clause 10 applies to all Users at any revenue metering point through which energy is transferred to or energy is taken from the Network Operator’s electricity network.

10.1 **Purpose of metering clause**

(a) The purpose of clause 10 is to set out the rights and obligations of Users and the Network Operator.

(b) Clause 10 sets out provisions relating to:

1. revenue metering installations used for the measurement of active energy and reactive energy, imported and/or exported;
2. check metering installations;
3. the collection of revenue metering data;
4. the provision, installation and maintenance of equipment;
5. the accuracy of revenue metering equipment;
6. testing requirements;
7. the security and rights of access to revenue metering data and equipment; and
8. the provision of revenue metering data.

10.2 **Metering principles**

The key metering principles are as follows:

(a) Each connection point shall have a revenue metering installation.

(b) The type of revenue metering installation at each revenue metering point is to be determined by the Network Operator in accordance with the annual amount of energy passing through that revenue metering point.

(c) The Network Operator will have responsibility for the provision and installation of revenue metering unless the User elects to provide and install the revenue metering, other than the revenue meters, which will be provided and installed by the Network Operator.

(d) The Network Operator will install the revenue meters or the revenue metering, and will commission and maintain the revenue metering.

(e) The Network Operator may offer to install a check meter, or check meters, or check metering, and commission and maintain check metering on behalf of the User.

(f) The Network Operator will own the revenue metering installation and the User may be required to make a non-refundable contribution to the cost of the installation.
(g) All costs associated with the auditing and maintenance of a revenue metering installation will be borne by the User.

(h) The Network Operator shall ensure that the accuracy of each component of a revenue metering installation complies with its accuracy class.

(i) Energy data is to be based on units of watt-hours active energy and var-hours reactive energy.

(j) The Network Operator will make revenue metering data available to Each User, subject to confidentiality requirements.

(k) The revenue meters used will make provision for signals comprising energy usage information to be available via volt free relay contacts at the revenue metering location.

(l) The specifications for the revenue metering voltage and current transformers will make provision for secondary voltages and currents to allow the User to readily install check metering, if required by the User.

(m) Historical revenue metering data is to be retained for a minimum of 7 years.

(n) The Network Operator will audit revenue metering when requested.

10.3 Responsibility for metering installation

10.3.1 Responsibility of the Network Operator

(a) No later than 20 business days after receiving a request for the provision of a revenue metering installation, or a revenue metering installation and a check metering installation from a prospective User, the Network Operator shall provide a quotation and any conditions on which the offer is made.

(b) The Network Operator will advise the User of its right to provide and install certain revenue metering components in accordance with Attachment 4 and the Network Operator’s Metering Manuals, Underground Manual and Overhead Line Manual.

(c) If the User accepts the offer, the Network Operator has the responsibility for the provision, installation, commissioning and maintenance of the revenue metering equipment in accordance with Attachment 4 and the Network Operator’s metering manuals, Underground Manual and Overhead Line Manual.

10.3.2 User elects to provide and install certain metering components

(a) If the User does not accept the offer made by the Network Operator to provide a revenue metering installation, the User will be responsible for the provision and installation of the revenue metering, except for the revenue meters in accordance with Attachment 4 and the Network Operator’s metering manuals and the check metering, if required by the User.
(b) The Network Operator will provide and install the revenue meters, commission the installation and provide ongoing maintenance of the revenue metering installation in accordance with Attachment 4 and the Network Operator’s metering manuals.

10.3.3 Other responsibilities

(a) The Network Operator shall ensure that the revenue metering installation is provided, installed and maintained in accordance with Attachment 4 and the Network Operator’s metering manuals.

(b) The User, if providing and installing revenue metering equipment, shall ensure that the equipment complies with Attachment 4 and the Network Operator’s metering manuals.

(c) Prior to installation, the equipment that is involved in measurement of energy, other than the check meters shall be submitted to the Network Operator for testing for compliance with the Network Operator’s metering manuals.

10.4 Metering installation arrangements

10.4.1 Metering installation components

(a) A revenue metering installation shall comply with the requirements of the National Standards (Weight & Measures) Act in regard to being a measuring device that is used for trade or legal purposes.

(b) A revenue metering installation shall:

(1) contain a measuring device for active and reactive energy and a visible display of all revenue metering data as per Australian Standard AS1284;
(2) be accurate in accordance with Attachment 4;
(3) have electronic data transfer facilities;
(4) be secure in accordance with the Network Operator’s metering manuals;
(5) have electronic data recording facilities for active and reactive energy flows;
(6) be capable of separately registering and recording energy import and export where bi-directional energy flows occur;
(7) be capable of providing revenue metering data to a communication system; and
(8) include a communication system for two way communications with the Network Operator.

(c) A revenue metering installation will consist of combinations of, but is not limited to, the following:

(1) current transformer;
(2) voltage transformers;
(3) secure and protected wiring;
(4) revenue meter panels on which the revenue meters and communication equipment are mounted;
(5) communication equipment such as modem, Public Switched Telephone Network connection, isolation, radio transmitter and receiver, data link, or power line carrier equipment;
(6) test links and fusing;
(7) energy and status signals;
(8) summation equipment;
(9) revenue metering enclosure;
(10) marshalling boxes; and
(11) revenue metering unit.

(d) The revenue metering installation is exclusively for revenue metering other than the provision of energy and status signals which may be provided to the User for other purposes.

10.4.2 Metering for connection of Small Inverter Energy Systems

(a) A User with a Small Inverter Energy System shall make provision for both an import and export meter.

(b) Should an additional meter be required for the export power meter, the User may need to install an additional meter box or rearrange the existing meter box to accommodate a second meter.

10.4.3 Use of meters

(a) Revenue metering data will be used by the Network Operator as the primary source of billing data.

(b) Where appropriate check metering data is available, it will be used by the Network Operator for:

(1) validation;
(2) substitution; and
(3) account estimation

of revenue metering data as required by clause 10.9.4.

10.4.4 Metering type and accuracy

(a) The accuracy for a revenue metering installation and the requirements for a revenue metering installation that shall be installed at each revenue metering point shall be in accordance with Attachment 4 and the Network Operator’s metering manuals.
(b) A check metering installation is not required, but if provided by a User it may use the voltages and currents provided by the revenue metering voltage transformers and current transformers. The check meter or check meters will be of the same class as the revenue meters.

(c) If the User elects to provide separate current transformers and voltage transformers they shall comply with clause 10.3.3.

10.4.5 Data collection system

(a) The Network Operator shall ensure that an appropriate communication system is installed to each revenue metering installation.

(b) The Network Operator shall establish processes for the collection of revenue metering data from each revenue metering installation for storage in a revenue metering data base in accordance with the Network Operator’s metering manuals.

(c) The Network Operator may obtain revenue metering data directly from a revenue metering installation.

10.4.6 Payment for metering

(a) The User is responsible for payment of all costs associated with the provision, installation, commissioning, maintenance, routine testing and inspection, routine audits, downloading of revenue metering data, processing and account resolution for a revenue metering installation.

(b) The cost of requisition testing and audits shall be borne by the party requesting the test or audit, except where the revenue metering installation is shown not to comply with this clause, in which case the Network Operator shall bear the cost.

10.5 Register of metering information

(a) As part of the revenue metering database, the Network Operator shall maintain a revenue metering register of all Users’ revenue metering installations and check metering installations that provide tariff data.

(b) The revenue metering register for a particular User’s revenue metering installation shall be made available to the User on request.

10.5.1 Meter register discrepancy

(a) If a discrepancy is noted between the User’s installation and the revenue metering register, the Network Operator shall correct the discrepancy within 2 days.

(b) If as a result of the correction of the revenue metering register it indicates that the revenue metering installation or check metering installation does not comply with the requirements of this clause, the Network Operator shall use its reasonable endeavours to rectify the situation in regard to the revenue metering installation. If the check metering installation does not comply with
the requirement of this clause, reference to it will be deleted from the revenue metering register.

10.6 Testing of metering installation

(a) Testing of a revenue metering installation shall be carried out in accordance with the Network Operator’s metering manuals.

(b) A User may request the Network Operator to arrange for the testing of any User’s revenue metering installation and the Network Operator shall not refuse any reasonable request.

(c) The User will have the right to be present at any such testing.

(d) The Network Operator shall arrange for sufficient audit testing of Users’ revenue metering installations to satisfy itself that each revenue metering installation conforms to the requirements of this clause.

(e) The Network Operator shall have unfettered access to any User’s revenue metering installation at any time for the purpose of testing the revenue metering installation.

10.6.1 Actions in event of non-compliance

(a) If a revenue metering installation does not comply with the requirements of this clause, the Network Operator shall as soon as practical advise the User and arrange for the revenue metering installation to be made compliant with the requirements of this clause.

(b) The Network Operator shall in conjunction with the User make appropriate corrections to the revenue metering data to take account of any errors as a result of the non-compliance found in 10.6.1(a).

10.6.2 Audits of metering data

(a) A User may request the Network Operator to conduct an audit to determine consistency between the data held in the revenue metering database and the revenue metering data held in the User’s revenue metering installation.

(b) If there is an inconsistency between the data held in a revenue metering installation and the data held in the revenue metering database, the data held in the revenue metering installation is to be taken as prima facie evidence of the revenue metering data.

10.7 Rights of access to metering data

(a) The only persons entitled to have either direct or remote access to revenue metering data from a revenue metering installation, the revenue metering database or the revenue metering register in relation to a revenue metering point are:

(1) the Network Operator; and
(2) the User whose account statement relates to energy measured at that revenue metering point.

(b) Electronic access to revenue metering data from a revenue metering installation shall only be provided where appropriate multi-level password revenue meters are installed and the appropriate software is obtained by the User.

10.8 Security of metering installations

10.8.1 Security of metering equipment

(a) The Network Operator is responsible for the security of the revenue metering installation and will fit seals or other devices to prevent or disclose unauthorised access.

10.8.2 Security controls

(a) The Network Operator is responsible for the security of revenue metering data held in the revenue metering installation and shall prevent local or remote access by suitable passwords and/or other security devices in accordance with clause 10.8.1.

(b) The Network Operator shall keep records of electronic passwords secure.

(c) The Network Operator may allocate a “read-only” password to a User where the revenue meters installed have provision for multi-level passwords.

10.8.3 Changes to metering equipment, parameters and settings

The Network Operator shall record all changes to revenue metering equipment, parameters and settings.

10.9 Processing of metering data for settlement purposes

10.9.1 Metering databases

(a) The Network Operator will create, maintain and administer a revenue metering database containing information for each User revenue metering installation.

(b) The revenue metering database shall include original energy readings and substitute calculated values where estimates may be required.

10.9.2 Remote acquisition of data

(a) The Network Operator is responsible for the remote acquisition of revenue metering data and for storing and processing this data for settlement purposes.

(b) If remote acquisition becomes unavailable, the Network Operator is responsible for obtaining the relevant revenue metering data from the revenue meters.
10.9.3 Periodic energy metering

Data relating to the amount of active and reactive energy passing through a revenue metering installation is normally collated in trading intervals of between 28 and 35 days inclusive unless it has been agreed between the User and the Network Operator that some other period will apply either on an ongoing or once-off basis.

10.9.4 Data validation and substitution

(a) At commissioning, the Network Operator will validate, on-site, the data being recorded by a revenue metering installation against the measurement of basic parameters and the User’s estimation of load.

(c) Check metering data, where available, may be used by the Network Operator to validate revenue metering data provided that the check metering data has been appropriately adjusted for differences in revenue metering installation accuracy.

(d) For the purpose of settlement, check metering data, if available, may be substituted either in whole or part for some or whole of the revenue metering readings.

(e) If a check meter is not available or metering data cannot be recovered from the metering installation within the time required for settlements, then a substitute value is to be prepared by the Network Operator using a method agreed with the User.

10.9.5 Errors found in metering tests, inspections or audits

(a) If a revenue metering installation test, inspection or audit demonstrates that a component of the revenue metering has errors in excess of those permitted by its class and it is not possible to determine from other data when the error occurred, the error will be deemed to have occurred at a time halfway between the time the error was found and the time of the previous most recent test or inspection which demonstrated that the installation compiled with Attachment 4 and the Network Operator’s metering manuals.

(b) If a test or audit of a revenue metering installation demonstrates that a component of a revenue metering system has an error less than 1.5 times the error permitted for that component, then no substitution of readings is required.

10.9.6 Load following and out of balance energy

The Network Operator shall forward metering data to the Power System Controller for load following reconciliation and out of balance energy settlement.

10.10 Confidentiality

Revenue metering data and passwords are confidential data and are to be treated as confidential information.
10.11 Meter time

(a) All revenue metering installation clocks are to be referenced to Australian Central Standard Time and maintained to a standard of accuracy as required by Australian Standard AS 1284.

(b) The revenue metering database shall be set within an accuracy of ±10 seconds of Australian Central Standard Time.
11 Information requirements for network connection

11.1 Scope

(a) The following information requirements apply to the connection of Users to the Power and Water networks.

(b) The Network Operator is obliged to obtain sufficient information in respect of a network connection to enable the Network Operator to ensure that the relevant User connection will not prevent the network performance standards in clause 2 of the Code from being met.

(c) If, in the opinion of the Network Operator, additional information for a particular User connection is required to ensure the network performance standards in clause 2 of the Code are met, the User shall supply the additional information.

(d) The User shall provide all data reasonably required by the Network Operator.

(e) Particular provisions may be waived for smaller Users and Users that have no potential to affect other Users, at the discretion of the Network Operator, in accordance with the derogation provisions of clause 12.

(f) Nothing in this section waives the requirements for all installations to comply with the Network Operator’s Service and Installation Rules, Metering Manual, Contractor’s Bulletins, and any requirement included in an Access Agreement.

11.2 Information to be provided by all network Users

11.2.1 Information on connected plant

(a) Before any new or additional equipment is connected, the User may be required to submit the following kinds of information to the Network Operator:

(1) a single line diagram with the protection details;

(2) metering system design details for equipment being provided by the User;

(3) a general arrangement locating all the equipment on the site;

(4) a general arrangement for each new or altered substation showing all exits and the position of all electrical equipment;

(5) type test certificates for all new switchgear and transformers, including measurement transformers to be used for metering purposes in accordance with clause 10 (metering) of this Code;

(6) the proposed methods of earthing cables and other equipment to comply with the Electricity Supply Association of Australia Substation Earthing Guide, or Australian Standard AS3000, or both, as appropriate;

(7) plant and earth grid test certificates from approved test authorities;
(8) a primary/secondary injection test of protection and trip test certificates on all circuit breakers;

(9) certification that all new equipment has been inspected before being connected to the supply;

(10) operational procedures;

(11) calculated maximum demand of the installation;

(12) details of potentially disturbing loads; and

(13) SCADA arrangements.

(b) Details of the kinds of data that may be required are included in Attachment 3.

11.2.2 Details of proposed Users’ protection

(a) Unless otherwise agreed by the Network Operator, Users shall provide the Network Operator with full details of proposed protection designs, together with all relevant plant parameters, a minimum of 12 months prior to energisation of the protected primary plant.

(b) The Network Operator shall provide comments on a User’s proposed protection designs within 65 business days, unless otherwise agreed.

11.2.3 Requirements where a critical fault clearance time exists

(a) Where a critical fault clearance time exists, Users shall maintain a record of design fault clearance times for all circuit breakers within their plant.

(b) Records of design fault clearance times shall be made available to the Network Operator on request.

11.3 Information to be provided by Users with Generators

(a) A User with a Generator shall provide the data specified in clause 11.2.

(b) The User shall provide all other data reasonably required by the Network Operator. This data shall include, without limitation, full models (and all model parameters) of:

(1) the Generation Units;

(2) the excitation control systems;

(3) turbine / engine governor systems; and

(4) power system stabilisers;

(5) to enable the Network Operator to conduct dynamic simulations.

(c) These models shall be in a form which is compatible with the power system analysis software used by the Network Operator (currently PSS/E from Siemens PTI) and shall be inherently stable.
(d) Details of the kinds of data that may be required are included in Attachment 3 of this Code, specifically:

1. Schedule S3.1 - Generation Unit design data;
2. Schedule S3.2 - Generation Unit setting data;
3. Schedule S3.5 - Network and plant technical data; and
4. Schedule S3.6 - Network plant and apparatus setting data.

11.4 Information to be provided by Users with Small Generators

(a) A User with a Small Generator shall provide the data specified in clause 11.2.

(b) A Small Generator shall provide all information in relation to the design, construction, operation and configuration of that small power station as is required by the Network Operator to ensure that the operation and performance standards of the network, or other Users, are not adversely affected by the operation of the power station.

(c) In order to assess the impact of the equipment on the operation and performance of the network or on other Users, the Network Operator may require a Small Generator to provide data on:

1. power station and Generation Unit aggregate real and reactive power; and
2. flicker coefficients and harmonic profile of the equipment, where applicable and especially for wind power and inverter connected equipment. Data on power quality characteristics, including flicker and harmonics, in accordance with IEC 61400-21 shall be provided for all wind turbines.

(d) Net import / export data shall be provided in the form of:

1. a typical 24 hour power curve measured at 15 minute intervals (or better if available); and
2. details of the maximum kVA output over a 60 second interval, or such other form as specified in the relevant Access Agreement.

(e) When requested by the Network Operator, a Small Generator shall provide details of the proposed operation of the equipment during start-up, shut-down, normal daily operation, intermittent fuel or wind variations and under fault or emergency conditions.

(f) Details of the kinds of data that may be required are included in Attachment 3 of this Code, specifically:

1. Schedule S3.3 - Generator data for Small Generation Units;
2. Schedule S3.5 - Network and plant technical data; and
3. Schedule S3.6 - Network plant and apparatus setting data.
11.5 Information to be provided by Users with Small Inverter Energy Systems

A Small Inverter Energy System may be installed as an addition to an existing load connection, in conjunction with a new load connection or as a stand-alone Generation system.

(a) A User with a Small Inverter Energy System shall provide the data specified in clause 11.2.

(b) Details of the kinds of data that may be required from a User with a Small Inverter Energy System are included in Attachment 3 of this Code, specifically:
   (1) Schedule S3.4 - Technical data for Small Inverter Energy Systems;
   (2) Schedule S3.5 - Network and plant technical data;
   (3) Schedule S3.6 - Network plant and apparatus setting data; and
   (4) Schedule S3.7 - Load characteristics at connection point.

11.6 Information to be provided by Users with loads

(a) A User with a Load shall provide the data specified in clause 11.2.

(b) Details of the kinds of data that may be required from a User with a Load are included in Attachment 3 of this Code, specifically:
   (1) Schedule S3.5 - Network and plant technical data;
   (2) Schedule S3.6 - Network plant and apparatus setting data; and
   (3) Schedule S3.7 - Load characteristics at connection point.
12 Derogations from the Code

12.1 Purpose and application

(a) This clause 12 prevails over all other clauses of this Code.

(b) Derogations of Users are:

(1) those provisions of the other clauses of the Code which shall not apply either in whole or part to particular Users or potential Users or others in relation to their facilities for a fixed or indeterminate period;

(2) any provisions which substitute for those provisions which are not to apply; and

(3) applicable only to that particular User or potential User.

(c) Derogations are for the purpose of:

(1) enabling Users to effect an orderly transition to the provisions of the Code from those provisions currently applying;

(2) providing specific exemptions from the Code for pre-existing arrangements which the Network Operator determines shall continue beyond a specific transition period; and

(3) providing specific exemptions from the Code for future arrangements that the Network Operator determines to be acceptable.

(d) Applications for derogations shall be submitted to and processed by the Network Operator in accordance with the Electricity Networks (Third Party Access) Act 2011.

12.2 Networks and facilities existing at 1 September 2012

All plant and equipment in the Network and all facilities connected to this network existing at 1 September 2012 are deemed to comply with the requirements of this Code. If at any time it is found that an installation is adversely affecting power system security, reliability of the power system and/or the quality of supply, the relevant User shall be responsible for remedying the problem at its cost.
Part C  **Network Planning Criteria**

*Power and Water* is the major custodian and operator of the power networks within the Northern Territory. *Power and Water* is responsible for the network security, reliability and quality of supply to all network Users. *Power and Water*'s technical requirements are intended to ensure that a high reliability of service is maintained when additions and changes to the networks or Users’ installations are made. Technical requirements are based on the rules, criteria and limits included in the *Technical Code* and these *Network Planning Criteria*.

The *Network Planning Criteria* provide for the requirements of the legislated Third Party Access regime, which permits network customers to use *Power and Water*'s regulated networks to enable contracted trade between Generator Users and customer Users.

The purpose of *Network Planning Criteria* is to strike a balance between each User’s need for a safe, secure, reliable, high quality electricity supply and the desire for this service to be provided at minimal cost. At the same time, environmental and social considerations shall be taken into account.

13  **Introduction**

(a) Additions to and reinforcement of the networks in the form of additional:

(1) Transmission lines and distribution feeders;

(2) Transformers;

(3) Generators;

(4) Loads; and

(5) Capacitors or reactors;

will produce an impact on the existing networks and customers.

(b) This Part C presents the Planning Criteria applied to ensure that *Power and Water*’s networks:

(1) Provide a high quality electricity supply;

(2) Provide a reliable electricity supply;

(3) Provide a secure electricity supply;

(4) Meet safety standards;

(5) Meet environmental standards;

(6) Optimise equipment utilisation; and

(7) Optimise network losses.

(c) The philosophy of network planning and the rationale behind the Planning Criteria are discussed in clause 13.1 of this document.

(d) The guidelines for network planning, which are provided in this document, outline the range of technical and environmental Planning Criteria.
13.1 Network design philosophy

(a) The Planning Criteria are used to assess the supply system capacity and determine the need for and timing of:

(1) Generation support;
(2) Demand management;
(3) Network reinforcement; or
(4) Network re-configuration;

to meet customers’ demand for electricity.

(b) Network reinforcement plans may then be developed which will satisfy the Planning Criteria and environmental constraints.

13.2 Amendments to the Planning Criteria

(a) Any System Participant may propose an amendment to the Planning Criteria.

(b) A proposal to amend the Planning Criteria shall be made in writing by the System Participant to the Network Operator and shall be accompanied by:

(1) the reasons for the proposed amendment to the Planning Criteria; and
(2) an explanation of the effect on System Participants of the proposed amendment to the Planning Criteria.

(c) The Network Operator shall review the proposed amendment to the Planning Criteria and within 30 days advise the System Participant or electricity entity:

(1) whether the proposed amendment to the Planning Criteria is accepted or rejected; and
(2) the reasons for the acceptance or rejection of the proposed amendment to the Planning Criteria.

(d) The Network Operator shall review the operation of the Planning Criteria at intervals of no more than 5 years and may seek submissions from System Participants and the Utilities Commission during the course of the review.

(e) The Network Operator may amend this Planning Criteria in accordance with the legislative provisions.

13.3 132 kV and 66 kV networks

The traditional planning philosophy for a meshed network has been that the loss of any one component of the network at a time of peak load will not result in the loss of supply to any customers. This is the ‘n-1’ criterion, which can result in imprudent capital expenditure if the frequency and consequences of breaching the criterion are not considered. Prudent capital expenditure involves the application of risk management techniques. This requires a consideration of the probability of an event occurring and the consequences of its occurrence, for example the impact on customers. If the probability of the event is low and the
consequences acceptable, it may be considered justified to delay system reinforcement beyond the date indicated by the n-1 criterion and peak loading.

(a) Power and Water designs its 132 kV and 66 kV systems as meshed networks.

(b) There may be radial 132 kV and 66 kV lines extending from the meshed network to many rural and developing areas.

(c) Generators are connected to the networks at voltages of 132 kV and 66 kV. The technical characteristics of Generator connections may be negotiated with the Generator provided that the network performance standards of clause 2 of the Network Technical Code are maintained.

13.4 Distribution networks

Power and Water designs its distribution networks as radial systems.

13.4.1 CBD area

(a) In the Darwin central business district, five 11 kV switching stations supply a network of underground HV feeder rings, with open points approximately mid-way between switching stations.

(b) The switching stations are remotely controlled, but the intermediate switches used to transfer load and restore supply in the event of a supply contingency are operated manually.

13.4.2 Urban areas

(a) In urban areas the lower density of Users generally results in an open, meshed network of HV feeders run radially with open points.

(b) This operating mode minimises fault levels and simplifies technical and operational requirements.

(c) In these situations the extent of the loss of supply can be minimised by the use of reclosers and sectionalisers to limit the impact of faults and the speed of restoration improved through the use of fault indicators to locate faults.

13.4.3 Rural areas

(a) In rural areas the distribution network is generally radial and interconnection to reduce supply restoration times is often not possible.

(b) In normal circumstances the loss of a component of the network will result in the loss of supply to a number of Users until the network is reconfigured or repaired.

1 Power and Water’s High Voltage (HV) networks operate at voltage levels of 22 kV in rural areas and 11 kV in urban areas.
13.4.4 Enhanced security of supply

(a) The Network Operator will provide for the reasonable request of a User requiring additional security of supply above the standard design philosophy.

(b) Additional costs incurred in providing the additional security of supply would ordinarily be charged to the User.

(c) In some circumstances, on-site standby Generation may be the only economic or practical alternative to improve supply security.

13.4.5 Embedded generation

(a) The distribution network is not designed to support the islanded operation of embedded Generators and Power and Water’s distribution equipment is not normally fitted with synchronising equipment.

(b) Embedded Generation Units, including small solar photo-voltaic and wind Generators at network Users’ premises shall be of a design that automatically disconnects from the network if the distribution feeder that they are connected to is separated from the remainder of the power system.

(c) The requirements concerning the connection of Small Generators and Small Inverter Energy Systems are set out in clauses 3.4 and 3.5 of the Network Technical Code.

13.5 Process to assess the need for network reinforcement

(a) Network capacity and the need for network reinforcement are assessed by comparing the Planning Criteria with network performance for:

(1) Increasing load levels;
(2) Changing load demand patterns;
(3) Particular load characteristics; and
(4) Reliability.

(b) To satisfy the performance levels, be they reliability, security, or quality levels, least cost and effective plans are developed. The extent of the network reinforcement works is dependent on:

(1) The load forecast;
(2) The anticipated maximum demands of all Users;
(3) Special conditions of the User’s load;
(4) The anticipated minimum demand of other Users;
(5) Users’ load profiles;
(6) The availability of non-network alternatives to network reinforcement; and
(7) The age and condition of existing assets.
(c) Economic analysis is used in assessing network reinforcement requirements and serves four functions as it:

1. Indicates the return to Power and Water of proposed capital investment;
2. Helps to choose between options;
3. Helps rank the project with other projects generated throughout Power and Water; and
4. Ensures the equitable allocation of costs between Users.

(d) In some cases, network reinforcement works may also be justified on an economic basis where there are immediate benefits in return for capital invested, e.g. network loss optimisation.

13.6 The process of developing network concept plans

(a) Power and Water, in developing network concept plans for the long-term development of the network, uses ultimate load horizon planning.

(b) In this methodology Power and Water considers the following information in assessing the ultimate load for an area:

1. Department of Lands Planning and Environment land use structure plans;
2. Australian Bureau of Statistics censuses;
3. Consultants’ reports on population growth in the major centres;
4. Any relevant town planning schemes;
5. Local Government advice on future planning proposals;
6. Geographic features and their associated design limitations; and
7. Any environmental constraints, including vegetation and ecology limitations.

(c) This information is combined with any other available future load information to produce an ultimate load assessment for an area and on the basis of this a network concept plan is developed.

13.7 Planning Criteria

Planning Criteria are a set of standards applied to maintain appropriate levels of network security and reliability. They are used as a planning and design tool to protect the interests of all network Users in terms of reliability and quality of supply. The criteria are also applied to protect all networks against instability.

13.8 Network development

The Network Operator is required to ensure that non-network alternatives to the reinforcement of the network are considered on an equivalent basis to network reinforcement and adopted where they can economically meet the network...
performance standards in clause 2 of the *Network Technical Code* and the supply contingency criteria in clause 14 of the *Network Planning Criteria*.

Non-*network* alternatives may include, without limitation, the following programs and technologies:

- Pricing signals to influence customer *demand*;
- Direct control of customer *demand*;
- Installation of power factor correction;
- Installation of embedded *generation*.

Non-*network* alternatives may involve agreements between the *Network Operator* and third parties for the provision of support to the *network* in specified contingency conditions.

### 13.8.1 Annual planning review

The *Network Operator* shall annually:

(a) Prepare a forecast of loads and *generation* for the system for a period of at least 5 years.

(b) Conduct a planning review of the adequacy of existing *connection points* and the capacity of the *transmission* and *distribution networks* to meet forecast *load demands* and *generation demands*.

(c) Consider the potential for augmentations, or non-*network* alternatives to augmentations, that are likely to provide economic benefit to all *network Users*.

(d) Identify where *network investments* are likely to be required and classify those investments as:
   1. a *small network investment*; or
   2. a *large network investment*.

(e) Prepare a *Network Management Plan* containing, amongst other things, *network* limitations and potential non-*network* and *network* solutions for *small network investments* and *large network investments* in a form suitable for public dissemination.

(f) The *Network Management Plan* shall be made available on Power and Water’s web site and made available to the interested parties established in clause 13.8.2(a) or to any person, upon application.

### 13.8.2 Non-*network* alternatives to *network* augmentation

(a) The *Network Operator* shall establish and maintain a list of interested parties that may be prepared to provide non-*network* alternatives to augmentation of the *network*.
(b) The Network Operator shall carry out a screening test to determine whether demand management or other non-network alternatives are likely to be viable for each network investment identified in clause 13.8.1(d).

(c) Where demand management or other non-network alternatives are not likely to be viable for a network investment the Network Operator shall carry out analysis of the network reinforcement in accordance with clause 13.9.

(d) Where demand management or other non-network alternatives are likely to be viable for a large network investment, the Network Operator shall:

(1) publish a report detailing the circumstances of the large network investment and the outcome of the demand management screening test in clause 13.8.2(b);

(2) advise interested parties of the large network investment;

(3) seek expressions of interest in providing a non-network alternative.

(e) If no expression of interest in providing a non-network alternative to a large network investment has been received within 60 business days the Network Operator shall carry out analysis of the network reinforcement in accordance with clause 13.9.

(f) Where demand management or other non-network alternatives are likely to be viable for a small network investment, the Network Operator shall inform interested parties of the outcome of the screening test in clause 13.8.2(b) and request expressions of interest in providing a non-network alternative.

(g) If no expression of interest in providing a non-network alternative to a small network investment has been received within 30 business days the Network Operator shall carry out analysis of the network reinforcement in accordance with clause 13.9.

(h) The Network Operator shall carry out the analysis of non-network alternatives provided by interested parties under clauses 13.8.2(d) and 13.8.2(f) in accordance with clause 13.9.

13.9 Investment analysis and reporting

In determining the preferred option for a new large network investment, the Network Operator shall:

(a) Analyse the proposed large network investment using financial parameters consistent with the most recent Network regulatory determination.

(b) Analyse non-network alternatives and network reinforcement alternatives on the same basis.

(c) Determine on a present value basis the least-cost non-network or network reinforcement alternative that meets the requirements of the network performance standards in clause 2 of the Code and the supply contingency criteria in clause 14 of the Network Planning Criteria.
(d) Include in the investment analysis an estimate of system benefits where they are likely to be material to the outcome of the analysis, including, but not limited to:

1. Electrical losses;
2. Changes in the level of involuntary load curtailment;
3. Fuel and generation costs;
4. Ancillary services provided to the system (eg. voltage support, spinning reserve, black start).

(e) The level of analysis undertaken in relation to system benefits in clause 13.9(c) shall be proportionate to the size and scale of the proposed new network investment.

(f) Determine and assess any non-quantifiable economic benefits of alternative investment options.

(g) Determine the preferred non-network or network investment alternative.

(h) Prepare a report on the network investment analysis in clause 13.9(a) to (g).

14 Supply contingency criteria

(a) Supply contingency criteria relate to the ability of the supply system (network and Generation) to be reconfigured after a fault, so that the supply to customers is restored. The criteria apply to Generation used to support the network and to the network interconnections to Generators.

(b) The following definitions apply.

14.1 Load areas

(a) The load areas that have been identified for the purpose of the supply contingency criteria are set out in Table 11.

Table 11 - Definition of load types

<table>
<thead>
<tr>
<th>Load type</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>CBD</td>
<td>Any area within a city or town that is zoned as CBD in the Northern Territory Planning Scheme.</td>
</tr>
<tr>
<td>Urban</td>
<td>An area in which the majority of the land is zoned for residential and/or commercial and/or industrial use within a major centre in the Northern Territory and is not CBD.</td>
</tr>
<tr>
<td>Non-urban</td>
<td>Areas that are not Urban and not within a CBD but which are within a 50km radius of a CBD.</td>
</tr>
<tr>
<td>Remote</td>
<td>Areas outside a 50km radius from a CBD.</td>
</tr>
</tbody>
</table>
A distinction has been made between the supply contingency criteria applicable to CBD and Urban load areas, and those applicable to Non-urban and Remote load areas.

A supply contingency may involve the unplanned failure of an element of network equipment or the failure of a Generator used to support the network at a particular location.

14.2 Supply contingencies

(a) A single supply contingency (first contingency) may involve the unplanned failure of an element of network equipment (a cable, line or transformer), or the failure of a Generator used to support the network or supply loads at a particular location.

(b) A second contingency provision has been included, which is similar to that in the CBD areas of most other Australian capital cities. Other CBDs currently are planned to provide second contingency capability at the subtransmission and zone substation level, as follows:

- **Brisbane**: in one hour;
- **Melbourne**: in 30 minutes; and
- **Sydney**: in one hour.

The longer time permitted for restoration of the Darwin CBD system recognises that manual switching of load on the CBD HV network would be necessary to restore capability.

(b) A second supply contingency involves the concurrent failure of two elements, which could comprise network equipment or Generators.

(c) In addition, at the discretion of the Network Operator, certain high impact but low risk failures such as the failure of a single zone substation HV busbar, or the failure of both circuits of a double circuit line, shall be considered as second contingency events.

14.3 Equipment capacities

Circuit capacities to be used in determining supply adequacy are the appropriate cyclic ratings for network equipment.

14.4 Forecast demand

(a) The forecast area demand used for determining supply adequacy is the coincident maximum demand for the load area, feeder or transformer concerned, with a 50% Probability of Exceedence.

(b) In calculating the maximum demand in clause 14.4(a), allowance shall be made for the coincident effect of demand reductions in the load area arising from:

(1) Any demand management initiative controlled by Power and Water;
Any customer contracted to Power and Water to reduce demand upon request;

(3) The net effect of any embedded Generation used to provide a demand reduction under an agreement with Power and Water; and

(4) Small scale embedded Generation such as solar PV installations.

14.5 Radial supply arrangements

(a) Where restoration of supply requires reinstatement or repair, a secure supply having an alternative path is not provided. Restoration targets are set out in Table 12.

Table 12 – Radial supply restoration targets

<table>
<thead>
<tr>
<th>Radial supply contingency</th>
<th>Restoration target</th>
</tr>
</thead>
<tbody>
<tr>
<td>For failure of a substation transformer</td>
<td>≤ 36 hours</td>
</tr>
<tr>
<td>For failure of a subtransmission line</td>
<td>≤ 6 hours (loads greater than 5MVA)</td>
</tr>
<tr>
<td>For failure of a subtransmission line</td>
<td>≤ 12 hours (loads less than 5MVA)</td>
</tr>
</tbody>
</table>

(b) The restoration times in Table 12 are Power and Water’s internal targets. They do not represent customer guarantees.

(c) Actual restoration times will be based on ensuring staff safety and being able to access and address the asset related issues.

14.6 Supply contingency criteria

The supply contingency criteria in the Network Planning Criteria have been designed to facilitate the Network Operator providing the specified response in the most appropriate and economical manner for the particular circumstances. The response to ensuring that the supply contingency criteria are met may include one or more of the following responses:

- Augmentation of the network;
- Reduction of demand on the network using demand management;
- Connection of generation within the load area concerned;
- Commercial arrangements with generators to provide demand support in contingency conditions;
- Enhanced operational response;
- Enhanced control of network configuration;
- Contingency planning, using strategically positioned spare equipment or mobile equipment such as generators and transformers.

(a) The supply contingency criteria in this clause 14.6 apply to loads and to groups of loads supplied by the network at various voltage levels and locations.
(b) In determining the relevant supply contingencies to loads and groups of loads, the potential unavailability of:

(1) elements of the network that normally supply those loads;
(2) the generators that normally supply those loads; and
(3) the associated generator connections;
shall all be considered.

(c) The relative likelihood (frequency) of supply contingencies shall also be considered by the Network Operator. The Supply Contingency Criteria requires that:

(1) The equipment that comprises elements of the system for the supply to loads and groups of loads shall be operated and maintained in such a way that the frequency of equipment unavailability is consistent with good industry practice; and
(2) The expected frequency of supply contingencies shall be considered by the Network Operator when developing options to maintain compliance with the Supply Contingency Criteria.

(d) The Network Operator shall aim to meet reliability of supply objectives established by the Regulator.

(e) Where the availability of generation is a factor in meeting the contingency criteria in a particular load area the Network Operator is required to consult with the relevant Generators to make appropriate allowance for Generation Unit maintenance.

(f) The Network Operator may enter into commercial arrangements with a Generator to provide demand support in supply contingency conditions.

(g) The Planning Criteria in Table 13 apply for the specified supply contingencies in CBD and Urban areas.

(h) The Planning Criteria in Table 14 apply for Non-Urban and Remote areas.

(i) The Planning Criteria in Table 13 and Table 14 apply to each load segment within the loads or groups of loads to which the associated Planning Criterion applies.
<table>
<thead>
<tr>
<th>Class of supply</th>
<th>Forecast area demand</th>
<th>Minimum demand to be met after:</th>
<th>Second supply contingency</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>A</td>
<td>Up to 1MVA</td>
<td>First supply contingency</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Within 8 hours: area demand</td>
<td></td>
<td>No special provision</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>Area demand is normally supplied from one source. Restoration of supply requires reinstatement or repair. Includes most HV customer connections and distribution substations. Where a single transformer supplies demand, the area demand may cover the transformer cyclic capacity.</td>
</tr>
<tr>
<td>B</td>
<td>Over 1 MVA and up to</td>
<td></td>
<td>(a)</td>
<td></td>
</tr>
<tr>
<td></td>
<td>5 MVA</td>
<td>(a) Within 3 hours: area demand</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>(b) Within 8 hours: area demand</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>Area demand is normally supplied from one source and may have partial to full supply available from an alternative source. Includes most HV feeders, allows for manual field switching.</td>
</tr>
<tr>
<td>C</td>
<td>Over 5 MVA and up to</td>
<td>(a) Within 60 minutes: area</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>50 MVA</td>
<td>demand</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>Area demand is normally supplied from one or more source and will have partial to full supply from an alternative source. Will include many HV feeders and all zone substations. Area demand will be restored with automatic or manual switching of alternative sources of supply.</td>
</tr>
<tr>
<td>D</td>
<td>Over 50 MVA</td>
<td>(a) Immediate restoration of</td>
<td>(b) Within time to restore</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>area demand</td>
<td>planned outage: area</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>demand</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>(c) Within 5 hours: area</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>demand</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>Area demand will normally be supplied by more than two alternative circuits with high level automatic and supervisory switching. The time permitted for restoration of supply to the Darwin CBD following a second contingency recognises that manual switching of load on the CBD HV network would be necessary. The second contingency provision is not intended to restrict the period during which maintenance can be scheduled. The provision for a second circuit outage assumes that normal maintenance would be undertaken when demand is less than peak.</td>
</tr>
</tbody>
</table>
### Table 14 - Supply contingency criteria - Non-Urban and Remote areas

<table>
<thead>
<tr>
<th>Class of supply</th>
<th>Forecast area demand</th>
<th>Minimum demand to be met after:</th>
<th>Second supply contingency</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>First supply contingency</td>
<td>Second supply contingency</td>
<td></td>
</tr>
<tr>
<td>E</td>
<td>Up to 1MVA</td>
<td>Within 12 hours: area demand</td>
<td>No special provision</td>
<td></td>
</tr>
<tr>
<td>F</td>
<td>Over 1 MVA and up to 5 MVA</td>
<td>(a) Within 6 hours: area demand less 1 MVA</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>(b) Within 12 hours: area demand</td>
<td></td>
<td></td>
</tr>
<tr>
<td>G</td>
<td>Over 5 MVA and up to 15 MVA</td>
<td>(a) Within 3 hours: area demand</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>(b) Within 36 hours: area demand</td>
<td></td>
<td></td>
</tr>
<tr>
<td>H</td>
<td>Over 15 MVA and up to 50 MVA</td>
<td>(a) Within 30 minutes: area demand</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>(b) Within 36 hours: area demand</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**Notes**
- *Area demand* is normally supplied from one source. Restoration of *supply* requires reinstatement or repair.
- Includes most rural spur connections, HV customer connections and distribution substations.
- Where a single transformer supplies *demand*, the area *demand* may cover the transformer cyclic capacity.
- *Area demand* is normally supplied from one source and will have partial to full *supply* available from an alternative source. Full restoration of *supply* may require reinstatement or repair.
- Includes most HV feeders, allows for manual field switching.
- *Area demand* is normally supplied from more than one source and will have full *supply* from an alternative source.
- Includes many zone *substations*.
- *Area demand* will be restored with manual switching of alternative sources of *supply*. Where *area demand* supplied from a single source (b) will apply.
- *Area demand* is normally supplied from more than one source and will have full *supply* from an alternative source.
- Will cover larger zone *substations*.
- *Area demand* will be restored with automatic or remote manual switching of alternative sources of *supply*. Where *area demand* supplied from a single source (b) will apply.
15 **Steady state criteria**

(a) The steady state criteria define the adequacy of the network to supply the energy requirements of Users within the equipment ratings, frequency and voltage limits, taking account of planned and unplanned outages.

(b) The steady state criteria apply to the normal continuous behaviour of a network and also cover post disturbance behaviour once the network has settled.

(c) In planning a network it is necessary to assess the reactive power requirements under both extremes of light and heavy load, to ensure that the reactive demand placed on the Generators, be it to absorb or generate reactive power, does not exceed the capability of the Generators and that system voltage levels remain within equipment ratings.

(d) Network frequency will fall if there is insufficient total Generation to meet demand. Although the reduction in frequency will cause a reduction in power demand, it is unlikely that this will be sufficient and in the event of a shortfall of Generation, loads shall be disconnected until the frequency rises to an acceptable level.

(e) In the following sub-clauses, the various components of the steady state Planning Criteria are defined.

### 15.1 Real and reactive generating limits

(a) Limits to the VAr Generation and absorption capability of Generators shall not be exceeded.

(b) Generators shall be specified and maintained so as to be capable of operating within the normal range of system voltage at their point of connection.

### 15.2 Steady state power frequency voltage

The range of steady-state voltage at different voltage levels of the power system under normal operating conditions is set out in this clause.


*Australian Standard AS 6038-2000* notes that 240/415 V systems shall evolve towards the new standard and a revised supply voltage range. *Power and Water* is participating in an Energy Networks Association review of issues associated with the potential migration from a nominal mid-range voltage of 240 V to 230 V.

(a) For voltages of 11 kV or more, the network shall be planned and designed to maintain a continuous network voltage at a User’s connection not exceeding the design limit of 110% of nominal voltage and not falling below 90% of nominal voltage during normal and maintenance conditions.
(b) The network shall be designed to maintain the low voltage steady state levels within the range set out in Table 15 for credible contingency events. These are referenced to the nominal voltage of 230/400 V.

Table 15 – Supply voltage range

<table>
<thead>
<tr>
<th>System condition</th>
<th>Lower range</th>
<th>Upper range</th>
</tr>
</thead>
<tbody>
<tr>
<td>Normal conditions</td>
<td>- 2%</td>
<td>+ 11%</td>
</tr>
<tr>
<td>Planned maintenance conditions</td>
<td>- 4%</td>
<td>+ 13%</td>
</tr>
<tr>
<td>Unplanned outage conditions</td>
<td>- 6%</td>
<td>+ 15%</td>
</tr>
</tbody>
</table>

(c) The power frequency voltage may vary outside the ranges set out in this clause 15.2 as a result of a non-credible contingency event.

15.3 Thermal rating criteria

(a) It should be noted that the thermal rating limits of equipment might not determine the capability of the network in a particular situation. Other factors such as the voltage drop or rise, voltage stability or system stability may impose a lower limit in certain circumstances.

(b) The thermal ratings of network components shall not be exceeded under normal or emergency operating conditions when calculated on the following basis:

1. **Transformers:** Manufacturer’s name plate rating, unless specific modelling has been carried out to determine a cyclic rating for the anticipated cyclic loading and ambient temperature conditions.

2. **Switchgear:** Manufacturer’s name plate rating.

3. **Overhead Lines:** Rating calculated in accordance with ESAA Code D(b)5, and based on:
   (i) ambient temperature of 35°C in the northern part of the Territory, and 40°C (summer) or 25°C (winter) in the southern part;
   (ii) wind speed being 0.5 m/s;
   (iii) solar radiation being 1000W/m² (weathered surface); and
   (iv) conductor design clearance temperature as defined in ESAA Code C(b)1.

4. **Cables:** Normal cyclic rating, calculated using the Neher McGrath methodology; with
   (i) maximum operating temperatures of 90°C for XLPE cables;
   (ii) 70°C for 11 kV paper insulated cable;
   (iii) 65°C for 11 kV paper insulated, belted cable and 22 kV paper insulated cables and;
(iv) during an emergency, for a period of up to 12 hours, the maximum allowable operating temperature for paper insulated cables may be increased to 80°C and for XLPE insulated cables to 120°C.

It should be noted that the thermal rating limits of equipment might not determine the capability of the network in a particular situation. Other factors such as the voltage drop or rise, voltage stability or system stability may impose a lower limit in certain circumstances.

15.4 Fault rating criteria

For safety reasons, the fault rating of any equipment shall not be less than the fault level in that part of the network at any time and for any normal network configuration.

As the system configuration is changed, fault levels may increase over time. New connections to the network shall therefore be designed with equipment fault level ratings reflecting modern standards that may exceed existing fault levels.

(a) The minimum fault levels for equipment to be connected to Power and Water’s networks are set out in Table 16.

<table>
<thead>
<tr>
<th>Network voltage level</th>
<th>Fault level rupturing capacity</th>
</tr>
</thead>
<tbody>
<tr>
<td>415 V</td>
<td>31.5 kA where supplied from one transformer; or 63 kA where supplied from two transformers in parallel</td>
</tr>
<tr>
<td>11 kV</td>
<td>25 kA in metropolitan areas; 20 kA in rural areas</td>
</tr>
<tr>
<td>22 kV</td>
<td>15 kA</td>
</tr>
<tr>
<td>66 kV</td>
<td>31 kA</td>
</tr>
<tr>
<td>132 kV</td>
<td>31 kA</td>
</tr>
</tbody>
</table>

(b) Equipment owned by Power and Water and Users connected to the network shall be designed to withstand these fault levels for 1 second.

16 Stability criteria

(a) A power system is stable if it returns to a steady-state or equilibrium operating condition following a disturbance. This criterion shall hold true for all loading conditions and Generation schedules, under normal operating conditions, following the loss of any item of plant, and for the most severe credible faults.

(b) In the planning and operation of a power system, it is important to consider the potential emergence of a variety of stability problems.
(c) The Network Planning Criteria are designed to ensure that the network has a high probability of returning to stable conditions, following all credible network disturbances.

(d) The stability of a power system can be classified into a number of categories to facilitate the analysis of stability problems, the identification of contributing factors, and the development of measures to control or prevent instability. Instability can take many different forms and is influenced by a wide range of factors.

(e) Two broad categories of stability are considered:

1. Angle stability, which mainly involves the dynamics of Generators and their associated control systems. Angle stability can be further categorised into transient stability and small-signal or steady-state stability. Frequency stability is closely related to angle stability.

2. Voltage stability, which mainly involves the dynamic characteristics of loads and reactive power compensation. Voltage collapse is perhaps the most widely recognised form of voltage instability.

16.1 Transient stability

Transient stability is the inherent ability of a power system to remain stable and maintain network synchronism when subjected to severe disturbances such as three-phase faults on power lines, loss of Generation, loss of a large load or other failures. Such large disturbances need to be cleared in order to prevent network instability and physical damage to plant.

Transient stability is assessed on the basis of the first angular swing following a solid three phase fault or single phase-to-ground fault on one circuit at the most critical location that is cleared by the faster of the two protection schemes with all intertrips assumed in service.

16.1.1 Transient stability criteria

(a) Transient stability is based on the relative rotor angle swing between two or more groups of synchronous machines when subjected to a disturbance. Relative rotor angle swings in excess of 90° may lead to the situation where the rotor angle does not return and increases beyond 180°, resulting in pole slipping or synchronous instability. Transient stability of the power system shall be maintained. To ensure transient stability is maintained, due consideration during system studies shall be given to the following:

1. the maximum allowable relative rotor angle swing between any two or more groups of Generators on the network shall not exceed 180° (after allowing for a safety margin consistent with good electricity industry practice);

2. the transient voltage dip limit as specified in clause 16.2.6; and

3. the possibility of delayed clearance of faults on the network.
(b) The most severe disturbance is to be selected from the following fault types to determine the stability of the power system (with due regard to be taken of reclosing onto a fault):

1. a three-phase-to-earth fault;
2. a single phase to earth fault cleared by backup protection;
3. high speed single phase auto-reclosing and
4. sudden disconnection of any plant, including a Generation Unit.

(c) If the rotor angles between one (or a group) of synchronous machines and the rest of the Generation Units on the network reaches and/or exceeds 180°, a “pole slip” occurs. This results in loss of synchronism or synchronous instability.

16.1.2 Rotor angle swing

(a) In general, an initial Generator rotor angle swing which does not exceed 120° and with XT ≤ 1.0 p.u. is considered stable.

(b) A rotor angle swing exceeding 120° has only a small margin before pole slipping, and an initial rotor swing angle which is higher than 120° may result in a pole slip or repeated pole slipping which is considered unstable.

(c) The relative rotor angle concept of synchronous instability is based on the rotor angle between two synchronous machines. In the case of two or more Generation groups containing various Generators a correlated effect on the network, like transient voltage dip limits, shall be used to prevent synchronous instability.

(d) Rotor angle swings in excess of 120° or transient voltage dips in excess of 25% can result in the following detrimental effects on the network:

1. Network voltage collapse; and

(e) Such impacts on a network are not acceptable and enforceable limits need to be used to prevent them.

16.1.3 Fault clearance time

(a) One of the major factors affecting transient stability is the fault clearance time. The critical fault clearance time is the longest time that a fault can be allowed to remain on the network whilst maintaining network stability. Protection shall be installed to ensure that the critical fault clearance times are achieved.

(b) A three-phase fault or a single-phase to ground fault (whichever is the more severe criterion), cleared by the primary protection, is selected by Power and Water as the basis for establishing transient stability. These faults shall be cleared within the critical fault clearance time.
(c) Transient stability shall be maintained for faults cleared by the tripping of any network element or a Generator under the worst possible network load or Generation pattern.

(d) Any plant leading to network instability shall be separated from the healthy network.

16.1.4 Rotor angle swing and transient voltage dip

(a) Rotor angle swing is not a practical parameter to be in field measured, but a measurable impact on Users is the transient voltage dip (TVD) resulting from real power swings.

(b) Any Generator connected to the distribution network shall not cause the Transmission voltage to exceed the transient voltage dip criteria defined in the Network Technical Code.

16.1.5 Pole slip protection

(a) The function of pole slip protection is to remove an unstable Generator from the network and prevent the disturbance from causing problems with other Users. Pole slip protection only removes the pole-slipping Generator from the network after the machine has slipped at least one pole.

(b) Pole slip protection is to be installed on all Generation Units where simulations show that pole slipping is likely following any credible plant outage or fault.

16.1.6 Small-signal stability

(a) A power system is small-signal stable for a particular steady-state operating condition if, following any small disturbance, it reaches an equilibrium condition which is identical or close to the pre-disturbance condition. Small disturbances include the continuously changing system load, OLTC operations, and minor switching operations.

(b) Small-signal instability may be oscillatory, where undamped rotor angle oscillations grow to dangerous magnitudes, or monotonic, where rotor angle differences increase in one direction. In either case Generation Units can fall out of synchronism with each other and pole slipping can occur.

(c) Small-signal stability is assessed on the basis of the damping design criterion which states that “System damping is considered adequate if, at any credible operating point, after the most critical single contingency, simulations indicate that the halving time of the least damped electromechanical mode of oscillation is not more than 5 sec. (The 5 sec. halving time corresponds to a damping constant of 0.14 Nepers/sec.).”

(d) Statistical effects shall be taken into account when analysing test results.
16.1.7 Oscillation damping

(a) All electromechanical oscillations resulting from any small or large disturbance in the power system shall be well damped and the power system shall return to a stable operating state.

(b) The damping ratio of the oscillations should be at least 0.5. For inter-area oscillation modes, lower damping ratios may be acceptable but the halving time of such oscillations should not exceed five seconds.

16.1.8 Power system stabilisers

(a) Power system simulation studies may indicate the possibility of insufficient damping on the system, and that the best solution to this problem would be the installation of power system stabilisers. These are to be installed on those Generation Units where they will be most effective in improving overall system damping.

(b) The stabilising circuits shall be responsive and adjustable over a wide range of frequency range, which shall include frequencies from 0.1 Hz to 2.5 Hz. The PSS settings shall be optimised to provide maximum damping.

16.2 Voltage stability criteria

16.2.1 Voltage stability limits

(a) All necessary steps should be taken to ensure that voltage collapse does not occur for the most onerous outage of a transmission element under credible Generation schedules under full load conditions. It should also be assumed that 3% of the installed capacitors are unavailable. Voltage collapse is associated with a deficit of reactive power. Adequate reactive reserves based on power system studies should be provided (see notes below).

Notes:

(1) The system load to be used in studies is the 1 in 10 year probability forecast.

(2) All Generation with the exception of one unit is to be taken as available with none of the MVAr limits to be exceeded.

(b) Voltage stability is a function of the dynamic characteristics of system loads. A power system at a given operating state and subject to a given disturbance is voltage stable if post-disturbance voltages at every point on the system reach equilibrium within satisfactory limits. Disturbances may be small or large, and time frames may vary from tenths of a second to several hours.

(c) Voltage instability most commonly results in voltage collapse, but may give rise to excessively high voltage levels under some conditions.

(d) Adequate and appropriate reactive power compensation shall be provided to ensure that the power system is protected against all forms of voltage
instability. This can include the use of shunt and series capacitors and / or reactors, SVCs, synchronous condensers, etc.

16.2.2 Voltage collapse

(a) A power system undergoes voltage collapse if post-disturbance voltages are below acceptable limits. Voltage collapse may be total (blackout) or partial.

(b) The possibility of an actual voltage collapse depends upon the nature of the load. If the load is stiff (constant power, such as a synchronous motor) the collapse is aggravated. If the load is soft, eg. heating, the power absorbed by the load falls off rapidly with voltage and the situation is alleviated.

16.2.3 Resonance conditions

(a) Voltage oscillations can arise within a power system as a result of resonance conditions. Resonance effects are generally caused by a series resonance between a capacitance and an inductance, for example a capacitor bank and the inductive reactance of a transmission line or transformer.

(b) Network resonant frequencies can exist above and below synchronous frequency and a latent resonance can be excited by a variety of network disturbances (large or small).

(c) If resonance is excited following a network disturbance, then oscillations appearing as network voltage amplitude modulations can arise.

(d) If the damping mode of the network at the resonant frequency is positive then the network will absorb the oscillation. However, if the damping is negative, the oscillations will build up and lead to supersynchronous (>50 Hz) or subsynchronous (<50 Hz) instability.

(e) If corrective action (typically in the form of load shedding) is not taken, then this form of oscillation can lead to extensive damage to network and customer equipment.

(f) Locations with a low fault level and a weak electrical connection (usually with impedance higher than 1.0 p.u. to the source) are prone to sub-synchronous oscillations or resonance.

16.2.4 Transient over-voltages

Transient over-voltages can arise from normal switching operations and external influences such as lightning strikes. Surge diverters are used where necessary to ensure that the transient over-voltage seen by an item of network plant is limited to its rated lightning impulse withstand voltage level.

16.2.5 Temporary over-voltages

Temporary AC over-voltages should not exceed the time duration limits given in Australian Standard AS2926 – 1987 unless specific designs are implemented to ensure the adequacy and integrity of equipment on the power system, and that the effects on loads have been adequately mitigated.
16.2.6 Transient voltage dip criteria (TVD)

After clearing a system fault the voltage should not drop below 75% and shall not be below 80% for more than 0.4 seconds during the power swing that follows the fault. The maximum transient voltage dip is 25% and the maximum duration of voltage dip exceeding 20% is 20 cycles (400ms).

16.3 Frequency stability criteria

(a) The frequency stability criterion relates to the recovery times for excursions of the system frequency from the steady state limits.

(b) To cover for a loss of Generation Facilities there are two measures applied to bring back the falling frequency:

(1) Spinning reserve; and

(2) Under frequency load shedding (UFLS).

(c) Under frequency load shedding relays are installed at zone substations to shed load at pre-determined levels of frequency at or below 49.25 Hz following loss of a major Generation Unit or its interconnection.

(d) Following loss of Generation Facilities, system frequency, depending on spinning reserve, may still decline to such levels that the UFLS automatic scheme will be used to reduce network load in order to help the frequency recovery.

(e) It is a requirement for power system security that 75% of the power system load at any time be available for disconnection under:

(1) The automatic control of under frequency relays; and

(2) Manual or automatic control from control centres; and/or

(3) The automatic control of undervoltage relays.

(f) In some circumstances, it may be necessary to have up to 90% of the power system load, or up to 90% of the load within a specific part of the network, available for automatic disconnection. Power and Water will advise Users if this additional requirement is necessary.

(g) Special load shedding arrangements may be required to be installed to cater for abnormal operating conditions.

(h) The settings for under-frequency load shedding in the various regions throughout the Northern Territory are given in Table 3 of this Code.

17 Quality of supply criteria

(a) Quality of supply criteria regulate the voltage and current waveforms in the network and criteria are established for the following aspects:

(1) Voltage fluctuation;

(2) System Frequency;
(3) Harmonic distortion;
(4) Voltage unbalance; and
(5) Network reliability.

(b) The networks are analysed to ensure satisfactory performance, in accordance with the quality of supply criteria, whenever a new User is connected or a complaint from an existing User is received.

(c) The aspects of quality of supply that are analysed are:

1. Steady state voltage;
2. Voltage fluctuation; and
3. Network frequency, on isolated regional networks.

(d) Harmonic voltage and current and voltage unbalance will be analysed depending on the nature of the load of the new User being connected.

17.1 Voltage fluctuation criteria

A voltage disturbance is where the voltage shape is maintained but the voltage magnitude varies and may fall outside the steady state supply voltage range set out in clause 15.2 of the Network Planning Criteria.

(a) Short duration voltage disturbances with durations of up to one minute are termed voltage sags and swells.

(b) Short duration voltage disturbances generally arise from faults on the network and may not be able to be economically eliminated.
17.1.1 Temporary over-voltages

(a) As a consequence of a credible contingency event, the voltage of supply at a connection point should not rise above its normal voltage by more than a given percentage of normal voltage for longer than the corresponding period shown in Figure 4 for that percentage.

Figure 4 – Over voltage limit for contingency events

(b) Users’ equipment shall also be designed to withstand these voltage levels.

(c) As a consequence of a contingency event, the voltage of supply at a connection point could fall to zero for any period.

17.1.2 Step changes in voltage levels

(a) Step changes in the power system voltage levels may take place due to switching operations on the network. The step changes in voltage shall not exceed the limits set out in Table 17.
Table 17 – Step change voltage limits

<table>
<thead>
<tr>
<th>Cause</th>
<th>Pre-tap-changing</th>
<th>Post-tap-changing (final steady state)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>≥ 66 kV</td>
<td>&lt; 66 kV</td>
</tr>
<tr>
<td>Routine Switching (1)</td>
<td>±4.0% (max)</td>
<td>±4.0% (max)</td>
</tr>
<tr>
<td>Infrequent Switching (2)</td>
<td>+6%, −10% (max)</td>
<td>+6%, −10% (max)</td>
</tr>
</tbody>
</table>

Notes:  
1. For example, capacitor switching, transformer tap action, motor starting, start-up and shutdown of Generation Units.  
2. For example, tripping of Generation Units, loads, lines and other components.

(b) Voltage fluctuation severity is characterised by the following two quantities, which are defined in Australian Standard AS/NZS 61000.3.7 (2001):

1. $P_{st}$ - short-term flicker severity term (obtained for each 10 minute period); and  
2. $P_{lt}$ - long-term flicker severity (obtained from 12 consecutive $P_{st}$ periods for each 2 hour period).

(c) Under normal operating conditions, flicker severity caused by voltage fluctuation in the transmission and network shall be within the planning levels shown in Table 18 for 99% of the time.

Table 18 – Flicker severity – planning levels

<table>
<thead>
<tr>
<th>Flicker Severity Quantity</th>
<th>LV 230/400 V</th>
<th>MV (11-66 kV)</th>
<th>HV (132 kV)</th>
</tr>
</thead>
<tbody>
<tr>
<td>$P_{st}$</td>
<td>1.0</td>
<td>0.9</td>
<td>0.8</td>
</tr>
<tr>
<td>$P_{lt}$</td>
<td>0.7</td>
<td>0.7</td>
<td>0.6</td>
</tr>
</tbody>
</table>

Notes:  
1. These values were chosen on the assumption that the transfer coefficients between MV or HV systems and LV systems are unity. The planning levels could be increased in accordance with AS61000.3.7 (2001).  
2. The planning levels in this Table are not intended to apply to flicker arising from contingency and other uncontrollable events in the power system, etc.

(d) Voltage fluctuations for individual Users shall be measured at the point of Common Coupling, which is the point of connection to other Users in the same portion of the network.
17.2 Harmonic voltage and current distortion

(a) Power and Water’s power networks and all plant and equipment connected thereto shall be planned and designed to ensure that harmonic voltages and currents do not exceed the limits defined in Australian Standard AS/NZS 61000.3.6 (2001).

(b) For planning purposes the harmonic voltage levels shown in Table 19 apply to the respective system voltage level.

Table 19 - Harmonic voltage distortion limits – planning levels

<table>
<thead>
<tr>
<th>Order h</th>
<th>Odd harmonics non multiple of 3</th>
<th>Even harmonics</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Harmonic voltage %</td>
<td></td>
</tr>
<tr>
<td></td>
<td>$LV \geq 11 \text{kV}$</td>
<td>$LV \geq 11 \text{kV}$</td>
</tr>
<tr>
<td>5</td>
<td>5.0 2.0</td>
<td>2.0</td>
</tr>
<tr>
<td>7</td>
<td>4.0 2.0</td>
<td>1.2</td>
</tr>
<tr>
<td>11</td>
<td>3.1 1.5</td>
<td>0.3</td>
</tr>
<tr>
<td>13</td>
<td>2.5 1.5</td>
<td>0.2</td>
</tr>
<tr>
<td>17</td>
<td>1.6 1.0</td>
<td>0.2</td>
</tr>
<tr>
<td>19</td>
<td>1.2 1.0</td>
<td>0.2</td>
</tr>
<tr>
<td>23</td>
<td>1.2 0.7</td>
<td>0.2</td>
</tr>
<tr>
<td>25</td>
<td>1.2 0.7</td>
<td>0.2</td>
</tr>
<tr>
<td>$&gt;25$</td>
<td>$0.2 + 0.5 \cdot \frac{25}{h}$</td>
<td>$0.2 + 0.5 \cdot \frac{25}{h}$</td>
</tr>
</tbody>
</table>

Notes to Table 19:

1. This Table is derived from Australian Standard AS/NZS 61000.3.6 (2001).
2. The total harmonic distortion ($U_t$) is calculated from the expression

$$U_t = \frac{U_{nom}}{U_1} \sqrt{\sum_{h=2}^{45} (U_h)^3}$$

Where:

$U_{nom}$ nominal voltage of a system

$U_1$ fundamental voltage

$U_h$ harmonic voltage of order $h$ expressed as a percentage of the nominal voltage.

3. The harmonic distortion limits apply to each phase.
4. Intermittent harmonic voltage distortion is subject to the same limits as continuous harmonic voltage distortion.
5. Existing (background) levels of harmonic voltage distortion are not included when assessing the harmonic contribution.

17.2.1.1 Inter-harmonic distortion

Inter-harmonic or non-integer harmonic distortion may arise from large convertors or power electronics equipment with Pulse Width Modulation (PWM) converters interfacing with the power system.

A User’s inter-harmonic voltage distortion contribution shall not exceed the planning level of 0.2% specified in section 9 of Australian Standard AS/NZS 61000.3.6:2001.

17.2.2 Direct current

(a) Plant and equipment shall comply with the requirements on direct current components as stipulated in clause 3.12 of Australian Standard AS 3100. In particular, the direct current in the neutral caused by the User’s plant and equipment shall not exceed 120mAh per day.

(b) The responsibility of the Network Operator for direct current in the neutral outside the limits specified in this clause shall be limited to direct current in the neutral caused by network assets.

(c) Plant and equipment at Users’ premises shall perform to the standards specified in subclause (a).

17.3 Voltage unbalance

(a) For normal system operation and for planned system outages, the voltage unbalance at each of connection points to the network shall not exceed the limits set out in clause 2.4.3 of the Code.

(b) The responsibility of Power and Water for voltage unbalance outside the limits specified in clause 17.3(a) shall be limited to voltage unbalance caused by network assets.

(c) Users’ equipment shall perform to the standards specified in clause 17.3(a).

17.4 Electromagnetic interference

Power and Water shall design its networks to ensure that the electromagnetic interference caused by its plant and equipment does not exceed the limits set out in Tables 1 and 2 of Australian Standard AS 2344.

18 Construction standards criteria

(a) Power and Water shall construct the overhead portions of its networks in accordance with the Electricity Supply Association of Australia publication C(b)1 -“Guidelines for Design and Maintenance of Overhead Distribution and Transmission lines”.
(b) *Power and Water* shall construct the underground portions of its *networks* in accordance with the Electricity Supply Association of Australia publication C(b)2 - “Guide to the Installation of Cables Underground”.

### 18.1 Conductor selection criteria

(a) *Power and Water* generally uses overhead conductors for *transmission* and *sub-transmission* circuits in order to minimise construction costs. *Power and Water* may use underground cables for such circuits where required by environmental constraints and where the additional cost can be justified.

(b) *Power and Water* uses underground cables for *distribution network* reinforcement and *extension* within the Darwin Metropolitan area, *Regional Centres*, new sub-divisions where in *Power and Water*’s opinion they are appropriate, or if required by legislation. Outside these areas *Power and Water* will generally install overhead conductors.

(c) In designing *extensions* to the *network*, ultimate *load* horizon planning shall be used to establish the *network* concept plan and the initial installation shall conform to that concept plan and use carriers that are appropriately sized. This methodology eliminates the need to disrupt the community in future years as *load* growth occurs and results in the minimum lifetime cost to the community.

(d) To achieve maximum cost efficiency in the installation of conductors, standard overhead conductor and underground cable sizes have been selected. This results in minimum stock holdings and purchase prices, giving the *User* the least cost *network*.

(e) The standard conductor size that is equal to, or greater than that required for the reasonably foreseeable *load*, shall be used for each overhead *network extension* or reinforcement.

(f) The standard cable size that is equal to, or greater than that required for the horizon *load*, shall be used for each underground *network extension* or reinforcement.
Environmental criteria

Power and Water’s environmental policy states that:

“Power and Water recognises and accepts its environmental responsibilities arising from the provision of power, water and sewerage services.

“Power and Water will seek to minimise environmental impacts and comply with environmental regulations.

“Continual improvement in environmental performance will be sought by Power and Water through:

• Implementing a comprehensive Environmental Management System;
• Minimising the environmental impacts of its operations;
• Promoting individual ownership of environmental care among its people; and
• Consulting with the community on environmental issues.

“Sustainable Development will be pursued by Power and Water through:

• Adoption of integrated resource planning;
• Use of renewable resources;
• Maximisation of long term benefits from non-renewable resources; and
• Promotion and adoption of waste minimisation and recycling practices.”

Power and Water commits to the following objectives to fulfil its environmental policy:

• To consult openly and fully with the community and government where Authority activity may affect the environment;
• To ensure that planning and design for new projects and changes to existing processes provide for consideration of best environmental practice technology and timely impact assessment; and
• To carry out its business in a resource efficient manner.

Power and Water’s power networks will be developed so that these commitments are met.

19.1 Social issues

Power and Water shall inform and consult with relevant public bodies and community interest groups and the general public on the planning of new developments and facilities.

19.2 Electromagnetic fields

Recognising the current state of scientific uncertainty regarding adverse health effects from exposure to power frequency electric and magnetic fields, Power and
Water shall act prudently and design, construct and operate all equipment and facilities to maintain electromagnetic field exposure to the public and Power and Water employees at levels within the Interim Guidelines on Limits of Exposure to 50/60 Hz Electric and Magnetic Fields set out in the ARPANSA Radiation Health Series No. 30 standard.

19.3 Land-Use considerations

Power and Water shall avoid, or minimise damage to natural, cultural and historical sites where reasonable and economically practical, consistent with the safe and reliable operation of the electricity supply network.

19.4 Noise

Power and Water shall comply with the noise limit provisions of the Environmental Protection Act.

19.5 Visual amenity

Given that the community and customers are sensitive to the visual impact of electrical installations, Power and Water shall conduct its electricity supply operations in a manner that minimises visual impact.
Part D Attachments

Attachment 1 Glossary of Terms

In this Code, unless the contrary intention appears:

(a) A word or phrase set out in column 1 of the table below has the meaning set out opposite that word or phrase in column 2 of the table below; and

(b) A word or phrase defined in the Power and Water Corporation Act has the meaning given in that Act unless redefined in the table below.

<table>
<thead>
<tr>
<th>Terminology</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>Access Agreement</td>
<td>Means a contract or agreement for the provision of network access services entered into between a network provider and a network User under the Code, and includes an award made by an arbitrator for the same purpose.</td>
</tr>
<tr>
<td>Access Applicant</td>
<td>An existing or new network User making an Access Application under clause 10 of the Electricity Networks (Third Party Access) Code.</td>
</tr>
<tr>
<td>Access Application</td>
<td>An Access Application made under clause 10 of the Electricity Networks (Third Party Access) Code, which is described in Attachment 6.</td>
</tr>
<tr>
<td>access services</td>
<td>The following services: use of system services; common services; connection services and ancillary services.</td>
</tr>
<tr>
<td>active energy</td>
<td>A measure of electrical energy flow, being the time integral of the product of voltage and the in-phase component of current flow across a connection point, expressed in Watt-hours (Wh) and multiples thereof.</td>
</tr>
<tr>
<td>active power</td>
<td>The rate at which active energy is transferred.</td>
</tr>
<tr>
<td>active power capability</td>
<td>The maximum rate at which active energy may be transferred from a Generation Unit to a connection point as specified in an Access Agreement.</td>
</tr>
<tr>
<td>active unit protection</td>
<td>Generally, a protection scheme that compares the conditions at defined primary plant boundaries and can positively identify whether a fault is internal or external to the protected plant. Unit protection schemes can provide high speed (less than 150 milliseconds) protection for the protected primary plant. Generally, unit protection schemes will not be capable of providing back up protection.</td>
</tr>
<tr>
<td>agreed capability</td>
<td>In relation to a connection point, the capability to receive or send out active power and reactive power for that connection point determined in accordance with the relevant Access Agreement.</td>
</tr>
<tr>
<td>ancillary services</td>
<td>The following services: voltage control, reactive power control, frequency control, control system services, spinning reserve and post-trip management.</td>
</tr>
<tr>
<td>ancillary services agreement</td>
<td>An agreement covering the provision of ancillary services.</td>
</tr>
<tr>
<td>Terminology</td>
<td>Definition</td>
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<tr>
<td>---------------------------------</td>
<td>-----------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td><strong>associated load</strong></td>
<td>A load which is normally supplied by a particular Generator and is associated with that Generator by ownership or some contractual arrangement. The load may be remote from the Generator or on-site.</td>
</tr>
<tr>
<td><strong>augment, augmentation</strong></td>
<td>In relation to the electricity network, means to enlarge or expand the capability of the electricity network to accept, transport and deliver electricity.</td>
</tr>
<tr>
<td><strong>Australian Standard (AS)</strong></td>
<td>The most recent edition of a standard publication by Standards Australia (Standards Association of Australia).</td>
</tr>
<tr>
<td><strong>automatic reclose equipment</strong></td>
<td>In relation to a power line, the equipment which automatically recloses the relevant line’s circuit breaker(s) following their opening as a result of the detection of a fault in the power line.</td>
</tr>
<tr>
<td><strong>backup protection</strong></td>
<td>A protection intended to supplement the main protection in case the latter should be ineffective, or to deal with faults in those parts of the power system that are not readily included in the operating zone of the main protection.</td>
</tr>
<tr>
<td><strong>black start capability</strong></td>
<td>In relation to a Generation Unit, the ability to start and synchronise without using supply from the power system.</td>
</tr>
<tr>
<td><strong>black start-up facilities</strong></td>
<td>The facilities required to provide a Generation Unit with black start-up capability.</td>
</tr>
<tr>
<td><strong>black system</strong></td>
<td>The absence of voltage on all or a significant part of the network following a major supply disruption, affecting one or more power stations and a significant number of customers.</td>
</tr>
<tr>
<td><strong>breaker fail protection</strong></td>
<td>In relation to a protection scheme, that part of the protection scheme that protects a User’s facilities against the non-operation of a circuit breaker when it is required to open.</td>
</tr>
<tr>
<td><strong>busbar</strong></td>
<td>A common connection point in a power station substation or a transmission network substation.</td>
</tr>
<tr>
<td><strong>business day</strong></td>
<td>Any day other than a Saturday, Sunday, or day that is a public holiday in the City of Darwin.</td>
</tr>
<tr>
<td><strong>capacitor bank, capacitor</strong></td>
<td>A type of static electrical equipment used to generate reactive power and therefore support voltage levels on network elements.</td>
</tr>
<tr>
<td><strong>cascading outage</strong></td>
<td>The occurrence of an uncontrollable succession of outages, each of which is initiated by conditions (eg. instability or overloading) arising or made worse as a result of the event preceding it.</td>
</tr>
<tr>
<td><strong>change</strong></td>
<td>Includes amendment, alteration, addition or deletion.</td>
</tr>
<tr>
<td><strong>check metering installation</strong></td>
<td>A metering installation which may be used as a source of metering data for validation, substitution or account estimation as provided in clause 10 of this Code.</td>
</tr>
<tr>
<td><strong>circuit breaker failure</strong></td>
<td>A circuit breaker will be deemed to have failed if, having received a trip signal from a protection scheme, it fails to interrupt fault current within its design operating time.</td>
</tr>
<tr>
<td><strong>Code, Technical Code</strong></td>
<td>This Code called the Technical Code.</td>
</tr>
<tr>
<td><strong>Code commencement date</strong></td>
<td>The date given in clause 1.4 of this Code.</td>
</tr>
<tr>
<td><strong>commitment</strong></td>
<td>The commencement of the process of starting up and synchronising.</td>
</tr>
<tr>
<td>Terminology</td>
<td>Definition</td>
</tr>
<tr>
<td>---------------------------------</td>
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</tr>
<tr>
<td><strong>common services</strong></td>
<td>A network service that ensures the integrity of the electricity network and benefits all Users and that cannot be practically be allocated to Users on a locational basis.</td>
</tr>
<tr>
<td><strong>complementary</strong></td>
<td>In relation to protection, two protection schemes are said to be complementary when, in combination, they provide dependable clearance of faults on plant within a specified time, but with any single failure to operate of the secondary plant, fault clearance may be delayed until the nature of the fault changes.</td>
</tr>
<tr>
<td><strong>connect, connection</strong></td>
<td>Means to establish an effective link via installation of the necessary connection equipment.</td>
</tr>
<tr>
<td><strong>connection asset</strong></td>
<td>Means all of the electrical equipment that is used only in order to transfer electricity to or from the electricity network at the relevant connection point and includes any transformers or switchgear at the relevant point or which is installed to support or to provide backup to such electrical equipment as are necessary for that transfer.</td>
</tr>
<tr>
<td><strong>connection point</strong></td>
<td>A point at which electricity is transferred to or from an electricity network.</td>
</tr>
<tr>
<td><strong>connection services</strong></td>
<td>In relation to a connection point, means the establishment and maintenance of that connection point.</td>
</tr>
<tr>
<td><strong>constraint, constrained</strong></td>
<td>A limitation on the capability of a network, load or a Generation Unit preventing it from either transferring, consuming or generating the level of electrical power which would otherwise be available if the limitation was removed.</td>
</tr>
<tr>
<td><strong>contingency capacity reserve</strong></td>
<td>Actual active and reactive energy capacity, interruptible load arrangements and other arrangements organised to be available to be utilised on the actual occurrence of one or more contingency events to allow the restoration and maintenance of power system security.</td>
</tr>
<tr>
<td><strong>contingency event</strong></td>
<td>An event affecting the power system which the Network Operator expects would be likely to involve the failure or removal from operational service of a Generation Unit or network element.</td>
</tr>
<tr>
<td><strong>control centre</strong></td>
<td>The facility used by the Power System Controller for directing the minute to minute operation of the power system.</td>
</tr>
<tr>
<td><strong>controller</strong></td>
<td>A person employed by a Power System Controller engaged in the activities of controlling the transfer of electrical energy at a connection point.</td>
</tr>
<tr>
<td><strong>control system</strong></td>
<td>Means of monitoring and controlling the operation of the power system or equipment including Generation Units connected to a network.</td>
</tr>
<tr>
<td><strong>control system services</strong></td>
<td>The 24-hour control of the power system through monitoring, switching and dispatch which is provided through control centres and SCADA and communication equipment.</td>
</tr>
<tr>
<td>Terminology</td>
<td>Definition</td>
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</tr>
<tr>
<td>credible contingency event</td>
<td>A contingency event the occurrence of which the Network Operator considers to be reasonably possible in the surrounding circumstances.</td>
</tr>
</tbody>
</table>
| critical fault clearance time                  | Refers to the maximum total fault clearance time that the power system can withstand without one or both of the following conditions arising:  
• Instability (refer to clause 2.6); and  
• Unacceptable disturbance of power system voltage or frequency.                                                                                     |
| critical single credible contingency event      | A single credible contingency event considered by the Network Operator, in particular circumstances, to have the potential for the most significant impact on the power system at that time. This would generally be the instantaneous loss of the largest Generation Unit or a fault on a network element on the power system. 
However, this may involve the consideration by the Network Operator of the impact of the loss of any interconnection under abnormal conditions. |
<p>| credible contingency                            | An individual credible contingency event for which a User adversely affected by the event would reasonably expect, under normal conditions, the design or operation of the relevant part of the meshed power system would adequately cater, so as to avoid significant disruption to power system security. |
| current rating                                  | The maximum current that may be permitted to flow (under defined conditions) through a power line or other item of equipment that forms part of a power system.                                                |
| current transformer (CT)                       | A transformer for use with meters and/or protection devices in which the current in the secondary winding is, within prescribed error limits, proportional to and in phase with the current in the primary winding. |
| customer                                        | A person who purchases electricity supplied through a network.                                                                                                                                                |
| day                                             | Unless otherwise specified, the 24 hour period beginning and ending at midnight Australian Central Standard Time.                                                                                           |
| decommission, decommissioning                   | In respect of an item of plant or a Generation Unit, ceasing to operate and being disconnected from a network.                                                                                               |
| derogation                                       | Modification, variation or exemption to one or more provisions of the Code in relation to a User according to clause 12.                                                                                      |
| de-synchronising/ de-synchronisation            | The act of disconnection of a Generation Unit from the power system, normally under controlled circumstances.                                                                                             |
| differing principle                             | Two protection schemes are said to be of differing principle when their functioning is based on different measurement or operating methods, or use similar principles but have been designed and manufactured by different organisations. |</p>
<table>
<thead>
<tr>
<th>Terminology</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>direction</td>
<td>A direction issued by the Network Operator or Power System Controller to any User requiring the User to do any act or thing which the Network Operator or Power System Controller considers necessary to maintain or re-establish power system security or to maintain or re-establish the power system in a reliable operating state in accordance with this Code.</td>
</tr>
<tr>
<td>disconnection, disconnect,</td>
<td>In respect of a connection point or item of plant, means to operate switching equipment so as to prevent the transfer of electricity through the connection point or item of plant.</td>
</tr>
<tr>
<td>disconnected, disconnecting</td>
<td></td>
</tr>
<tr>
<td>dispatch</td>
<td>The act of committing to service all or part of the Generation available from a scheduled Generation Unit.</td>
</tr>
<tr>
<td>distribution system,</td>
<td>That part or those parts of the electricity network used for transporting electricity at nominal voltages of less than 66 kV and at a nominal frequency of 50Hz.</td>
</tr>
<tr>
<td>distribution network</td>
<td></td>
</tr>
<tr>
<td>dynamic performance</td>
<td>The response and behaviour of networks and facilities which are connected to the networks when the normal operating state of the power system is disturbed.</td>
</tr>
<tr>
<td>electrical energy loss</td>
<td>Energy loss incurred in the production, transportation and/or use of electricity.</td>
</tr>
<tr>
<td>electricity network</td>
<td>The connection assets and network system assets which together are operated by the network provider for the purposes of transporting electricity from Generators of electricity to a transfer point or to consumers of electricity.</td>
</tr>
<tr>
<td>electricity transmission capacity</td>
<td>The capacity of the transmission network to transmit power between two or more points under the full range of operating conditions likely to be experienced in service.</td>
</tr>
<tr>
<td>embedded Generator</td>
<td>A Generator which supplies on-site loads or distribution network loads and is connected either indirectly (ie. via the distribution network) or directly to the transmission network.</td>
</tr>
<tr>
<td>energise/energisation</td>
<td>The act of operation of switching equipment or the start-up of a Generation Unit, which results in there being a non-zero voltage beyond a connection point or part of the network.</td>
</tr>
<tr>
<td>energy</td>
<td>Active energy and/or reactive energy.</td>
</tr>
<tr>
<td>energy data</td>
<td>The data that results from the measurement of the flow of electricity in a power conductor. The measurement is carried out at a metering point.</td>
</tr>
<tr>
<td>excitation control system</td>
<td>In relation to a Generation Unit, the automatic control system that provides the field excitation for the Generator of a Generation Unit (including excitation limiting devices and any power system stabiliser).</td>
</tr>
<tr>
<td>extension</td>
<td>The capital investment associated with the designing, constructing, installing and commissioning of the electricity network assets required to connect a User to the electricity network.</td>
</tr>
<tr>
<td>Terminology</td>
<td>Definition</td>
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</tr>
</tbody>
</table>
| facility                          | A generic term associated with the apparatus, equipment, buildings and necessary associated supporting resources provided at, typically:  
• a power station or Generation Unit, including start-up facilities;  
• a substation or power station substation;  
• a control centre.                                                                                                                                         |
<p>| fault clearance time              | The time interval between the occurrence of a fault and the fault clearance.                                                                                                                                  |
| financial year                    | A period commencing on 1 September in one calendar year and terminating on 30 June in the following calendar year.                                                                                         |
| frequency                         | For alternating current electricity, the number of cycles occurring in each second. The term Hertz (Hz) corresponds to cycles per second.                                                                 |
| frequency operating standards     | The frequency standards set out in clauses 2.2, and 2.4 of this Code.                                                                                                                                         |
| frequency response mode           | The mode of operation of a Generation Unit which allows automatic changes to the generated power when the frequency of the power system changes.                                                        |
| generated                         | In relation to a Generation Unit, the amount of electrical energy produced by the Generation Unit as measured at its terminals.                                                                             |
| Generating System                 | A system comprising one or more Generation Units.                                                                                                                                                           |
| Generator, Generation Unit/Facilities | An electricity generator, and all related equipment essential to the generator’s operation, which supplies electricity into an electricity network and together function as a single entity. |
| Generation                        | The production of electrical energy by converting another form of energy in a Generation Unit.                                                                                                               |
| generation centre                 | A geographically concentrated area containing a Generation Unit or Generation Units with significant combined generating capability.                                                                           |
| Generator User                    | A person who has been granted access to the electricity network by the network provider and who supplies electricity into the electricity network at an entry point.                                       |
| good electricity industry practice| The exercise of that degree of skill, diligence, prudence and foresight that reasonably would be expected from a significant proportion of operators of facilities forming part of a power system for the Generation, transmission distribution and supply of electricity comparable to those applicable to the relevant facility consistent with applicable laws, the Access Code, the Technical Code, licences, industry Codes, reliability, safety and environmental protection. |
| governor system                   | The automatic control system which regulates the speed and power output of a Generation Unit through the control of the rate of entry into the Generation Unit of the primary energy input (for example, steam, gas or water). |
| instrument transformer            | Either a current transformer (CT) or a voltage transformer (VT).                                                                                                                                             |</p>
<table>
<thead>
<tr>
<th>Terminology</th>
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</tr>
</thead>
<tbody>
<tr>
<td>interconnection, interconnector,</td>
<td>A transmission line or group of transmission lines that connects the transmission networks in adjacent regions.</td>
</tr>
<tr>
<td>interconnect, interconnected</td>
<td></td>
</tr>
<tr>
<td>interruptible load</td>
<td>A load which is able to be disconnected, either manually or automatically initiated, which is provided for the restoration or control of the power system frequency by the Power System Controller to cater for contingency events or shortages of supply</td>
</tr>
<tr>
<td>intra-regional</td>
<td>Within a region.</td>
</tr>
<tr>
<td>Large Generator</td>
<td>A Generator that is not a Small Generator.</td>
</tr>
<tr>
<td>large network investment</td>
<td>A proposed investment in augmentation of the network or a non-network alternative with a capitalised net present value in excess of $5 Million.</td>
</tr>
<tr>
<td>load, loading</td>
<td>The amount of electrical energy delivered at a defined instant at a connection point or aggregated over a group of connection points.</td>
</tr>
<tr>
<td>load centre</td>
<td>A geographically concentrated area containing load or loads with a significant combined consumption capability.</td>
</tr>
<tr>
<td>load shedding</td>
<td>Reducing or disconnecting load from the power system. (See also under frequency load shedding, under voltage load shedding).</td>
</tr>
<tr>
<td>local black system procedures</td>
<td>The procedures, described under clause 4.7.9 applicable to a User as procedures approved by the Power System Controller from time to time.</td>
</tr>
<tr>
<td>low voltage (LV)</td>
<td>That portion of the network and connections to it operating at a nominal voltage of 230 volts single phase or 400 volts three phase.</td>
</tr>
<tr>
<td>maximum fault current</td>
<td>The current that will flow to a fault on an item of plant when maximum system conditions prevail.</td>
</tr>
<tr>
<td>maximum system conditions</td>
<td>For any particular location in the power system, maximum system conditions are those which will prevail with the maximum number of Generators and network elements normally connected at times of maximum Generation.</td>
</tr>
<tr>
<td>meter, metering, metering equipment</td>
<td>Equipment used to measure and record the rate at which electricity is transferred and the quantity of electricity transferred to and from the network.</td>
</tr>
<tr>
<td>minimum fault current</td>
<td>The current that will flow to a fault on an item of plant when present day minimum system conditions prevail.</td>
</tr>
<tr>
<td>minimum system conditions</td>
<td>For any particular location in the power system, minimum system conditions are those which will prevail with the least number of Generators and network elements normally connected at times of minimum Generation, in combination with one primary plant outage. The primary plant outage shall be taken to be that which, in combination with the minimum Generation, leads to the lowest fault current at the particular location for the fault type under consideration.</td>
</tr>
<tr>
<td>monitoring equipment</td>
<td>The testing instruments and devices used to record the performance of plant for comparison with expected performance.</td>
</tr>
<tr>
<td>Terminology</td>
<td>Definition</td>
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<td>---------------------------------</td>
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</tr>
<tr>
<td><em>month</em></td>
<td>Unless otherwise specified, the period beginning at 12.00 am on the “relevant commencement date” and ending at 12.00 am on the date in the “next calendar <em>month</em>” corresponding to the commencement date of the period. If the “relevant commencement date” is the 29th, 30th or 31st and this date does not exist in the “next calendar <em>month</em>”, then the end date in the “next calendar <em>month</em>” shall be taken as the last day of that <em>month</em>.</td>
</tr>
<tr>
<td><em>nameplate rating</em></td>
<td>The maximum continuous output or consumption in MW or MVA of an item of equipment as specified by the manufacturer.</td>
</tr>
<tr>
<td><em>NATA</em></td>
<td>National Association of Testing Authorities.</td>
</tr>
<tr>
<td><em>network</em></td>
<td>See definition for <em>electricity network</em>.</td>
</tr>
<tr>
<td><em>Network Access Code</em></td>
<td></td>
</tr>
<tr>
<td><em>network capability</em></td>
<td>The capability of the <em>network</em> or part of the <em>network</em> to transfer electrical energy from one location to another.</td>
</tr>
<tr>
<td><em>network losses</em></td>
<td>The energy loss incurred in the transportation of electricity from an entry or transfer point to an exit point or another transfer point on an <em>electricity network</em>.</td>
</tr>
<tr>
<td><em>Network Management Plan</em></td>
<td>A report prepared and published annually by the <em>Network Operator</em>. Amongst other things, this report contains the following details:</td>
</tr>
<tr>
<td></td>
<td>• network limitations;</td>
</tr>
<tr>
<td></td>
<td>• potential non-network and network solutions for small network investments; and</td>
</tr>
<tr>
<td></td>
<td>• potential non-network and network solutions for large network investments.</td>
</tr>
<tr>
<td><em>Network Operator</em></td>
<td>A body defined as a “<em>network provider</em>” in the <em>Electricity Networks (Third Party Access) Act</em> as in force at 1 February 2011. The <em>Network Operator</em> provides <em>access services</em> in respect of Power and Water’s electricity network.</td>
</tr>
<tr>
<td><em>Network Operator’s metering manuals</em></td>
<td>Specifications prepared by the <em>Network Operator</em> for equipment including revenue metering and communications enclosures, indoor and outdoor revenue metering units (VTs and CTs plus enclosure), CTs, VTs, marshalling boxes and wiring.</td>
</tr>
<tr>
<td><em>Network Planning Criteria</em></td>
<td>Criteria consistent with this <em>Code</em> prepared by the <em>Network Operator</em> which include the following: contingency criteria; steady-state criteria; stability criteria (transient, dynamic, <em>voltage</em>, and <em>frequency</em>); <em>quality of supply criteria</em> (<em>voltage</em> limits, <em>voltage</em> fluctuation, system <em>frequency</em>, harmonic <em>voltage</em>, harmonic current, <em>voltage</em> unbalance, electro-magnetic interference) and environmental criteria.</td>
</tr>
<tr>
<td><em>nomenclature standards</em></td>
<td>The standards approved by the <em>Network Operator</em> relating to numbering, terminology and abbreviations used for information transfer by <em>Users</em> as provided for in clause 4.9.</td>
</tr>
<tr>
<td><em>non-credible contingency event</em></td>
<td>A <em>contingency event</em> other than a <em>credible contingency event</em>. It means a <em>contingency event</em> in relation to which, in the circumstances, the probability of occurrence is considered by the</td>
</tr>
<tr>
<td>Terminology</td>
<td>Definition</td>
</tr>
<tr>
<td>----------------------------------------</td>
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</tr>
<tr>
<td>Network Operator</td>
<td>To be very low.</td>
</tr>
<tr>
<td>normal operating frequency</td>
<td>In relation to the frequency of the power system, means the range specified in clause 2.2.1.</td>
</tr>
<tr>
<td>band</td>
<td></td>
</tr>
<tr>
<td>normal operating frequency</td>
<td>In relation to the frequency of the power system, means the range specified as being acceptable for infrequent and momentary excursions of frequency outside the normal operating frequency band being the range specified in clause 2.2.1.</td>
</tr>
<tr>
<td>excursion band</td>
<td></td>
</tr>
<tr>
<td>operational communication</td>
<td>A communication concerning the arrangements for, or actual operation of the power system in accordance with the Code.</td>
</tr>
<tr>
<td>outage</td>
<td>Any planned or unplanned full or partial unavailability of plant or equipment.</td>
</tr>
<tr>
<td>peak load</td>
<td>Maximum load.</td>
</tr>
<tr>
<td>plant</td>
<td>Includes all equipment involved in generating, utilising or transmitting electrical energy.</td>
</tr>
<tr>
<td>post-trip management</td>
<td>The maintenance of system security in the aftermath of trips.</td>
</tr>
<tr>
<td>Power and Water Corporation</td>
<td>The body corporate established under the Government Owned Corporations Act as in force at 1 February 2011.</td>
</tr>
<tr>
<td>Power system security</td>
<td>The responsibilities described in clause 4.3.</td>
</tr>
<tr>
<td>responsibilities</td>
<td></td>
</tr>
<tr>
<td>power factor</td>
<td>The ratio of the active power to the apparent power at a point.</td>
</tr>
<tr>
<td>power station</td>
<td>In relation to a Generator, a facility in which any of that Generator’s Generation Units are located.</td>
</tr>
<tr>
<td>power system</td>
<td>The Generation facilities and electricity network facilities which together are integral to the supply of electricity, operated as an integrated arrangement.</td>
</tr>
<tr>
<td>Power System Controller</td>
<td>See definition in the Electricity Networks (Third Party Access) Act as in force at 1 February 2011. The power system controller controls the day-to-day dispatch of generators and associated ancillary services and the maintains power system security.</td>
</tr>
<tr>
<td>power system operating procedures</td>
<td>The procedures to be followed by Users in carrying out operations and/or maintenance activities on or in relation to primary and secondary equipment connected to or forming part of the power system or connection points, as described in clause 4.6.</td>
</tr>
<tr>
<td>power system security</td>
<td>The safe scheduling, operation and control of the power system on a continuous basis in accordance with the principles set out in clause 4.2.3.</td>
</tr>
<tr>
<td>power system stabiliser</td>
<td>An auxiliary control device connected to an excitation control system to provide additional feedback signals to reduce power system oscillations.</td>
</tr>
<tr>
<td>power transfer</td>
<td>The instantaneous rate at which active energy is transferred between connection points.</td>
</tr>
<tr>
<td>power transfer capability</td>
<td>The maximum permitted power transfer through a network or part thereof.</td>
</tr>
<tr>
<td>primary equipment, primary plant</td>
<td>Refers to apparatus which conducts power system load or conveys power system voltage.</td>
</tr>
<tr>
<td>Terminology</td>
<td>Definition</td>
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<td>-----------------------------</td>
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</tr>
<tr>
<td><strong>protection</strong></td>
<td>Used to describe the concept of detecting, limiting and removing the effects of primary plant or primary equipment faults from the power system. Also used to refer to the apparatus required to achieve this function.</td>
</tr>
<tr>
<td><strong>protection apparatus</strong></td>
<td>Includes all relays, meters, power circuit breakers, synchronisers and other control devices necessary for the proper and safe operation of the power system.</td>
</tr>
<tr>
<td><strong>protection scheme</strong></td>
<td>A collection of one or more sets of protection for the purpose of protecting facilities and the electricity network from damage due to an electrical or mechanical fault or due to certain conditions of the power system.</td>
</tr>
<tr>
<td><strong>protection system</strong></td>
<td>A system which includes all the protection schemes applied to the system.</td>
</tr>
<tr>
<td><strong>quality of supply</strong></td>
<td>Refers to, with respect to electricity, technical attributes to a standard referred to in clause 2.4, unless otherwise stated in this Code or an Access Agreement.</td>
</tr>
<tr>
<td><strong>ramp rate</strong></td>
<td>The rate of change of electrical power produced from a Generation Unit.</td>
</tr>
<tr>
<td><strong>reactive energy</strong></td>
<td>A measure, in var-hours (VArh) of the alternating exchange of stored energy in inductors and capacitors, which is the time-integral of the product of voltage and the out-of-phase component of current flow across a connection point.</td>
</tr>
<tr>
<td><strong>reactive plant</strong></td>
<td>Plant which is normally specifically provided to be capable of providing or absorbing reactive power and includes the plant identified in clause 3.6.7.</td>
</tr>
</tbody>
</table>
| **reactive power**          | The rate at which reactive energy is transferred. Reactive power is a necessary component of alternating current electrical power which is separate from active power and is predominantly consumed in the creation of magnetic fields in motors and transformers and produced by plant such as:  
  - alternating current Generators;  
  - capacitors, including the capacitive effect of power lines; and  
  - synchronous condensers. |
<p>| <strong>reactive power capability</strong> | The maximum rate at which reactive energy may be transferred from a Generation Unit to a connection point as specified in an Access Agreement. |
| <strong>reactive power reserve</strong>  | Unutilised sources of reactive power arranged to be available to cater for the possibility of the unavailability of another source of reactive power or increased requirements for reactive power. |
| <strong>reactive power support</strong>  | The provision of reactive power.                                                                                                             |
| <strong>reactive support</strong>        | The provision of reactive power.                                                                                                             |
| <strong>reactor</strong>                 | A device, similar to a transformer, specifically arranged to be connected into the network during periods of low load demand or low reactive power demand to counteract the natural capacitive effects of long transmission lines in generating excess reactive |</p>
<table>
<thead>
<tr>
<th>Terminology</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>reconnection</strong></td>
<td>In respect of a connection point, means to operate switching equipment so as to restore the transfer of electricity through the connection point.</td>
</tr>
<tr>
<td><strong>region, regional</strong></td>
<td>An area determined by the Network Operator, being an area served by a particular part of the transmission network containing one or more major load centres or generation centres or both.</td>
</tr>
<tr>
<td><strong>regulating duty</strong></td>
<td>In relation to a Generation Unit, the duty to have its generated output adjusted frequently so that any power system frequency variations can be corrected.</td>
</tr>
<tr>
<td><strong>reliability</strong></td>
<td>The probability of a system, device, plant or equipment performing its function adequately for the period of time intended, under the operating conditions encountered.</td>
</tr>
<tr>
<td><strong>reliable</strong></td>
<td>The expression of a recognised degree of confidence in the certainty of an event or action occurring when expected.</td>
</tr>
<tr>
<td><strong>remote back up protection</strong></td>
<td>Refers to the detection and initiation of tripping at a location other than that at which the main protection scheme of the faulted plant is located. Remote back up protection provides a means of detecting and initiating clearance of small zone faults or fault contributions supplied via failed circuit breakers.</td>
</tr>
<tr>
<td><strong>remote control equipment (RCE),</strong></td>
<td>Equipment installed to enable control or monitoring of a facility from a control centre, including a remote terminal unit (RTU).</td>
</tr>
<tr>
<td><strong>remote monitoring equipment (RME)</strong></td>
<td></td>
</tr>
<tr>
<td><strong>representative</strong></td>
<td>In relation to a person, any employee, agent or Consultant of: (a) that person; or (b) a related body corporate of that person; or (c) a third party contractor to that person.</td>
</tr>
<tr>
<td><strong>reserve</strong></td>
<td>The active power and reactive power available to the power system at a nominated time but not currently utilised.</td>
</tr>
<tr>
<td><strong>revenue meter</strong></td>
<td>A device complying with Australian Standards which measures and records the production or consumption of electrical energy that is used for obtaining the primary source of revenue metering data.</td>
</tr>
<tr>
<td><strong>revenue metering installation</strong></td>
<td>A metering installation used for recording the production or consumption of electrical energy.</td>
</tr>
<tr>
<td><strong>revenue metering data</strong></td>
<td>The data obtained from a revenue metering installation, the processed data or substituted data.</td>
</tr>
<tr>
<td><strong>revenue metering database</strong></td>
<td>A database of revenue metering data.</td>
</tr>
<tr>
<td><strong>revenue metering point</strong></td>
<td>The point of physical connection of the device measuring the current in the power conductor.</td>
</tr>
<tr>
<td><strong>revenue metering register</strong></td>
<td>A register of information associated with a revenue metering installation as required by clause 10.2.</td>
</tr>
<tr>
<td><strong>revenue metering system</strong></td>
<td>The collection of all components and arrangements installed or existing between each revenue metering point and the revenue metering database.</td>
</tr>
<tr>
<td>Terminology</td>
<td>Definition</td>
</tr>
<tr>
<td>------------------------------------</td>
<td>-----------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td><strong>RTU</strong></td>
<td>A Remote Terminal Unit installed within a substation or generating station to enable monitoring and control of a facility from a control centre.</td>
</tr>
<tr>
<td><strong>satisfactory operating state</strong></td>
<td>In relation to the power system, has the meaning given in clause 4.2.1.</td>
</tr>
<tr>
<td><strong>SCADA system</strong></td>
<td>Supervisory control and data acquisition equipment which enables the Power System Controller to continuously and remotely monitor, and to a limited extent control, the import or export of electricity from or to the power system.</td>
</tr>
<tr>
<td><strong>scheduled Generation Unit</strong></td>
<td>A Generation Unit that is dispatched by the Power System Controller.</td>
</tr>
<tr>
<td><strong>secondary equipment, secondary plant</strong></td>
<td>Those assets of a facility and the electricity network which do not carry the energy being traded, but which are required for control, protection or operation of assets that carry such energy.</td>
</tr>
<tr>
<td><strong>secondary plant contingency</strong></td>
<td>Any single failure of secondary plant.</td>
</tr>
<tr>
<td><strong>secure operating state</strong></td>
<td>In relation to the power system has the meaning given in clause 5.2.2.</td>
</tr>
<tr>
<td><strong>sensitivity</strong></td>
<td>In relation to protection schemes, has the meaning in clause 6.1.6.1.</td>
</tr>
<tr>
<td><strong>settlements</strong></td>
<td>The activity of producing bills and credit notes for Users.</td>
</tr>
<tr>
<td><strong>single contingency</strong></td>
<td>In respect of a network, a sequence of related events which result in the removal from service of one line, transformer or other item of plant. The sequence of events may include the application and clearance of a fault of defined severity.</td>
</tr>
<tr>
<td><strong>small network investment</strong></td>
<td>A proposed investment in augmentation of the network or a non-network alternative with a capitalised net present value in excess of $1 Million that is not a large network investment.</td>
</tr>
<tr>
<td><strong>Small Generator</strong></td>
<td>A Generation Unit or group Generation Units with:</td>
</tr>
<tr>
<td></td>
<td>(1) aggregate rated capacity of no more than 2 MW or 10% of the minimum demand of an isolated network, whichever is the lesser;</td>
</tr>
<tr>
<td></td>
<td>(2) connected to the 22 kV, 11 kV or low voltage networks; and</td>
</tr>
<tr>
<td></td>
<td>(3) not subject to dispatch by the System Operator.</td>
</tr>
<tr>
<td><strong>Small Inverter Energy System</strong></td>
<td>A Small Inverter Energy System is a Generation Unit which uses an inverter that changes its direct-current power to alternating current power acceptable for power system connection.</td>
</tr>
<tr>
<td></td>
<td>The nominal network voltages and maximum energy system capacities for which these requirements apply are:</td>
</tr>
<tr>
<td></td>
<td>(1) 230 V single phase 10 kVA</td>
</tr>
<tr>
<td></td>
<td>(2) 400 V three phase 30 kVA</td>
</tr>
<tr>
<td><strong>small zone fault</strong></td>
<td>A fault which occurs on an area of plant that is within the zone of detection of a protection scheme, but for which not all contributions will be cleared by the circuit breaker(s) tripped by that protection scheme. For example, a fault in the area of plant between a current transformer and a circuit breaker, fed from the current transformer side, may be a small zone fault.</td>
</tr>
<tr>
<td>Terminology</td>
<td>Definition</td>
</tr>
<tr>
<td>--------------------------------</td>
<td>----------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td>spare network capacity</td>
<td>The capacity to transport electricity over a particular electricity network which the network provider assesses is in surplus to the capacity that existing end-use customers forecast will be required to satisfy their reasonably foreseeable requirements for the transport of electricity.</td>
</tr>
<tr>
<td>spinning reserve</td>
<td>The ability to immediately and automatically increase Generation or reduce demand in response to a fall in frequency.</td>
</tr>
<tr>
<td>standby power</td>
<td>The amount of electrical energy which could be supplied to a load User in accordance with the terms of a standby Generation agreement.</td>
</tr>
<tr>
<td>static excitation system</td>
<td>An excitation control system in which the power to the rotor of a synchronous Generation Unit is transmitted through high power solid-state electronic devices.</td>
</tr>
<tr>
<td>static var compensator</td>
<td>A device specifically provided on a network to provide the ability to generate and absorb reactive power and to respond automatically and rapidly to voltage fluctuations or voltage instability arising from a disturbance or disruption on the network.</td>
</tr>
<tr>
<td>sub-network</td>
<td>A particular portion of the network.</td>
</tr>
<tr>
<td>substation</td>
<td>A facility at which lines are switched for operational purposes. May include one or more transformers so that some connected lines operate at different nominal voltages to others.</td>
</tr>
<tr>
<td>supply, supplying</td>
<td>The delivery of electricity.</td>
</tr>
<tr>
<td>synchronise</td>
<td>The act of synchronising a Generation Unit to the power system.</td>
</tr>
<tr>
<td>synchronised</td>
<td>In the case of a Generation Unit, to be connected to and operate at the same frequency as the power system.</td>
</tr>
<tr>
<td>synchronising, synchronisation</td>
<td>To electrically connect a Generation Unit to the power system.</td>
</tr>
<tr>
<td>synchronous condensers</td>
<td>Plant, similar in construction to a Generation Unit of the synchronous Generator category, which operates at the equivalent speed of the frequency of the power system, specifically provided to generate or absorb reactive power through the adjustment of excitation current.</td>
</tr>
<tr>
<td>unsynchronised</td>
<td>In the case of a Generation Unit, to operate disconnected from the power system, or to operate at a different frequency to the power system during an electrical disturbance.</td>
</tr>
<tr>
<td>under frequency load shedding</td>
<td>A load shedding scheme designed to automatically disconnect load on the network to restore frequency to the normal operating range.</td>
</tr>
<tr>
<td>under frequency relay</td>
<td>The component of an under frequency load shedding scheme that initiates disconnection of the load.</td>
</tr>
<tr>
<td>synchronous Generator</td>
<td>The automatic voltage control system of a Generation Unit of the synchronous Generator category which changes the output voltage of the Generation Unit through the adjustment of the Generator excitation current and effectively changes the reactive power output from that Generation Unit.</td>
</tr>
<tr>
<td>synchronous Generator, voltage control</td>
<td>The alternating current Generators which operate at the equivalent frequency of the power system, or to operate at a different frequency to the power system during an electrical disturbance.</td>
</tr>
<tr>
<td>Terminology</td>
<td>Definition</td>
</tr>
<tr>
<td>------------------------------------------------</td>
<td>------------------------------------------------------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td>synchronous Generation Unit</td>
<td>of the frequency of the power system in its satisfactory operating state.</td>
</tr>
<tr>
<td>tap-changing transformer</td>
<td>A transformer with the capability to allow internal adjustment of output voltages which can be automatically or manually initiated and which is used as a major component in the control of the voltage of the networks in conjunction with the operation of reactive plant.</td>
</tr>
<tr>
<td>technical envelope</td>
<td>The limits described in clause 4.2.2.</td>
</tr>
<tr>
<td>teleprotection signalling</td>
<td>Equipment used to transfer a contact state from one location to another using communications equipment. The equipment used for this purpose will meet the reliability and quality requirements protection equipment.</td>
</tr>
<tr>
<td>time</td>
<td>Central Australian Standard Time, as defined by the National Measurement Act, 1960.</td>
</tr>
<tr>
<td>total fault clearance time</td>
<td>Refers to the time from fault inception to the time of complete fault interruption by a circuit breaker or circuit breakers.</td>
</tr>
<tr>
<td>transformer</td>
<td>A plant or device that reduces or increases the voltage of alternating current.</td>
</tr>
<tr>
<td>transformer tap position</td>
<td>Where a tap changer is fitted to a transformer, each tap position represents a change in voltage ratio of the transformer which can be manually or automatically adjusted to change the transformer output voltage. The tap position is used as a reference for the output voltage of the transformer.</td>
</tr>
<tr>
<td>transmission element</td>
<td>A single identifiable major component of a transmission network involving:</td>
</tr>
<tr>
<td></td>
<td>• an individual transmission circuit or a phase of that circuit; and</td>
</tr>
<tr>
<td></td>
<td>• a major item of transmission plant necessary for the functioning of a particular transmission circuit or connection point (such as a transformer or a circuit breaker).</td>
</tr>
<tr>
<td>transmission line</td>
<td>A power line that is part of a transmission network.</td>
</tr>
<tr>
<td>transmission network</td>
<td>The components of the electricity network used for transmitting electricity at nominal voltages of 66 kV or higher and at a nominal frequency of 50Hz.</td>
</tr>
<tr>
<td>transmission network connection point</td>
<td>A connection point on a transmission network.</td>
</tr>
<tr>
<td>transmission network test</td>
<td>Test conducted to verify the magnitude of the power transfer capability of the transmission network or investigating power system performance in accordance with clause 5.5.</td>
</tr>
<tr>
<td>transmission plant</td>
<td>Apparatus or equipment associated with the function or operation of a transmission line or an associated substation, which may include transformers, circuit breakers, reactive plant and monitoring equipment and control equipment.</td>
</tr>
<tr>
<td>trip circuit supervision</td>
<td>A function incorporated within a protection scheme that results in alarming for loss of integrity of the protection scheme’s trip circuit.</td>
</tr>
<tr>
<td>Terminology</td>
<td>Definition</td>
</tr>
<tr>
<td>----------------------------------------------------------</td>
<td>-----------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td>Trip circuit supervision</td>
<td>Trip circuit supervision supervises a protection scheme’s trip supply together with the integrity of associated wiring, cabling and circuit breaker trip coil.</td>
</tr>
<tr>
<td>trip supply supervision</td>
<td>A function incorporated within a protection scheme that results in alarming for loss of trip supply.</td>
</tr>
<tr>
<td>two fully independent protection schemes of differing principle</td>
<td>Where an item of plant is required to be protected by two fully independent protection schemes of differing principle, such protection schemes shall, in combination, provide dependable clearance of faults on that plant within a specified time, with any single failure to operate of the secondary plant. To achieve this, complete secondary plant redundancy is required including, but not necessarily limited to, current transformer and voltage transformer secondaries, auxiliary supplies, signalling systems, cabling, wiring, and circuit breaker trip coils. Auxiliary supplies include DC supplies for protection purposes. Therefore, to satisfy the redundancy requirements, each fully independent protection scheme would need to have its own independent battery and battery charger system supplying all that protection scheme’s trip functions. The protection schemes shall be so chosen as to have differing principles of operation.</td>
</tr>
<tr>
<td>under frequency load shedding</td>
<td>Equipment designed to automatically disconnect load from the power system if the frequency falls below a set level.</td>
</tr>
<tr>
<td>under voltage load shedding</td>
<td>Equipment designed to automatically disconnect load from the power system if the voltage falls below a set level.</td>
</tr>
<tr>
<td>User</td>
<td>A person, whether a load User or a Generator User, who has been granted access to the electricity network by the Network Operator in order to transport electrical energy to or from a particular point.</td>
</tr>
<tr>
<td>use of system services</td>
<td>A network service provided to a User for use of the electricity network for the transportation of electrical energy that can be reasonably allocated to a User on a locational basis.</td>
</tr>
<tr>
<td>voltage</td>
<td>The electronic force or electric potential between two points that gives rise to the flow of electrical energy.</td>
</tr>
<tr>
<td>voltage control</td>
<td>Keeping network voltages within operational limits in normal operation and in the aftermath of trips by automatic regulation of Generation MVAr output or by voltage control equipment such as capacitor banks and automatic tap-changers.</td>
</tr>
<tr>
<td>voltage transformer (VT)</td>
<td>A transformer for use with meters and/or protection devices in which the voltage across the secondary terminals is, within prescribed error limits, proportional to and in phase with the voltage across the primary terminals.</td>
</tr>
</tbody>
</table>
Attachment 2  Rules of interpretation

Subject to the *Interpretation Act*, this *Code* shall be interpreted in accordance with the following rules of interpretation, unless the contrary intention appears:

(a) a reference in this *Code* to a contract or another instrument includes a reference to any amendment, variation or replacement of it;

(b) a reference to a person includes a reference to the person’s executors, administrators, successors, substitutes (including, without limitation, persons taking by novation) and assigns;

(c) if an event shall occur on a *day* which is not a *business day* then the event shall occur on the next *business day*;

(d) any calculation shall be performed to the accuracy, in terms of a number of decimal places, determined by the *Network Operator* in respect of all *Users*;

(e) if examples of a particular kind of conduct, thing or condition are introduced by the word “including”, then the examples are not to be taken as limiting the interpretation of that kind of conduct, thing or condition;

(f) a *connection* is a *User’s connection* or a *connection* of a *User* if it is the subject of an *Access Agreement* between the *User* and the *Network Operator*; and

(g) a reference to a half hour is a reference to a 30 minute period ending on the hour or on the half hour and, when identified by a *time*, means the 30 minute period ending at that *time.*
Attachment 3  Technical details for connection and access

A3.1 Introduction

Various clauses of the Code require that Users submit technical data to the Network Operator. This attachment contains schedules which list the typical range of data which may be required. Data additional to those listed in the schedules may be required. The actual data required will be advised by the Network Operator at the time of assessment of a network Access Application, and will form part of the technical specification in the Access Agreement.

A3.2 Data categories

Data is Coded in categories, according to the stage at which it is available in the build-up of data during the process of forming a connection or obtaining access to a network, with data acquired at each stage being carried forward, or enhanced in subsequent stages, for example by testing.

A3.2.1 Preliminary system planning data

This is data required for submission with the Access Application, to allow the Network Operator to prepare an offer of terms for an Access Agreement and to assess the requirement for, and effect of, network augmentation or extension options. Such data is normally limited to the items denoted as Standard Planning Data (S) in the technical data schedules S3.1 to S3.7.

The Network Operator may, in cases where there is reasonable doubt as to the viability of a proposal, require the submission of other data before making an access offer to connect or to amend an Access Agreement.

A3.2.2 Registered system planning data

This is the class of data which will be included in the Access Agreement signed by both parties. It consists of the preliminary system planning data plus those items denoted in the attached schedules as Detailed Planning Data (D). The latter shall be submitted by the User in time for inclusion in the Access Agreement.

Registered data

Registered Data consists of data validated and augmented prior to actual connection as a provision of access, from manufacturers’ data, detailed design calculations, works or site tests, etc. (R1); and data derived from on-system testing after connection (R2).

All of the data will, from this stage, be categorised and referred to as Registered Data; but for convenience the schedules omit placing a higher ranked Code next to items which are expected to already be valid at an earlier stage.

A3.3 Data review

Data will be subject to review at reasonable intervals to ensure its continued accuracy and relevance. The Network Operator shall initiate this review. A User may
change any data item at a time other than when that item would normally be reviewed or updated by submission to the Network Operator of the revised data, together with authentication documents, eg. test reports.

A3.4 Data schedules

Schedules S3.1 to S3.7 cover the following data areas:

(a) Schedule S3.1 - Generation Unit Design Data. This comprises Generation Unit fixed design parameters.

(b) Schedule S3.2 - Generation Unit Setting Data. This comprises settings which can be varied by agreement or by direction of the Network Operator.

(c) Schedule S3.3 – Generator data for small Generation Units

(d) Schedule S3.4 – Technical data for Small Invertor Energy Units

(e) Schedule S3.5 - Network and Plant Technical Data. This comprises fixed electrical parameters.

(f) Schedule S3.6 - Plant and Apparatus Setting Data. This comprises settings which can be varied by agreement or by direction of the Network Operator.

(g) Schedule S3.7 - Load Characteristics. This comprises the estimated parameters of load groups in respect of, for example, harmonic content and response to frequency and voltage variations.

A3.5 Non synchronous Generators

A Generator that connects a Generation Unit, that is not a synchronous Generation Unit, shall be given exemption from complying with those parts of schedules S3.1 and S3.2 that are determined by the Network Operator to be not relevant to such Generation Units, but shall comply with those parts of Schedules S3.3, S3.5, and S3.6 that are relevant to such Generation Units, as determined by the Network Operator.

Codes:

S = Standard Planning Data

D = Detailed Planning Data

R = Registered Data (R1 pre-connection, R2 post-connection)
### Schedule S3.1  Generation Unit design data

<table>
<thead>
<tr>
<th>Symbol</th>
<th>Data Description</th>
<th>Units</th>
<th>Data Category</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td><strong>Power station technical data:</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td><em>Connection point to Network</em></td>
<td>Text, diagram</td>
<td>S, D</td>
</tr>
<tr>
<td></td>
<td>Nominal voltage at connection to Network</td>
<td>kV</td>
<td>S</td>
</tr>
<tr>
<td></td>
<td>Total Station Net Maximum Capacity (NMC)</td>
<td>MW (sent out)</td>
<td>S, D, R2</td>
</tr>
<tr>
<td></td>
<td><strong>At connection point:</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>• Symmetrical</td>
<td>kA</td>
<td>S, D</td>
</tr>
<tr>
<td></td>
<td>• Asymmetrical</td>
<td>kA</td>
<td>D</td>
</tr>
<tr>
<td></td>
<td>Minimum zero sequence impedance</td>
<td>% on 100 MVA base</td>
<td>D</td>
</tr>
<tr>
<td></td>
<td>Minimum negative sequence impedance</td>
<td>% on 100 MVA base</td>
<td>D</td>
</tr>
<tr>
<td></td>
<td><strong>Individual Generation Unit data:</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>MBASE Rated MVA</td>
<td>MVA</td>
<td>S, D, R1</td>
</tr>
<tr>
<td></td>
<td>PSO Rated MW (Sent Out)</td>
<td>MW (sent out)</td>
<td>S, D, R1</td>
</tr>
<tr>
<td></td>
<td>PMAX Rated MW (Generated)</td>
<td>MW (Gen)</td>
<td>S, D</td>
</tr>
<tr>
<td></td>
<td>VT Nominal Terminal Voltage</td>
<td>kV</td>
<td>S, D, R1</td>
</tr>
<tr>
<td></td>
<td>PAUX Auxiliary load at PMAX</td>
<td>MW</td>
<td>S, D, R1</td>
</tr>
<tr>
<td></td>
<td>Qmax Rated Reactive Output at PMAX</td>
<td>MVAr (sent out)</td>
<td>S, D, R1</td>
</tr>
<tr>
<td></td>
<td>PMIN Minimum Load (ML)</td>
<td>MW (sent out)</td>
<td>S, D, R2</td>
</tr>
<tr>
<td></td>
<td>H Turbine plus Generator Inertia Constant</td>
<td>MWs/rated MVA</td>
<td>S, D, R1</td>
</tr>
<tr>
<td></td>
<td>Hg Generator Inertia Constant (applicable to synchronous condenser mode of operation)</td>
<td>MWs/rated MVA</td>
<td>S, D, R1</td>
</tr>
<tr>
<td></td>
<td>GSCR Short Circuit Ratio</td>
<td></td>
<td>D, R1</td>
</tr>
<tr>
<td></td>
<td>ISTATOR Rated Stator Current</td>
<td>A</td>
<td>D, R1</td>
</tr>
<tr>
<td></td>
<td>IROTOR Rated Rotor Current at rated MVA and Power factor, rated terminal volts and rated speed</td>
<td>A</td>
<td>D, R1</td>
</tr>
<tr>
<td></td>
<td>VROTOR Rotor Voltage at which IROTOR is achieved</td>
<td>V</td>
<td>D, R1</td>
</tr>
<tr>
<td></td>
<td>VCEIL Rotor Voltage capable of being supplied for five seconds at rated speed during field forcing</td>
<td>V</td>
<td>D, R1</td>
</tr>
<tr>
<td></td>
<td><strong>Generation Unit resistance:</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>RA</td>
<td>Stator Resistance</td>
<td>% on MBASE</td>
<td>S, D, R1, R2</td>
</tr>
</tbody>
</table>

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<table>
<thead>
<tr>
<th>Parameter</th>
<th>Description</th>
<th>Units</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>RF</td>
<td>Rotor resistance at 20°C</td>
<td>ohms</td>
<td>S, D, R1</td>
</tr>
</tbody>
</table>

**Generation Unit sequence impedances (saturated):**

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Description</th>
<th>Values</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>Z0</td>
<td>Zero Sequence Impedance</td>
<td>(a+jb)% on MBASE</td>
<td>D,R1</td>
</tr>
<tr>
<td>Z2</td>
<td>Negative Sequence Impedance</td>
<td>(a+jb)% on MBASE</td>
<td>D,R1</td>
</tr>
</tbody>
</table>

**Generation Unit reactances (saturated):**

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Description</th>
<th>Values</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>XD' (sat)</td>
<td>Direct Axis Transient Reactance</td>
<td>% on MBASE</td>
<td>D,R1</td>
</tr>
<tr>
<td>XD'' (sat)</td>
<td>Direct Axis Sub-Transient Reactance</td>
<td>% on MBASE</td>
<td>D,R1</td>
</tr>
</tbody>
</table>

**Generation Unit reactances (unsaturated):**

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Description</th>
<th>Values</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>XD</td>
<td>Direct Axis Synchronous Reactance</td>
<td>% on MBASE</td>
<td>S, D, R1, R2</td>
</tr>
<tr>
<td>XD'</td>
<td>Direct Axis Transient Reactance</td>
<td>% on MBASE</td>
<td>S, D, R1, R2</td>
</tr>
<tr>
<td>XD''</td>
<td>Direct Axis Sub-Transient Reactance</td>
<td>% on MBASE</td>
<td>S, D, R1, R2</td>
</tr>
<tr>
<td>XQ</td>
<td>Quadrature Axis Synch Reactance</td>
<td>% on MBASE</td>
<td>S, D, R1, R2</td>
</tr>
<tr>
<td>XQ'</td>
<td>Quadrature Axis Transient Reactance</td>
<td>% on MBASE</td>
<td>S, D, R1, R2</td>
</tr>
<tr>
<td>XQ''</td>
<td>Quadrature Axis Sub-Transient Reactance</td>
<td>% on MBASE</td>
<td>S, D, R1, R2</td>
</tr>
<tr>
<td>XL</td>
<td>Stator Leakage Reactance</td>
<td>% on MBASE</td>
<td>S, D, R1, R2</td>
</tr>
<tr>
<td>XO</td>
<td>Zero Sequence Reactance</td>
<td>% on MBASE</td>
<td>S, D, R1</td>
</tr>
<tr>
<td>X2</td>
<td>Negative Sequence Reactance</td>
<td>% on MBASE</td>
<td>S, D, R1</td>
</tr>
<tr>
<td>XP</td>
<td>Potier Reactance</td>
<td>% on MBASE</td>
<td>S, D, R1</td>
</tr>
</tbody>
</table>

**Generation Unit time constants (unsaturated):**

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Description</th>
<th>Values</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>TDO'</td>
<td>Direct Axis Open Circuit Transient</td>
<td>Seconds</td>
<td>S, D, R1, R2</td>
</tr>
<tr>
<td>TDO''</td>
<td>Direct Axis Open Circuit Sub-Transient</td>
<td>Seconds</td>
<td>S, D, R1, R2</td>
</tr>
<tr>
<td>TKD</td>
<td>Direct Axis Damper Leakage</td>
<td>Seconds</td>
<td>S, D, R1, R2</td>
</tr>
<tr>
<td>TQO'</td>
<td>Quadrature Axis Open Circuit Transient</td>
<td>Seconds</td>
<td>S, D, R1, R2</td>
</tr>
<tr>
<td>TQO''</td>
<td>Quadrature Axis Open Circuit Sub-Transient</td>
<td>Seconds</td>
<td>S, D, R1, R2</td>
</tr>
</tbody>
</table>

**Charts:**

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Description</th>
<th>Type</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>GCD</td>
<td>Capability Chart</td>
<td>Graphical data</td>
<td>S, D, R1, R2</td>
</tr>
<tr>
<td>GOCC</td>
<td>Open Circuit Characteristic</td>
<td>Graphical data</td>
<td>R1</td>
</tr>
<tr>
<td>GSChC</td>
<td>Short Circuit Characteristic</td>
<td>Graphical data</td>
<td>R1</td>
</tr>
<tr>
<td>GZPC</td>
<td>Zero power factor curve</td>
<td>Graphical data</td>
<td>R1</td>
</tr>
<tr>
<td>GOVC</td>
<td>V curves</td>
<td>Graphical data</td>
<td>R1</td>
</tr>
<tr>
<td>GOTC</td>
<td>MW, MVAr outputs versus temperature chart</td>
<td>Graphical data</td>
<td>D, R1, R2</td>
</tr>
</tbody>
</table>

**Generation Unit transformer:**
**GTW**  Number of windings  Text  S, D

**GTR\textsubscript{n}**  Rated MVA of each winding  MVA  S, D, R1

**GTTR\textsubscript{n}**  Principal tap rated voltages  kV/kV  S, D, R1

**GTZI\textsubscript{n}**  Positive Sequence Impedances (each wdg)  (a - jb)% on 100 MVA base  S, D, R1

**GTZ2\textsubscript{n}**  Negative Sequence Impedances (each wdg)  (a - jb)% on 100 MVA base  S, D, R1

**GTZ0\textsubscript{n}**  Zero Sequence Impedances (each wdg)  (a - jb)% on 100 MVA base  S, D, R1

**GTZ0**  Tapped Winding  Text, diagram  S, D, R1

**GTAPR**  Tap Change Range  kV - kV  S, D

**GTAPS**  Tap Change Step Size  %  S, D

**Tap Changer Type, On/Off load**  On/Off  S, D

**Tap Change Cycle Time**  Seconds  D

**GTGV**  Vector Group  Diagram  S, D

**Earthing Arrangement**  Text, diagram  S, D

**Saturation curve**  Diagram  R1

---

**Generation Unit reactive capability (at machine terminals):**

- Lagging *Reactive power at PMAX*  MVAr export  S, D, R2
- Lagging *Reactive power at ML*  MVAr export  S, D, R2
- Lagging Reactive Short *Time*  MVAr  D, R1, R2
- capability at rated MW, terminal  *(for time)*
- Leading *Reactive power at rated MW*  MVAr import  S, D, R2

---

**Generation Unit excitation system:**

- Make  S, D
- Model  S, D
- General description of *excitation control system* (including functional block diagram)  Text, diagram  S, D

**Rated Field Voltage**  at rated MVA and *Power factor* and rated terminal volts and speed  V  S, D, R1

**Maximum Field Voltage**  V  S, D, R1

**Minimum Field Voltage**  V  S, D, R1

**Maximum rate of change of Field Voltage**  Rising V/s  S, D, R1

**Maximum rate of change of Field Voltage**  Falling V/s  S, D, R1

**Generation Unit and exciter Saturation Characteristics 50 - 120%**  Diagram  S, D, R1

**Dynamic Characteristics of Over Excitation Limiter**  Text/ Block diagram  S, D, R2

---
Dynamic Characteristics of Under Excitation Limiter  

**Generation Unit load controller (governor):**

General description of governor control system (including functional block diagram).

Format to be compatible with PSS/E software from Siemens PTI.

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Unit</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>Maximum Droop</td>
<td>%</td>
<td>S, D, R1</td>
</tr>
<tr>
<td>Normal Droop</td>
<td>%</td>
<td>D, R1</td>
</tr>
<tr>
<td>Minimum Droop</td>
<td>%</td>
<td>D, R1</td>
</tr>
<tr>
<td>Maximum Frequency Dead band</td>
<td>Hz</td>
<td>D, R1</td>
</tr>
<tr>
<td>Normal Frequency Dead band</td>
<td>Hz</td>
<td>D, R1</td>
</tr>
<tr>
<td>Minimum Frequency Dead band</td>
<td>Hz</td>
<td>D, R1</td>
</tr>
<tr>
<td>MW Dead band</td>
<td>MW</td>
<td>D, R1</td>
</tr>
</tbody>
</table>

**Generation Unit response capability:**

Sustained response to frequency change MW/Hz D, R2

Non-sustained response to frequency change MW/Hz D, R2

Load Rejection Capability MW S, D, R2

**Mechanical shaft model:**

(Multiple-stage steam turbine Generators only)

Dynamic model of turbine/Generator shaft system in lumped element form showing component inertias, damping and shaft stiffness. Format to be compatible with PSS/E software from Siemens PTI.

Natural damping of shaft torsional oscillation modes (for each mode)

- Modal frequency Hz D
- Logarithmic decrement Nepers/Sec D

**Steam turbine data:**

(Multiple-stage steam turbines only)

Fraction of power produced by each stage:

<table>
<thead>
<tr>
<th>Symbol</th>
<th>Per unit of Pmax</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>KHP</td>
<td></td>
<td>D</td>
</tr>
<tr>
<td>KIP</td>
<td></td>
<td></td>
</tr>
<tr>
<td>KLP1</td>
<td></td>
<td></td>
</tr>
<tr>
<td>KLP2</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Stage and reheat time constants:
Symbols

<table>
<thead>
<tr>
<th>Symbol</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>THP</td>
<td></td>
</tr>
<tr>
<td>TRH</td>
<td></td>
</tr>
<tr>
<td>TIP</td>
<td></td>
</tr>
<tr>
<td>TLP1</td>
<td></td>
</tr>
<tr>
<td>TLP2</td>
<td></td>
</tr>
</tbody>
</table>

Turbine frequency tolerance curve

Gas turbine data:

<table>
<thead>
<tr>
<th>Data Type</th>
<th>Units</th>
<th>Reference</th>
</tr>
</thead>
<tbody>
<tr>
<td>HRSG Waste heat recovery boiler time constant</td>
<td>Seconds</td>
<td>D</td>
</tr>
<tr>
<td>(where applicable)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>MW output versus turbine speed (47-52 Hz)</td>
<td>Diagram</td>
<td>D, R1, R2</td>
</tr>
<tr>
<td>Type of turbine (heavy industrial, aero</td>
<td>Text</td>
<td>S</td>
</tr>
<tr>
<td>derivative etc.)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Number of shafts</td>
<td></td>
<td>S, D</td>
</tr>
<tr>
<td>Gearbox Ratio</td>
<td></td>
<td>D</td>
</tr>
<tr>
<td>Fuel type (gas, liquid)</td>
<td>Text</td>
<td>S, D</td>
</tr>
<tr>
<td>Base load MW vs temperature</td>
<td>Diagram</td>
<td>D</td>
</tr>
<tr>
<td>Peak load MW vs temperature</td>
<td>Diagram</td>
<td>D</td>
</tr>
<tr>
<td>Rated exhaust temperature °C</td>
<td></td>
<td>S, D</td>
</tr>
<tr>
<td>Controlled exhaust temperature °C</td>
<td></td>
<td>S, D, R1</td>
</tr>
<tr>
<td>Turbine frequency tolerance capability</td>
<td>Diagram</td>
<td>D</td>
</tr>
<tr>
<td>Turbine compressor surge map</td>
<td>Diagram</td>
<td>D</td>
</tr>
</tbody>
</table>

Hydraulic turbine data

<table>
<thead>
<tr>
<th>Data Type</th>
<th>Units</th>
<th>Reference</th>
</tr>
</thead>
<tbody>
<tr>
<td>Required data will be advised by the</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Network Operator</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Wind farm/wind turbine data

<table>
<thead>
<tr>
<th>Data Type</th>
<th>Units</th>
<th>Reference</th>
</tr>
</thead>
<tbody>
<tr>
<td>A typical 24 hour power curve measured at</td>
<td></td>
<td>S, D, R1</td>
</tr>
<tr>
<td>15-minute intervals or better if available;</td>
<td></td>
<td></td>
</tr>
<tr>
<td>maximum kVA output over a 60 second interval</td>
<td></td>
<td>S, D, R1</td>
</tr>
<tr>
<td>Long-term flicker factor for Generation Unit</td>
<td></td>
<td>S, D, R1</td>
</tr>
<tr>
<td>Long term flicker factor for wind farm</td>
<td></td>
<td>S, D, R1</td>
</tr>
<tr>
<td>Maximum output over a 60 second interval kVA</td>
<td></td>
<td>S, D, R1</td>
</tr>
<tr>
<td>Harmonics current spectra</td>
<td>A</td>
<td>S, D, R1</td>
</tr>
<tr>
<td>Power curve MW vs. wind speed</td>
<td>Diagram</td>
<td>D</td>
</tr>
<tr>
<td>Spatial Arrangement of wind farm</td>
<td>Diagram</td>
<td>D</td>
</tr>
<tr>
<td>Startup profile MW, MVAr vs time for</td>
<td>Diagram</td>
<td>D</td>
</tr>
<tr>
<td>individual Wind Turbine Unit and Wind farm</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
Total
Low Wind Shutdown profile MW, MVAr vs time for individual Wind Turbine Unit and Wind farm Total

MW, MVAr vs time profiles for individual Wind Turbine Unit under normal ramp up and ramp down conditions.

High Wind Shutdown profile MW, MVAr vs time for individual Wind Turbine Unit and Wind farm Total

**Induction Generation Unit data**

- **Make**
- **Model**
- **Type (squirrel cage, wound rotor, doubly fed)**

<table>
<thead>
<tr>
<th>MBASE</th>
<th>Rated MVA</th>
<th>MVA</th>
<th>S,D,R1</th>
</tr>
</thead>
<tbody>
<tr>
<td>PSO Rated MW (Sent out)</td>
<td>MW</td>
<td>S,D,R1</td>
<td></td>
</tr>
<tr>
<td>PMAX Rated MW (generated)</td>
<td>MW</td>
<td>D</td>
<td></td>
</tr>
<tr>
<td>VT Nominal Terminal Voltage kV</td>
<td>S,D,R1</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

- **Synchronous Speed** rpm | S,D,R1 |
- **Rated Speed** rpm | S,D,R1 |
- **Maximum Speed** rpm | S,D,R1 |
- **Rated Frequency** Hz | S,D,R1 |

**Qmax**

- **Reactive consumption at PMAX** MVAr import | S,D,R1 |
- **Curves showing torque, power factor, efficiency, stator current, MW output versus slip (+ and -)**. Graphical data | D,R1,R2 |

- **Number of capacitor banks and MVAr size at rated voltage for each capacitor bank (if used).** Text | S |
- **Control philosophy used for VAr /voltage control.** Text | S |

**H**

Combined inertia constant for all rotating masses connected to the Generation Unit shaft (for example, Generation Unit, turbine, gearbox, etc.) calculated at the synchronous speed MW-sec/MVA | S,D,R1 |

**Resistance**

- **Rs** Stator resistance | % on MBASE | D,R1 |
- **Rs** Stator resistance versus slip curve, or two extreme values for zero (nominal) and unity (negative) slip Graphical data or % on MBASE | D,R1 |
### Reactances (saturated)

<table>
<thead>
<tr>
<th>Symbol</th>
<th>Description</th>
<th>Units</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>$X'$</td>
<td>Transient reactance</td>
<td>% on MBASE</td>
<td>D,R1</td>
</tr>
<tr>
<td>$X''$</td>
<td>Subtransient reactance</td>
<td>% on MBASE</td>
<td>D,R1</td>
</tr>
</tbody>
</table>

### Reactances (unsaturated)

<table>
<thead>
<tr>
<th>Symbol</th>
<th>Description</th>
<th>Units</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>$X$</td>
<td>Sum of magnetising and primary winding leakage reactance.</td>
<td>% on MBASE</td>
<td>D,R1</td>
</tr>
<tr>
<td>$X'$</td>
<td>Transient reactance</td>
<td>% on MBASE</td>
<td>D,R1</td>
</tr>
<tr>
<td>$X''$</td>
<td>Subtransient reactance</td>
<td>% on MBASE</td>
<td>D,R1</td>
</tr>
<tr>
<td>$X_l$</td>
<td>Primary winding leakage reactance</td>
<td>% on MBASE</td>
<td>D,R1</td>
</tr>
</tbody>
</table>

### Time constants (unsaturated)

<table>
<thead>
<tr>
<th>Symbol</th>
<th>Description</th>
<th>Units</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>$T'$</td>
<td>Transient</td>
<td>sec</td>
<td>S,D,R1,R2</td>
</tr>
<tr>
<td>$T''$</td>
<td>Subtransient</td>
<td>sec</td>
<td>S,D,R1,R2</td>
</tr>
<tr>
<td>$T_a$</td>
<td>Armature</td>
<td>sec</td>
<td>S,D,R1,R2</td>
</tr>
<tr>
<td>$T_o'$</td>
<td>Open circuit transient</td>
<td>sec</td>
<td>S,D,R1,R2</td>
</tr>
<tr>
<td>$T_o''$</td>
<td>Open circuit subtransient</td>
<td>sec</td>
<td>S,D,R1,R2</td>
</tr>
</tbody>
</table>

### Converter data

Control: *transmission* system commutated or self commutated

Additional data may be required by the *Network Operator*

### Doubly fed induction *Generation Unit* data

Required data will be advised by the *Network Operator*
### Schedule S3.2  *Generation Unit setting data*

<table>
<thead>
<tr>
<th>Description Category</th>
<th>Units</th>
<th>Data Category</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Protection data:</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Settings of the following protections:</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Loss of field</td>
<td>Text</td>
<td>D</td>
</tr>
<tr>
<td>Under excitation</td>
<td>Text, diagram</td>
<td>D</td>
</tr>
<tr>
<td>Over excitation</td>
<td>Text, diagram</td>
<td>D</td>
</tr>
<tr>
<td>Differential</td>
<td>Text</td>
<td>D</td>
</tr>
<tr>
<td><strong>Under frequency</strong></td>
<td>Text</td>
<td>D</td>
</tr>
<tr>
<td><strong>Over frequency</strong></td>
<td>Text</td>
<td>D</td>
</tr>
<tr>
<td>Negative sequence component</td>
<td>Text</td>
<td>D</td>
</tr>
<tr>
<td>Stator over voltage</td>
<td>Text</td>
<td>D</td>
</tr>
<tr>
<td>Stator overcurrent</td>
<td>Text</td>
<td>D</td>
</tr>
<tr>
<td>Rotor overcurrent</td>
<td>Text</td>
<td>D</td>
</tr>
<tr>
<td>Reverse power</td>
<td>Text</td>
<td>D</td>
</tr>
<tr>
<td>Stator E/F</td>
<td>Text</td>
<td>D</td>
</tr>
<tr>
<td>Rotor E/F</td>
<td>Text</td>
<td>D</td>
</tr>
<tr>
<td>Out of step</td>
<td>Text</td>
<td>D</td>
</tr>
<tr>
<td><strong>Control Data:</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Details of excitation control system described in block diagram form showing transfer functions of individual elements, parameters and measurement units (in Siemens PTI PSS/E format).</td>
<td>Text, diagram</td>
<td>S, D, R1, R2</td>
</tr>
<tr>
<td>Automatic voltage regulator</td>
<td>Text, diagram</td>
<td>S, D, R1, R2</td>
</tr>
<tr>
<td>Power system stabiliser</td>
<td>Text, diagram</td>
<td>S, D, R1, R2</td>
</tr>
<tr>
<td><strong>Settings of the following controls:</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Details of the governor system described in block diagram form showing transfer functions of individual elements and measurement units (in Siemens PTI PSS/E format).</td>
<td>Text, diagram</td>
<td>S, D, R1, R2</td>
</tr>
<tr>
<td>Over excitation limiter</td>
<td>Text, diagram</td>
<td>S, D</td>
</tr>
<tr>
<td>Under excitation limiter</td>
<td>Text, diagram</td>
<td>S, D</td>
</tr>
<tr>
<td>Stator current limiter (if fitted)</td>
<td>Text, diagram</td>
<td>S, D</td>
</tr>
<tr>
<td>Manual restrictive limiter (if fitted)</td>
<td>Text</td>
<td>S, D</td>
</tr>
<tr>
<td><em>Load</em> drop compensation/VAr sharing (if fitted)</td>
<td>Text, function</td>
<td>S, D</td>
</tr>
<tr>
<td>V/f limiter (if fitted)</td>
<td>Text, diagram</td>
<td>S, D</td>
</tr>
</tbody>
</table>
### Schedule S3.3  
**Generator data for small Generation Units**

<table>
<thead>
<tr>
<th><strong>Power station</strong></th>
<th><strong>Data Category</strong></th>
</tr>
</thead>
<tbody>
<tr>
<td>Address</td>
<td>S, R1</td>
</tr>
<tr>
<td>Description of power station, for example, is it a green or brownfield site, is there a process steam or heat requirement, any other relevant information</td>
<td>S</td>
</tr>
<tr>
<td>Site-specific issues which may affect access to site or design, eg. other construction onsite, mine site, environmental issues, soil conditions</td>
<td>S, D</td>
</tr>
<tr>
<td>Number of <em>Generation Units</em> and ratings (kW)</td>
<td>S, D, R1</td>
</tr>
<tr>
<td>Type: eg. synchronous, induction</td>
<td>S, D, R1</td>
</tr>
<tr>
<td>Manufacturer</td>
<td>D</td>
</tr>
<tr>
<td>Connected to the <em>network</em> via: eg. inverter, transformer, u/g cable etc.</td>
<td>S</td>
</tr>
<tr>
<td>Prime mover types: eg. reciprocating, turbine, hydraulic, photovoltaic, other</td>
<td>S</td>
</tr>
<tr>
<td>Manufacturer</td>
<td>D</td>
</tr>
<tr>
<td><em>Energy source</em>: eg. natural gas, landfill gas, distillate, wind, solar, other</td>
<td>S</td>
</tr>
<tr>
<td>Total <em>power station</em> total capacity (kW)</td>
<td>S, D, R1</td>
</tr>
<tr>
<td><em>Power station</em> export capacity (kVA)</td>
<td>S, D, R1</td>
</tr>
<tr>
<td>Forecast annual <em>energy Generation</em> (kWh)</td>
<td>S, D</td>
</tr>
<tr>
<td>Normal mode of operation as per clause 3.4.3 of the <em>Network Technical Code</em> ie.</td>
<td>S</td>
</tr>
<tr>
<td>(1) continuous parallel operation</td>
<td></td>
</tr>
<tr>
<td>(2) occasional parallel operation</td>
<td></td>
</tr>
<tr>
<td>(3) short term test parallel operation</td>
<td></td>
</tr>
<tr>
<td>(4) bumpless (make before break) transfer</td>
<td></td>
</tr>
<tr>
<td>(i) rapid transfer</td>
<td></td>
</tr>
<tr>
<td>(ii) gradual transfer</td>
<td></td>
</tr>
<tr>
<td>Purpose: eg. power sales, peak lopping, <em>demand</em> management, exercising, emergency back up</td>
<td>S</td>
</tr>
</tbody>
</table>
## Schedule S3.4  Technical data for *Small Inverter Energy Systems*

<table>
<thead>
<tr>
<th>Description</th>
<th>Units</th>
<th>Data Category</th>
</tr>
</thead>
<tbody>
<tr>
<td>Address</td>
<td>Text</td>
<td>S</td>
</tr>
<tr>
<td>Number of <em>Small Inverter Energy Systems</em> and ratings</td>
<td>kW</td>
<td>S, D</td>
</tr>
<tr>
<td>Manufacturer</td>
<td>Text</td>
<td>D</td>
</tr>
</tbody>
</table>

**Connection voltage**

<table>
<thead>
<tr>
<th>Description</th>
<th>Units</th>
<th>Data Category</th>
</tr>
</thead>
<tbody>
<tr>
<td>Nominal voltage</td>
<td>V</td>
<td>S, D</td>
</tr>
<tr>
<td>Single/three phase</td>
<td>Number</td>
<td>S, D</td>
</tr>
</tbody>
</table>
### Schedule S3.5  *Network and plant technical data*

<table>
<thead>
<tr>
<th>Description</th>
<th>Units</th>
<th>Data Category</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Voltage rating</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Nominal voltage</td>
<td>kV</td>
<td>S, D</td>
</tr>
<tr>
<td>Highest voltage</td>
<td>kV</td>
<td>D</td>
</tr>
</tbody>
</table>

| **Insulation co-ordination** |       |               |
| Rated lightning impulse withstand voltage | kVp | D            |
| Rated short duration power frequency withstand voltage | kV | D            |

| **Rated currents** |       |               |
| Circuit maximum current | kA | S, D          |
| Rated Short *Time* Withstand Current | kA for seconds | D |
| Ambient conditions under which above current applies | Text | S,D           |

| **Earthing** |       |               |
| System Earthing Method | Text | S, D          |
| Earth grid rated current | kA for seconds | D            |

| **Insulation pollution performance** |       |               |
| Minimum total creepage | mm | D            |
| Pollution level | Level of IEC 815 | D          |

| **Controls** |       |               |
| Remote control and data *transmission* arrangements | Text | D            |

| **Metering provided by customer** |       |               |
| Measurement transformer ratios: |       | D            |
| Current transformers | A/A | D            |
| Voltage transformers | V/kV | D            |
| Measurement Transformer Test Certification details | Text | R1           |

| **Network configuration** |       |               |
| Operation Diagrams showing the electrical circuits of the existing and proposed main facilities within the User’s ownership including *busbar* arrangements, phasing arrangements, earthing arrangements, switching facilities and operating *voltages* | Single line Diagrams | S, D, R1 |

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Network impedances
For each item of plant (including lines): details of the positive, negative and zero sequence series and shunt impedances, including mutual coupling between physically adjacent elements.

Short circuit infeed to the network
The total infeed at the instant of fault (including contribution of induction motors).
Minimum zero sequence impedance of User’s network at connection point.
Minimum negative sequence impedance of User’s network at connection point.

Load Transfer Capability:
Where a load, or group of loads, may be fed from alternative connection points:
Load normally taken from connection point X
Load normally taken from connection point Y
Arrangements for transfer under planned or fault outage conditions

Circuits Connecting Embedded Generation Units to the Network:
For all Generation Units, all connecting lines/cables, transformers etc.
Series Resistance (-ve, -ve & zero seq.)
Series Reactance (-ve, -ve & zero seq.)
Shunt Susceptance (-ve, -ve & zero seq.)
Normal and short-time emergency ratings
Technical Details of Generation Units as per schedules S1, S2, S3.

Transformers at connection points:
Saturation curve

% on 100 MVA base         S, D, R1
kA symmetrical          S, D, R1
kA                        D, R1
% on 100 MVA base        D, R1
% on 100 MVA base        D, R1
MW                      D, R1
MW                      D, R1
Text                    D

% on 100 MVA base        S, D, R
% on 100 MVA base        S, D, R
% on 100 MVA base        S, D, R
MVA                    S, D, R
Schedule S3.6  *Network plant* and apparatus setting data

<table>
<thead>
<tr>
<th>Description</th>
<th>Units</th>
<th>Data Category</th>
</tr>
</thead>
<tbody>
<tr>
<td>Protection data for protection relevant to connection point:</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Reach of all protection schemes on lines, or cables</td>
<td>ohms or % on 100 MVA base</td>
<td>S, D</td>
</tr>
<tr>
<td>Number of protection schemes on each item</td>
<td>Text</td>
<td>S, D</td>
</tr>
<tr>
<td>Total fault clearing times for near and remote faults</td>
<td>ms</td>
<td>S, D, R1</td>
</tr>
<tr>
<td>Line reclosure sequence details</td>
<td>Text</td>
<td>S, D, R1</td>
</tr>
</tbody>
</table>

**Tap change control data:**

*Time* delay settings of all transformer tap changers.  
Seconds  
D, R1

**Reactive compensation (including filter banks):**

<table>
<thead>
<tr>
<th>Location and Rating of individual shunt reactors</th>
<th>MVAr</th>
<th>S, D, R1</th>
</tr>
</thead>
<tbody>
<tr>
<td>Location and Rating of individual shunt capacitor banks</td>
<td>MVAr</td>
<td>S, D, R1</td>
</tr>
<tr>
<td>Capacitor bank capacitance</td>
<td>Microfarads</td>
<td>S, D</td>
</tr>
<tr>
<td>Inductance of switching reactor (if fitted)</td>
<td>millihenries</td>
<td>S, D</td>
</tr>
<tr>
<td>Resistance of capacitor plus reactor</td>
<td>Ohms</td>
<td>S, D</td>
</tr>
<tr>
<td>Details of special controls (eg. Point-on-wave switching)</td>
<td>Text</td>
<td>S, D</td>
</tr>
</tbody>
</table>

**For each shunt reactor or capacitor bank (including filter banks):**

<table>
<thead>
<tr>
<th>Method of switching</th>
<th>Text</th>
<th>S</th>
</tr>
</thead>
<tbody>
<tr>
<td>Details of automatic control logic such that operating characteristics can be determined</td>
<td>Text</td>
<td>D, R1</td>
</tr>
</tbody>
</table>

**FACTS Installation:**

Data sufficient to enable static and dynamic performance of the installation to be modelled  
Text, diagrams, control settings  
S, D, R1

**Under frequency load shedding scheme:**

Relay settings (*frequency and time*)  
Hz, seconds  
S, D

**Islanding scheme:**

<table>
<thead>
<tr>
<th>Triggering signal (eg. voltage, frequency)</th>
<th>Text</th>
<th>S, D</th>
</tr>
</thead>
<tbody>
<tr>
<td>Relay settings</td>
<td>Control settings</td>
<td>S, D</td>
</tr>
</tbody>
</table>
**Schedule S3.7  Load characteristics at connection point**

<table>
<thead>
<tr>
<th>Data Description</th>
<th>Units</th>
<th>Data Category</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>For all types of load</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Type of Load eg. controlled rectifiers or large motor drives</td>
<td>Text</td>
<td>S</td>
</tr>
<tr>
<td>Rated capacity</td>
<td>MW, MVA</td>
<td>S</td>
</tr>
<tr>
<td>Voltage level</td>
<td>kV</td>
<td>S</td>
</tr>
<tr>
<td>Rated current</td>
<td>A</td>
<td>S</td>
</tr>
<tr>
<td><strong>For fluctuating loads</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Cyclic variation of active power over period</td>
<td>Graph - MW/time</td>
<td>S</td>
</tr>
<tr>
<td>Cyclic variation of reactive power over period</td>
<td>Graph - MVAr/time</td>
<td>S</td>
</tr>
<tr>
<td>Maximum rate of change of active power</td>
<td>MW/s</td>
<td>S</td>
</tr>
<tr>
<td>Maximum rate of change of reactive power</td>
<td>MVAr/s</td>
<td>S</td>
</tr>
<tr>
<td>Shortest Repetitive time interval between fluctuations in active power and reactive power reviewed annually</td>
<td>s</td>
<td>S</td>
</tr>
<tr>
<td>Largest step change in active power</td>
<td>MW</td>
<td>S</td>
</tr>
<tr>
<td>Largest step change in reactive power</td>
<td>MVAr</td>
<td>S</td>
</tr>
<tr>
<td><strong>For commutating power electronic load:</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>No. of pulses</td>
<td>Text</td>
<td>S</td>
</tr>
<tr>
<td>Maximum voltage notch</td>
<td>%</td>
<td>S</td>
</tr>
<tr>
<td>Harmonic current distortion (up to the 50th harmonic)</td>
<td>A or %</td>
<td>S</td>
</tr>
</tbody>
</table>
Attachment 4  Metering requirements

A4.1 General

(a) Revenue metering equipment, other than revenue meters and Communications equipment may be provided and installed by the User or will be provided and installed by the Network Operator at the User’s request.

(b) Indoor revenue metering units provided by the Network Operator will normally be of a type suitable for use with a specific make of switchgear which will vary from time to time.

(c) Revenue meters and the communications equipment other than a connection to the Public Switched Telephone Network (PSTN) will be provided and installed by the Network Operator. The PSTN connection and any isolation required will be provided by the User.

(d) Revenue metering equipment will comprise a revenue metering unit containing voltage transformers (VTs) and current transformers (CTs), or for system voltages of 66 kV and 132 kV, free standing post type VTs and CTs (other than free standing post type VTs and CTs may be acceptable and each request will be considered), two or more revenue meters, cabling, communications equipment, marshalling box and a revenue meter enclosure.

A4.2 Installation

(a) The maximum cable route length between the CTs and VTs and the revenue meters is 80 metres.

(b) Marshalling boxes located close to the CTs and VTs will be required for all indoor revenue metering units and for all outdoor revenue metering units for system voltages of 66 kV and 132 kV. Indoor revenue metering marshalling boxes will be an integral part of the indoor revenue metering unit.

(c) Prefabricated free standing or wall mounted revenue meter enclosures are available from the Network Operator or a suitable enclosure may be assembled by the User. Revenue meters may also be located within a building which has provision for unrestricted 24 hour access for revenue metering personnel. It may be located adjacent to the Network Operator’s protection or SCADA equipment. Preference is for a purpose constructed, ventilated, insulated or naturally insulated room of plan dimensions not less than 2m X 2m which substantially maintains ambient air temperature. If the Network Operator is requested to provide a free standing revenue meter enclosure and its support frame, the User will need to provide a concrete footing as specified in the Network Operator’s metering manuals.

(d) Unrestricted, 24 hour access to revenue metering equipment by revenue metering personnel is required.
A4.3 3-4 wire metering

(a) Three-wire revenue metering, that is, revenue metering with three-phase to neutral VTs and two CTs, one in each of the red and blue currents, may be used when the load measured by the revenue metering equipment is a three-wire load. The load is three-wire when it comprises a delta-wound transformer primary or a star-wound transformer primary with the star point not earthed, provided the load is not a distributed load and is within 2 km of the revenue metering CTs and VTs and the system voltage is less than 66 kV. All other revenue metering will be four-wire, that is, as for three-wire but with an additional CT in the white phase. Co-Generation revenue metering will normally be four-wire.

(b) The Network Operator will, if requested by a User, advise the User whether an installation is 3-wire or 4-wire.

A4.4 Signals

(a) Signals comprising energy usage information may be made available via volt free relay contacts rated to 30V AC or DC at a maximum of 60 mA. These signals comprise momentary relay closures each time a given amount of energy (kWh) is imported or exported and each time a given number of kVArh is imported, the start of each 30 minute demand period (or other period if appropriate) and relay closures when the rate changes (on-peak or off-peak or shoulder etc.).

A4.5 Accuracy requirements

Table A4.1 - Overall Accuracy Requirements of Revenue metering installation

<table>
<thead>
<tr>
<th>Type</th>
<th>Energy per meter point (GWh pa.)</th>
<th>Maximum allowable overall error (+/- %) at full load active / reactive</th>
<th>Minimum acceptable class of components</th>
<th>Meter clock error seconds</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>≥ 1000</td>
<td>+0.5 / -1.0</td>
<td>0.2 CT/VT/meter Wh 0.5 Meter VArh</td>
<td>±5</td>
</tr>
<tr>
<td>2</td>
<td>100 – 1000</td>
<td>+1.0 / -2.0</td>
<td>0.5 CT/VT/meter Wh 1.0 Meter VArh</td>
<td>±7</td>
</tr>
<tr>
<td>3</td>
<td>&lt; 100</td>
<td>+1.5 / -3.0</td>
<td>0.5 CT/VT Meter Wh 2.0 Meter VArh</td>
<td>±10</td>
</tr>
</tbody>
</table>

Note to Table A4.1:

The method for calculating the overall error is the vector sum of the errors of each component part, ie. a - b - c, where:

a = the error of the Voltage Transformer and wiring

b = the error of the Current Transformer and wiring
\[ c = \text{the error of the revenue meter.} \]

**A4.6 Other metering requirements**

(a) Specifications for revenue meter and communications enclosures, indoor and outdoor revenue metering units (VTs and CTs plus enclosure), 66 kV and 132 kV CTs, VTs, marshalling box and wiring are contained in the *Network Operator’s metering manuals*. 
Attachment 5  Test schedule

The following test schedule is used for specific performance verification and model validation.

A5.1  General

(a) Recorders should be calibrated or checked prior to use.
(b) Recorders should not interact with any plant control functions.
(c) Galvanic isolation and filtering of input signals should be provided whenever necessary.

A5.2  Test preparation and presentation of test results

Information/data prior to tests

(a) a detailed schedule of tests agreed by the Network Operator. The schedule should list the tests, when each test is to occur and whose responsibility it will be to perform the test.
(b) Schematics of equipment and sub-networks plus descriptive material necessary to draw up/agree upon a schedule of tests
(c) Most up to date relevant technical data and parameter settings of equipment as specified in Attachment 3 of this Code.

Test notification

(a) Prior notice of test commencement should be given to the Network Operator for the purpose of arranging witnessing of tests.
(b) The Network Operator’s representative should be consulted about proposed test schedules, be kept informed about the current state of the testing program, and give permission to proceed before each test is carried out.

Test results

(a) Test result data shall be presented to the Network Operator within 5 business days of completion of each test or test series.
(b) Where test results are not favourable it will be necessary to rectify problems and repeat tests.

A5.3  Quantities to be measured

(a) Wherever appropriate and applicable for the tests, the following quantities should be measured on the machine under test:

Generator and excitation system

• stator L-N terminal voltages
• stator terminal currents
- **Active power MW**
- **Reactive power MVAr**
- **Generator rotor field voltage**
- **Generator rotor field current**
- **Main exciter field voltage**
- **Main exciter field current**
- **AVR reference voltage**
- **Voltage applied to AVR summing junction (step etc.)**
- **Power system stabiliser output**
- **DC signal input to AVR which corresponds to terminal volts**

**Steam turbine**

- Shaft speed
- *Load demand* signal
- Valve positions for control and interceptor valves
- Governor set point

**Gas turbine**

- Shaft speed (engine)
- Shaft speed of turbine driving the *Generator*
- Engine speed control output Free turbine speed control output
- *Generator*-compressor speed control output
- Ambient/turbine air inlet temperature
- Exhaust gas temperature control output
- Exhaust temperature
- Fuel flow
- Governor/load reference set point

**Reciprocating engine**

- Engine crank speed driving the *Generator*
- Type of governor *load* / speed control
- Ambient / charge air / exhaust temperature
• Fuel flow

(b) Additional test quantities may be requested and advised by the *Network Operator* if other special tests are necessary.

(c) Key quantities such as stator terminal *voltages*, currents, *active power* and *reactive power* of the other *Generation Units* connected on the same bus and also *interconnection* lines with the *Network Operator’s network* (from control room readings) before and after each test shall also be provided.
<table>
<thead>
<tr>
<th>Test No</th>
<th>TEST DESCRIPTION</th>
<th>Changes Applied</th>
<th>Test Conditions</th>
</tr>
</thead>
<tbody>
<tr>
<td>C1</td>
<td>Step change to AVR voltage reference with the Generator on open circuit</td>
<td>(a) -2.5%  (b) -2.5%  (c) -5.0%  (d) -5.0%</td>
<td>nominal stator terminal volts</td>
</tr>
<tr>
<td>C2</td>
<td>Step change to AVR voltage reference with the Generator connected to the system at the following outputs 50% rated MW 100% rated MW</td>
<td>(a) -1.0%  (b) -1.0%  (c) -2.5%  (d) -2.5%  (e) -5.0%  (f) -5.0%  repeat (e) &amp; (f) twice see notes below</td>
<td>nominal stator terminal volts unity or lagging power factor system base load Generator outputs: (i) 50% rated MW (ii) 100% rated MW all tests in (i) should precede test in (ii) smaller step changes should precede larger step changes</td>
</tr>
<tr>
<td>C3</td>
<td>As for C2 but with the power system stabiliser in service and with the system conditions (i) and (ii) as indicated in column 3 (Test Conditions)</td>
<td>As in C2</td>
<td>As in C2, but system base load with no other Generation on the same bus system maximum load and maximum Generation on same bus</td>
</tr>
<tr>
<td>C4</td>
<td>Manual variation of Generator open circuit voltage</td>
<td>Stator terminal voltage ($U_t$) (a) increase from 0.5 pu to 1.1 pu (b) decrease from 1.1 pu to 0.5 pu</td>
<td>in 0.1 pu step for $U_t$ between 0.5 – 0.9 pu on 0.5 pu step for $U_t$ between 0.9 – 1.1 pu</td>
</tr>
<tr>
<td>C5</td>
<td>Load rejection (active power)</td>
<td>(a) 25% rated MW  (b) 50% rated MW  (c) 100% rated MW</td>
<td>nominal stator terminal volts unity power factor smaller amount should precede larger amount of lead rejection</td>
</tr>
<tr>
<td>C6</td>
<td>Load rejection (reactive power)</td>
<td>(5) -30% rated MVAr  (6) -25% rated MVAr</td>
<td>nominal stator terminal volts 0 or minimum MW output</td>
</tr>
<tr>
<td>C7</td>
<td>Load rejection (reactive power)</td>
<td>(a) -30% rated MVAr</td>
<td>nominal stator terminal volts Excitation Manual Control</td>
</tr>
</tbody>
</table>
Attachment 6  Access Application schedule

The following Schedule of information to be submitted in an Access Application is pursuant to Schedule 2 of the Electricity Networks (Third Party Access) Code.

A6.1 Access Application information requirements

(a) A person who is not an existing User and who wants the Network Operator to provide it with one or more access services shall make an Access Application in accordance with this schedule.

(b) A person who is an existing User and who wants the Network Operator to provide it with one or more access services (including additional capacity) in addition to those which the User has access already shall make an Access Application in accordance with this schedule.

(c) An Access Application may only be made for the provision of access services that the applicant wishes the Network Operator to commence to provide within 3 years of the date of the Access Application.

(d) An Access Application shall contain the following information:

(1) the name and address of the person making the Access Application and of any other persons for whom that person is acting in making the Access Application;

(2) the type of network access services requested, when those access services are required and for how long they will be required;

(3) the entry points and exit points in respect of which access is being applied for and the capacity (expressed in kVA) for each of those entry points and exit points for which access is being applied for;

(4) the type of plant in respect of which the access services are required and the configuration of that plant;

(5) where the entry points and exit points are to be on the electrical network and any alternative points (in order of preference);

(6) the expected maximum demand of the plant connected or to be connected at each of the entry points;

(7) the maximum Generation capacity and the proposed declared sent out capacity of the Generation Units (including embedded Generation Units) connected or to be connected at each of the exit points;

(8) the expected electricity production and consumption of the plant connected or to be connected at each of the entry points and exit points;

(9) when the applicant expects the plant to be connected at each of the entry points and exit points to be in service (if appropriate);

(10) details of the controllers of the plant connected or to be connected at each of the entry points and exit points;
(11) the proposed design of each of the connections (if appropriate);

(12) the arrangements which the applicant proposes to enter into in relation to the construction and supply of the connection in respect of the plant;

(13) the nature of any disturbing load (size of disturbing component MW/MVAr, duty cycle, nature of power electronic plant which may produce harmonic distortion);

(14) any information as required by this Network Technical Code;

(15) commercial information concerning the applicant to allow the Network Operator to make an assessment of the ability of the applicant to meet its obligations under any Access Agreement that results from the Access Application; and

(16) any other information reasonably required by the Network Operator; and may specify that the applicant wishes the Network Operator to make a preliminary assessment of the application.

The following clauses are intended to provide a guide for existing and intending network Users (Access Applicants) on the process of connection to the network. Full details of the network connection procedures and the obligations of participants and the Network Operator are contained in Chapter 2 and Schedules 2, to 5 of the Electricity Networks (Third Party Access) Code.

A6.2 Access Application

(a) The Access Applicant must lodge a written Access Application to the Network Operator containing the relevant information set out in Schedule 2 of the Electricity Networks (Third Party Access) Code.

(b) If necessary, the Network Operator may request further information from the Access Applicant within 7 days of its lodgement.

(c) Within 7 days of receiving an Access Application or further information, the Network Operator must notify:

(1) the Utilities Commission; and

(2) any network User that would be materially affected by the Access Application.

A6.3 Initial response to Access Application by the Network Operator

(a) The Network Operator shall provide the Access Applicant with a written initial response to an Access Application:

(1) within 10 days of receiving an Access Application from an existing network user; or

(2) within 21 days of receiving an Access Application from a new network user; or

(3) where the Network Operator has requested further information, within an equivalent period after receiving that information.
(b) The initial response by the *Network Operator* in respect of an *Access Application* shall include the following information:

(1) the period within which the *Network Operator* is able to make a preliminary assessment of the *Access Application*; and

(2) an estimate of the reasonable expenses expected to be incurred by the *Network Operator* in processing the *Access Application*, preparing an initial response, carrying out a preliminary assessment, making an offer and negotiating the *Access Agreement*.

**A6.4 Preliminary assessment of Access Application by the Network Operator**

(a) If a preliminary assessment is requested in the *Access Application*, the *Network Operator* must make the assessment and give the *Access Applicant* a report of the assessment within the time period specified in the initial response to the *Access Application*.

(b) A preliminary assessment shall include the following information:

(1) whether it is likely that there is sufficient spare capacity to provide the *access services* requested in the *Access Application* or whether the *electricity network* will have to be *augmented* to provide those services;

(2) whether it is likely that any *connection* will have to be installed or upgraded to provide the *connection services* (if any) requested in the *Access Application*;

(3) whether or not a capital contribution will be required of the *Access Applicant* and if so, an indication of the likely amount of that capital contribution;

(c) The information provided under clauses A6.3(b)(1), (b)(2) and (b)(3) above may be subject to change under conditions specified by the *Network Operator* in the preliminary assessment.

**A6.5 Access offer**

(a) The *Network Operator* must make an access offer to provide to the *Access Applicant* the network *access services* requested in the *Access Application* within:

(1) 30 days of receiving the request; or

(2) if within that period the *Network Operator* has requested further information, within 30 days after receiving the information;

unless agreed by the *Access Applicant* and the *Network Operator*, or as otherwise approved by the Utilities Commission.
(b) The access offer by the Network Operator may require the Access Applicant to make a contribution towards capital investment to provide the requested access.

(c) If the Access Applicant does not conclude negotiations with the Network Operator within 60 days, the access offer expires and the Access Application lapses.

A6.6 Access Agreement

(a) The Network Operator will prepare an Access Agreement setting out the specific technical, commercial and legal conditions under which access to the network is provided, in accordance with Schedule 4 of the Electricity Networks (Third Party Access) Code.

(b) The Access Applicant must execute the Access Agreement before a new or modified connection will be made to the network and is required to abide by the terms and conditions of the Access Agreement and this Code.